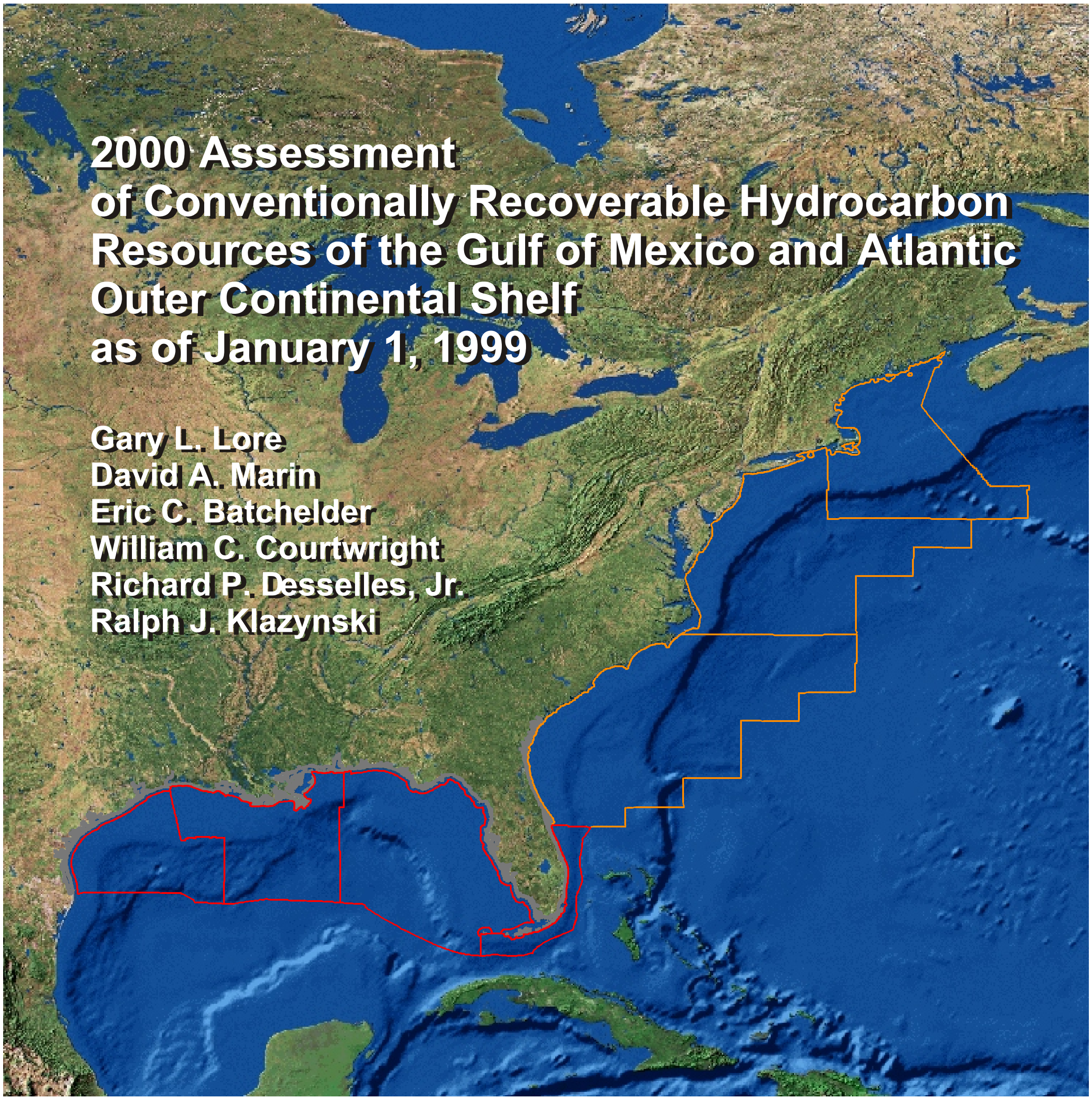
OCS Report
MMS 2001-087

2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999

Gary L. Lore
David A. Marin
Eric C. Batchelder
William C. Courtwright
Richard P. Desselles, Jr.
Ralph J. Klazynski



MMS
U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region
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Dedication

In memory of
a true friend, and admirable colleague,
and an inspiration to us all.

Barbara J. Bascle
1951-2001

Largest Plays Lists

(hyperlinked)

The ten largest plays by BOE mean total endowment:

1) UPL-LL X2 p. 467	8.970 BBOE
2) UP F2 p. 273	7.479 BBOE
3) LPL F2 p. 257	7.443 BBOE
4) LPL P1 p. 249	6.335 BBOE
5) UM3 P1 p. 305	5.577 BBOE
6) MM9 F2 p. 357	4.954 BBOE
7) LM2 F2 p. 433	4.885 BBOE
8) LM4 F2 p. 423	4.885 BBOE
9) UM3 F2 p. 313	4.836 BBOE
10 LPL F1 p. 253	4.498 BBOE

The ten largest plays by BOE mean undiscovered conventionally recoverable resources (UCRR):

1) UPL-LL X2 p. 467	6.432 BBOE
2) UP F2 p. 273	5.058 BBOE
3) LM2 F2 p. 433	4.885 BBOE
4) LM4 F2 p. 423	4.885 BBOE
5) LPL F2 p. 257	4.522 BBOE
6) MM9 F2 p. 357	4.033 BBOE
7) ALK C1 p. 561	2.816 BBOE
8) MM7 F2 p. 385	2.646 BBOE
9) UM1 F2 p. 333	2.567 BBOE
10) MM4 F2 p. 405	2.495 BBOE

The ten largest plays by BOE total reserves:

1) LPL P1 p. 249	5.997 BBOE
2) UM3 P1 p. 305	5.341 BBOE
3) MPL P1 p. 233	3.773 BBOE
4) LPL F1 p. 253	3.544 BBOE
5) UPL P1 p. 215	3.492 BBOE
6) LP P1 p. 281	3.353 BBOE
7) UP P1 p. 265	3.202 BBOE
8) LPL F2 p. 257	2.921 BBOE
9) UM1 P1 p. 325	2.575 BBOE
10) UPL-LL X2 p. 467	2.538 BBOE

The ten largest conceptual plays by mean BOE:

1) LM2 F2 p. 433	4.885 BBOE
2) LM4 F2 p. 423	4.885 BBOE
3) ALK C1 p. 561	2.816 BBOE
4) MM4 F2 p. 405	2.495 BBOE
5) AUJ C1 p. 573	2.415 BBOE
6) UK5-LK3 X5 p. 503	2.160 BBOE
7) LO-LL C2 p. 457	1.927 BBOE
8) UK5-LK3 X4 p. 499	1.773 BBOE
9) LM1 F2 p. 443	1.653 BBOE
10) UK5-LTR BC4 p. 537	1.603 BBOE

Summary

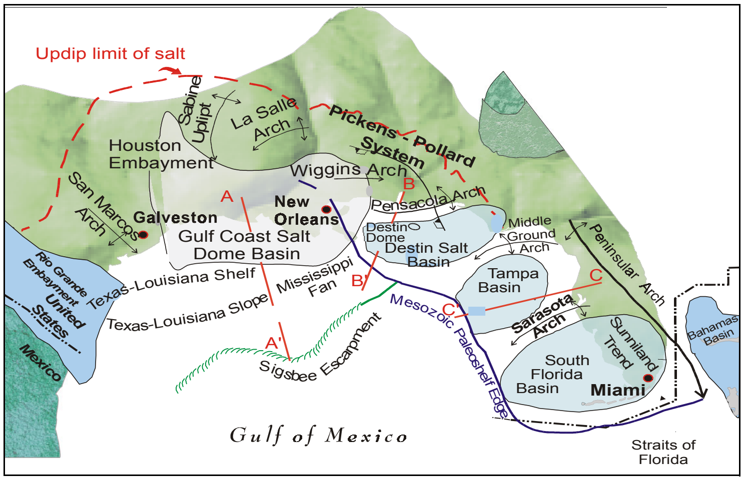

Figure 1. Physiographic map of the northern Gulf of Mexico Outer Continental Shelf.

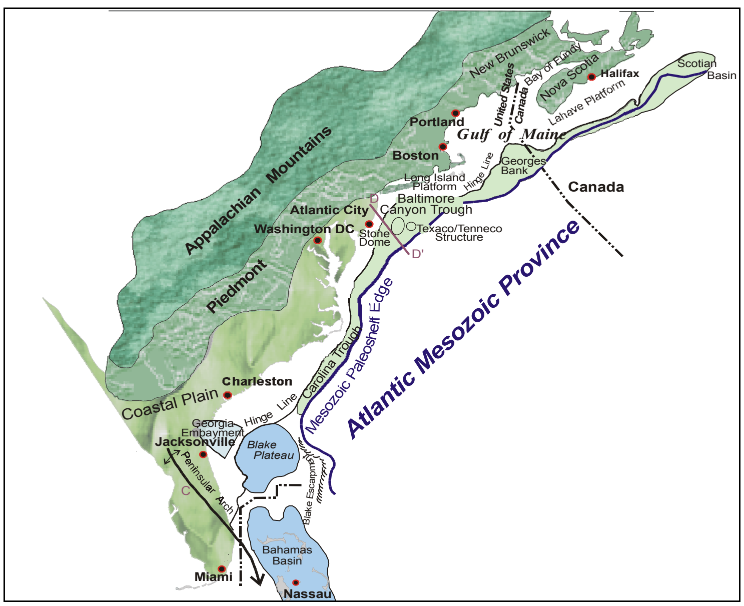

Figure 2. Physiographic map of the U.S. Atlantic Outer Continental Shelf.

Report Description

This report presents the results of the 2000 assessment of the conventionally recoverable hydrocarbon resources for the northern Gulf of Mexico and U.S. Atlantic Outer Continental Shelf (OCS) (figures 1 and 2). 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 2000 assessment considered data and information available as of January 1, 1999.

Introduction

Worldwide reliance on petroleum resources will continue for decades to be the principal means to satisfy future energy demand. 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 on the basis of current geologic, engineer-

Gulf of Mexico Region Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2369	14.266	162.711	43.218
Cumulative production	--	10.908	132.677	34.515
Remaining proved	--	3.358	30.034	8.703
Unproved	84	0.995	5.102	1.903
Appreciation (P & U)	--	7.736	68.096	19.853
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	22.821	145.088	49.851
Mean	2870	37.126	191.627	71.223
5th percentile	--	56.054	246.600	97.602
Total Endowment				
95th percentile	--	45.818	380.998	114.825
Mean	5323	60.123	427.537	136.197
5th percentile	--	79.051	482.510	162.576

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment of the Gulf of Mexico Region.

Atlantic Region 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	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	1.207	16.117	4.558
Mean	502	2.307	27.712	7.238
5th percentile	--	3.706	43.499	10.739
Total Endowment				
95th percentile	--	1.207	16.117	4.558
Mean	502	2.307	27.712	7.238
5th percentile	--	3.706	43.499	10.739

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment for the Atlantic Region.

ing, 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. For these assessments 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

GOM Region (Total of All Water Depths)				
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		13.968	84.530	29.009
Mean		17.467	100.260	35.307
5th percentile		21.851	114.075	42.149
Half-Cycle	1.00			
95th percentile		14.905	90.434	30.996
Mean		18.569	105.167	37.282
5th percentile		23.073	118.912	44.232
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		24.749	129.389	47.772
Mean		28.134	140.731	53.175
5th percentile		34.749	151.929	61.783
Half-Cycle	1.00			
95th percentile		25.171	133.790	48.977
Mean		28.811	143.986	54.431
5th percentile		35.643	155.311	63.278

Table 3. Undiscovered economically recoverable resources of the Gulf of Mexico Region.

Atlantic Region (Total of All Water Depths)				
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		0.216	2.325	0.630
Mean		0.530	6.649	1.713
5th percentile		1.067	12.546	3.300
Half-Cycle	1.00			
95th percentile		0.280	3.059	0.824
Mean		0.602	7.310	1.903
5th percentile		1.178	13.280	3.541
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.823	7.939	2.235
Mean		1.338	12.780	3.612
5th percentile		1.920	19.205	5.338
Half-Cycle	1.00			
95th percentile		1.044	10.100	2.842
Mean		1.570	14.875	4.216
5th percentile		2.011	21.847	5.898

Table 4. Undiscovered economically recoverable resources of the Atlantic Region.

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, which included 103 plays. Because of 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 the same play analysis approach as used for the 1995 assessment (Lore *et al*., 1999), which represented a major change from the procedures used by MMS for earlier assessments (Cooke, 1985; Cooke and Dellagiarino, 1990). A major strength of the current 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 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 ana-

GOM and Atlantic Regions Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2,369	14.266	162.711	43.218
Cumulative production	--	10.908	132.677	34.515
Remaining proved	--	3.358	30.034	8.703
Unproved	84	0.995	5.102	1.903
Appreciation (P & U)	--	7.736	68.096	19.853
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	24.520	165.587	55.512
Mean	3,372	39.433	219.338	78.461
5th percentile	--	59.047	282.935	106.617
Total Endowment				
95th percentile	--	47.517	401.497	120.486
Mean	5,825	62.430	455.248	143.435
5th percentile	--	82.044	518.845	171.591

Table 5. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment of the combined Gulf of Mexico and Atlantic Regions.

GOM and Atlantic Regions Total (Total of All Water Depths)				
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		14.264	91.944	30.624
Mean		17.936	106.756	36.932
5th percentile		22.030	123.673	44.036
Half-Cycle	1.00			
95th percentile		15.447	97.187	32.740
Mean		19.134	112.203	39.099
5th percentile		23.574	127.304	46.226
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		25.822	141.839	51.061
Mean		29.331	153.598	56.661
5th percentile		34.807	168.857	64.853
Half-Cycle	1.00			
95th percentile		26.680	146.738	52.790
Mean		30.236	158.999	58.527
5th percentile		36.210	173.879	67.150

Table 6. Undiscovered economically recoverable resources of the combined Gulf of Mexico and Atlantic Regions.

logs was used for conceptual and frontier 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, Gulf of Mexico

The total endowment (all conventionally recoverable hydrocarbon resources) of the Gulf of Mexico OCS as of January 1, 1999, is shown in table 1. The Gulf of Mexico OCS total endowment, which includes cumulative production, is estimated to be between 46 and 79 billion barrels of oil (Bbo) and 381 and 483 trillion cubic feet of gas (Tcfg). This is equal to 115 and 163 billion barrels of oil equivalent (BBOE). The 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 60 Bbo and 428 Tcfg (136 BBOE). Nearly 23 Bbo and 236 Tcfg (65 BBOE), or approximately 48 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 23 to 56 Bbbl (billion barrels); the estimates for gas range from 145 to 247 Tcf (trillion cubic feet); and the estimates for BOE (barrels of oil equivalent) range from 50 to 98 Bbbl. The mean estimates of UCRR are 37 Bbo and 192 Tcfg (71 BBOE).

Beneath the Gulf of Mexico Continental Margin are approximately 35 to 68 Bbbl of remaining conventionally recoverable oil, with a mean of 49 Bbbl. This includes remaining reserves (proved and unproved), reserves appreciation, and UCRR.

The estimates of remaining conventionally recoverable gas range from 248 to 350 Tcf, with a mean of 295 Tcf; and the estimates of remaining conventionally recoverable BOE range from 80 to 128 Bbbl, with a mean of 102 Bbbl.

Assessment Results, Atlantic

The total endowment of the Atlantic OCS as of January 1, 1999, is shown in table 2. The Atlantic OCS total endowment is estimated to be between 1 and 4 Bbo and 16 and 43 Tcfg (5 and 11 BBOE) at the 95th and 5th percentiles, respectively. The mean estimates are 2 Bbo and 28 Tcfg (7 BBOE). No reserves are assigned to the Atlantic OCS and, therefore, undiscovered conventionally recoverable resources (UCRR) are equal to total endowment.

Economic Assessment, Gulf of Mexico

An economic analysis determined the portions 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 Region are shown in table 3.

In the full-cycle, $18/bbl scenario, the estimates of UERR for oil range from 14 to 22 Bbbl; the estimates for gas range from 85 to 114 Tcf; and the estimates for BOE range from 29 to 42 Bbbl. The mean estimates of UERR are 17 Bbo and 100 Tcfg (35 BBOE). In the $30/bbl scenario, the estimates of mean UERR increase by approximately 61 percent for oil and 40 percent for gas.

In the half-cycle, $18/bbl scenario, the estimates of UERR for oil range from 15 to 23 Bbbl; the estimates for gas range from 90 to 119 Tcf; and the estimates for BOE range from 31 to 44 Bbbl. The mean estimates of UERR are 19 Bbo and 105 Tcfg (37 BBOE). This represents an increase of 6 percent over the equivalent full-cycle analysis. In the half-cycle, $30/bbl scenario, the mean estimates of UERR increase by approximately 2 percent for oil and 2 percent for gas over the equivalent full-cycle analysis.

Approximately 47 percent of the mean undiscovered conventionally recoverable oil and 52 percent of mean undiscovered conventionally recoverable gas resources are economic in the full-cycle, $18/bbl scenario. The percentages increase to 76 percent of the oil and 73 percent of the gas in the $30/bbl full-cycle scenario. In the half-cycle analysis, these percentages are approximately 50 for oil and 55 for gas in the $18/bbl scenario and 78 and 75 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.

Economic Assessment, Atlantic

The results of both the full- and half-cycle economic analysis for the Atlantic Region are shown in table 4. In the full-cycle, $18/bbl scenario, the estimates of UERR for oil range from <1 to 1 Bbbl, the estimates for gas range from 2 to 13 Tcf, and the estimates for BOE range from <1 to 3 Bbbl. The mean estimates of UERR are 1 Bbo and 7 Tcfg (2 BBOE). In the $30/bbl scenario, the estimate of mean UERR more than doubles.

In the half-cycle, $18/bbl scenario, the estimates of UERR for oil range from <1 to 1 Bbbl; the estimates for gas range from 3 to 13 Tcf; and the estimates for BOE range from 1 to 4 Bbbl. The mean estimates of UERR are 1 Bbo and 7 Tcfg (2 BBOE). This represents an increase of 11 percent over the equivalent full-cycle analysis. In the half-cycle, $30/bbl scenario, the mean estimates of UERR increase 17 percent over the equivalent full-cycle scenario.

Approximately 23 percent of the mean undiscovered conventionally recoverable oil and 24 percent of the mean undiscovered conventionally recoverable gas resources are economic in the full-cycle, $18/bbl scenario. The percentages increase to 58 percent of the oil and 46 percent of the gas in the $30/bbl scenario. In the half-cycle analysis, these percentages are approximately 26 for both oil and gas in the $18/bbl scenario and 68 and 54 percent, respectively, for oil and gas in the $30/bbl scenario.

Assessment results and economic analysis for the combined Gulf of Mexico and Atlantic OCS Regions are presented in tables 5 and 6, respectively.

Companion Publication

A companion publication—*Atlas of Gulf of Mexico Gas and Oil Sands as of January 1, 1999* (Bascle, *et al.*, 2001)—reports proved and unproved reserves in the Gulf of Mexico OCS and includes an extensive geologic, engineering, and production database. While some pool level reserves data is included in the 2000 Assessment, detailed reserves information is provided in the Atlas at the sand level, where all volume-weighted reservoir data has been rolled up into the common producing sand.

The Atlas also contains GIS capabilities that enable users to query, retrieve, and display tabular data in map form. Data are linked at the sand, field, and play levels.

Together, these two publications allows others to use their own techniques in performing a resource assessment or to evaluate the economic viability of drilling prospects.

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 solid basis for decisions related to resource management issues. With this as the primary objective, the MMS periodically performs an assessment of the undiscovered conventionally recoverable oil and gas resources of the United States Outer Continental Shelf (OCS). This report presents the results of the 2000 assessment of the conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic OCS. This latest assessment reflects data and information available as of January 1, 1999, thus incorporating data and information not available at the time of the January 1, 1995 MMS assessment (Lore *et al.*, 1999). It also provides a more detailed presentation of the results previously summarized on the MMS website (Hunt and Dickerson, 2001).

Objectives

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 gas and oil atlas (Bascle *et al*., 2001), to allow others to use their own techniques to perform a resource assessment or evaluate the economic viability of the postulated resources.

Reliance on Petroleum

Energy is the lifeblood of the world's economy. Since displacing coal early in the last century, crude oil has been the world's primary source of energy. The United States is currently experiencing a dramatic increase in the use of natural gas, mainly as the environmentally preferred fuel for the generation of electricity. In 1998, oil and gas resources comprised 63 percent of the world's total energy consumption, up from 60 percent in 1994. 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. The Gulf of Mexico OCS, which currently contributes 13 and 25 percent, respectively, of the United States domestic oil and gas production, is obviously a critical component of any deliberations concerning future domestic petroleum supplies.

Resource Estimates

A reasonable 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 making 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.

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*. Dreyfus and Ashby (1989) noted that resource assessments are performed at widely varying levels of detail and precision.

At one end of the spectrum lie estimates of proved reserves. These assessments rely primarily upon detailed investigations incorporating relatively abundant subsurface geologic and geophysical data, as well as actual reservoir performance information associated with the particular reservoir. At the other end of the spectrum is the appraisal of undiscovered resources that might exist in areas of regional, national or even global scope. In dealing with the same type of data as reserve estimates, the scope is extended to a generalized inference of the probable quantities of undiscovered hydrocarbon resources that may exist in broad areas.

The various estimates presented in this report encompass this spectrum and should be viewed as indicators and not predictors of the petroleum potential of the plays, 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.

Pools and Plays

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, sand 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, province, region, planning area, and margin level data and information.

Definition of Resource Terms

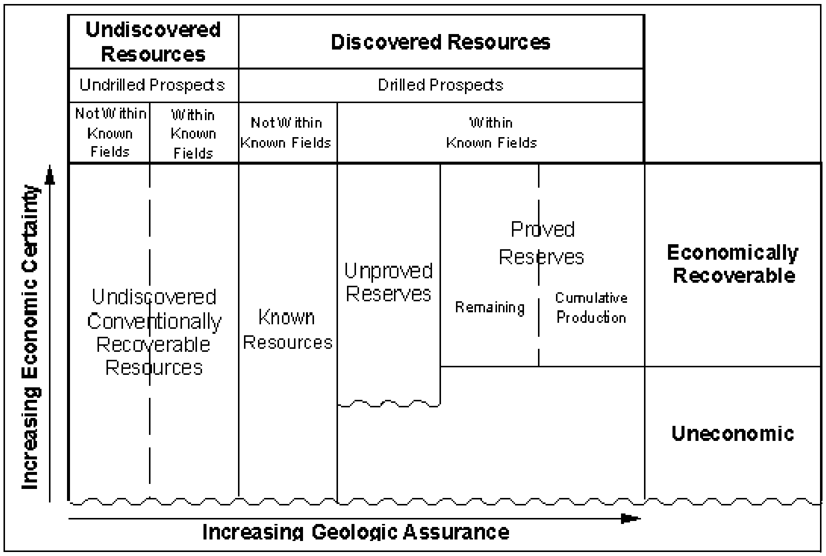

Figure 1. MMS classification scheme for conventionally recoverable hydrocarbon resources (U.S. Bureau of Mines and U.S. Geological Survey, 1980).

The terminology associated with resource assessments is involved, but it must be understood so that the results can be correctly interpreted and applied. A set of precise definitions regarding resource assessment terminology that is universally accepted does not exist. 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 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.

The initial concept to be grasped is that of recoverable resources. Resource assessments that are intended to be of more than scientific interest are generally limited to accumulations that are believed to be amenable to discovery and production employing conventional techniques under reasonably foreseeable technological and economic conditions. This distinction eliminates from consideration significant portions of the resource base that may be developable sometime after the next 25 or 30 years. 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.

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

***B) Marginal probability of hydrocarbons (MP_{hc})*:** 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.

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

***D) 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.

***d1) Recoverable resources*:** The volume of hydrocarbons that is potentially recoverable, regardless of the size, accessibility, recovery technique, or economics of the postulated accumulations.

d1i) 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.

d1i') 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.

d1ii) 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.

d2) 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.

d2i) 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.

d2ii) Undiscovered economically recoverable resources (UERR): The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic and technologic conditions.

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

e1) Proved reserves: The quantities of hydrocarbons 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.

e1i) Remaining proved reserves: The quantities of proved reserves currently estimated to be recoverable. Estimates of remaining proved reserves equal proved reserves minus cumulative production.

e2) Unproved reserves: Quantities of hydrocarbon reserves that are assessed on the basis of 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.

e3) 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.

e4) 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.

F) 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, about 9,400 permits to conduct prelease geologic or geophysical exploration have been issued in the study area. In addition, more than 17,250 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 1.1 million line-miles of two-dimensional common depth point (CDP) seismic data and about 140,000 square miles of three-dimensional CDP seismic data. Moreover, MMS has accumulated geologic information from over 36,850 wells drilled on the Gulf of Mexico and Atlantic Continental Margin. These activities resulted in the discovery in the Gulf of Mexico of 984 proved fields and 58 active unproved fields containing over 22,000 reservoirs. A single noncommercial accumulation 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 as an offshore Gulf of Mexico gas and oil atlas (Bascle *et al.*, 2001).

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 that 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 50º API) or "heavy" (i.e., generally less than 20º API). Condensate is a very high-gravity (i.e., generally greater than 50º 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 10º 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.

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. Rogner (1997) concluded “over the last century technology has probably had a more profound and lasting impact on prices than prices have had on technology.” 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 1991 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 because of 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."

Deepwater Gulf of Mexico

During the 1980's and early 1990's, industry progressively moved farther offshore as drilling and production technologies developed to operate in increasing water depths. Over the last decade, the deepwater (defined here as water depths 1,000 ft or greater) areas of the Gulf of Mexico have become the focus of leasing, seismic acquisition, drilling, and production activity. The major oil companies forged the way in deepwater until 1996, when nonmajors joined the trend (Baud *et al.*, 2000).

In 1995, interest in the Gulf of Mexico deepwater increased dramatically as record lease sales saw an extraordinary number of bids in water depths over 1,000 ft. This unparalleled interest was spurred by a number of earlier, large, deepwater field discoveries (some of which were already in the developmental stages or producing), including Mississippi Canyon 194 (Cognac), Green Canyon 65 (Bullwinkle), Garden Banks 426 (Auger), Mississippi Canyon 807 (Mars), and Mississippi Canyon 731 (Mensa). The significance of these discoveries is that during the 1990's, the average new shallow-water field in the northern Gulf of Mexico added approximately 5 MMBOE of reserves, while the average deepwater field added over 47 MMBOE (Baud *et al.*, 2000). For a variety of reasons, deepwater fields generally have higher per well production rates. For example, in 1994 a well at Auger set a milestone with a production rate of about 10,000 bopd, and Mensa set the record for gas production from a single well with 196 MMcfd. Additionally, Mississippi Canyon 810 (Ursa) now holds the record for oil production from a single well with 36,520 bopd. Technological advances in drilling and development systems capable of exploring for and producing oil and gas in water depths up to 10,000 ft were critical to spurring industry's deepwater interest (figure 1).

Moreover, one of the most significant reasons for heightened interest in the deepwater Gulf was the passage of the OCS Deep Water Royalty Relief (DWRR) Act of 1995 (43 U.S.C. Section 1337). This Act provided suspension of Federal royalty payments for new leases issued from 1996 to 2000 for water depths of 656 ft and greater. Specifically, royalties are suspended on the initial

- 17.5 MMBOE produced from a field in 656-1,312 ft of water;
- 52.5 MMBOE produced from a field in 1,312-2,624 ft of water; and
- 87.5 MMBOE produced from a field in greater than 2,624 ft of water.

The law also provided for reduction of royalty payments through a special application process on deepwater fields leased prior to the DWRR Act, but had not gone on production at the time the Act was passed in November 1995. Two years of record-setting deepwater lease activity followed passage of the DWRR Act.

As of January 1, 2000, industry had discovered more than 120 fields in the deepwater GOM, nearly half of which were discovered subsequent to the January 1, 1995, data presented in the previous assessment (Lore *et al.,* 1999). Although further delineation/appraisal drilling will be required, initial industry estimates are that several of these fields are among the largest discoveries in the Gulf of Mexico in decades. Discoveries currently estimated by MMS to contain over 100 MMBOE proved and unproved reserves plus discovered resources include Atwater 575 (Neptune), East Breaks 602 (Nansen), Green Canyon 644

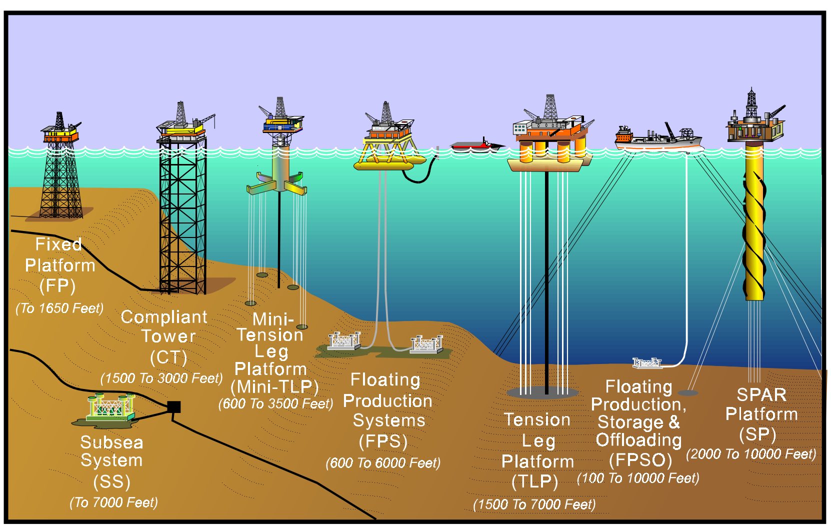

Figure 1. Deepwater development systems in use, or soon to be in use, are crucial to spurring industry's deepwater interest in the Gulf of Mexico.

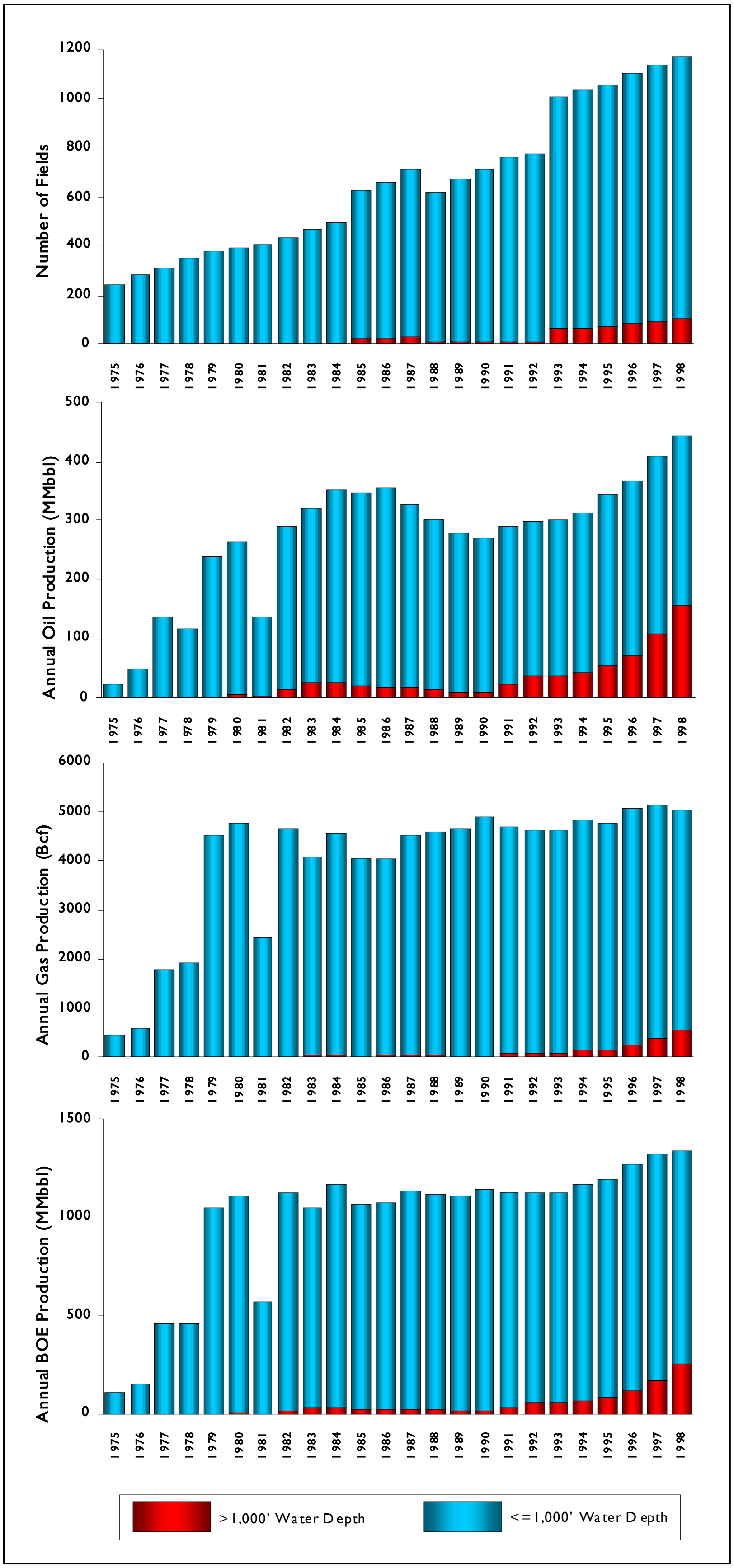

Figure 2. Graphs illustrating the increase in number of fields and production of oil and gas in water depths greater than 1,000 ft (red bars) in the northern Gulf of Mexico.

(Holstein), Green Canyon 826 (Mad Dog), Mississippi Canyon 582 (Medusa), Mississippi Canyon 778 (Crazy Horse), and Mississippi Canyon 899 (Flathead). Reserves (proved plus unproved) and cumulative production for deepwater fields nearly doubled from January 1, 1995, to January 1, 1999 (figure 2).

Because of the large, prolific discoveries, annual production from deepwater fields throughout the 1990's has steadily increased. Of the total annual northern Gulf of Mexico production in 1998, 11 percent of the gas and 35 percent of the oil (19% of the BOE) came from deepwater fields. Additionally, annual production from deepwater fields almost quadrupled (from 64.028 MMBOE to 255.292 MMBOE) since the January 1, 1995, data presented in the previous assessment. In fact, in 2000, for the first time oil production from deepwater exceeded that of the rest of the northern Gulf of Mexico.

Subsalt

Introduction

As much as 60 percent of the northern Gulf of Mexico Outer Continental Shelf and upper slope is covered by allochthonous, tabular salt that occurs in tongues, sheets/ nappes/or canopies (Montgomery and Moore, 1997). This region covers an estimated 36,000 square miles or 4,000 standard-sized Gulf of Mexico blocks (Leibman *et al.,* 1994). The subsalt trend that developed through this area during the 1990's is characterized by Miocene-Pleistocene siliciclastic reservoirs deposited during sea level lowstands as slope fan and basin-floor fan systems. Source rocks consist of both upper Jurassic marls, carbonates, and shales, and lower Tertiary marine and intermediate shales. Seals include shales, basal shear zone sediments, "gouge," and salt. Subsalt structural traps include four-way dipping anticlines and three-way dipping faulted structures, e.g., compressional folds, turtle structures, or faulted folds.

In ultra-deepwater, a number of wells have now been drilled through the Sigsbee Salt Canopy testing the underlying, objective sediments. Several of these wells have found thick, oil-filled, reservoir-quality sands in large compressional structures in the Mississippi Fan Fold Belt.

The MMS does not group subsalt reservoirs into a separate, single play because the reservoirs span ages as well as different structural regimes. In many cases, the hydrocarbon trap may be totally unrelated to the overlying salt sheet; the salt sheet may only mask the subsalt geology. Thus, known subsalt reservoirs are accounted for in (1) deep-sea fan plays of various ages and structural settings (i.e., F1 vs. F2) and (2) the Mississippi Fan Fold Belt play, which is subdivided according to age.

Changes in Salt Tectonic Paradigms

Before the 1980's, salt bodies in the Gulf of Mexico were generally considered to be "rooted" in autochthonous upper Jurassic Louann Salt, e.g., Martin, 1978. Salt was also viewed as having moved downslope as a complex, intact body on a basal, detachment/shear zone within the salt itself, e.g., Humphris, 1978. Consequently, except when sediments below salt overhangs were specifically targeted, most wells on the outer shelf and upper slope were stopped as soon as they encountered salt, then considered to be economic basement. By the early 1980's, the "rooted" salt paradigm began to change because of better seismic imaging and modeling of the salt bodies and underlying sediments. In addition, new wells that penetrated the tabular salt bodies on the outer shelf and upper slope encountered subsalt reservoir quality siliciclastic sediments.

The most significant advance in the understanding of salt occurred in about 1989 when salt tectonics began to be increasingly approached as a system involving a strong, brittle, fractured overburden rather than a weak fluid one (Jackson, 1995). During the late 1980's, "brittle era" models provided a framework from which salt movement and associated structures could be predicted. Regional detachment and salt evacuation surfaces (salt and fault welds) along vanished salt allochthons, raft tectonics, shallow spreading, and segmentation of salt sheets all trended a role in furthering the understanding of salt tectonic processes and responses. This evolved into a better-defined tectonic image of what had been previously masked by the shallow, tabular salt bodies.

In the 1990's, salt tectonic interpretation further evolved through applying and developing general structural principals for salt tectonics. These included section balancing of salt tectonic processes, predicting the geometry of the base of salt by applying ramp-flat theory, reactive piercement as a diapir initiator caused by tectonic differential loading, cryptic thin-skinned extension, the influence of sedimentation rate on the geometry of diapirs and extrusions, the importance of critical overburden thickness to the viability of active diapirs, the amalgamation of salt bodies, the coalescence of individual fault-segmented sheets, counter-regional fault systems, subsiding diapirs, and extensional turtle anticlines and mock turtle structures (Jackson, 1995).

The tabular salt of the subsalt trend originated from the deeper autochthonous Jurassic Louann Salt. The earliest salt features formed during the Mesozoic by gravity gliding of the salt under minimal sedimentary overburden thickness. This resulted in the formation of salt rollers and a variety of other generally low-relief salt structures, such as salt pillows. During the Cenozoic, prograding siliciclastic sedimentation ultimately caused regional extension. Depending on the volume of salt available, many of the earlier structures developed into high-relief salt structures, such as salt diapirs, or their growth stopped when the salt supply was exhausted.

Vendeville and Jackson (1992) describe a three-stage evolutionary model for salt diapirs triggered by extension that is applicable to Gulf of Mexico Cenozoic salt structures. The first stage, reactive diapirism, occurs when thin-skinned regional extension causes brittle deformation (faulting) of the overburden above the salt. This tectonic thinning of the sedimentary overburden creates a potential void that salt, which can be considered a pressurized, viscous fluid over geologic time, fills. In the succeeding active diapir stage, the overburden continues to thin and weaken, and salt driven by differential pressure breaks through at or near the seafloor. The third stage of diapirism occurs when a salt diapir nears the water bottom surface. It continues to grow passively, by down-building during continued sedimentation, i.e., the diapir crest remains at or near the surface, while its source layer sinks. Without continued sedimentation, the ability of the diapir to continue to rise vertically is limited; instead, it begins to spread laterally (Vendeville and Jackson, 1992). During this lateral spreading stage, salt is emplaced as extrusive glaciers at or very near the seafloor (Fletcher *et al.,* 1995; Harrison and Patton, 1995). These salt glaciers may grow and coalesce forming salt canopies (made up of amalgamated salt tongues or stocks) or salt nappes (that can be distinguished from the former by the lack of a local "salt feeder" system) until the supply of salt coming from the Louann Salt is exhausted. Burial of the salt sheet generally follows pinch-off of the salt feeder (Fletcher *et al.,* 1995). However, since a salt sheet may retain several hundred feet of relief at its downdip end, the sheet may continue to advance as a composite salt-sediment glacier. After cessation of sheet advance, burial and confinement of the salt sheet initiates secondary salt diapirism, salt sheet segmentation, and rafting (Harrison and Patton, 1995). Subsalt exploration targets the thick accumulations of sediment that now lie between the autochthonous Louann Salt layer and the allochthonous salt sheets (figure 1).

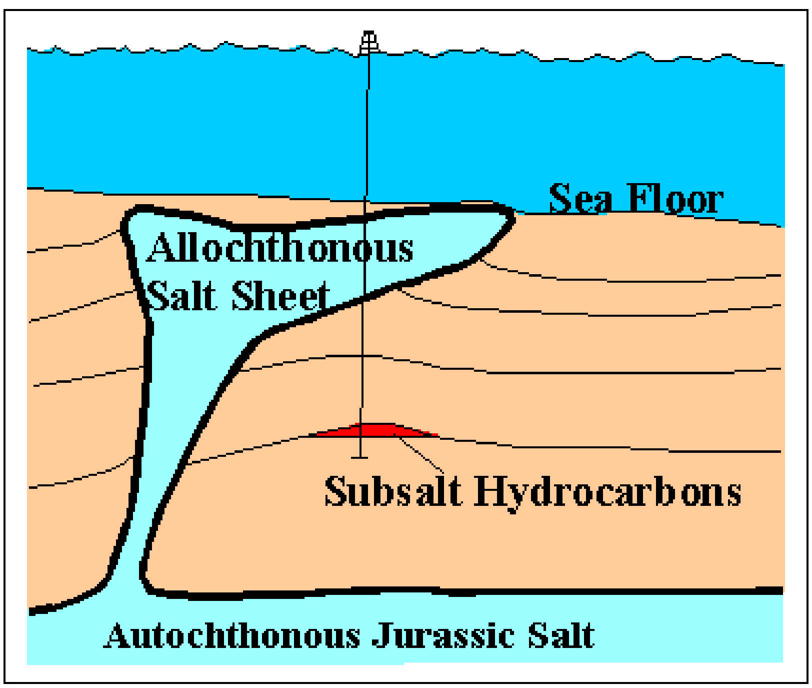

Figure 1. Schematic diagram illustrating a hydrocarbon trap located between an allochthonous salt sheet and the autochthonous Louann Salt layer.

Three important volumes published on salt tectonics in the early-mid 1990's provided a perspective to that time. These publications provide the basis for much of the salt-related exploration that occurs in the Gulf of Mexico today. The first, AAPG's Memoir 65, Salt Tectonics (Jackson *et al.,* 1995) resulted from a symposium held in 1993. The second was the proceedings of the GCSSEPM 16th Annual Research Conference, *Salt, Sediment and Hydrocarbons* (Travis *et al.,* 1995). The third was The Geological Society Special Publication No. 100, *Salt Tectonics* (Alsop *et al.,* 1996) consisting largely of papers presented to the Petroleum and Tectonics Groups of the Geological Society in 1994.

Figure 2 shows a representation of allochthonous salt distribution (Simmons, 1992) across the northern Gulf of Mexico. The area of allochthonous salt can be divided into two broad zones: (1) a zone dominated by diapirs with minor lateral salt flow that occurs primarily throughout the present-day inner and middle shelf regions, and (2) a region of primarily allochthonous, tabular salt that covers most of the present-day outer shelf and slope regions. Subsalt discoveries occur in the latter area (Figure 2).

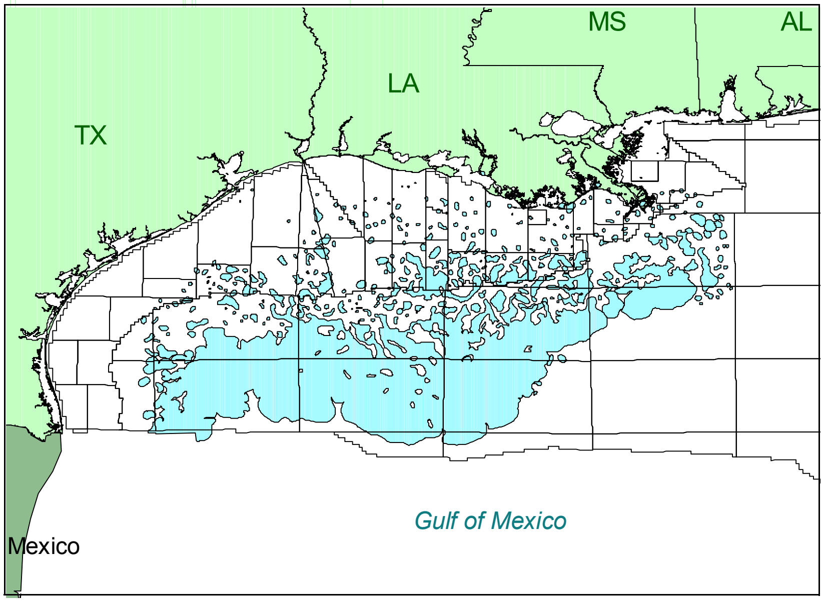

Figure 2. Allochthonous salt distribution in the northern Gulf of Mexico (after Simmons, 1992)

Drilling History--The 1980's

Prior to the 1980's, hydrocarbon traps beneath salt dome overhangs had been targeted in onshore and offshore oil and gas fields, but the area beneath tabular salt bodies was considered economic basement and therefore was unexplored and untested. Regionally extensive, high-quality two-dimensional (2-D) seismic data that imaged not only the salt body but also the subsalt geology led to initial subsalt exploration in the Gulf of Mexico.

From 1983 to 1990, an average of more than one well per year was drilled through tabular salt (wells drilled through salt welds are not considered in this discussion). The majority of the wells drilled during this period did not target subsalt objectives.

In late 1983, Placid Oil Company drilled the Ship Shoal 366 #2 well (OCS-G-05588 #2) to test a hydrocarbon indicator (HCI) or bright spot (Moore and Brooks, 1995). The well drilled through two thin salt sheets before being plugged and abandoned in a third salt body. A total of 295 ft of subsalt sediments were drilled among the three salt bodies, although the 54 ft of sediment between the first and second salt may be interpreted as sedimentary inclusions.

Several wells were drilled into salt during 1984. Marathon unintentionally drilled through a 1,100 ft thick salt sheet, with sedimentary inclusions, in the Garden Banks 171 #1 well (OCS-G-06353 #1). Subsalt sediments consisted of nearly 1,000 ft of primarily shale.

Placid drilled through a salt layer in Green Canyon 39 #1 ST 1 well (OCS-G- 05883 #1 ST1) before abandoning the well in salt. As in the Ship Shoal 366 #2, the 193 ft of sediment between the salt layers may be interpreted as a depositional unit or a shale inclusion within a salt sheet (Moore and Brooks, 1995).

One of the first hydrocarbon shows in the subsalt trend area was in the Green Canyon 98 #1 well (OCS-G-05092 #1). In this well, Conoco drilled through a 1,380 ft of salt before penetrating a thin oil-bearing sand beneath what is interpreted to be a salt feeder (Moore and Brooks, 1995).

At West Cameron 505 #2 well (OCS-G-05337 #2) Gulf Oil penetrated a 1, 690 ft thick salt sheet between -13,900 ft and -15,590 ft. No significant reservoir-quality sands were encountered in the 2,820 ft thick subsalt siliciclastic section (Moore and Brooks, 1995).

Four other wells tested traps below a salt feeder. Two were drilled by Amoco at Mississippi Canyon 400. The #1 well (OCS-G-05844 #1) penetrated a 3,450 ft thick salt sheet and 1,840 ft of subsalt section with only one thin sand. The #2 well (OCS-G-05844 #2) penetrated 1,290 ft of salt and 1,700 ft of subsalt sediments with no sandstone. A similar test was drilled over 100 miles to the west in East Breaks 170. The Amoco EB 170 #1 well (OCS-G-07394 #1) drilled through 250 ft of salt that has been interpreted as a salt feeder before penetrating 1,100 ft of subsalt Miocene siliciclastics that lacked reservoir quality sandstone. At Green Canyon 152, Marathon drilled the #1 ST1 well. The original hole did not penetrate salt, whereas the sidetrack encountered 1,130 ft of salt and 1,623 ft of Pliocene subsalt section that contained several reservoir quality sandstones (Moore and Brooks, 1995).

During 1985, Mobil drilled the High Island A-374 #1 well (OCS-G-05108 #1) that penetrated a salt feature believed to be detached from a more extensive salt body. This feature was probably drilled as an HCI because of its limited area and thickness (Moore and Brooks, 1995). Beneath the 250 ft thick salt body, the well penetrated over 5,000 ft of Pliocene and 2,000 ft of Miocene shales.

Diamond Shamrock drilled the South Marsh Island

200 #1 well (OCS-G-07719 #1) in 1986. This well was significant in that it penetrated a 990 ft thick salt sheet and 1,000 ft of subsalt reservoir-quality sandstone with porosities in excess of 30 percent and permeabilities approaching 2000 millidarcies. This conclusively established the presence of thick subsalt reservoirs that had been deposited in deepwater paleoenvironments. Like many of the other early subsalt wells, the well was drilled to test a HCI, which was misinterpreted and subsequently found to be the salt body (Moore and Brooks, 1995).

In late 1987, less than 20 miles west of the SM 200 #1 well, Mobil drilled the Vermilion 412 #1 well (OCS-G-06685 #1). Presumably drilled to test a deep salt flank HCI, the well encountered a 1,315 ft thick salt layer and approximately 1,000 ft of subsalt Pleistocene shale before drill pipe was stuck. Moore and Brooks (1995) interpret the salt in this well to represent a secondary horizontal salt layer emplaced after the primary salt sheet.

Less than 20 miles north of the sand-rich SM 200 #1, Amoco drilled the Vermilion 356 #1 well (OCS-G-07690 #1) to a total depth of 17,000 ft penetrating a 2,100 ft thick salt sheet. This well encountered nearly 5,000 ft of Pliocene section containing a 600 ft thick zone of lower Pliocene sandstones, and a Miocene siliciclastic interval 1,500 ft thick that contained intermittent sands. Although no hydrocarbons were encountered, the well provided another control point for reservoir-quality sandstones in a deepwater paleoenvironment in a subsalt setting (Moore and Brooks, 1995).

Salt was apparently unintentionally penetrated in development wells drilled in the Eugene Island 385 field. The #A-12 well (OCS-G-02329 #A012) penetrated 60 ft of salt, and drilling was stopped less than 100 ft below the base of the salt sheet. The Eugene Island 371 #B-4 well (OCS-G-05525 #B004) was drilled through 1,875 ft of salt. When drilling was halted, less than 50 ft of subsalt sediments had been tested (Moore and Brooks, 1995).

Conoco's Green Canyon 184 #A-12 well (OCS-G-04518) drilled through a 300 ft-thick salt sheet and tested 3,700 ft of subsalt shales and sandstones. Two thin oil sands were encountered in the subsalt Pliocene section (Moore and Brooks, 1995).

The Early 1990's

In 1990, Exxon's Mississippi Canyon 211 #1 well (OCS-G-08803 #1) at the "Mickey Prospect" (now called "Mica") tested a subsalt prospect below a "shallow" salt sheet. Drilled in 4,352 ft of water, a 3,300 ft thick salt sheet was penetrated approximately 1,400 ft below the seafloor. A thin, gas-filled sand was encountered near 10,700 ft, and four additional thin, oil-filled sands were found between 12,500 ft and the well total depth of 14,670 ft (Moore and Brooks, 1995). An Exxon press release in May 1991 announced the discovery of 100-200 million barrels of oil from five pay sands between 10,000 ft and 13,000 ft (Moore and Brooks, 1995). Core analyses and wireline log data are reported (Moore and Brooks, 1995) to indicate quality reservoir rock with good porosities and permeabilities. Because of its water depth (over 4,000 ft) and lack of infrastructure, "Mickey" has not yet been brought on production.

In 1992, Chevron drilled the Garden Banks 165 #2 well (OCS-G-12635 #2) through 6,950 ft of salt, testing approximately 5,150 ft of subsalt section. Nearly 250 ft of high porosity, high permeability, reservoir-quality sandstones were penetrated between 15,200 ft and 15,900 ft, below which several thin sandstones occur. The well proved that thick salt sheets could be penetrated and that significant objective sections could be drilled below salt. Although the well was plugged and abandoned, it provided a template that drillers could use for planning and implementing subsalt drilling programs. It also furnished explorationists with another example of subsalt reservoir-quality sandstones (Moore and Brooks, 1995).

Although the Garden Banks 260 field (Baldpate Prospect) was a conventional "suprasalt" discovery, the GB 260 #1 ST2 (OCS-G-07462 #1 ST2) encountered two thick water-bearing sandstones beneath 1,607 ft of salt (Moore and Brooks, 1995). The well was drilled in late spring of 1993.

By mid-1993, several significant subsalt tests were being drilled, or proposed for drilling, on prospective subsalt acreage leased in late 1980's and early 1990's. However, in October 1993, the first commercial discovery in the trend was announced by Phillips/Anadarko/Amoco at Ship Shoal 349 #1 well (OCS-G-12008 #1). The well was drilled in 372 ft of water to a total depth of 16,500 ft. A salt section of approximately 3,800 ft was penetrated and three main subsalt sandstone pay intervals were identified (Camp, 2000). The well was tested at a combined flow rate of 7,256 bopd and 9.9 MMcfd with a FTP of 7,063 psi on a ½ inch choke from several pay intervals (Moore and Brooks, 1995). Because of its location in shallow water and its proximity to infrastructure, the Mahogany

Prospect became the first subsalt producing field in early 1997. Reservoir sandstones are primarily channel-levee sands and deeper lobate sandstones of upper Miocene age (Rowan *et al.,* 2001). The traps are combination structural-stratigraphic (Harrison *et al.,* 1995) and the faulting and folding are related to a deeper level of salt, not the overlying Mahogany salt sheet (Rowan *et al.,* 2001). The primary reservoir sand ranges in thickness from 100 ft to 350 ft and is divided into upper and lower members. The oil pay occurs primarily in the upper member. Porosity and permeability variations are facies dependent (Camp and McGuire, 1997; Camp, 2000) with average porosity from conventional cores being 29 percent (range 20-36%) and average permeability being about 1,500 millidarcies (range 0.5-7,460 millidarcies).

Following the initial excitement of the Mahogany discovery and its implication for additional, large subsalt discoveries, a number of costly dry, or disappointing, wells were drilled, including the Phillips and Anadarko South Timbalier 260 #1 well (OCS-G-12037 #1), "Teak Prospect". A 1,860 ft thick salt sheet was penetrated with 100 ft of reported gross pay (Montgomery and Moore, 1997). The well reached a total depth of 16,610 ft in 1994. Hydrocarbons were tested from three zones in the well, but the discovery may be considered noncommercial (Bugosh *et al.,* 2000).

Late in 1993 Amoco drilled the South Marsh Island 169 #1 well (OCS-G-09554 #1), "Mattaponi Prospect," approximately 60 miles west of the Mahogany discovery. The well penetrated 1,170 ft of salt and 5,520 ft of subsalt sediments (Montgomery and Moore, 1997). The well has been reported as being located on the eastern edge of a large salt sheet that extends over 10 miles to the west, where it was penetrated more than five years earlier by the Amoco Vermilion 356 #1 well (Moore and Brooks, 1995).

The euphoria of this new trend gave way to a reevaluation of the geologic complexities of subsalt prospects. Structural complexities, seismic uncertainties, and drilling difficulties associated with subsalt exploration made the trend very high risk. Thus, it had become readily apparent that a number of technical challenges had to be met for successful subsalt exploration to occur routinely rather than haphazardly.

The Middle and Late 1990's

In 1994, Shell Offshore, Pennzoil, and Amerada Hess announced a significant discovery in Garden Banks 128 #1 (OCS-G-11455 #1), "Enchilada Prospect." The primary objective of the well was a gently east-dipping seismic amplitude anomaly above a Late Pliocene stratigraphic marker. Approximately half of the anomaly was located under the adjacent tabular salt body. The updip trap was interpreted to consist of the reservoir subcropping against the base of the tabular salt. Although the Enchilada discovery was deviated around and underneath the salt body, it penetrated the primary and deeper objectives in a subsalt position (Robison *et al.,* 1997). In 1995, Shell *et al.* announced another discovery, at Garden Banks 127 #1 (G-OCS-11454 #1), "Chimichanga." The well was a subsalt follow-up to the Enchilada discovery. The Enchilada/Chimichanga was the second "commercial" subsalt discovery, and began producing in July of 1998.

The commercial confirmation for the trend was important since dry holes were also drilled at "Mesquite" (Vermilion 349), "Rhino" (Ship Shoal 360), "Citation" (Ship Shoal 368), "Cypress" (South Timbalier 289), and Ship Shoal 250. Since many of these wells encountered reservoir quality sandstones below the salt, post-drilling, dry hole analyses raised questions regarding hydrocarbon migration routes, timing, and seal.

In 1995, Texaco and Chevron announced a discovery at Mississippi Canyon 292 #1, "Gemini Prospect" (OCS-G-08806 #1) in 3,400 ft of water. The field began producing in June 1999 through a subsea system of wells, manifold, and flowlines at an initial rate of 77 MMcfd and 1,500 bcpd from one well. These initial rates are expected to peak at daily rates of 150-200 MMcfgd and 2,000-3,000 bcpd. According to a Texaco press release of June 8, 1999, the projected recoverable reserves for Gemini are estimated at 250 to 300 Bcfg and 3 to 4 MMbbl of condensate.

In 1996, Phillips and Anadarko announced a discovery at the "Agate Prospect," Ship Shoal 361 #1 (OCS-G-14514 #1), five miles west of Mahogany. Two separate porosity zones in a single sandstone interval were tested at a combined rate of 4,126 bopd and 24 MMcfgpd (Montgomery and Moore, 1997). Agate is currently producing through a subsea tieback to Mahogany.

Anadarko, Phillips and BHP announced a discovery at their "Monzanite Prospect," Vermilion 375 #1 well (OCS-G-14427 #1). The well encountered multiple hydrocarbon-bearing sandstones, but was plagued by mechanical problems, including excessive sand production. Consequently, it was plugged and abandoned (Montomery and Moore, 1997).

A discovery was also made at "North Lobster Prospect," South Timbalier 308 #2 ST1 (OCS-G-12043 #2 ST1) in 1996 by Marathon *et al.*

Six other new field exploratory wells drilled during 1996 were dry holes. One of the most disappointing was drilled at the "Alexandrite Prospect," Ship Shoal 337 #1 (OCS-G-14510 #1). The well was located updip from the Mahogany discovery, at an excellent structural position beneath the same salt sheet (Montgomery and Moore, 1997).

In 1997, Amerada Hess and Kerr-McGee drilled a discovery at Garden Banks 215 #4, "Conger Prospect" (OCS- G-09216 #4). The discovery was drilled to a total depth of 21,652 ft in about 1,500 ft of water and encountered about 300 ft of net pay both above and below the salt (OGJ, June 9, 1997, p. 28). Later in the year, the same partners made another discovery in the same area at Garden Banks 216 #3 (OCS- G-14224 #3), "Penn State Prospect." The company press release (OGJ, October 13, 1997) reports the discovery cut 123 ft of net pay in four zones not previously found productive. These were the only successful new field wildcats reported during the year.

Anadarko reinvigorated interest in the trend in 1998 by announcing two discoveries. The first was at Eugene Island 346 #1, the "Tanzanite Prospect" (OCS-G-14482 #1); the second was located at Grand Isle 116, the "Hickory Prospect" (OCS-G-13944 #1). According to the Anadarko press release, Tanzanite cut 450 ft of hydrocarbon pay and found estimated reserves of 140 MMBOE, while Hickory encountered 300 ft of hydrocarbon pay below an 8,000 ft thick salt layer. Production from these fields came on-line in December of 2000. Anadarko reported in the August 17, 1998 issue of Oil & Gas Journal that 13 of the industry's 43 Gulf of Mexico wells that deliberately targeted subsalt prospects found oil and gas. According to Anadarko, eight of these discoveries were commercial. Adding Tanzanite and Hickory to the successful (and commercial) wells and three other wells that were plugged and abandoned as dry holes, increases the numbers at that point to 15 of 48 wells, a 31 percent success rate.

Not all of the subsalt interest has been on the Gulf of Mexico shelf and upper slope. Many of the major companies have focused their exploration efforts in ultra-deepwater (water depths greater than 3,300 ft). Although some of the early subsalt discoveries were in ultra-deepwater, e.g., Mickey (1990, water depth >4,000 ft) and Gemini (1996 in 3,400 ft of water), the discovery of several "world class" (>100 MMBOE) discoveries focused industry attention on the subsalt trend in these water depths.

Several of the significant discoveries have occurred in compression fold structures of the Mississippi Fan Fold Belt. The most significant discoveries in this part of the trend have been on structures that are partially exposed south of the Sigsbee Salt Canopy. The trend began with the "Neptune Prospect" (OCS-G-08036 #1), Atwater Valley 575 #1, in 1995 that was drilled in >6,200 ft of water. Industry reports that reserves are approximately 100 MMBOE. Subsequent discoveries have been made at "Atlantis Prospect," Green Canyon 699 #1 (OCS-G-15604 #1) in 1998 in 6,133 ft of water; and "Mad Dog Prospect", Green Canyon 826 #1 (OCS-G-09982 #1) in 1999 in >6,500 ft of water. Initial industry assessment of reserves in these discoveries are "multi-hundred million BOE's," and 400-800 MMBOE's respectively.

Discoveries at the "K2/Timon Prospects," Green Canyon 562/563 (OCS-G-11075 #1 and -11076 #1), and "Champlain Prospect" Atwater Valley 63 #1 (OCS-G-13198 #1) are totally under the salt. Reserves in these discoveries have been reported by industry as totaling 280 MMBOE.

The largest of the discoveries was made by BP and ExxonMobil at the "Crazy Horse Prospect," Mississippi Canyon 778 #1 (OCS-G-09868 #1) in 6,000 ft of water on a 'turtle' structure. Turtle structures are formed by structural inversion of a primary peripheral sink when salt is withdrawn from the margins of the peripheral sink by growing salt diapirs (Jackson and Talbot, 1991). Turtle structures are descriptively named since they have a flat base and a rounded crest, resembling a turtle shell. They are cored by either a sedimentary thick or a low-relief salt pillow that is not connected to the rising higher relief salt structures that form the turtle. In the press release announcing the discovery in July 1999, Crazy Horse was called the biggest deepwater Gulf of Mexico discovery to date, with reserves of at least 1 billion BOE. A second discovery, Crazy Horse North, at Mississippi Canyon 776 #1 (OCS- G-09866 #1) in nearly 5,700 ft of water was announced in February 2001. Industry press releases report that the entire Crazy Horse-Crazy Horse North complex may have reserves of 1.5 billion BOE.

Advances in Subsalt Seismic Imaging

Because of the hydrocarbon volumes encountered in subsalt traps and the area over which the subsalt trend extends, companies have undertaken a major effort to enhance the seismic imaging of salt bodies. Extensive sets of speculative, three-dimensional (3-D) seismic data covering most of the area with subsalt potential were acquired and processed in the early 1990's. Exploration companies could now cost-effectively buy and manipulate these 3-D data sets to improve their ability to define subsalt prospects.

Conventional 3-D time migration of seismic reflection data is a computer processing technique that is usually adequate for imaging geologic features in the Gulf of Mexico. The basic assumption of time migration is that the acoustic properties of subsurface layers do not have abrupt lateral variations. This assumption breaks down near salt bodies because acoustic waves travel much faster through salt than through the surrounding siliciclastics. Because of these velocity variations, conventional time migration is very poor in correctly positioning, or even imaging, subsalt seismic events. Conversely, depth migration takes into account vertical and lateral velocity variations in the subsurface, creating a more accurate image. Depth migration can be performed either before or after summing (stacking) the seismic offset traces. In poststack depth migration, the seismic offset traces are first stacked to produce a single trace at each shotpoint location. The resulting summed traces are then migrated to their presumed correct position in time, and then further manipulated using velocity functions to determine their depth. Poststack depth migration makes adjustments for abrupt interval velocity variations, and thus images salt-sediment interfaces more accurately than conventional time migration. In prestack depth migration, each offset seismic trace is migrated individually before summing them, thus placing each offset trace in its true subsurface position before any further manipulation. Hence, prestack depth-migrated seismic data give an even more accurate picture of the subsurface and improved seismic event imaging. The main drawback of prestack depth migration is its cost in computing time and power because tens of millions of seismic traces have to be processed. Until recently, such computing power was not widely available or cost effective.

The earliest subsalt wells were drilled on prospects defined using conventional 2-D time-migrated data. As long as the salt bodies had a smooth top and bottom that were relatively two dimensional in nature, these data were able to provide some detail of the base of salt and the underlying subsalt sediments and structures. Industry then moved to employing 2-D depth migration, which was much better at imaging the base of salt and subsalt seismic events. However, it became apparent that 2-D depth migration still could not image salt bodies that exhibited a complex three-dimensional morphology, where salt surfaces were rugose or salt flanks were steeply dipping or faulted. To image these complex salt bodies better, a three-dimensional solution was needed.

To image the subsurface features where there are strong velocity variations, such as a varying thickness of salt and underlying clastic sediments, 3-D poststack depth-migrated data proved helpful. However, these data could not deal well with extremely rugose salt surfaces. Consequently, the current state-of-the-art normal seismic data processing for imaging the most complex salt bodies has become 3-D prestack depth-migration modeling. This type of modeling requires the integration of the depositional model, lithologic parameters, and velocity model and, typically, several iterations of fine tuning before a satisfactory product is obtained. In addition, ray-trace modeling improves the image that can be extracted from the seismic data. Ray-trace modeling, using complex, geophysical algorithms, further corrects for the actual positions of subsurface events by predicting the movement of acoustic energy in the subsurface. High-resolution gravity and magnetic data can also be integrated with the seismic interpretation to constrain and corroborate the seismic model.

Drilling Technology Advances

In addition to geological and geophysical advances, drilling technology also had to deal with salt and rapidly changing subsalt pressure environments. The drilling costs of a subsalt well can be formidable, especially if mechanical problems arise. This is because subsalt wells are often deeper than non-subsalt wells because of the extra section imposed by the salt body itself. Drilling the salt requires using special (and expensive) drilling muds to achieve a chemical balance so that salt saturation of drilling fluids is maintained to prevent water loss to the formation, while avoiding dissolving the wellbore wall with undersaturated drilling fluids (LeBlanc, 1994). The driller also has to pay careful attention to drilling fluid weight when drilling through the lower portion of the salt section. Often, beneath the salt, an unconsolidated ("gumbo") section occurs, which has a tendency to absorb large amounts of drilling fluid quickly when an over-balanced condition exists. However, too great an under-balance allows formation flow into the wellbore if the fluids in the gumbo zone are highly pressured.

Salt tends to flow like plastic under conditions of high temperature and pressure. The vertical and lateral movement of salt can reduce wellbore gauge in an open hole or “oval” a casing string while drilling the well. These conditions require the salt section to be drilled as quickly as possible (LeBlanc, 1994). However, because vibrations within the salt can damage the bottom hole tool assembly, salt must be drilled in a relatively slow and controlled manner (Tyler, 2000). Additional drilling costs are also incurred when an extra string of heavy-walled, intermediate casing is set through the salt to try to withstand the forces created by the tendency of salt to flow.

Setting casing can become a problem if salt ledges or washout zones occur in the borehole. Salt ledges can hang up centralizers, while washout zones can prevent good cement bonding between the casing and the formation, leading to nonuniform loading on the casing. When casing strings have been cemented in place for long periods of time, salt creep can bend, stretch, and shear them. In subsalt producing wells, casing and production tubing through the salt interval can shift significantly in a lateral direction. This lateral movement can create problems for well workovers, especially with tools that need maximum hole gauge or minimal dogleg.

The Future of Subsalt Exploration

The subsalt trend has been one of the most complex undertakings in the Gulf of Mexico. Given the area of the Gulf of Mexico covered by lateral salt bodies, the advances made in defining and delineating subsalt prospects, and the significant reserves discovered in subsalt fields, subsalt exploration may be in a relatively early stage. The interaction of salt, sediment and hydrocarbons is being better understood with each well drilled.

Methodology Introduction

Among MMS's objectives for this assessment was the use of an appraisal method allowing the input of a 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).

Prior to 1995, MMS assessments presented estimates of undiscovered conventionally recoverable oil and gas resources only as cumulative distributions of the quantities of resources expected in a particular area. While useful, of even more value in formulating a corporate exploration strategy or considering national policy would be a knowledge of both the total amount of undiscovered conventionally recoverable oil and gas resources and the number and size distribution of potential individual accumulations. The methodology used in the 1995 assessment (Lore *et al.,* 1999) presented this information in the form of pool rank plots for each play.

Similarly, prior to 1995, estimates of undiscovered economically recoverable oil and gas resources were presented only as cumulative distributions at discrete sets of economic conditions. In the 1995 assessment, these estimates were for the first time also presented as price-supply curves that show incrementally the costs associated with transforming a volume of undiscovered conventionally recoverable resources to undiscovered economically recoverable resources. This assessment update uses the same methodology as was employed in 1995 and presents the assessment results in a like manner.

Reserves

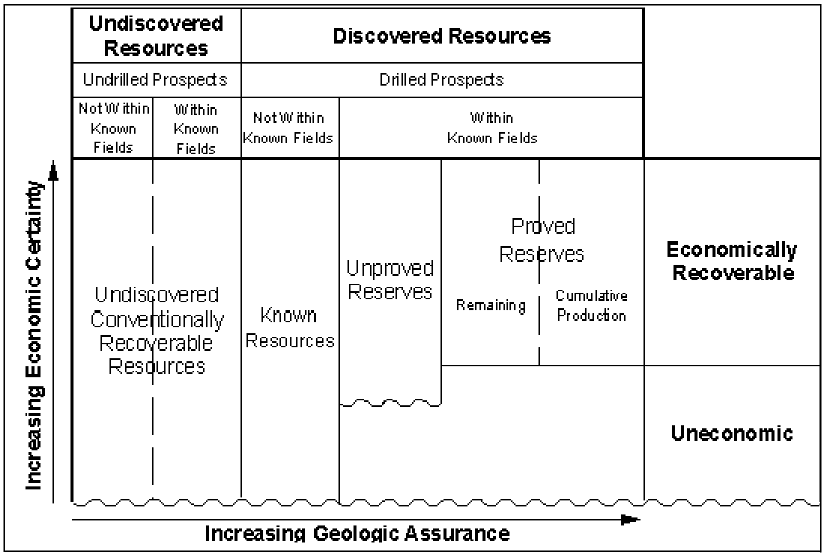

Figure 1. MMS classification scheme for conventionally recoverable hydrocarbon resources (U.S. Bureau of Mines and U.S Geological Survey, 1980).

The reserves of an oil or gas field cannot be measured directly, but only estimated on the basis of geophysical, geological, and engineering knowledge and principles. Therefore, reserve estimates are subject to varying degrees of uncertainty. 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 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 uniformly continue to 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—Overview

Various analyses of published estimates of oil and gas field sizes made at any particular point in time have demonstrated that they are generally too low. As successive estimates are made of the aggregate size of groups of fields, they invariably increase, even though the estimates for individual fields are highly variable.

The observed incremental increase through time in the estimates of proved reserves of an oil and/or gas field is commonly referred to as reserves growth or reserves appreciation. The reserves appreciation phenomenon contributes a very significant portion of the current domestic petroleum supply and must be an integral part of any resource assessment.

Reserves appreciation 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 resulting from 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 984 OCS fields with proved reserves at the end of 1998. 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.

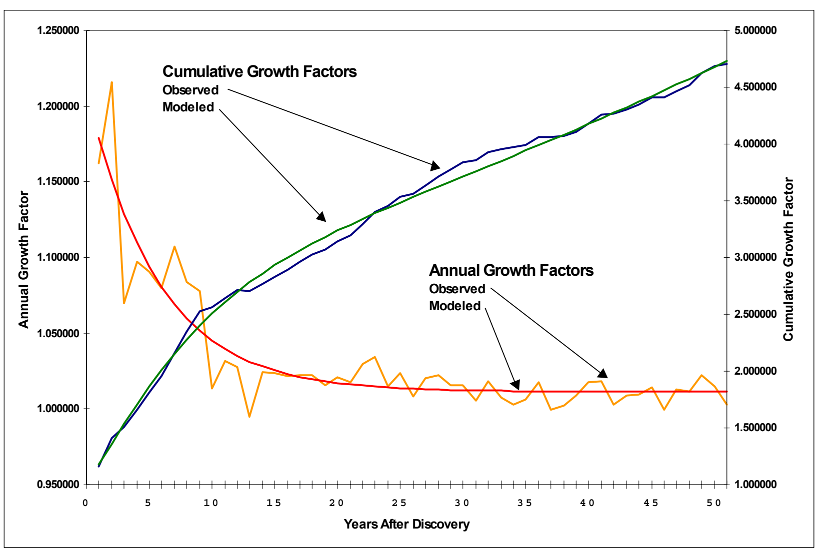

Figure 1. Observed and modeled annual and cumulative growth factors for reserves appreciation.

The estimate of total reserves appreciation in known fields 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. 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 additional appreciation with time. The oldest fields in the database were 51 years old. The appreciation model used in this assessment projects no additional 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 1,042 fields (984 proved and 58 unproved) as of January 1, 1999, were known, the growth model was applied to this set of fields to develop an aggregate estimate of appreciation.

Reserves Appreciation—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 conservatism, 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, 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 and its predecessors have 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 984 proved fields and 58 unproved fields with reserves discovered between 1947 and 1998. Because of 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 984 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 984 OCS fields with proved reserves. The procedure involves developing AGF's from equation 1 (Root and Attanasi, 1993):

$$AGF = \sum_d c(d,e+1)/\sum_d c(d,e) \qquad (1)$$

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), 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 those 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. Equation 3 is the model used as the basis for the projection:

$$AGF = 1.01138 + 0.20027\exp(-x/5.63808) \qquad (3)$$

where x is the age of the field in years.

The correlation coefficient for this model was 0.81763, 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 graphical (figure 1) and tabular (table 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 4.7, 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 1,042 fields (984 proved and 58 unproved) as of January 1, 1999, were known, the growth model was applied to this set of fields to develop an aggregate estimate of appreciation through 51 years.

The oldest fields in the database were 51 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 with 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

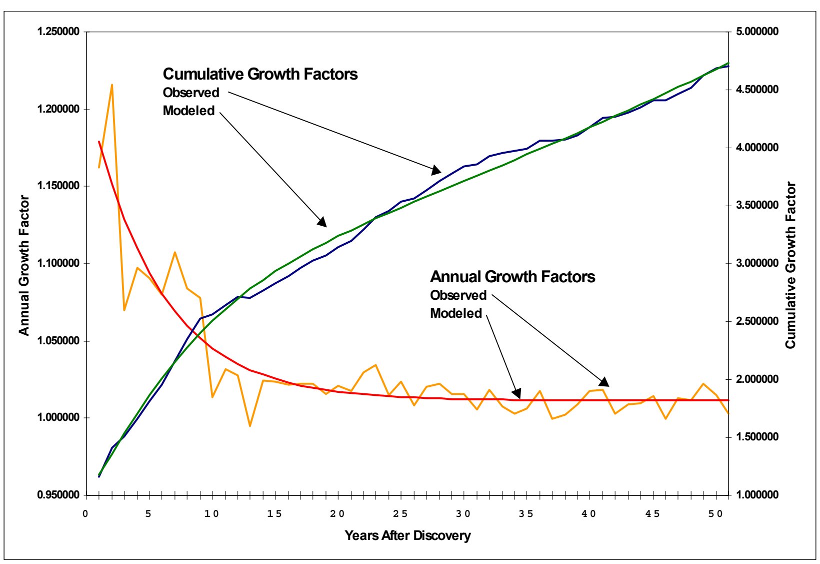

Figure 1. Observed and modeled annual and cumulative growth factors for reserves appreciation.

Years After Discovery	Annual Growth Factor		Cumulative Growth Factor	
	Observed	Modeled	Observed	Modeled
1	1.162416	1.179100	1.162416	1.179100
2	1.216007	1.151841	1.413506	1.358136
3	1.069552	1.129013	1.511818	1.533354
4	1.097489	1.109895	1.659204	1.701862
5	1.090617	1.093884	1.809556	1.861641
6	1.080113	1.080476	1.954525	2.011458
7	1.107387	1.069246	2.164415	2.150744
8	1.083841	1.059842	2.345882	2.279449
9	1.077701	1.051966	2.528160	2.397904
10	1.013799	1.045370	2.563046	2.506697
11	1.031549	1.039847	2.643907	2.606581
12	1.027845	1.035220	2.717527	2.698386
13	0.994927	1.031346	2.703741	2.782970
14	1.024045	1.028102	2.768752	2.861176
15	1.023334	1.025385	2.833358	2.933806
16	1.021829	1.023109	2.895208	3.001603
17	1.022389	1.021203	2.960028	3.065246
18	1.022235	1.019607	3.025845	3.125347
19	1.015916	1.018270	3.074004	3.182449
20	1.020997	1.017151	3.138549	3.237031
21	1.017804	1.016214	3.194428	3.289515
22	1.029994	1.015429	3.290241	3.340267
23	1.034402	1.014771	3.403432	3.389607
24	1.015130	1.014220	3.454926	3.437808
25	1.023552	1.013759	3.536296	3.485110
26	1.008115	1.013373	3.564993	3.531716
27	1.020404	1.013050	3.637734	3.577804
28	1.022103	1.012779	3.718138	3.623524
29	1.015754	1.012552	3.776714	3.669006
30	1.015663	1.012362	3.835869	3.714362
31	1.005895	1.012203	3.858481	3.759688
32	1.018395	1.012070	3.929458	3.805066
33	1.007555	1.011958	3.959145	3.850567
34	1.002653	1.011865	3.969649	3.896252
35	1.006375	1.011786	3.994955	3.942174
36	1.017435	1.011721	4.064607	3.988380
37	0.999705	1.011666	4.063408	4.034907
38	1.002043	1.011620	4.071710	4.081793
39	1.009102	1.011581	4.108770	4.129066
40	1.017346	1.011549	4.180041	4.176753
41	1.018014	1.011522	4.255340	4.224878
42	1.002898	1.011500	4.267672	4.273462
43	1.008665	1.011481	4.304652	4.322524
44	1.009920	1.011465	4.347354	4.372081
45	1.014544	1.011451	4.410582	4.422148
46	0.999835	1.011440	4.409854	4.472738
47	1.013118	1.011431	4.467702	4.523866
48	1.011592	1.011423	4.519492	4.575544
49	1.022374	1.011417	4.620611	4.627781
50	1.014911	1.011411	4.689509	4.680590
51	1.003066	1.011407	4.703887	4.733980

Table 1.Observed and modeled annual and cumulative growth factors. Growth factors are used to estimate reserves appreciation.

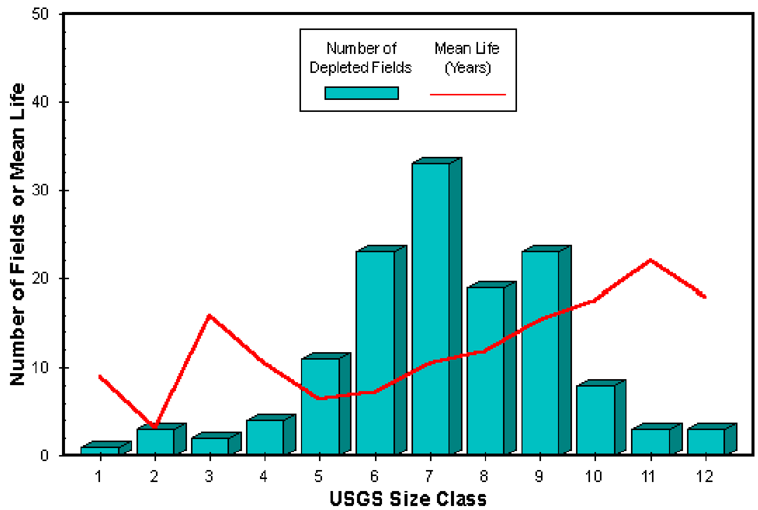

Figure 2. Abandoned fields in the Gulf of Mexico OCS through 1994 by USGS size classes.

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 of the total estimated proved reserves. The distribution of abandoned fields through 1994 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.

Years After Discovery	Number of Fields	Observed Growth Factors	
		Annual	Cumulative
1	71	1.686727	1.686727
2	174	1.241472	2.094024
3	323	1.114302	2.333376
4	303	1.079238	2.518268
5	317	1.061580	2.673342
6	323	1.106803	2.958863
7	327	1.078990	3.192584
8	325	1.078757	3.444022
9	304	1.104861	3.805166
10	396	0.999168	3.802000
11	251	1.005088	3.821345
12	218	1.046963	4.000807
13	198	0.989202	3.957606
14	167	1.014801	4.016182
15	96	1.036184	4.161504
16	74	1.016941	4.232004
17	41	1.076761	4.556857
18	22	1.013521	4.618470

Table 2. Observed growth factors for fields in the Gulf of Mexico OCS discovered since 1980.

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).

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.

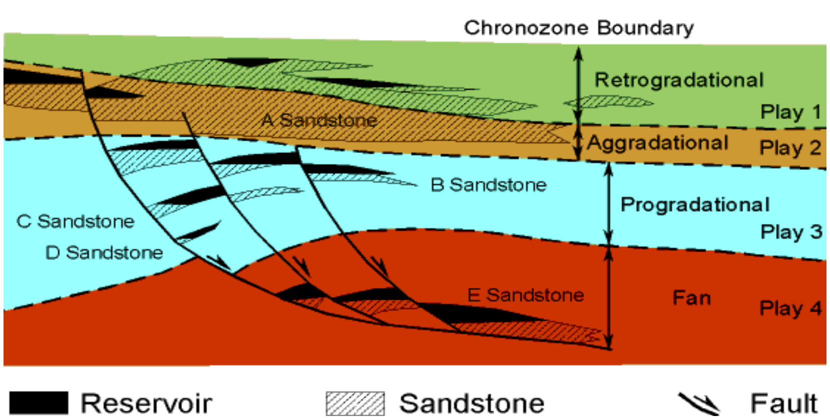

Figure 3. Diagrammatic illustrating stacked pools within a single field.

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. However, the relatively short duration of observations for each play family and the variability in the outyear AGF's for the few observations made these projections highly uncertain (Lore *et al.*, 1999).

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

Play Delineation Procedures—Overview

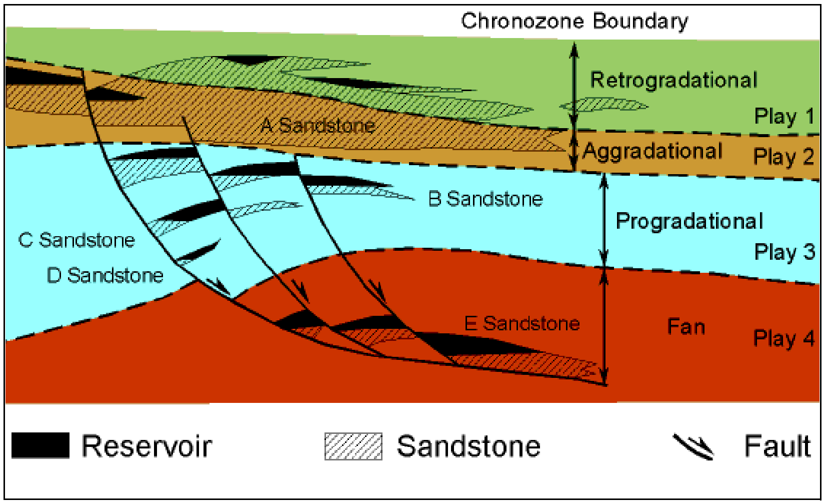

Figure 1. Schematic cross section of a typical field illustrating 12 fault-block reservoirs ("reservoirs"), 5 sandstone-body reservoirs ("sands"), 4 plays (equal to 4 pools within the one field), and 4 depositional styles/facies.

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) and the recent OCS update (Bascle *et al.*, 2001) from which much of this 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 structurally defined field with examples of reservoirs, sands, plays, pools, and 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. Initially all reservoirs were organized by geologic age and pro-

Region	Province	System	Series	Chronozone Name	Chronozone Number	Biozone
Gulf of Mexico	**Cenozoic**	Quaternary	Pleistocene	UPL	01	*Sangamon fauna* *Trimosina "A" 1st* *Trimosina "A" 2nd* *Hyalinea "B" / Trimosina "B"*
				MPL	05	*Angulogerina "B" 1st* *Angulogerina "B" 2nd*
				LPL	07	*Lenticulina 1* *Valvulineria "H"*
		Tertiary	Pliocene	UP	09	*Buliminella 1*
				LP	10	*Textularia "X"*
			Miocene	UM3	11	*Robulus "E" / Bigenerina "A"* *Cristellaria "K"*
				UM1	13	*Discorbus 12*
				MM9	14	*Bigenerina 2* *Textularia "W"*
				MM7	16	*Bigenerina humblei* *Cristellaria "I"* *Cibicides opima*
				MM4	19	*Amphistegina "B"* *Robulus 43* *Cristellaria 54 / Eponides 14* *Gyroidina "K"*
				LM4	23	*Discorbus "B"* *Marginulina "A"*
				LM2	25	*Siphonina davisi*
				LM1	26	*Lenticulina hanseni*
			Oligocene	UO	27	*Discorbis Zone / Robulus "A"* *Heterostegina texana*
				MO	29	*Camerina "A"*
				LO	30	*Textularia warreni*
			Eocene	UE	31	*Hantkenina alabamensis* *Camerina moodybranchensis*
				ME	33	*Discorbis yeguaensis*
				LE	34	*Globorotalia wilcoxensis*
			Paleocene	UL	35	*Globorotalia velascoensis* *Cristellaria longiforma*
				LL	37	*Globorotalia uncinata*

Figure 2. MMS Cenozoic chronostratigraphic/biostratigraphic chart used for the 2000 Assessment. In this assessment, MMS uses Gulf of Mexico provincial biozone terminology to define the Pliocene-Pleistocene and the Miocene-Pliocene boundaries. Refer to the "MMS 1995 versus 2000 Assessment Results" section for a more complete discussion of provincial versus global biozone terminology. Chronozones are after Reed et al. (1987).

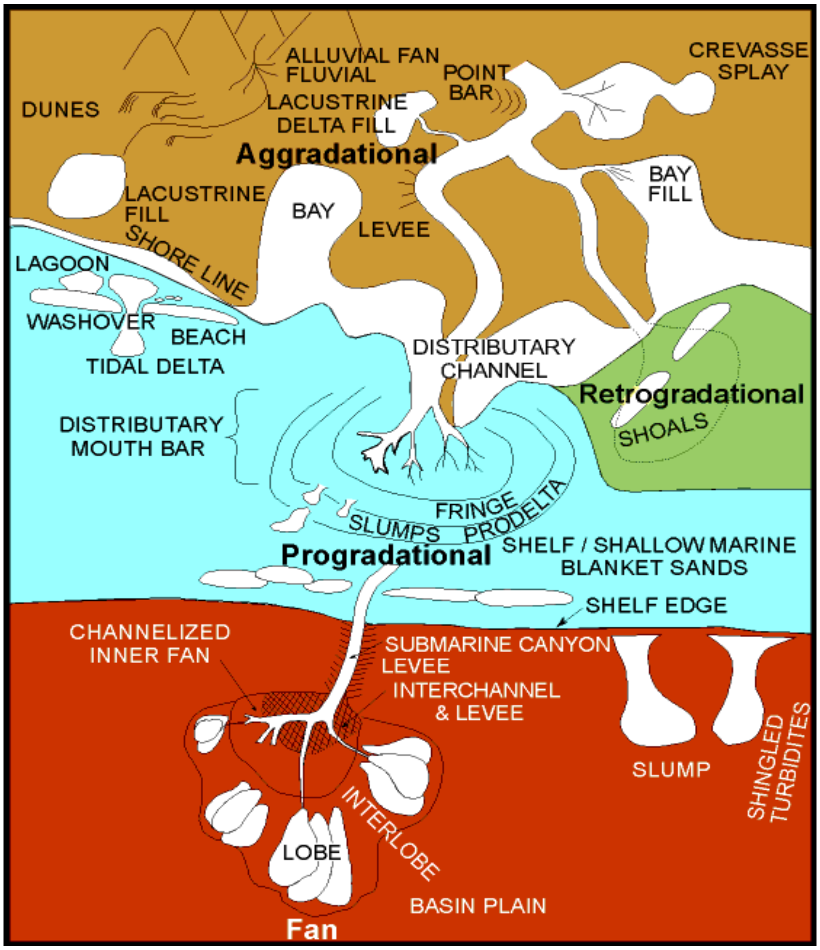

Figure 3. Map view illustrating the relationships between depositional environments and depositional styles.

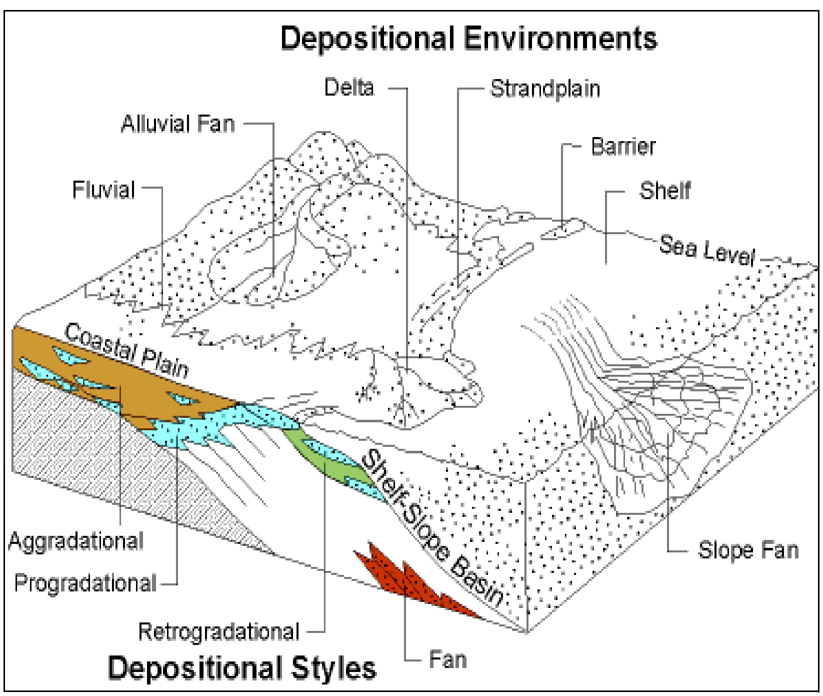

Figure 4. Block diagram illustrating the relationship between depositional environments and depositional styles.

ducing chronostratigraphic unit (chronozone). Cenozoic sediments were grouped into 21 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 may produce hydrocarbons 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 post-depositional modification). Consequently, an originally continuous sandstone body may eventually be segmented into separate reservoir compartments by displacement along faults. 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.

Within the Mesozoic Provinces of the Gulf of Mexico and Atlantic Continental Margins, similar data are not as readily available to identify the depositional styles of plays as precisely. Commercially recoverable hydrocarbons have been discovered, which resulted in the development of 13 fields of upper Jurassic age and 5 fields of lower Cretaceous age. On the Atlantic Continental Margin, only

54 wells have been drilled, resulting in several subeconomic hydrocarbon flows from upper Jurassic and lower Cretaceous clastic reservoirs.

An essential 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. For conceptual plays without good analogs in the United States, appropriate analogs from producing regions around the world were used. Even though identifying adequate analogs for the Atlantic Mesozoic Province was more problematic, two analog areas were identified as models for assessing the clastic plays: the onshore United States Gulf Coast and the Scotian Shelf offshore Canada.

Because fewer data exist and analogs were necessary for the evaluation, the play descriptions for the Mesozoic Provinces are less precise than those of the Cenozoic Province. The Mesozoic sediments were grouped into nine chronozones for this assessment (figure 2). In contrast to the Cenozoic chronozones, most of the Mesozoic chronozones are described as either clastic or carbonate (e.g., Lower Cretaceous Clastic (LK C1), Atlantic Middle Jurassic Carbonate (AMJ B1) 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.

Play Delineation Procedures—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 reservoirs are 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 1,042 OCS fields used in this study (984 proved and 58 unproved) containing over 10,000 sands and 22,000 reservoirs. A principal 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 (only play limit is provided in this report).

• 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. In the OCS portion of the basin, 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 (Reed *et al.*, 1987). Continuing with this method, we further grouped Cenozoic strata into 21 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 siliciclas-

Region	Province	System	Series	Chronozone Name	Chronozone Number	Biozone
Gulf of Mexico	**Cenozoic**	Quaternary	Pleistocene	UPL	01	*Sangamon fauna* *Trimosina "A" 1st* *Trimosina "A" 2nd* *Hyalinea "B" / Trimosina "B"*
				MPL	05	*Angulogerina "B" 1st* *Angulogerina "B" 2nd*
				LPL	07	*Lenticulina 1* *Valvulineria "H"*
		Tertiary	Pliocene	UP	09	*Buliminella 1*
				LP	10	*Textularia "X"*
			Miocene	UM3	11	*Robulus "E" / Bigenerina "A"* *Cristellaria "K"*
				UM1	13	*Discorbus 12*
				MM9	14	*Bigenerina 2* *Textularia "W"*
				MM7	16	*Bigenerina humblei* *Cristellaria "I"* *Cibicides opima*
				MM4	19	*Amphistegina "B"* *Robulus 43* *Cristellaria 54 / Eponides 14* *Gyroidina "K"*
				LM4	23	*Discorbus "B"* *Marginulina "A"*
				LM2	25	*Siphonina davisi*
				LM1	26	*Lenticulina hanseni*
			Oligocene	UO	27	*Discorbis Zone / Robulus "A"* *Heterostegina texana*
				MO	29	*Camerina "A"*
				LO	30	*Textularia warreni*
			Eocene	UE	31	*Hantkenina alabamensis* *Camerina moodybranchensis*
				ME	33	*Discorbis yeguaensis*
				LE	34	*Globorotalia wilcoxensis*
			Paleocene	UL	35	*Globorotalia velascoensis* *Cristellaria longiforma*
				LL	37	*Globorotalia uncinata*

Figure 1. MMS Cenozoic chronostratigraphic/biostratigraphic chart used for the 2000 Assessment. In this assessment, MMS uses Gulf of Mexico provincial biozone terminology to define the Pliocene-Pleistocene and the Miocene-Pliocene boundaries. Refer to the "MMS 1995 versus 2000 Assessment Results" section for a more complete discussion of provincial versus global biozone terminology. Chronozones are after Reed et al. (1987).

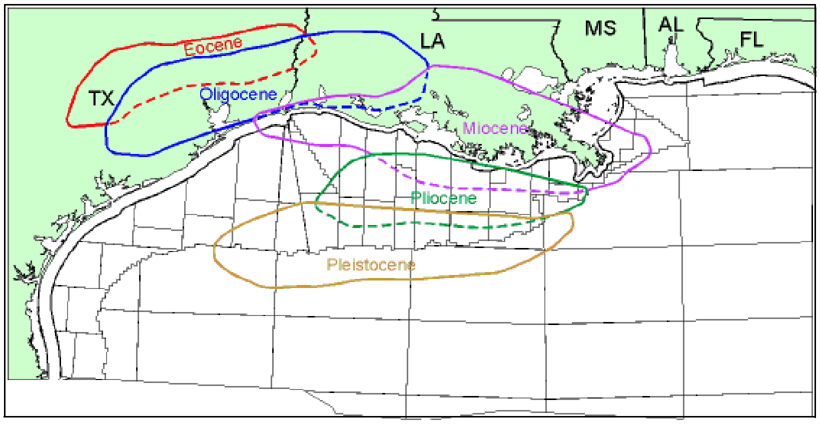

Figure 2. Locations of major depocenters in the northern Gulf of Mexico illustrating the shift of depocenters from west to east and from north to south over time.

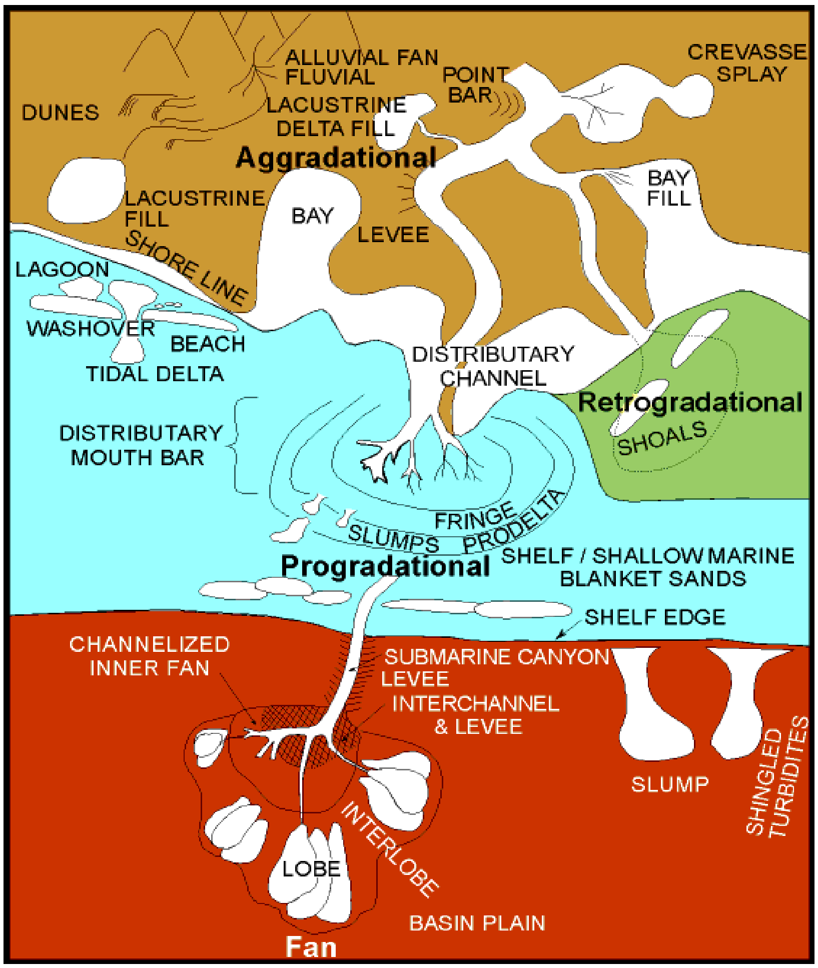

Figure 3. Map diagram illustrating the relationships between depositional environments and depositional styles.

tic 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 depositional facies (fan) were used to define the large-scale patterns of basin fill in the northern Gulf of Mexico and to 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 (figure 4), 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

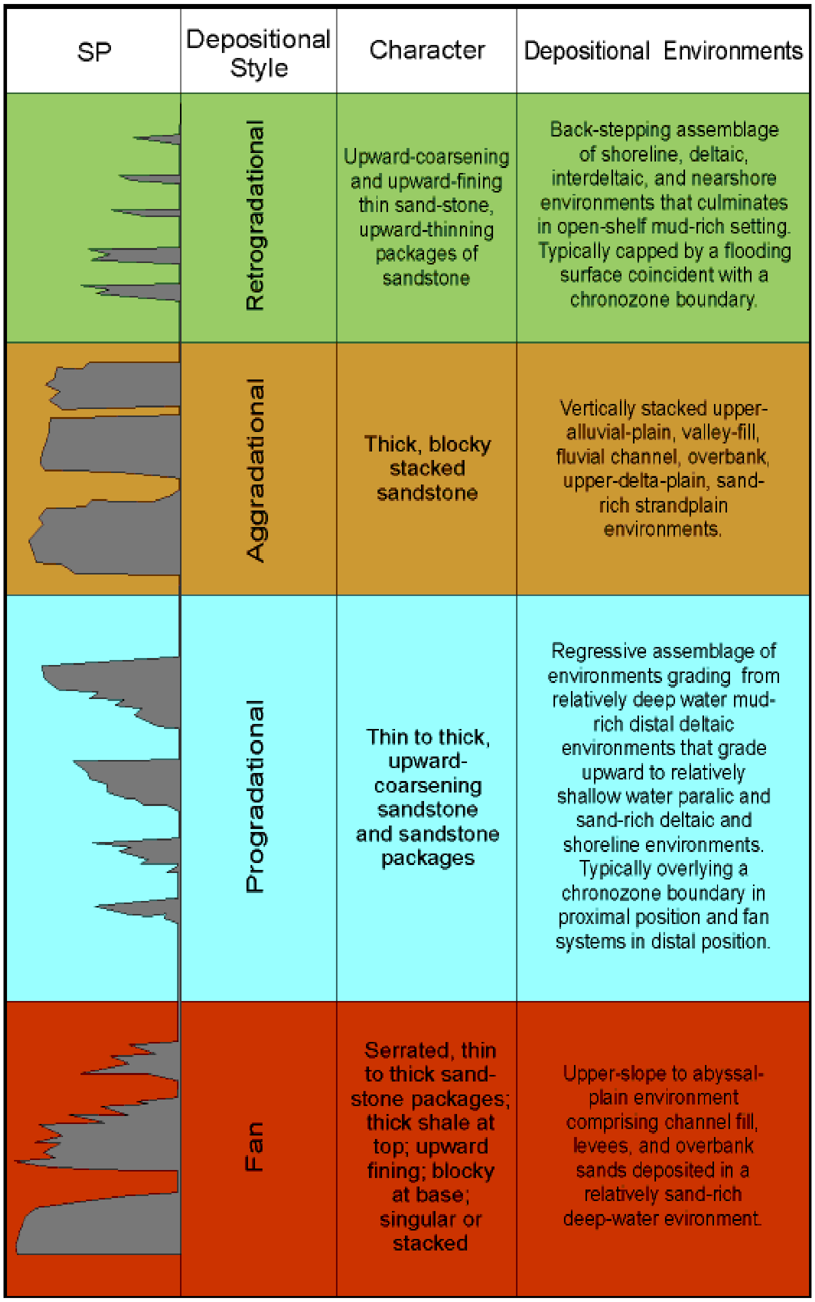

Figure 4. Schematic electric log illustrating typical SP response by depositional style/facies.

upward-coarsening progradational parasequences. When stacked, the thin progradational parasequences form a back-stepping 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 (figure 4). 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 typically coarsen and thicken upward (figure 4) 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.

Major structural processes in the northern Gulf of Mexico include the formation of large, allochthonous salt bodies, updip extension by growth faulting, and downdip contraction by folding and thrusting or canopy shortening (Peel *et al.*, 1995). Seni et al., (1997) and Hentz et al., (1997) treated fan plays somewhat simplistically, defining each fan play solely by its chronozone. However, because of the linked structural system within the northern Gulf of Mexico, fan plays can be refined to fit into a structural setting that better relates them to their depositional and salt tectonic history.

Fan 1 Plays (F1) — The area of the F1 fan plays occurs between the present-day coast and the shelf edge. This is the

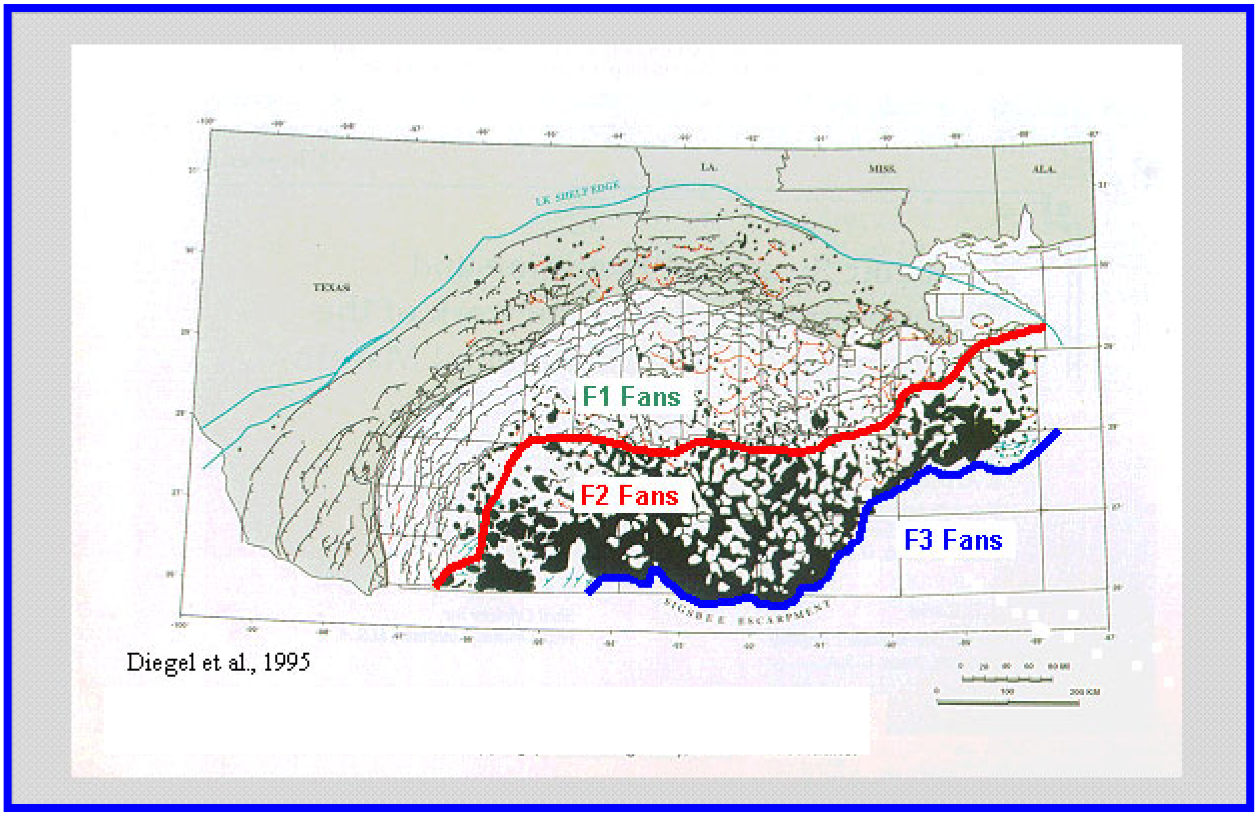

Figure 5. Structural summary map of the northern Gulf of Mexico Basin with superimposed F1, F2, and F3 play areas. Black areas are shallow salt bodies. Tick marks are on the downthrown side of major growth faults: black = seaward dipping; red = landward dipping (counter-regional).

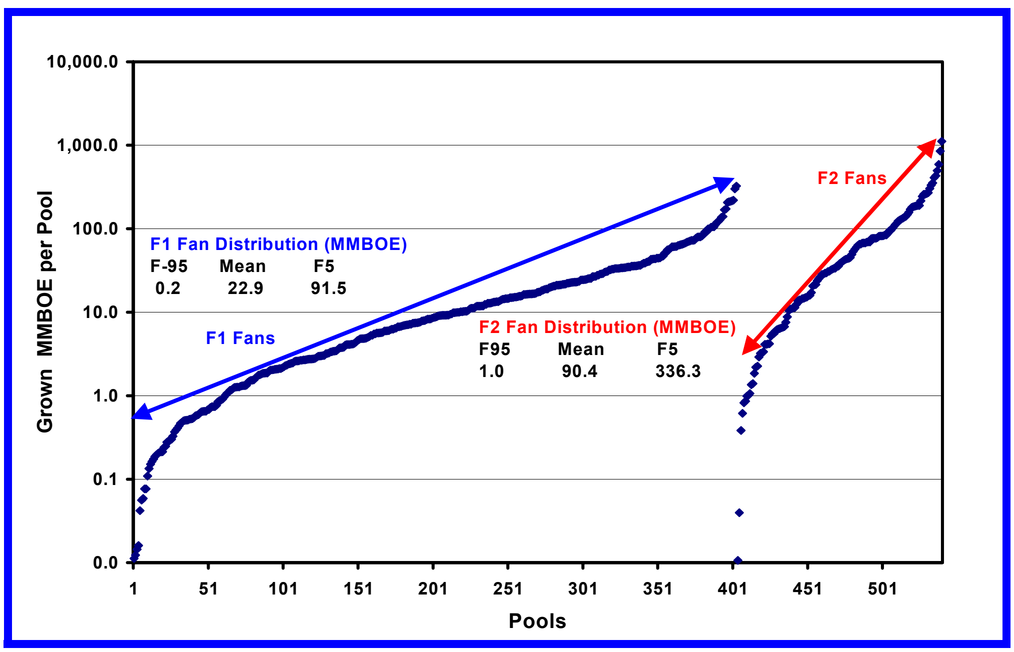

Figure 6. Ranked pool size distribution curves of appreciated reserves. The curves illustrate the two populations of F1 fan and F2 fan pools, and that F2 fan pools can be significantly larger than F1 fan pools.

major region of extension on the GOM shelf. Salt-withdrawal basins and down-to-the-south, listric growth faults that sole into salt decollements and extensive salt welds linking the isolated salt bodies are the primary structural features in this area. These Cenozoic structures are thin-skinned, gravity-driven, and powered by the deposition of sediment on the shelf and upper slope. Deformation driven by sedimentation takes the form of salt displacement (including diapirism, salt withdrawal, and salt canopy development) and seaward gravity spreading and sliding (Peel *et al.,* 1995). This structural style developed in the Eocene and continues through the present as the result of the clockwise regional migration of a series of Cenozoic deltas from south Texas in the Eocene to southeast Louisiana in the Plio-Pleistocene (Feng and Buffler, 1996; Peel *et al*., 1995; Fiduk *et al.,* 1999; Trudgill *et al*., 1999;).

Fan 2 Plays (F2) — The area of the F2 fan plays is located primarily on the present-day northern Gulf of Mexico slope. This area comprises the second part of the linked depositional and salt tectonic regime of the Gulf of Mexico, and contains a wide array of salt features. In the western and central Gulf, F2 fans occur approximately from the present-day shelf edge to the farthest downdip limit of potential, allochthonous, tabular salt bodies. This downdip limit is defined by either (1) the Sigsbee Escarpment or (2) the downdip extent of the Perdido and Mississippi Fan Fold Belts, when they are outboard of the Sigsbee Escarpment. In the eastern Gulf, F2 fans continue to the southern extent of Louann Salt deposition, as defined by the downdip extent of the Salt Roller/High-Relief Salt Structure Play (UK5-UJ4 S1) (Lore *et al*., 2001).

In general, there is a gradual transition from small, isolated salt stocks and sheets surrounded by interconnected, fault-bounded salt-withdrawal basins (e.g., the Auger sub-basin) in the upper slope to large, contiguous salt canopies in the lower slope (Diegel *et al.,* 1995). The middle slope comprises large salt canopies and recently subsided salt-withdrawal basins, many of which appear thrusted over adjacent basin edges (Peel *et al.,* 1995). The emplacement and shortening of the salt canopies of the middle to lower slope and the formation of the Perdido and Mississippi Fan Fold Belts beneath and in front of the Sigsbee Salt Canopy comprise the contractional phase of the linked structural system in the northern Gulf of Mexico (Peel *et al.,* 1995).

In the southeastern Gulf of Mexico, salt structure growth may occur throughout the upper Jurassic through upper Pleistocene stratigraphic section. F2 fans typically occur in potential hydrocarbon traps consisting of high-relief, autochthonous salt swells and vertical welds/pinnacle salt structures. These structures formed when updip extension and associated gravity gliding continued into the Cenozoic and adequate salt volumes existed to provide salt to core them.

Fan 3 Plays (F3) — The F3 fan area covers the abyssal plain of the Gulf of Mexico in front of the Perdido and Mississippi Fan Fold Belts or the Sigsbee Escarpment. Since this area is basinward from the depositional edge of the Jurassic Louann Salt, there are no salt-cored or salt-withdrawal structures. However, differential compaction and some faulting may affect the F3 fan intervals near the ‘buried hill’ structures that occur in parts of the area. There are no productive F3 fan plays yet in the GOM.

Comparing the pool populations of F1 and F2 fans (figure 6), F2 pools, while fewer in number because of the relative immaturity of F2 plays, include significantly larger pools than are found in more mature F1 fan plays. The difference in the size ranges between F1 and F2 pools may be explained by the greater association with various salt structures found in the slope fan play area, and by more continuous reservoir sands, especially in the Miocene section.

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.

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 that have variable dip orientations and are predominant in central offshore Louisiana and eastern far-offshore Texas. 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.

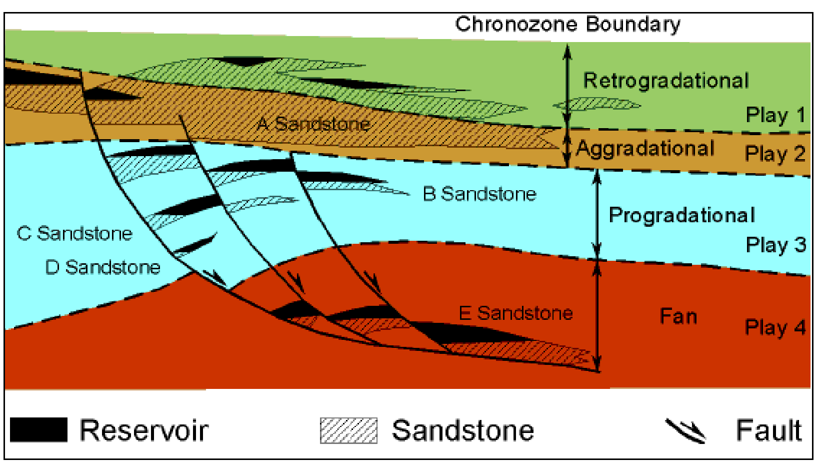

Figure 7. Schematic cross section of a typical field illustrating 12 fault-block reservoirs ("reservoirs"), 5 sandstone-body reservoirs ("sands"), 4 plays (equal to 4 pools within the one field), and 4 depositional styles/facies.

Structural control over the distribution of sands 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 and are assigned to a sand. Next, an extensive grid of approximately 100 geologic cross sections with parallel interpreted seismic cross sections was assembled correlating depositional styles and facies between each of the OCS fields. 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, play boundaries were defined for each of the established plays. The boundaries enclosed all active fields with proved reserves, selected unproved fields deemed economically viable at the time of this assessment, and outlier exploratory or field wells containing hydrocarbon shows. Finally, the same procedure was used to define the extent of potentially productive sands within the same chronozone and facies. The result was a play limit map illustrating the maximum extent of each play. The only significant exceptions to this procedure were for fan plays where structural setting partly defined play boundaries, and in purely structurally defined plays where structural setting alone defined plays.

Because a single field may produce hydrocarbons from several sands 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 existing offshore fields are associated with growth-fault systems and salt domes, they are structurally complex. As a result, an originally continuous sandstone body may eventually be segmented into separate reservoir compartments by displacement along faults. To manage the large volume of exploration and production data effectively, 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 7 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 Gulf of Mexico and Atlantic Continental Margin contain relatively few fields, and a limited number of wells have been drilled. Commercially recoverable hydrocarbons have been discovered and resulted in the development of 13 fields of upper Jurassic age and 5 fields of lower Cretaceous age. On the Atlantic Continental Margin, only 54 wells have been drilled, resulting in several subeconomic hydrocarbon flows from upper Jurassic and lower Cretaceous clastic reservoirs.

A significant problem in assessing plays that 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.

For conceptual plays without good analogs in the United States, appropriate analogs from producing regions around the world were used. 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 nine chronozones for this assessment (figure 1). In contrast to the Cenozoic chronozones, the Mesozoic chronozones are described as either clastic or carbonate (e.g., Lower Cretaceous Clastic (LK C1) or Atlantic Middle Jurassic Carbonate (AMJ B1) 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

Play Risk Analysis Form **2000 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	
2. Reservoir component **a.** Reservoir quality **b.** Depositional environment **c.** Diagenesis	
3. Trap component **a.** Closure **b.** Seal	
Play Success (Marginal Probability of hydrocarbons, MPhc) (1) x (2) x (3) **Play Risk** (1 - Play Success)	
Comments:	

Figure 1. MPhc worksheet used for estimating play geologic risk (refer to text for explanation).

Geologic risk assessment is the process of subjectively estimating the chance that at least a single hydrocarbon accumulation is present in the area being assessed (i.e., the marginal probability of hydrocarbons [MP_{hc}]). 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 MP_{hc} 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 MP_{hc} 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 MP_{hc} differs from the prospect-level MP_{hc}, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect. The play-level MP_{hc} 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.

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 exist in the play. Elements that affect the probability of hydrocarbons existing 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 on the basis of 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 predate the main phases of hydrocarbon expulsion.

Score 0.6-0.4

Source rock: Source rock may or may not be present according to 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 DHI's, 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 postdate 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 the trap component is assessed. 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 on the basis of 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: On the basis of 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)—Overview

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 (UCRR) 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 UCRR 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.

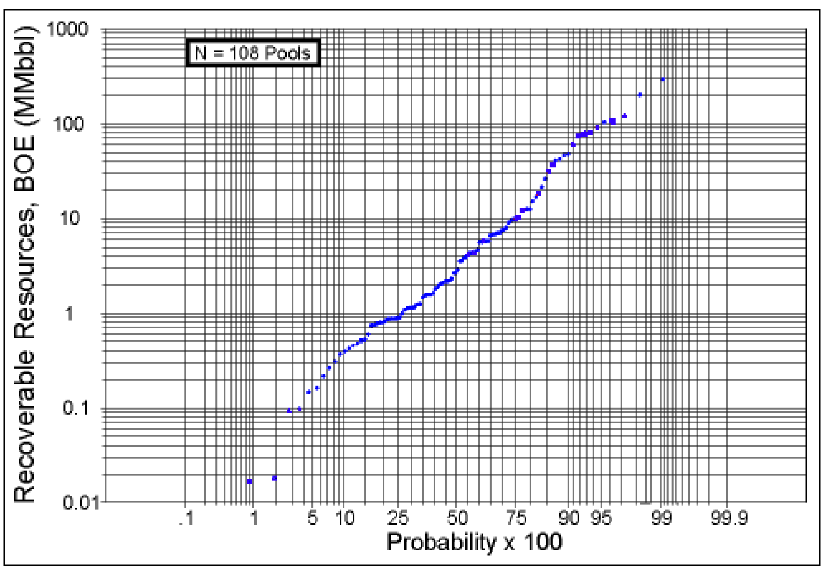

Figure 1. Sample lognormal distribution.

It has been recognized 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 specified by the mean (m, 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 character-

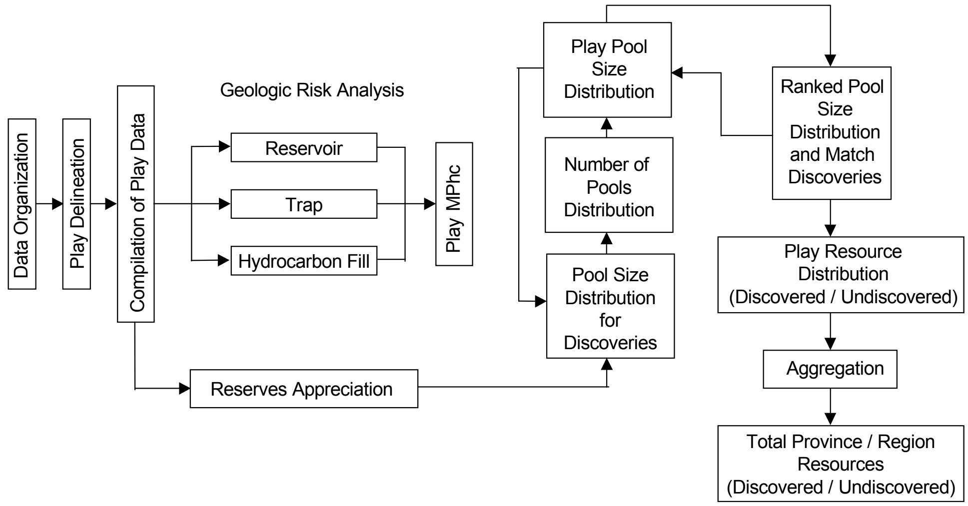

Figure 2. Process flow chart for resource assessment.

istic 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 UCRR were to

- 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.

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.

Established Plays

An effective assessment of undiscovered petroleum in a play can be developed from estimates of (1) the size distribution of the potential pools in the play, (2) the distribution of the total number of pools (N) if the play exists, and (3) an assessment of the appropriate marginal probability of hydrocarbons (MP_{hc}) (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

2000 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 1/1/99	
Oil	____MMbo
Gas	____Bcfg
BOE	____MMBOE
after reserves appreciation (through 12/________)	
Oil	____MMbo
Gas	____Bcfg
BOE	____MMBOE
Unproved reserves of play as of 1/1/99	
Oil	____MMbo
Gas	____Bcfg
BOE	____MMBOE
after reserves appreciation (through 12/________)	
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 discovery 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).

2000 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 (3 chances in 4 that at least this many pools remain to be discovered)	____pools
High estimate (1 chance in 4 that at least this many pools remain to be discovered)	____pools
Mean estimate (2 chances in 4 that at least this many pools remain to be discovered)	____pools
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).

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 m, σ^2, and N. The model selects values from the distribution of each parameter and generates pool rank plots. For each iteration the discovered pools are then matched to the predicted pool size distribution. 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 m 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

2000 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).

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 m and low σ^2 values. Therefore, m 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.

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 m, σ^2, and N values related to the play's geologic model. Different geologic models may have different values for these parameters and thus different pool size distributions.

Once a final acceptable model has been determined, additional program modules constrain predicted pool size ranges by the discovered sizes. The subjective process of matching discoveries to the pool size distributions further reduces the uncertainty associated with the potential resource volume of the play. The pool rank plots and cumulative probability distributions illustrate this process. In the pool rank plots, discovered pools are shown as single point values (dots) and projected undiscovered pools as distributions (bars). The length of the bar represents the F^{95} to F^{5} (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 imma-

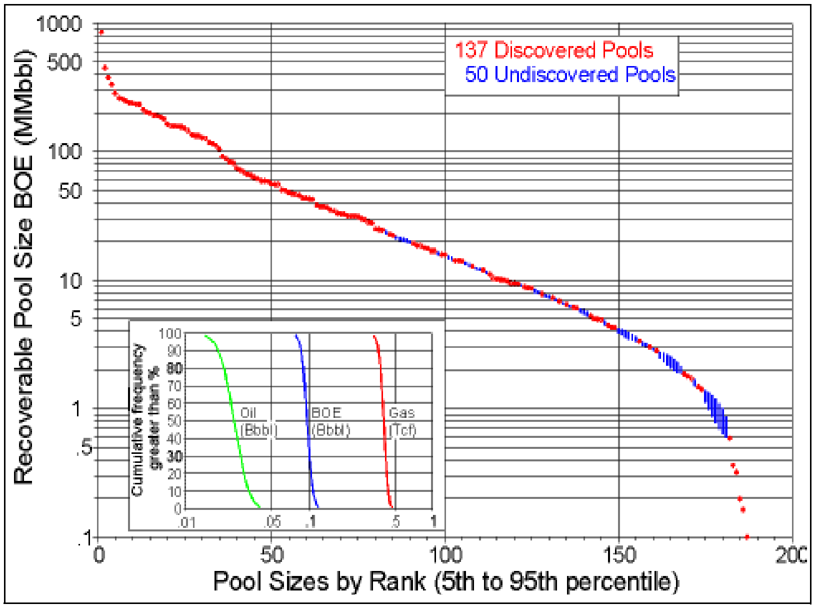

Figure 6. Pool rank plot of a mature play.

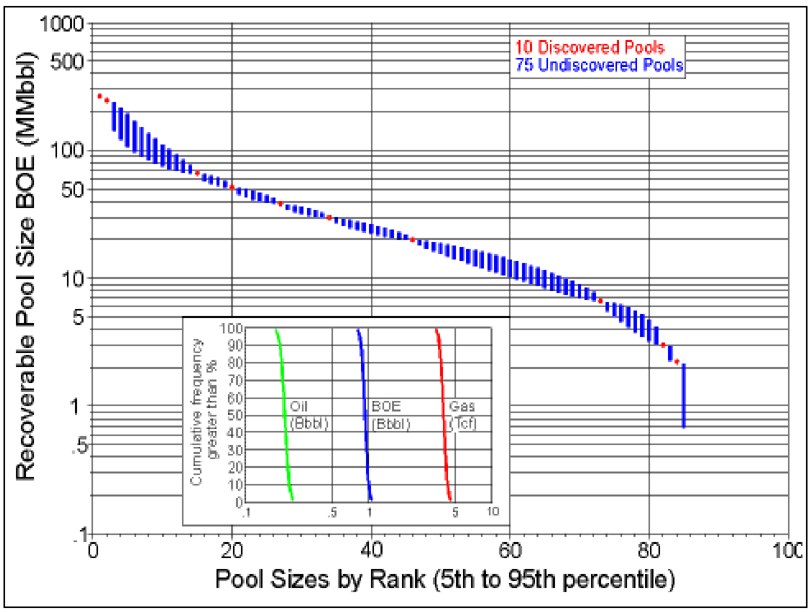

Figure 7. Pool rank plot of an immature play.

ture 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).

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 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., MP_{hc}, m, σ^2, and N) affecting the forecast for the play being assessed.

The basic data used in this assessment for the Cenozoic Province of the Gulf of Mexico have been released in the Bascle *et al*. (2001). 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 Norphlet Formation (UJ4 A1) play and the Lower Lower Cretaceous James Limestone (LK3 B1) play in the Gulf of Mexico have 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)—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 (UCRR) were to

- 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 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 UCRR is the play.

The assessment of UCRR 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

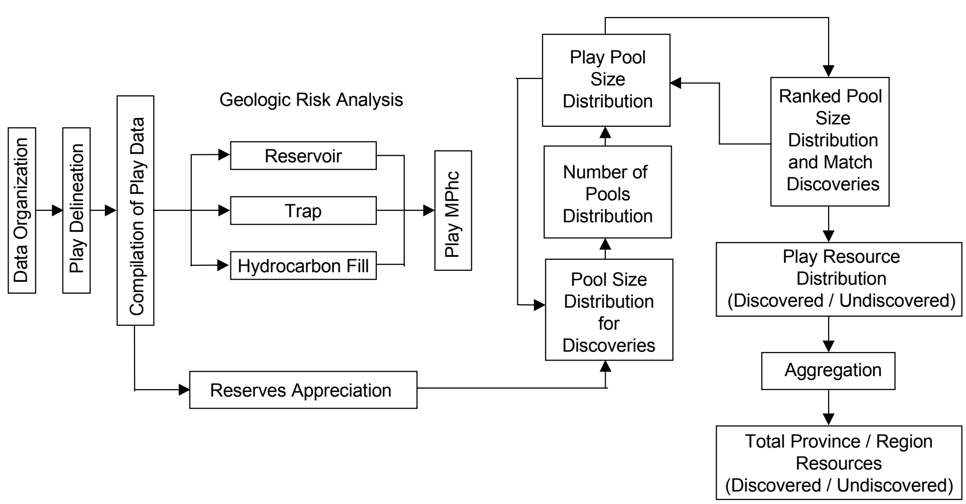

Figure 1. Process flow chart for resource assessment.

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. 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

- organizing data,
- delineating plays,
- compiling play data,
- estimating play and prospect chance of success,
- preparing discovery histories and pool size distributions for discoveries in established or analog plays,
- developing the number of pools distribution,
- estimating the play pool size distribution,
- estimating individual ranked pool size distributions and matching discovery data with forecast pool sizes, and
- estimating play resource distribution.

An effective assessment of undiscovered petroleum in a play can be developed from estimates of (1) the size distribution of the potential pools in the play, (2) the range in the total number of pools (discovered and undiscovered) (N), assuming that the play exists, and (3) an assessment of the appropriate marginal probability of hydrocarbons (MP_{hc}) (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 from repeated exploration of a particular play model.

A statistically significant number of commercial discoveries existed in 69 of the 92 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 and no model can accurately simulate them. 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 [MP_{hc}]). 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 MP_{hc} 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 MP_{hc} 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 for 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. Guidelines for estimating play geologic risk are provided in the *Geologic Risk Assessment* section. 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 MP_{hc} differs from the prospect-level MP_{hc}, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect. The play-level MP_{hc} 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 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 prop-

Play Risk Analysis Form **2000 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	
2. Reservoir component **a.** Reservoir quality **b.** Depositional environment **c.** Diagenesis	
3. Trap component **a.** Closure **b.** Seal	
Play Success (Marginal Probability of hydrocarbons, MPhc) (1) x (2) x (3) **Play Risk** (1 - Play Success)	
Comments:	

Figure 2. Mphc worksheet and guidelines for estimating play geologic risk.

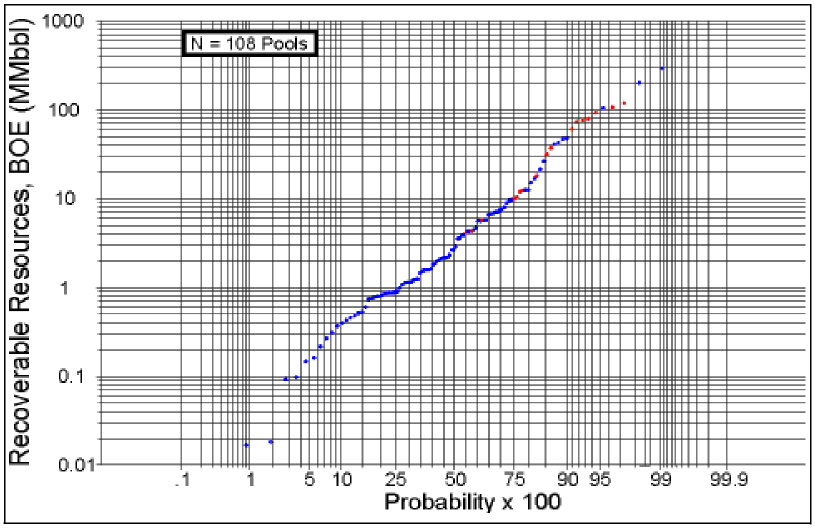

Figure 3. A lognormal distribution approximates a straight line.

erties 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 that pool size distributions can therefore be completely specified by the mean (*m*, 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:

$$Y = e^x;\ x \sim N(m, \sigma^2),$$

where $x \sim N(m, \sigma^2)$ means that x is normally distributed with mean m 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 (m 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 *m*, 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,* and *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.

As seen previously, a lognormal distribution may be described by a simple equation that is the function of two parameters, *m* and σ^2. If it is assumed that the pool size distribution is lognormal, the value for any individual pool can be estimated. Figure 3 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 are 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 *m* and σ^2, which 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 that satisfy the parameters of *m*, 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

2000 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 1/1/99	
Oil	________________MMbo
Gas	________________Bcfg
BOE	________________MMBOE
after reserves appreciation (through 12/________)	
Oil	________________MMbo
Gas	________________Bcfg
BOE	________________MMBOE
Unproved reserves of play as of 1/1/99	
Oil	________________MMbo
Gas	________________Bcfg
BOE	________________MMBOE
after reserves appreciation (through 12/________)	
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 discovery 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 4. Play analysis worksheet, part 1 (prior to GRASP).

(*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 4) 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 m 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 m 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 m 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 m and low σ^2 values. Therefore, m 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 m and σ^2 for the play pool size distribution.

The play's 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 m, σ^2, and N. The model selects

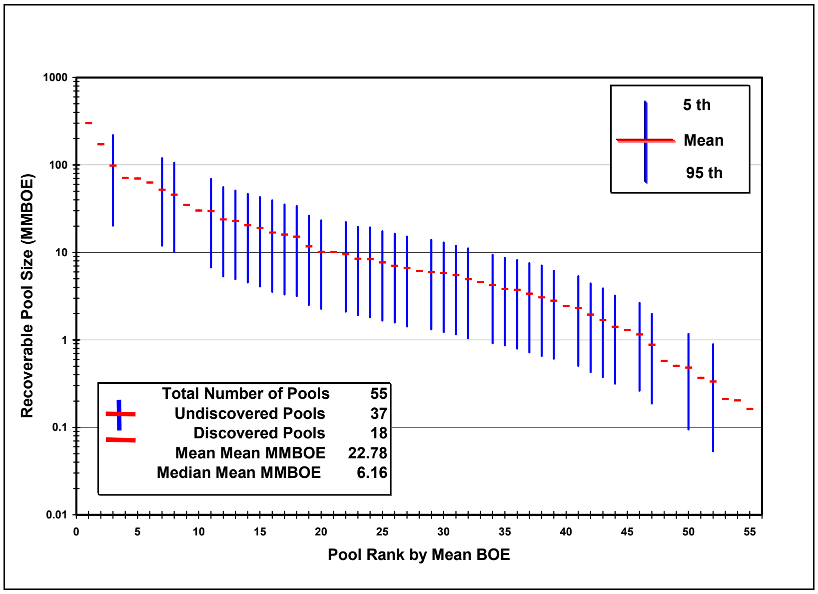

Figure 5. Sample pool rank plot. See text for description.

2000 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 6. Play analysis worksheet, part 2 (GRASP input).

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 5) indicates that the largest pool has been discovered with the largest undiscovered pool in the second rank. Each potential match is examined along with others for consistency 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 6). 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

2000 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 7. Play analysis worksheet, part 3 (after GRASP).

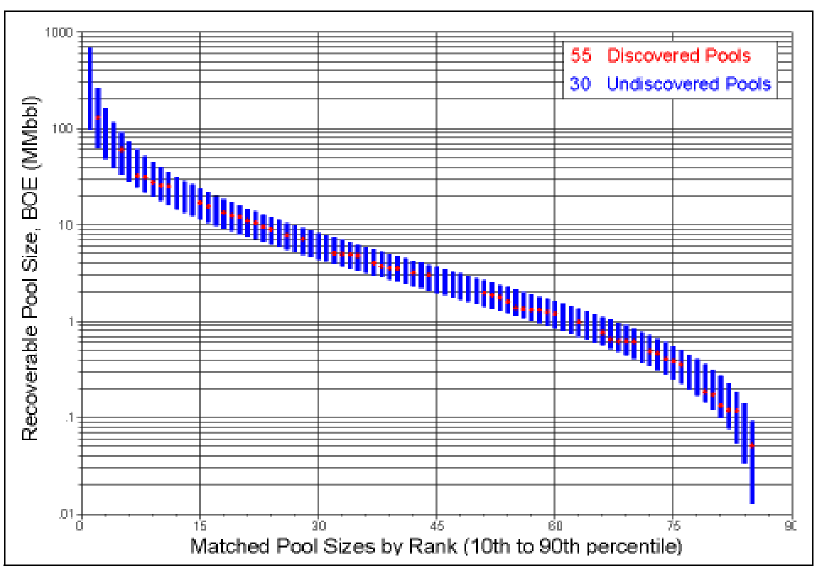

Figure 8. Matched pool rank plot. See text for description.

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 with an essential and valuable feedback mechanism. It provides an opportunity to challenge the geologic model, consider the feedback from “what if” analyses, and consider new information with which to refine the pool size distribution parameters and the total number of pools in the play (figure 7).

The model generates the ranked pools consistent with the inputs of m, 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 8 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

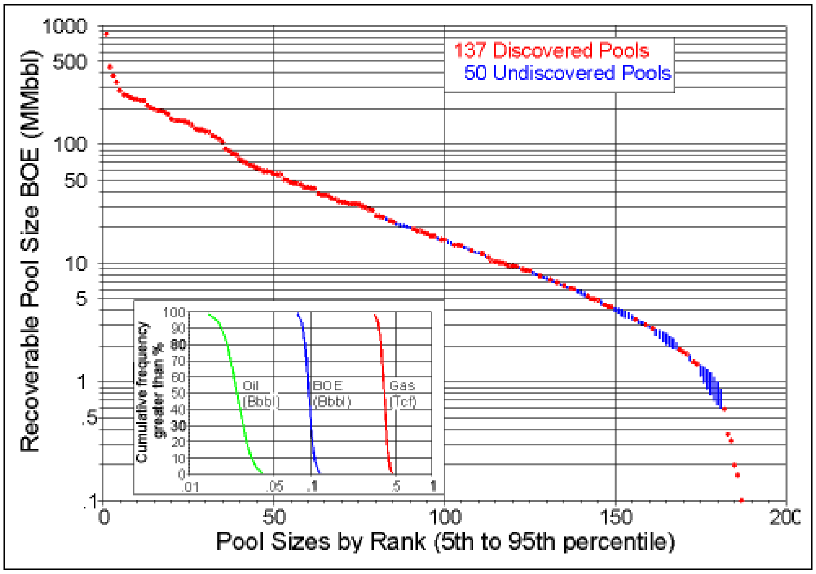

Figure 9. Pool rank plot for a mature play.

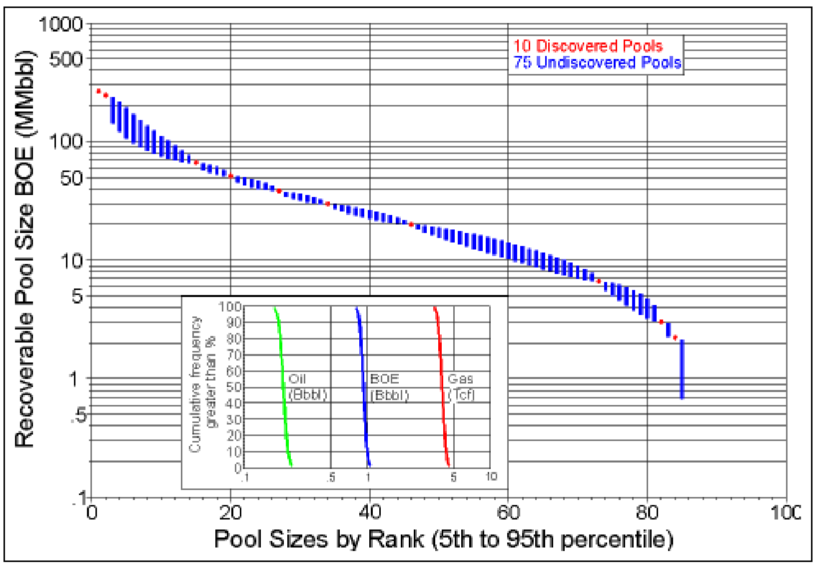

Figure 10. Pool rank plot for an immature play.

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 F_{95} to F_5 (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 9 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 10). 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), estimates of hydrocarbon volumes can be generated. 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, to generate the gas, oil, and BOE distributions:

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

Oil volume = (pore volume)(RECO)(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 on the basis of comparisons with other basins and plays and the expert judgment of the assessors. If sufficient subsurface mapping were available in the area, distributions for prospect size (area), number of prospects, and an average prospect-level MP_{hc} 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 m, 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 ($MPhc$, m, σ^2, and N) affecting the forecast for the play being assessed.

The basic data used in this resource assessment for the Cenozoic Province of the Gulf of Mexico are found in Bascle *et al*. (2001). 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 Norphlet Formation (UJ4 A1) play and the Lower lower Cretaceous James Limestone (LK3 B1) play in the Gulf of Mexico have 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 were gathered, there were three critical steps involved in the evaluation process: (1) assessing the play marginal probability, (2) developing a 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 a number of pools distribution, 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 MP_{hc}) 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 MP_{hc} to derive a number of pools distribution. The prospect-level MP_{hc} 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 then were 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 m 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 11 and 12, respectively.

Once the above steps were completed, the result was the development of a statistical model for each analog play fully described by $MPhc$, m, 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 (UCRR) 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

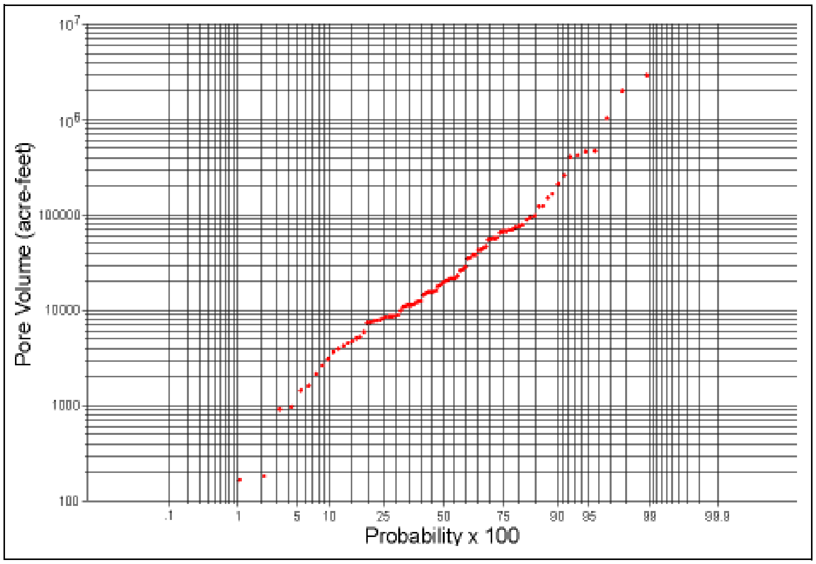

Figure 11. Gulf Coast analog pool size distribution.

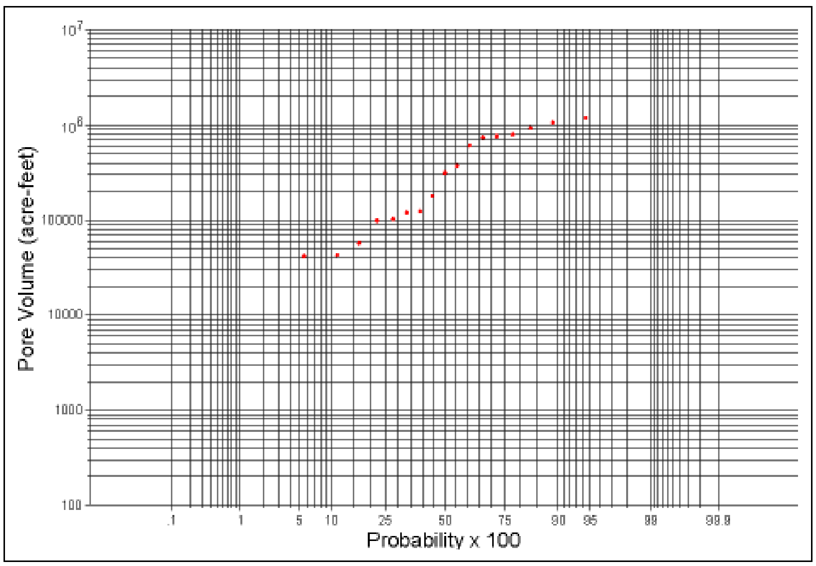

Figure 12. Scotian Shelf analog pool size distribution.

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 Economically Recoverable Resources (UERR)—Overview

The objective of the economic analysis phase of this assessment was to estimate the portion of the undiscovered conventionally recoverable resources (UCRR) that is expected in the long term to be commercially viable 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 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 decision maker; 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 (MP_{hc}) 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.

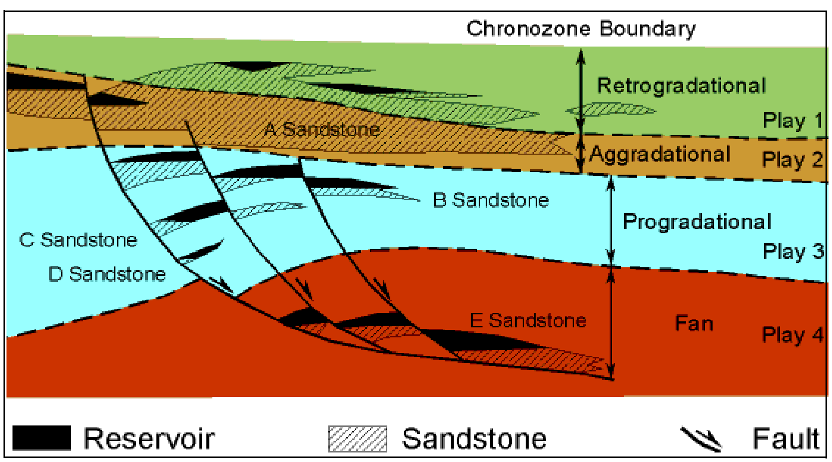

Figure 1. Schematic cross section illustrating stacked plays.

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 (UERR) would be overly 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 and planning area 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 UERR 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. The simulations used generalized exploration, development, and transportation costs and tariffs with their associated development scheduling scenarios for each relevant area. The basic economic test was performed at the pool (or

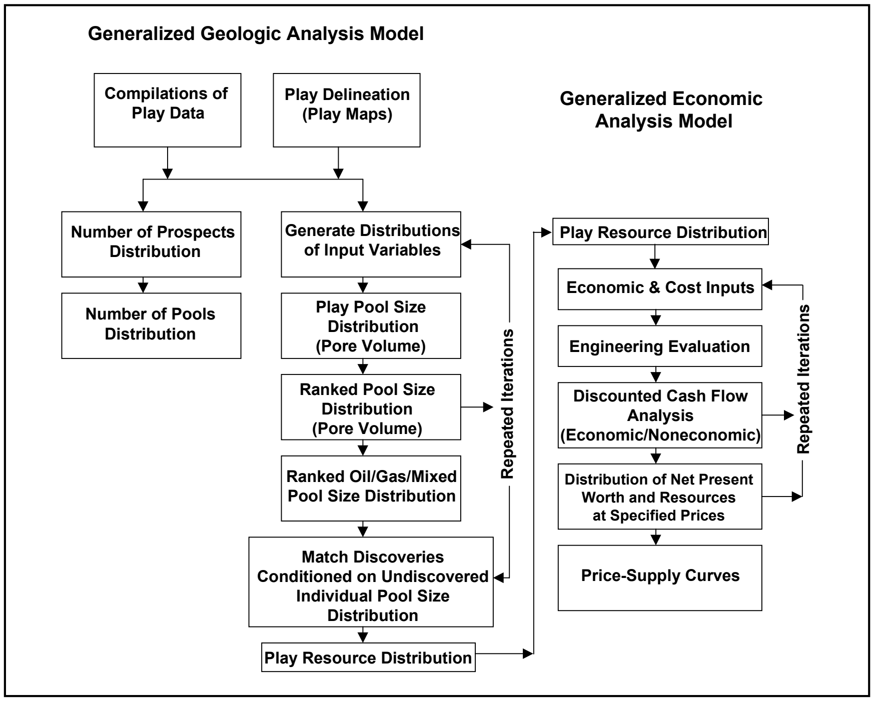

Figure 2. Process flow chart for economic resource assessment.

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 results.

Estimates of UERR are sensitive to price and technology assumptions and are presented primarily as price-supply curves (P-S curves) that describe a functional relationship between economically recoverable resources and product price. The P-S curves developed in this assessment are marginal-cost curves representing the incremental costs per unit of cumulative output (undiscovered economically recoverable resources). The P-S curves portray the estimated quantity of UCRR 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 P-S 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 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 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 field 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

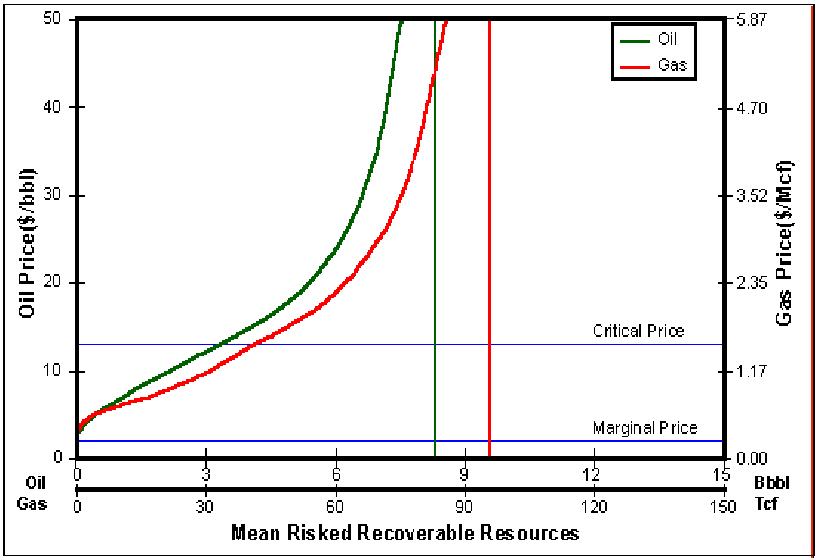

Figure 3. Sample price-supply curve.

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 UERR approaches this limit.

Undiscovered Economically Recoverable Resources (UERR)—Discussion

Since the resource assessment and economic evaluation of recoverable resources must be performed "pre-drill," considerable uncertainty exists 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 (MP_{hc}) 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. During 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 to a complete discounted cash flow model that analyzes the economics of every pool (or field) in an area. It then 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 insuffi-

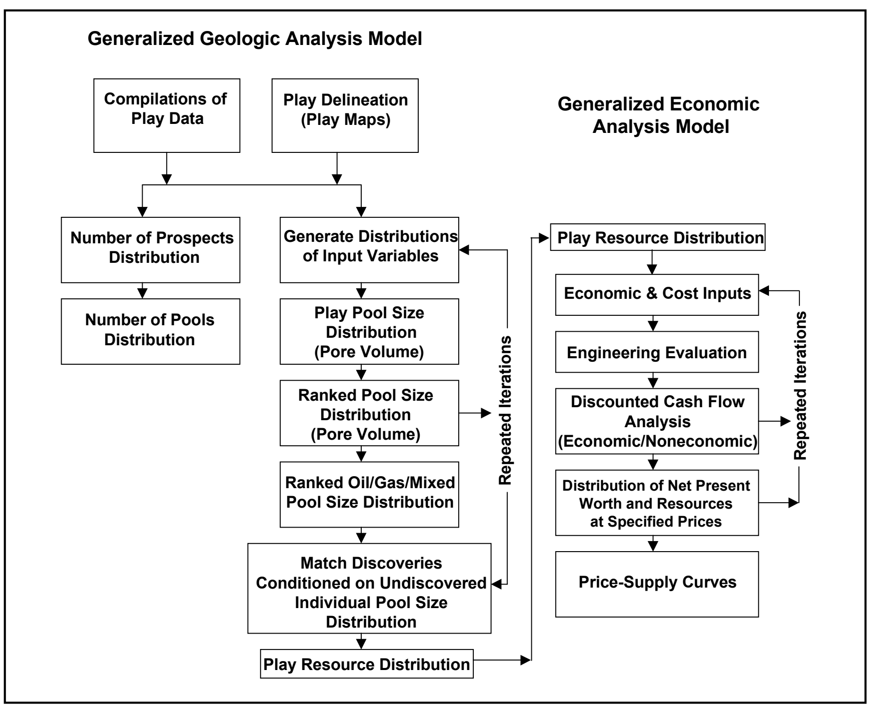

Figure 1. Process flow chart for economic resource assessment.

cient 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 (UCRR), 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 UCRR depends primarily upon (1) the total volume of UCRR, (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 are 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 will 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. Undiscovered economically recoverable resources (UERR) represent only a fraction of the physically recoverable resource. Estimates are derived of the potential volumes of economically recoverable hydrocarbon resources that may be discovered, as well as certain economic measures associated with the production of these resources.

Commercial viability or profitability is measured in this study from the two perspectives referred to as full- and half-cycle analysis. Full-cycle analysis does not include pre-lease costs, but does consider all leasehold, geophysical, geologic, and exploration costs incurred subsequent to a decision to explore in determining the economic viability of a prospect. The decision point is whether or not to explore. However, in the exploration process, fields are often discovered that cannot support both exploration and development costs. Some of these fields can be profitably developed once discovered. In a half-cycle analysis, leasehold and exploration costs, as well as delineation costs that are incurred prior to the field development decision, are assumed to be sunk and are not used in the discounted cash flow calculations to determine whether a field is commercially viable. The decision point is whether or not to proceed with development. In neither the full- nor the half-cycle scenario is lease acquisition or other pre-decision point leasehold costs considered in the evaluation. It is assumed in this analysis that the operator is a rational decision maker; 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 UERR 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 (MP_{hc}) generated by GRASP for each play are the key geologic inputs to the economic analysis performed by PRESTO. The Gulf of Mexico and Atlantic Regions both contain "stacked plays" (i.e., plays

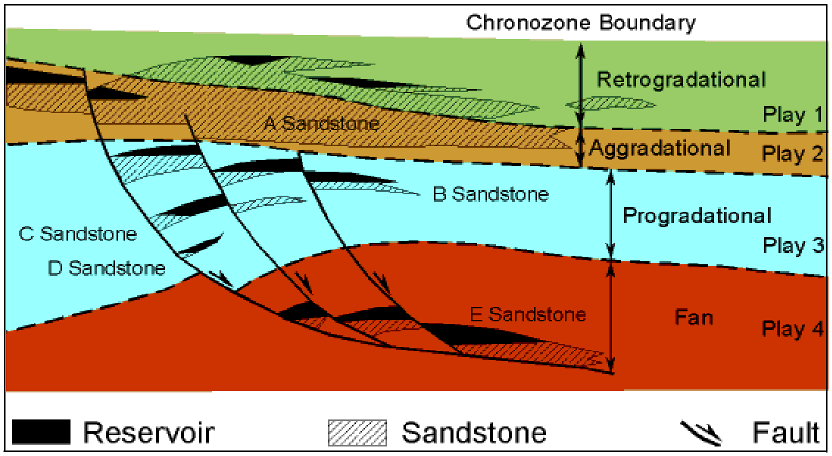

Figure 2. Schematic cross-section through a field illustrating stacked plays.

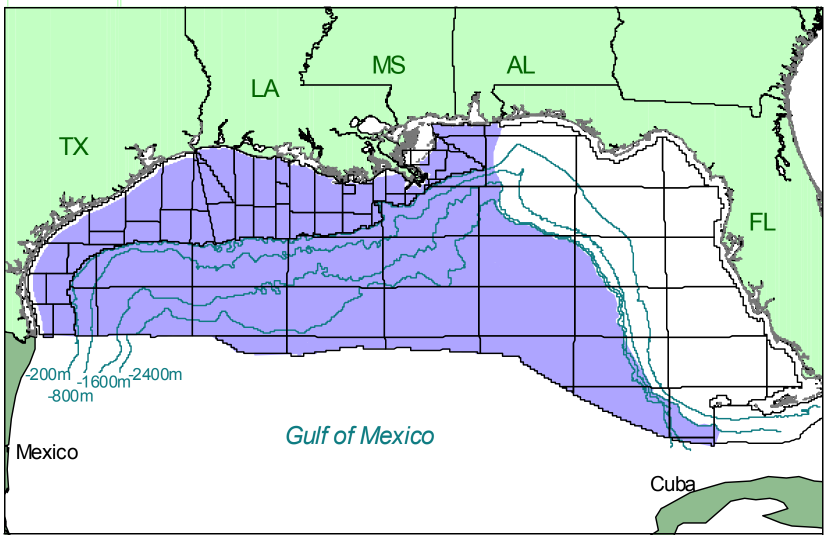

Figure 3. Map of the Gulf of Mexico Cenozoic Province. The shaded areas indicate the extent of the assessed plays in the Province. Fields in the Gulf of Mexico Cenozoic Province are used to illustrate field rank plots (figure 4).

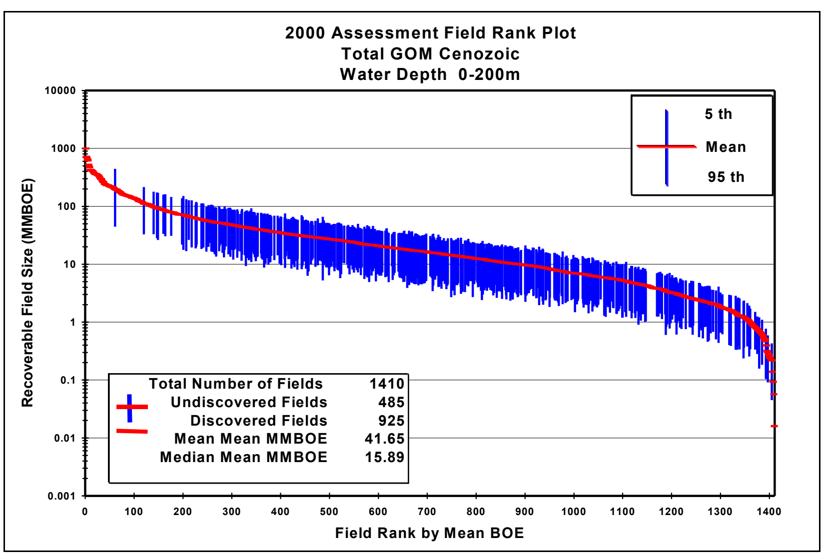

Figure 4. Gulf of Mexico Cenozoic Province 0-200 m field rank plot.

that overlie other plays at different depths) (figure 2). A "pool" is a hydrocarbon accumulation that exists in a play within a field. These stacked pools are commercially developed as single fields, and since 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.

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 in various water depth ranges 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 MP_{hc}, 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 compati-

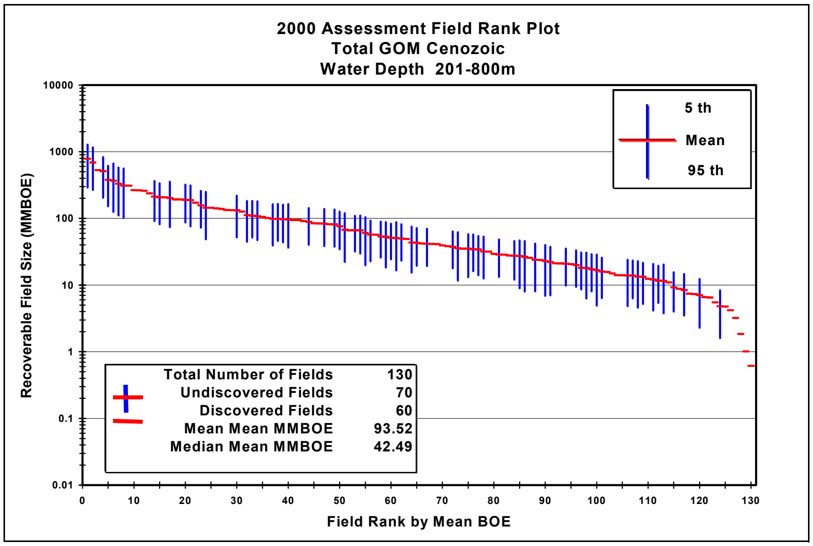

Figure 5. Gulf of Mexico Cenozoic Province 201-800 m total field rank plot.

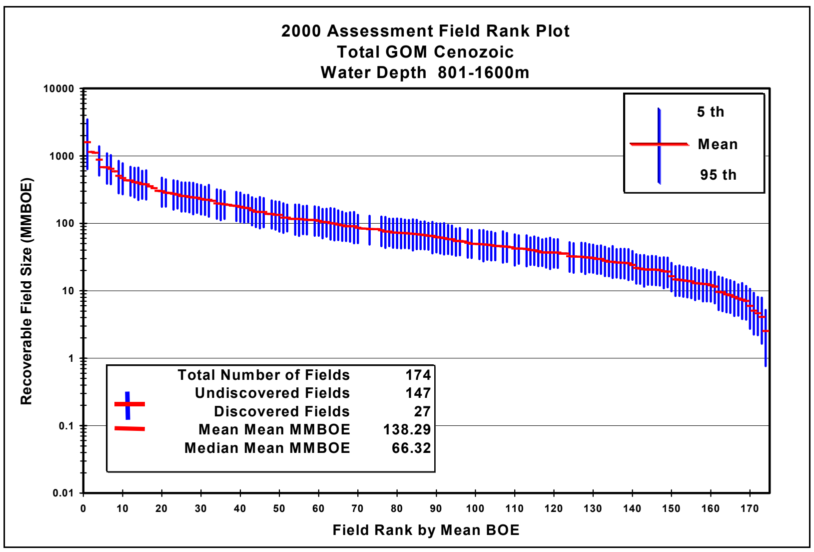

Figure 6. Gulf of Mexico Cenozoic Province 801-1,600 m field rank plot.

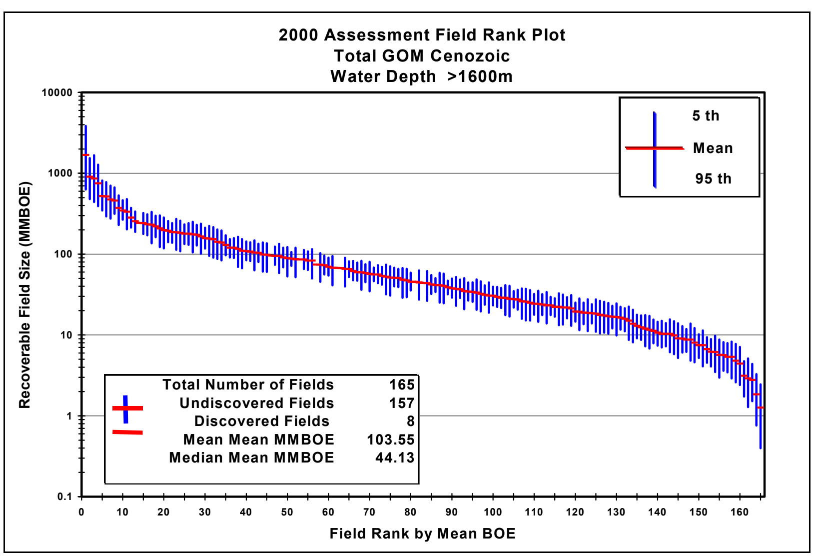

Figure 7. Gulf of Mexico Cenozoic Province greater than 1,600 m field rank plot.

ble 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 water depth. 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. Figures 4 through 7 show the field rank plots by various 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. On the basis of mean total endowment, the fields were allocated into the U.S. Geological Survey's field size classes (table 1) (Drew *et al.*, 1982). Both discovered and undiscovered fields were included in the field size classes (figures 8 through 11).

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 produc-

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	.38 - .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 1. USGS field size classes.

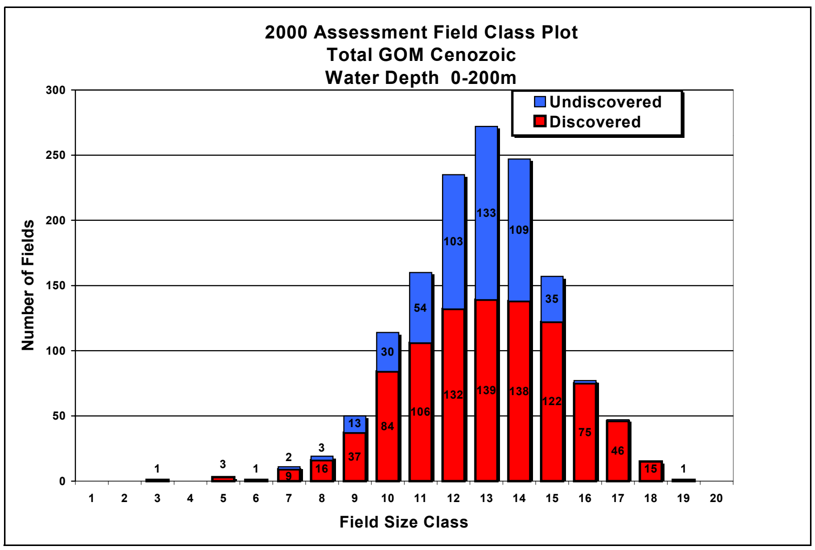

Figure 8. Gulf of Mexico Cenozoic Province 0-200 m field size histogram.

tion 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 explo-

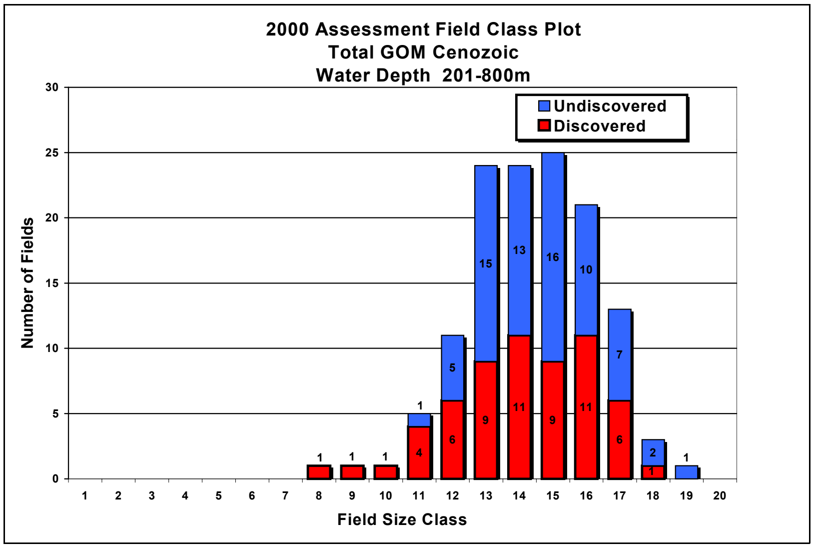

Figure 9. Gulf of Mexico Cenozoic Province 201-800 m field size histogram.

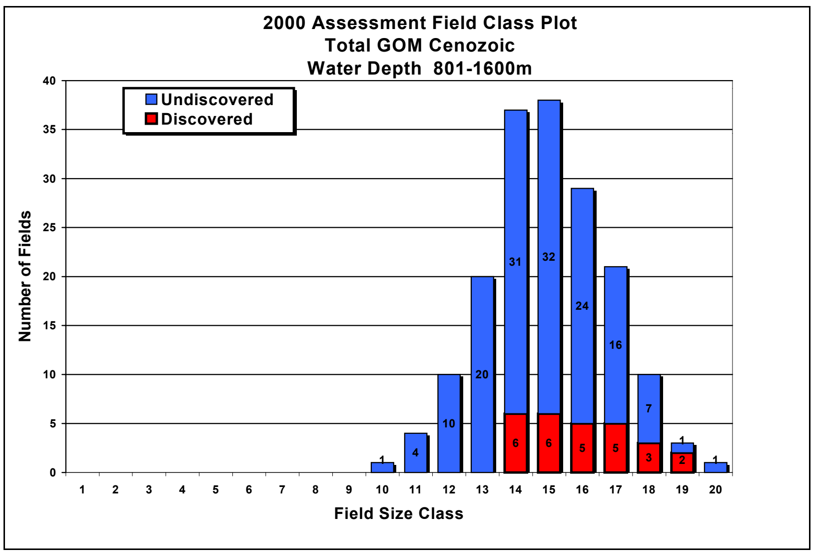

Figure 10. Gulf of Mexico Cenozoic Province 801-1,600 m field size histogram.

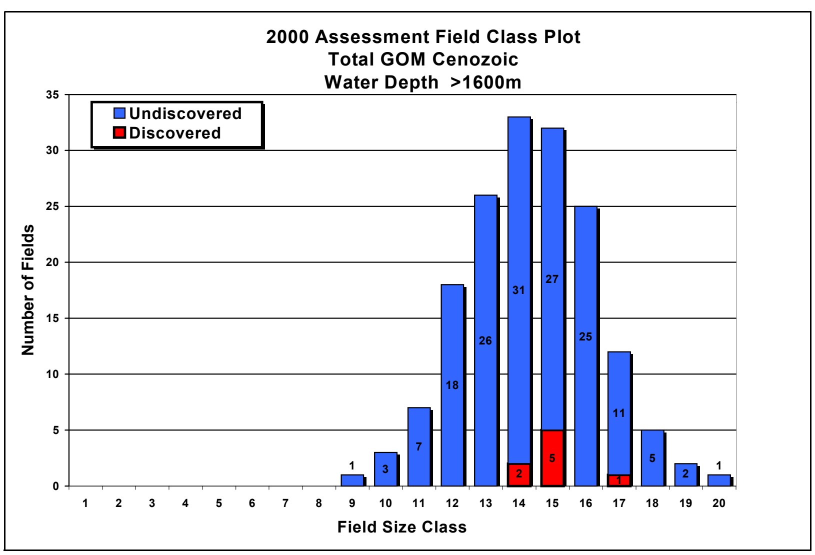

Figure 11. Gulf of Mexico Cenozoic Province greater than 1,600 m field size histogram.

ration 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 by use of 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

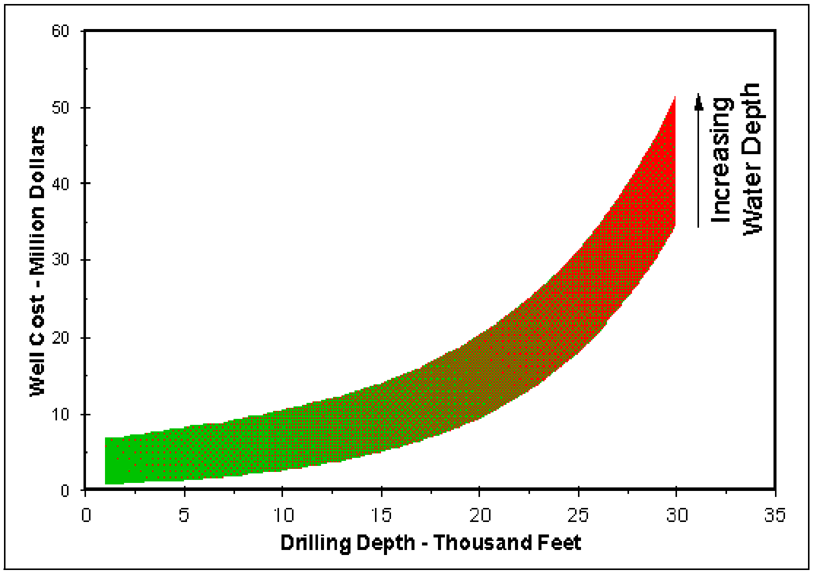

Figure 12. Exploration and delineation well costs by drilling depth.

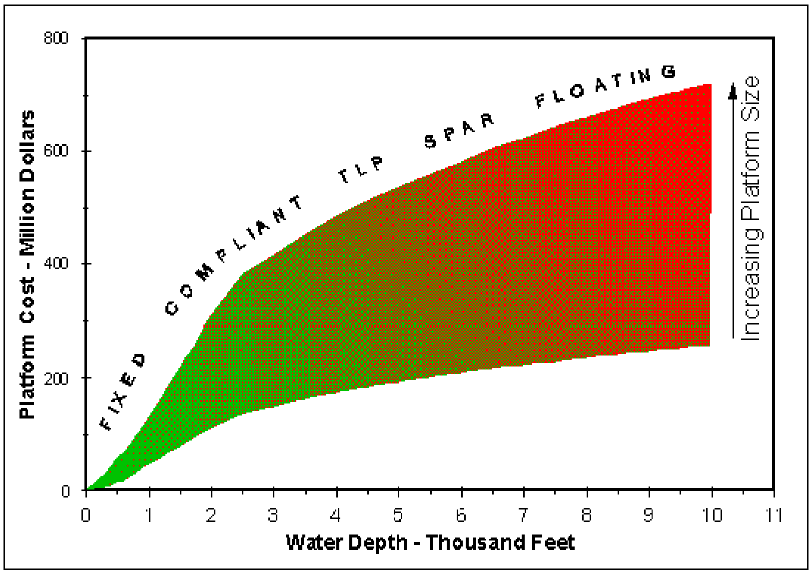

Figure 13. Platform and production facility costs by water depth.

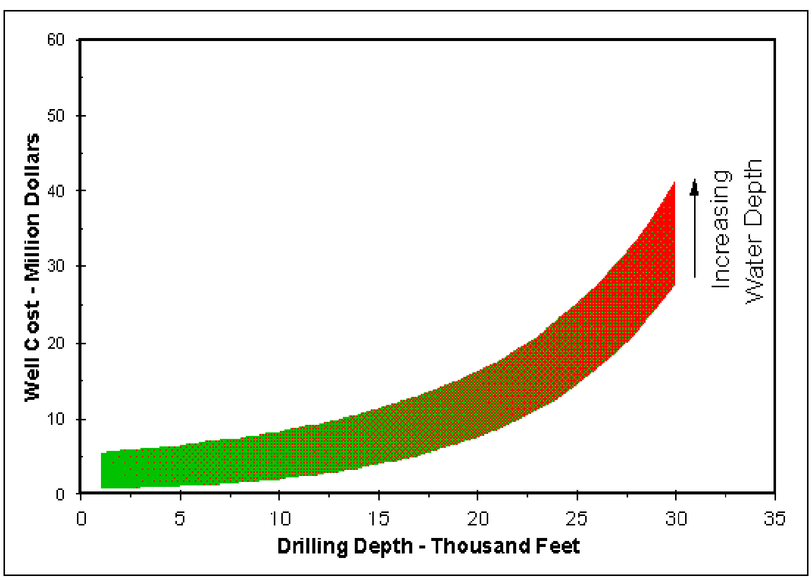

Figure 14. Development well costs by drilling depth.

(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 evalu-

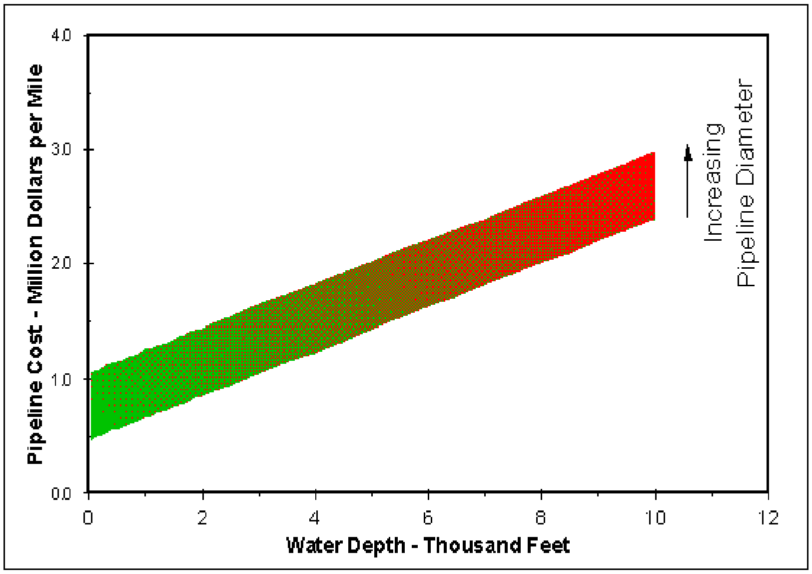

Figure 15. Pipeline costs by water depth.

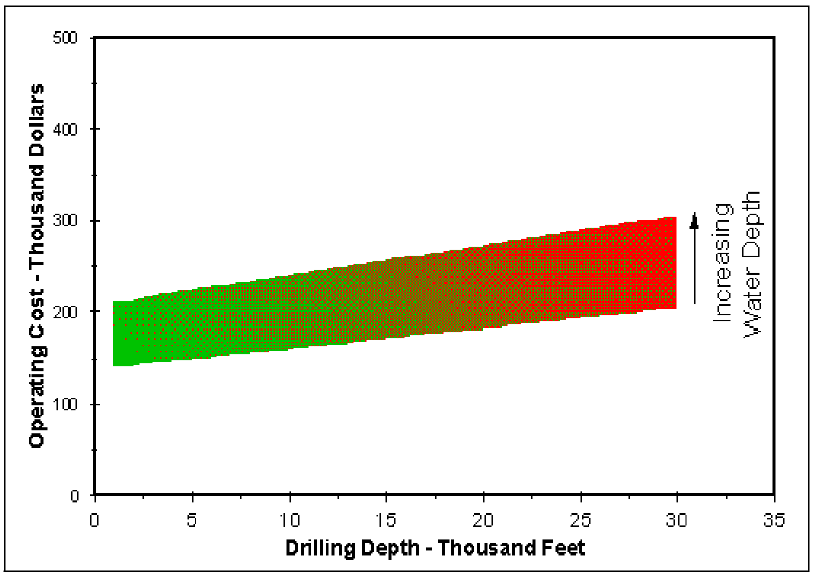

Figure 16. Operating costs per well per year by drilling depth.

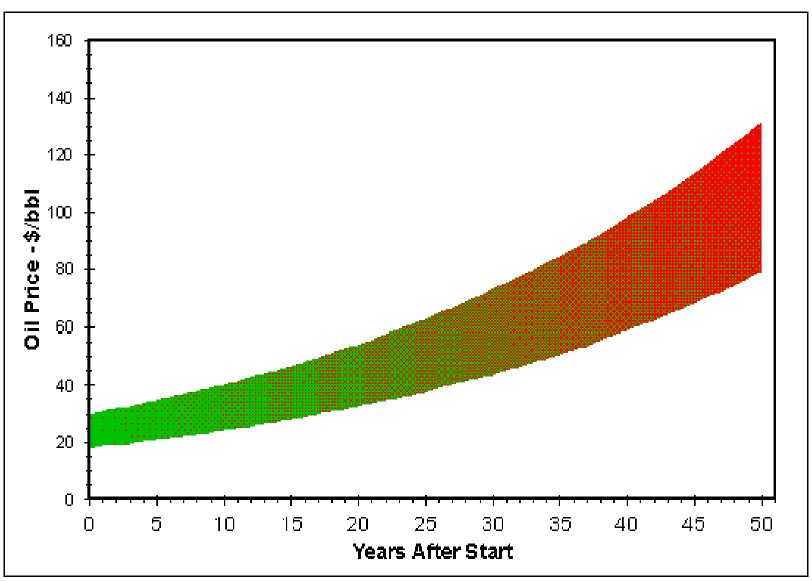

Figure 17. Oil price projections.

ations 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], and a $30/bbl scenario [$30.00/bbl and $3.52/Mcf] were used; figure 17 and figure 18),

- 12.5- or 16.7-percent royalty rate (The royalty rates used in the economic analysis do not reflect any royalty suspensions that may be applicable pursuant to the Deep Water Royalty Relief Act. 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.

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 fol-

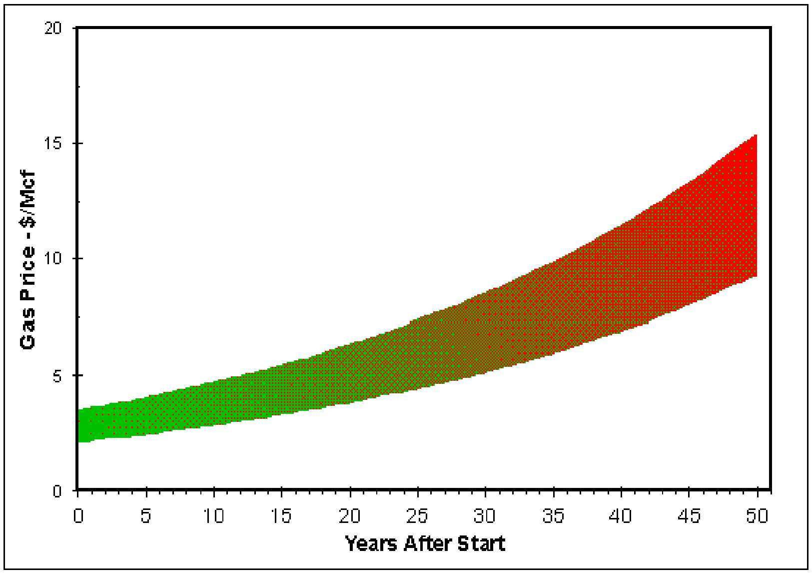

Figure 18. Gas price projections.

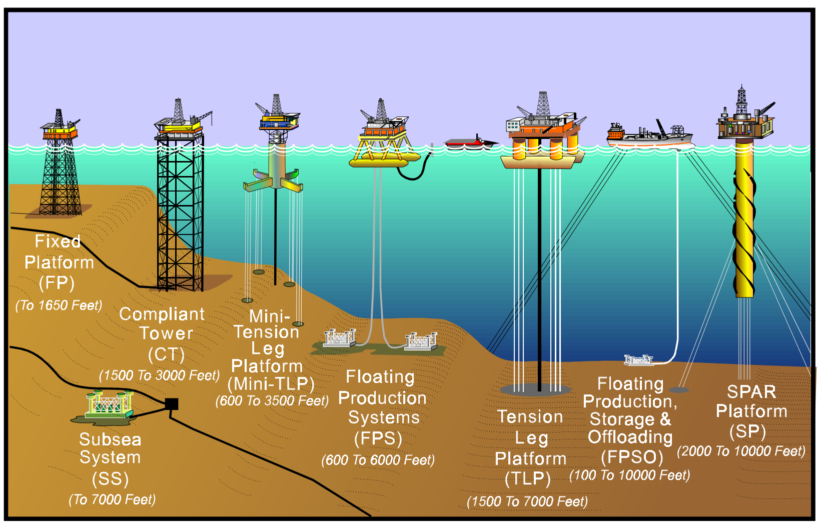

Figure 19. OCS development systems.

lowing:

- various water depth categories, each having differences in technologic requirements, are evaluated; Gulf of Mexico Region: 0-200 m, 200-800 m, 800-1600 m, 1600-2400 m, and >2400 m; Atlantic Region: 0-200m, 200-800 m, and >800 m.

- exploratory wells are generally drilled from jack-ups or semi-submersibles in 0-200 m, from semi-submersibles or drill ships in 200-800 m, and from drillships in >800 m,

- production wells are drilled from the platform (i.e., no pre-drills and templates),

- platforms are fixed structures in 0-200 m; a combination of fixed structures, compliant towers, and tension-leg platforms in 200-800 m; and a combination of tension-leg platforms, SPAR, and floating systems in >800 m (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 UERR 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

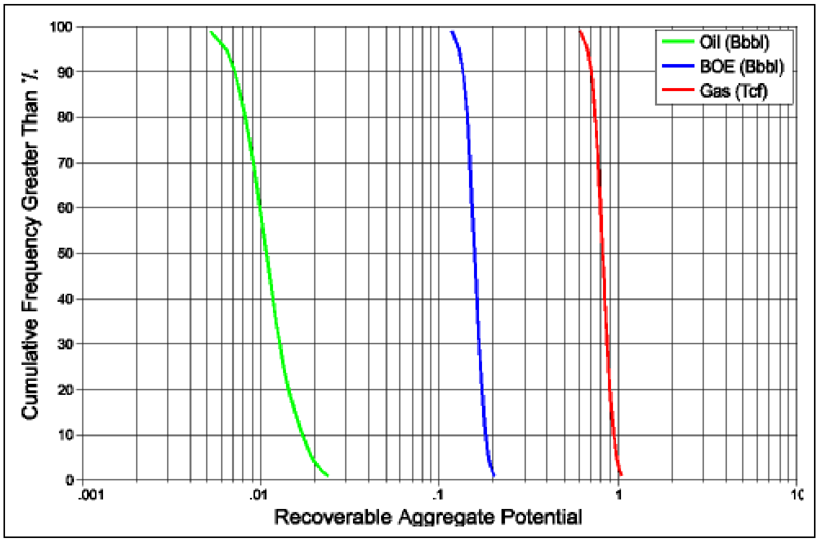

Figure 20. Cumulative probability distribution for an area having economic risk.

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.

Presentation of 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 UERR conditional on economic success represent the range of possible economic 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 UERR 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 they are present, contains them in quantities too small to be economic. Risked estimates of UERR 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 ($MP_{hc,econ}$), which is the joint probability of recoverable hydrocarbons being present and being present in commercial quantities:

$MP_{hc,econ}$ = (MP_{hc})(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 UERR are sensitive to price and technology assumptions and are presented primarily as price-supply curves (P-S curves) that describe a functional relationship between economically recoverable resources and product price. The P-S curves developed in this assessment are marginal-cost curves representing the incremental costs per unit of cumulative output (undiscovered economically recoverable resources). The P-S curves portray the estimated quantity of UCRR 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

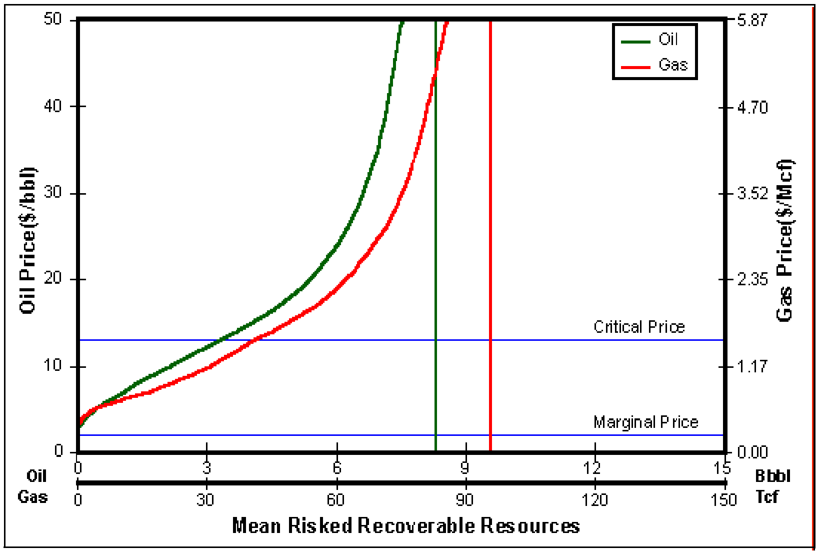

Figure 21. Sample price supply curve.

generated at each price level, but all of the P-S 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 UERR 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 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.

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 subsequent further analysis.

Assessment Results Introduction

A general discussion of the results of this assessment can be found in the following sections.

Detailed results of the assessment of undiscovered conventionally recoverable resources can be found in the various Gulf of Mexico and Atlantic play and play aggregation write-ups.

Detailed results of the assessment of undiscovered economically recoverable resources can be found in the *Economic Results* section for each planning area by water depth.

Reserves Results

Proved Reserves

Proved reserves in the 1,042 Gulf of Mexico Region fields used in this study (consisting of 2,369 pools) are estimated to be 14.266 Bbo and 162.711 Tcfg (43.218 BBOE). Of these fields, 47 are classified as oil and 640 are classified as gas, and 355 are mixed oil and gas; 181 of these fields are now depleted and abandoned. All of the proved oil and 99 percent of the proved gas reserves are within the Cenozoic Province. Of those in the Mesozoic Province, most are are in the Upper Jurassic Aggradational Norphlet Formation (UJ4 A1) play (<0.001 Bbbl, 2.232 Tcfg [0.397 BBOE]). There are no reserves in the Atlantic Mesozoic Province.

Remaining Proved Reserves

Remaining proved reserves in the 803 active proved fields within the Gulf of Mexico Region are estimated at 3.358 Bbo and 30.034 Tcfg. This represents 24 and 19 percent, respectively, of the current estimate of the original volume of proved reserves in these fields.

Unproved Reserves

Unproved reserves are present in 58 active unproved fields in the Gulf of Mexico Region. Preliminary estimates of unproved reserves in these 58 fields are 0.995 Bbo and 5.102 Tcfg (1.903 BBOE). Almost all of the unproved oil and 88 percent of the unproved gas reserves are located within the Cenozoic Province.

Reserves Appreciation

As of January 1, 1999, reserves appreciation projected 50 years into the future in the 1,042 fields are estimated to total 7.736 Bbo and 68.096 Tcfg (19.853 BBOE). All but 2.353 Tcfg and <0.001 Bbo (0.419 BBOE) of the appreciation are attributable to fields in the Cenozoic Province. The Atlantic Region contains no proved or unproved reserves and, therefore, has no 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.

Total Reserves

As of January 1, 1999, total reserves in the Gulf of Mexico Region are 22.997 Bbo and 235.910 Tcfg, of which 10.908 Bbbl and 132.677 Tcfg have been produced. Subtracting, 12.089 Bbbl, or 53 percent of the oil, and 103.233 Tcfg, or 44 percent of the gas, is estimated to remain in the ground.

Total Reserves by Depositional Style/ Facies

Uneven distribution of reserves by depositional style/ facies in the Gulf of Mexico Region is illustrated by total reserves amounts in the Cenozoic Province (table 1, figure 1). Historically, progradational sands contain the most total gas reserves and total BOE reserves, with 59 percent of the gas (137.441 Tcf), and 53 percent of the BOE (34.558 Bbbl). 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, rollover anticlines, and diapiric salt. All of these factors contribute to the high productivity of these sediments (Seni *et al.,* 1994).

In contrast to the progradational depositional style,

Cenozoic Province Total Reserves			
Depositional Style/Facies	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Retrogradational	0.131	4.878	0.999
Aggradational	1.270	10.694	3.173
Progradational	10.102	137.441	34.558
Fan	11.431	71.672	24.184
Other	0.063	5.992	1.129

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

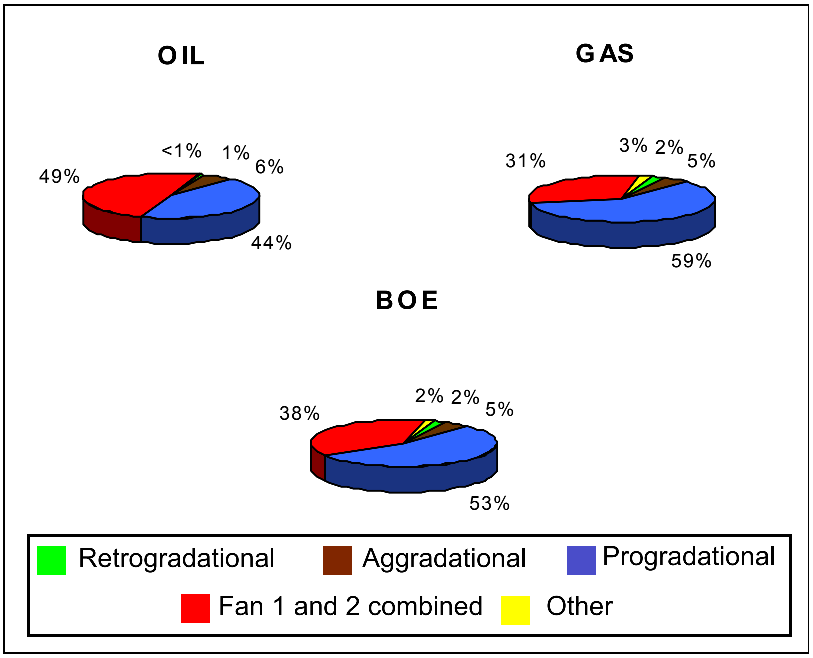

Figure 1.Total reserves in the Gulf of Mexico Cenozoic Province depositional style/facies. The progradational depositional style and the fan facies contain by far the most total reserves in the Gulf of Mexico Region.

Total Reserves by Geologic Age GOM Region	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pleistocene	7.571	90.953	23.755
Pliocene	6.324	34.547	12.471
Miocene	7.848	97.867	25.262
Oligocene	0.001	0.066	0.013
Eocene	na	na	na
Paleocene	na	na	na
Upper Cretaceous	0.000	0.000	0.000
Lower Cretaceous	<0.001	0.212	0.038
Upper Jurassic	<0.001	5.020	0.894
Middle Jurassic	na	na	na
Lower Jurassic	na	na	na
Upper Triassic	na	na	na
Span Ages	1.252	7.244	2.541

Table 2 . Total reserves in the Gulf of Mexico Region by geologic age. The structurally defined Cenozoic Perdido and Mississippi Fan Fold Belt plays span the Paleocene through Pleistocene and are included in the "Span Ages" category.

combined fan 1 and 2 facies in the Cenozoic Province contain the most oil total reserves, and the second-most gas and BOE total reserves (49 percent of the oil [11.431 Bbbl], 31 percent of the gas [71.672 Tcfg], and 38 percent of the BOE [24.184 BBOE]). Reflecting their increasing importance in the reserves base, the deepwater fan facies contain almost all of the unproved reserves of oil and gas, with 0.994 Bbbl and 4.423 Tcf (1.781 BBOE) in the Cenozoic Province.

Aggradational deposits contain 6 percent of the oil (1.270 Bbbl), 5 percent of the gas (10.694 Tcf), and 5 percent of the BOE (3.173 Bbbl) total reserves. The remaining 1 percent of the oil (0.131 Bbbl), 2 percent of the gas (4.878 Tcf), and 2 percent of the BOE (0.999 Bbbl) total reserves are within the retrogradational deposits. The remainder of total reserves in the Cenozoic Province are contained in an "other" category that includes mixed depositional styles, structurally defined plays, or caprock production.

Total Reserves by Geologic Age

Reserves in the Gulf of Mexico Region have been discovered in sediments ranging in age from Upper Jurassic to Pleistocene (table 2; figure 2). Miocene age sediments contain the most total reserves (39 percent mean BOE), followed closely by Pleistocene age sediments (37 percent mean BOE). Pliocene age deposits contain 19 percent of the Region's mean BOE total reserves. With reserves being discovered in the structurally defined Perdido and Mississippi Fan Fold Belt plays, 4 percent of mean total reserves in the Gulf of Mexico Region occur in plays that span geologic ages.

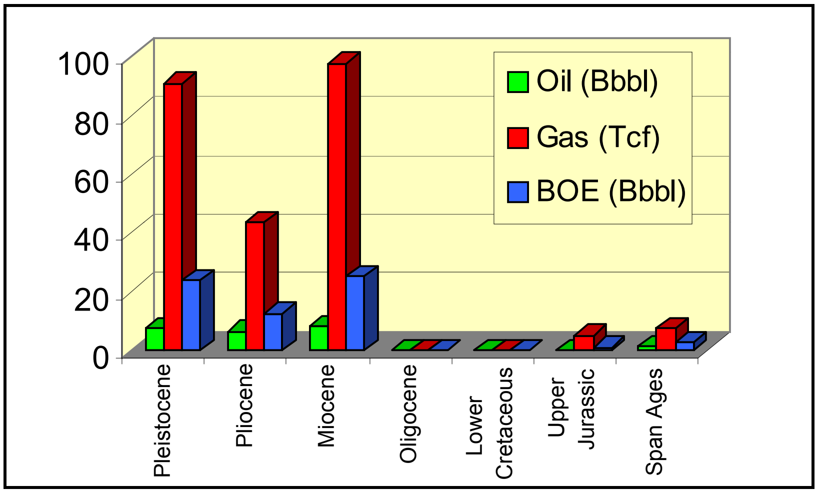

Figure 2. Total reserves in the Gulf of Mexico Region by geologic age. Series and systems not shown do not contain reserves. The structurally defined Cenozoic Perdido and Mississippi Fan Fold Belt plays span the Paleocene through Pleistocene and are included in the "Span Ages" category.

Undiscovered Conventionally Recoverable Resources Results

UCRR	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Gulf of Mexico Region (MPhc = 1.00)				
95th percentile		22.821	145.09	49.851
Mean	2,870	37.126	191.63	71.223
5th percentile		56.054	246.600	97.602
Cenozoic Province (MPhc = 1.00)				
95th percentile		25.754	145.26	52.708
Mean	2,532	30.783	170.65	61.148
5th percentile		36.390	198.66	70.393
Mesozoic Province (MPhc = 1.00)				
95th percentile		0.728	4.023	1.499
Mean	338	6.342	20.979	10.075
5th percentile		20.023	57.101	29.708
Atlantic Region (MPhc = 1.00)				
95th percentile		1.297	16.117	4.558
Mean	502	2.307	27.712	7.238
5th percentile		3.706	43.499	10.739

Table 1. Undiscovered conventionally recoverable resources (UCRR) for the Gulf of Mexico Region and Provinces, and for the Atlantic Region (equal to the Atlantic Mesozoic Province).

Cenozoic Province Mean UCRR Depositional Style/Facies	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Retrogradational	0.012	0.450	0.092
Aggradational	0.046	0.986	0.222
Progradational	0.657	13.612	3.079
Fan	30.060	154.574	57.565
Other	0.008	1.026	0.190

Table 2. Mean undiscovered conventionally recoverable resources (UCRR) in the Gulf of Mexico Region Cenozoic Province by depositional style/facies. Fan 1 plays and Fan 2 plays are combined into a single fan facies.

Gulf of Mexico Region

Mean undiscovered conventionally recoverable resources (UCRR) for the Gulf of Mexico Region are 37.126 Bbo and 191.627 Tcfg (71.223 BBOE). These resource estimates range from 22.821 to 56.054 Bbo and 145.088 to 246.600 Tcfg (49.851 to 97.602 BBOE) (table 1). The Cenozoic Province is forecast to contain 83 percent of the mean undiscovered conventionally recoverable oil and 89 percent of the mean undiscovered conventionally recoverable gas resources in the Region.

Gulf of Mexico Cenozoic Province

Plays in the Gulf of Mexico Cenozoic Province are forecast to contain mean UCRR of 30,783 Bbo and 170.648 Tcfg (61.148 BBOE). Resource estimates at the 95th and 5th percentiles are 25.754 to 36.390 Bbo and 145.264 to 198.661 Tcfg (52.708 to 70.393 BBOE) (table 1).

Gulf of Mexico Mesozoic Province

Plays in the Gulf of Mexico Mesozoic Province are forecast to contain mean UCRR of 6.342 Bbo and 20.979 Tcfg (10.075 BBOE). Resource estimates at the 95th and 5th percentiles are 0.728 to 20.023 Bbo and 4.023 to 57.101 Tcfg (1.499 to 29.708 BBOE) (table 1).

Four plays in the Mesozoic Province are forecast to contain approximately 2 BBOE each in mean UCRR. The largest of these plays is the concep-

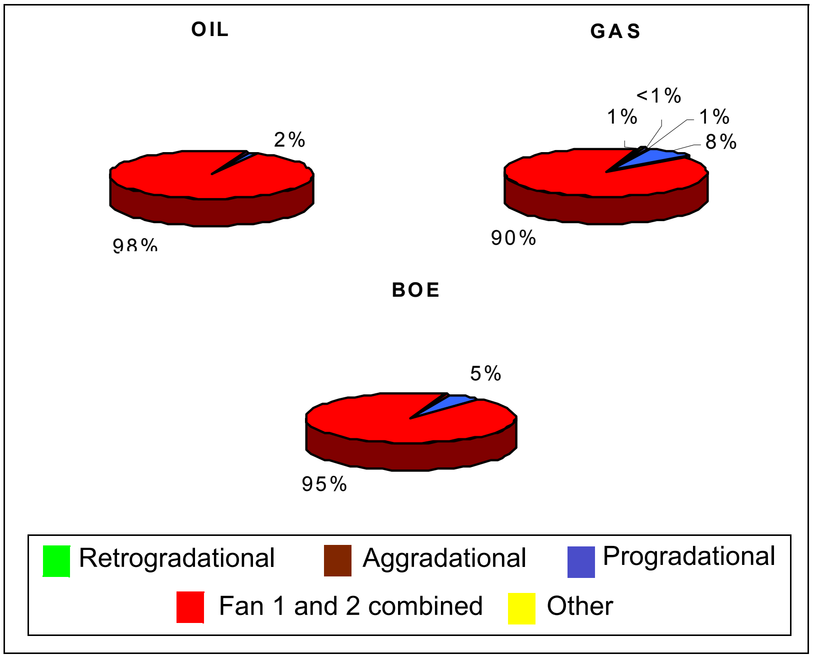

Figure 1. Mean undiscovered conventionally recoverable resources (UCRR) in the Gulf of Mexico Region Cenozoic Province by depositional style/facies. The fan facies contains by far the most UCRR.

Mesozoic Province Mean UCRR			
Lithology	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Siliciclastics	3.078	16.322	5.983
Carbonates	1.465	1.414	1.717
Other	1.799	3.242	2.376

Table 3. Mean undiscovered conventionally recoverable resources (UCRR) in the Gulf of Mexico Region Mesozoic Province by lithology. The “other” category includes structurally defined plays and plays containing both siliciclastic and carbonate potential reservoirs.

Atlantic Region Mean UCRR			
Lithology	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Siliciclastics	1.943	25.612	6.500
Carbonates	0.364	2.100	0.738

Table 4. Mean undiscovered conventionally recoverable resources (UCRR) in the Atlantic Region by lithology.

tual Cretaceous Mississippi Fan Fold Belt (UK5-LK3 X5) play (2.160 BBOE). Second is the established Upper Jurassic Aggradational Norphlet Formation (UJ4 A1) play (1.868 mean BBOE). Third is the conceptual Cretaceous Perdido Fold Belt (UK5- LK3 X4) play (1.773 BBOE). The fourth is the conceptual Mesozoic Structural Buried Hill (UK5-LTR BC4) play (1.603 BBOE). The Cretaceous Perdido Fan Fold Belt and the Mesozoic Structural Buried Hill plays in particular are noted for containing structures with very large closures.

Atlantic Region

All assessed Atlantic Region plays fall within the Atlantic Mesozoic Province. The Atlantic Mesozoic Province is forecast to contain mean UCRR of 2.307 Bbo and 27.712 Tcfg (7.238 BBOE). Sixty-eight percent of these total undiscovered resources is gas (table 1).

UCRR by Depositional Style/Facies and Lithology

The largest amount of UCRR in the Gulf of Mexico Cenozoic Province is forecast to occur in fan plays (table 2). Mean UCRR for these fan plays are 30.060 Bbo and 154.574 Tcfg (57.565 BBOE), corresponding to 98 percent of the mean oil, 90 percent of the mean gas, and 95 percent of the mean BOE in the Cenozoic Gulf of Mexico Region (figure 1).

Because so many of the plays in the Gulf of Mexico Mesozoic Province are conceptual and their depositional styles/facies unknown, the plays have been categorized into siliciclastic, carbonate, and “other” plays. “Other” plays include both structurally defined and mixed clastic and carbonate plays. The

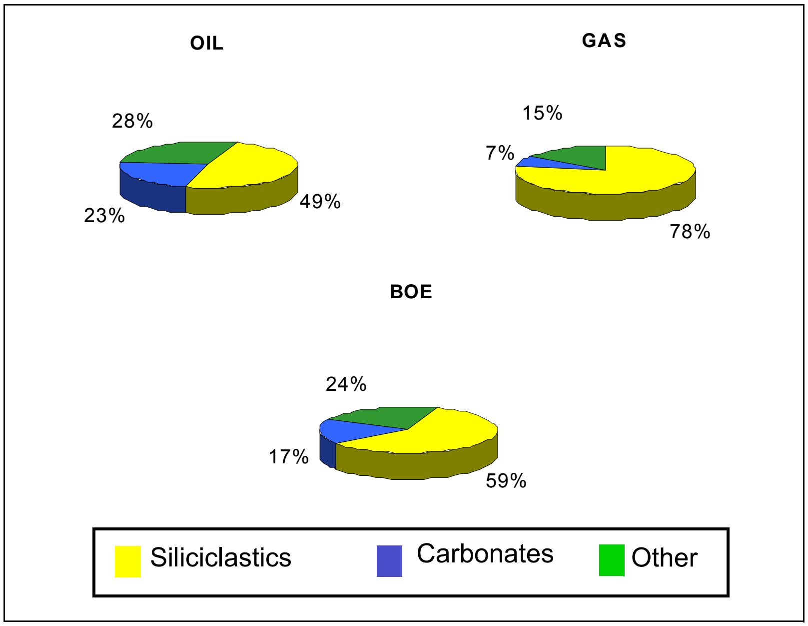

Figure 2. Mean undiscovered conventionally recoverable resources (UCRR) in the Gulf of Mexico Mesozoic Province by lithology. The "other" category includes structurally defined plays and plays containing both siliciclastic and carbonate potential reservoirs.

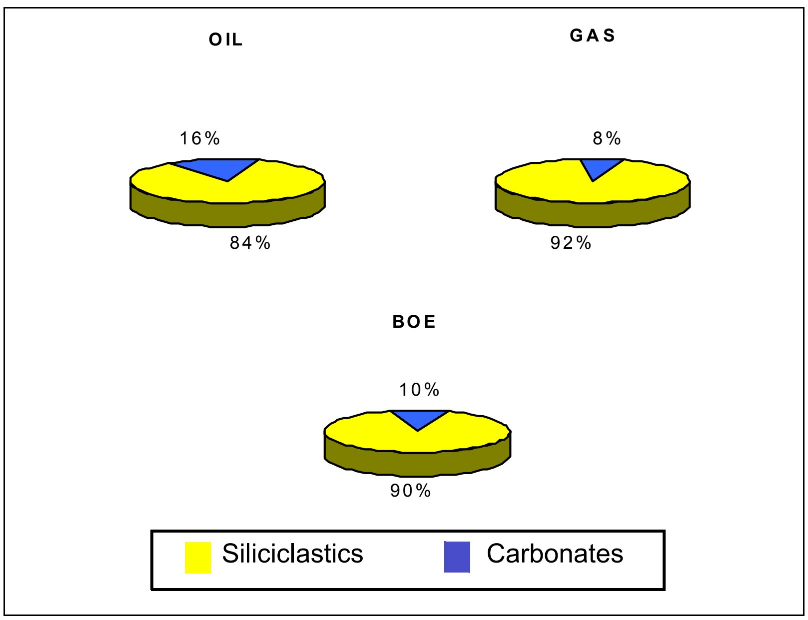

Figure 3. Mean undiscovered conventionally recoverable resources (UCRR) in the Atlantic Region by lithology.

largest amount of UCRR is forecast to occur in siliciclastic plays (table 3). Mean UCRR for the siliciclastics are 3.078 Bbo and 16.322 Tcfg (5.983 BBOE), corresponding to 49 percent of the mean oil, 78 percent of the mean gas, and 59 percent of the mean BOE in the Gulf of Mexico Mesozoic Province (figure 2).

Ninety percent of mean BOE UCRR in the Atlantic Region are forecast to occur in siliciclastic plays (table 4; figure 3).

UCRR by Geologic Age

UCRR in the Gulf of Mexico Region are forecast to be discovered in sediments ranging in age from the Triassic to the Pleistocene (table 5; figure 4). Structurally defined plays, or plays that otherwise span geologic ages, are included in the "Span Ages" category. These plays account for 25 percent of mean BOE UCRR.

Of Gulf of Mexico Region plays that fall into discrete geologic ages, the Miocene accounts for 44 percent of total mean BOE UCRR (the most), while the Pleistocene accounts 14 percent of the total mean BOE UCRR (second most).

Mean UCRR by Geologic Age GOM Region	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pleistocene	4.559	31.389	10.144
Pliocene	4.704	23.407	8.868
Miocene	14.880	92.528	31.344
Oligocene	0.024	0.785	0.164
Eocene	na	na	na
Paleocene	na	na	na
Upper Cretaceous	0.045	0.070	0.057
Lower Cretaceous	1.107	0.657	1.224
Upper Jurassic	1.132	7.670	2.497
Middle Jurassic	na	na	na
Lower Jurassic	na	na	na
Upper Triassic	na	na	na
Span Ages	11.717	35.306	17.999

Table 5. Mean undiscovered conventionally recoverable resources (UCRR) in the Gulf of Mexico Region by geologic age. Note the large amount of UCRR forecast to occur in plays that span ages.

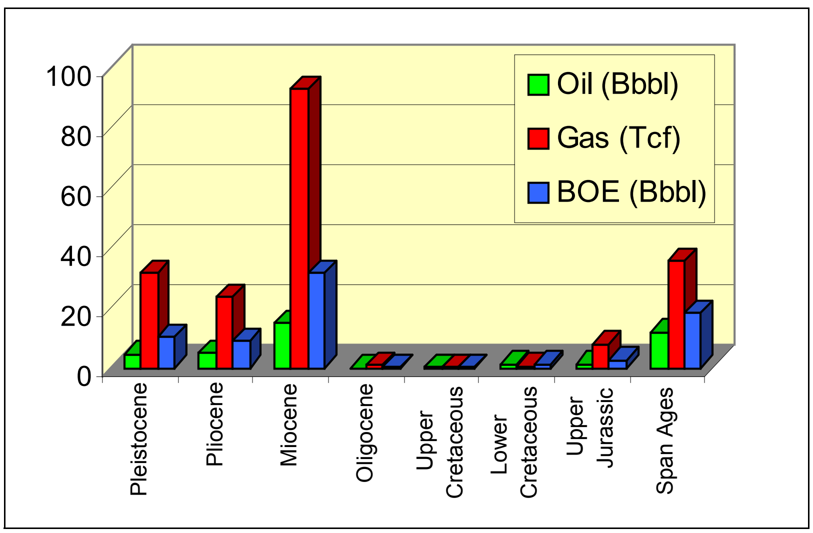

Figure 4. Mean undiscovered conventionally recoverable resources (UCRR) in the Gulf of Mexico Region by geologic age. Series or systems without UCRR are not shown. Structurally defined plays, or plays that otherwise span geologic ages, are included in the "Span Ages" category. Such plays range in age from Triassic to Pleistocene.

Undiscovered Economically Recoverable Resources Results

UERR	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
Gulf of Mexico Region									
Risked Full-Cycle									
@ $18/bbl & $2.11/Mcf	13.968	17.467	21.851	84.530	100.260	114.075	29.009	35.307	42.149
@ $30/bbl & $3.52/Mcf	24.749	28.134	34.749	129.389	140.731	151.929	47.772	53.175	61.783
Risked Half-Cycle									
@ $18/bbl & $2.11/Mcf	14.905	18.569	23.073	90.434	105.167	118.912	30.996	37.282	44.232
@ $30/bbl & $3.52/Mcf	25.171	28.811	35.643	133.790	143.986	155.311	48.977	54.431	63.278
Atlantic Region									
Risked Full-Cycle									
@ $18/bbl & $2.11/Mcf	0.216	0.530	1.067	2.325	6.649	12.546	0.630	1.713	3.300
@ $30/bbl & $3.52/Mcf	0.823	1.338	1.920	7.939	12.780	19.205	2.235	3.612	5.338
Risked Half-Cycle									
@ $18/bbl & $2.11/Mcf	0.280	0.602	1.178	3.059	7.310	13.280	0.824	1.903	3.541
@ $30/bbl & $3.52/Mcf	1.044	1.570	2.011	10.100	14.875	21.847	2.842	4.216	5.898

Table 1. Undiscovered Economically Recoverable Resources (UERR) of the Gulf of Mexico and Atlantic Regions.

Commercial viability or profitability is measured in this study from the perspectives of 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. 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 if 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 in the ***General Text, Methodology, Undiscovered Economically Recoverable Resources*** 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; used in the 1995 assessment (Lore et al., 1999) and (2) a $30/bbl scenario ($30.00/bbl and $3.52/Mcf; roughly corresponding to prices at the time of the assessment).

Gulf of Mexico Region

Gulf of Mexico Region estimates of UERR are presented 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 (37.126 Bbbl.) and gas (191.627 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, 47 percent of the undiscovered conventionally recoverable oil and 52 percent of the undiscovered conventionally recoverable gas are economic. This increases to about 75 percent for both oil and gas in the full-cycle, $30/bbl scenario. More than 8.992 Bbo and 50.896 Tcfg of the undiscovered conventionally recoverable resources require prices above $30/bbl and $3.52/Mcf scenario 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, 52 percent of the undiscovered conventionally recoverable resources is economic. This increases to 76 percent in the $30/bbl scenario. The percent increase in UERR from the full- to the half-cycle analysis is relatively small, ranging from

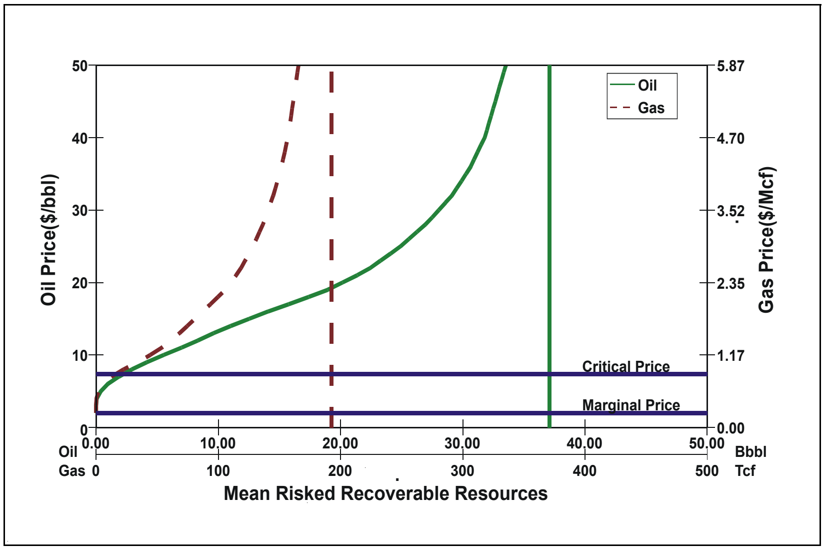

Figure 1. Gulf of Mexico Region full-cycle price-supply curve.

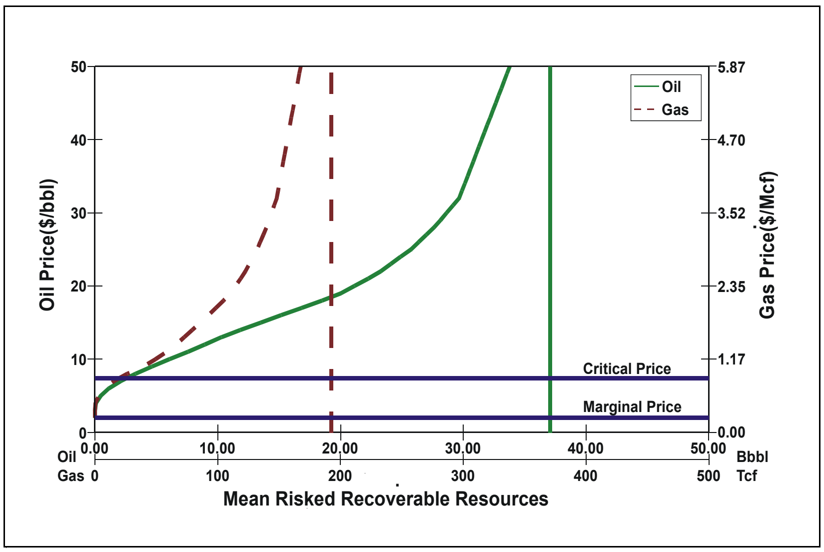

Figure 2. Gulf of Mexico Region half-cycle price-supply curve.

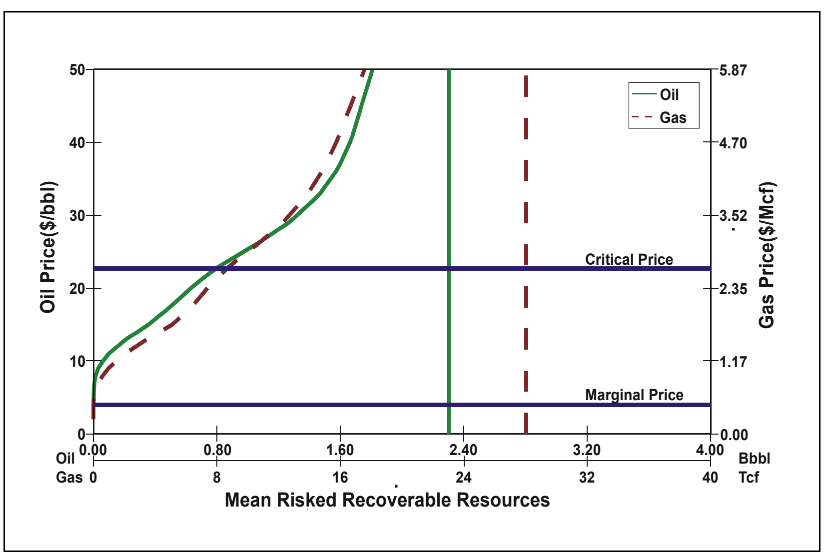

Figure 3. Atlantic Region full-cycle price-supply curve.

approximately 2 percent to about 6 percent. The smallest increase occurs in well-explored, mature areas (i.e., shallow-water central Gulf of Mexico), where the necessary exploration and delineation costs compared with 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.

Atlantic Region

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 $4.00/bbl and $0.45/Mcf. The critical price in the Atlantic Region is significantly higher, $22.70/bbl and $2.65/Mcf. This dramatically illustrates the 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 discrete price levels are shown in table 1. In the $18/bbl scenario, only 23 percent of the

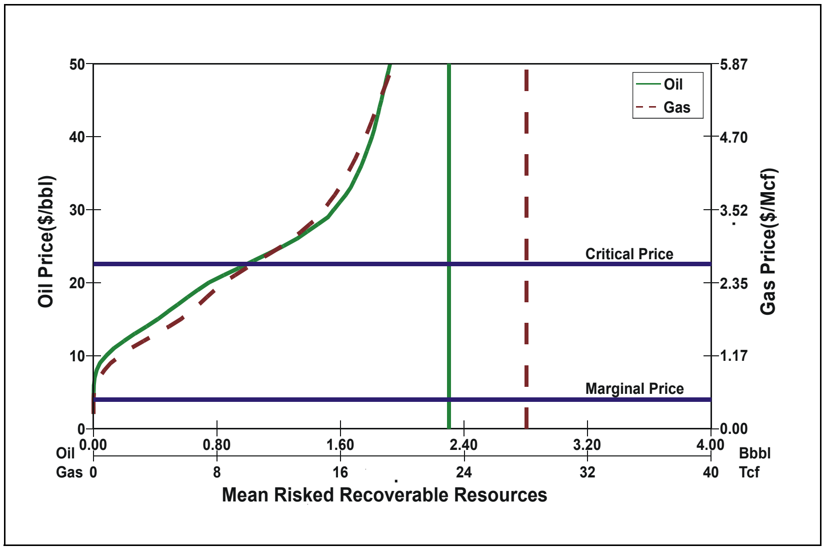

Figure 4. Atlantic Region half-cycle price-supply curve.

undiscovered conventionally recoverable oil (0.530 Bbbl) and 24 percent of the gas (6.649 Tcf) are economic. This increases to 58 and 46 percent (1.338 Bbo and 12.780 Tcfg), respectively, in the $30/bbl scenario.

Figure 4 shows the mean half-cycle price-supply curve for the Atlantic Region. In the half-cycle, $18/bbl scenario, the mean estimates of UERR increase by 0.072 Bbo and 0.661 Tcfg over the full-cycle analysis. In the half-cycle, $18/bbl scenario, 26 percent of the undiscovered conventionally recoverable oil (0.602 Bbbl) and 26 percent of the gas (7.310 Tcf) are economic. This increases to 68 and 54 percent (1.570 Bbo and 14.875 Tcfg), respectively, in the $30/bbl scenario.

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 11 percent to almost 17 percent. This is because the Atlantic Region is a frontier area requiring a much more extensive, time consuming, and expensive exploration and delineation program than the Gulf of Mexico Region. 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 Region than it does in the Gulf of Mexico Region.

Total Endowment Results

Total Endowment	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Gulf of Mexico Region				
95th percentile		45.818	380.998	114.825
Mean	5,323	60.123	427.537	136.197
5th percentile		79.051	482.510	162.576
Cenozoic Province				
95th percentile		48.751	375.941	116.750
Mean	4,967	53.780	401.325	125.190
5th percentile		59.387	429.338	134.435
Mesozoic Province				
95th percentile		0.728	9.255	2.430
Mean	356	6.342	26.211	11.006
5th percentile		20.023	62.333	30.639
Atlantic Region				
95th percentile		1.297	16.117	4.558
Mean	502	2.307	27.712	7.238
5th percentile		3.706	43.499	10.739

Table 1. Total endowment of the Gulf of Mexico and Atlantic Regions.

Cenozoic Province Mean Total Endowment			
Depositional Style/Facies	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Retrogradational	0.143	5.328	1.091
Aggradational	1.316	11.680	3.395
Progradational	10.759	151.053	37.637
Fan	41.491	226.246	81.749
Other	0.071	7.018	1.319

Table 2. Mean total endowment of the Gulf of Mexico Cenozoic Province by depositional style/facies. Fan 1 plays and fan 2 plays are combined into a single fan facies.

Gulf of Mexico Region

The mean total endowment for the Gulf of Mexico Region is 60.123 Bbo and 427.537 Tcfg (136.197 BBOE). The total endowment at the 95th and 5th percentiles ranges from 45.818 to 79.051 Bbo and 380.998 to 482.510 Tcfg (114.825 to 162.576 BBOE) (table 1). After 50 years of exploration and development, 75 percent of the mean BOE total endowment comprises remaining reserves, reserves appreciation, and undiscovered conventionally recoverable resources---the sources of future production.

Atlantic Region

The total endowment of the Atlantic Region ranges from 1.297 to 3.706 Bbo and 16.117 to 43.499 Tcfg (4.558 to 10.739 BBOE), with mean estimates of 2.307 Bbo and 27.712 Tcfg (7.328 BBOE) (table 1). On a mean BOE basis, The Atlantic Region's total endowment is only about 5 percent of the Gulf of Mexico Region's total endowment.

Total Endowment by Depositional Style/ Facies and Lithology

Within the Gulf of Mexico Cenozoic Province, fan depositional facies (combined fan 1 and fan 2 plays) are projected to contain the largest mean oil endowment, 41.491 Bbbl, and the progradational depositional style is projected to contain the largest mean gas endowment, 226.246 Tcf (table 2; figure 1).

Because so many of the plays in the Gulf of Mexico Mesozoic Province are concep-

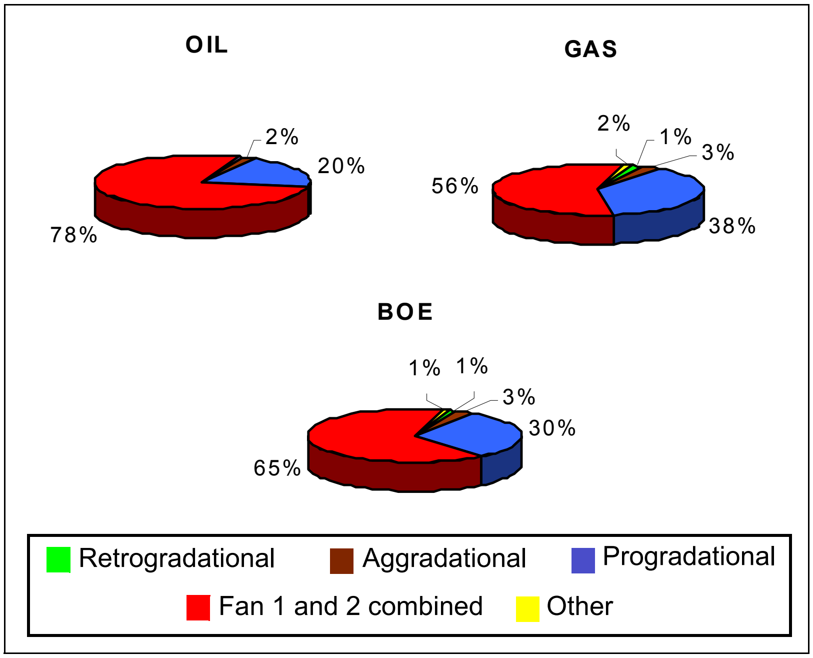

Figure 1. Mean total endowment of the Gulf of Mexico Cenozoic Province by depositional style/facies. The fan facies contains the largest total endowment.

Mesozoic Province Mean Total Endowment			
Depositional Style/Facies	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Siliciclastics	3.078	21.342	6.877
Carbonates	1.465	1.626	1.755
Other	1.799	3.242	2.376

Table 3. Mean total endowment of the Gulf of Mexico Mesozoic Province by lithology. The “other” category includes structurally defined plays and plays containing both siliciclastics and carbonates.

Atlantic Region Mean Total Endowment			
Depositional Style/Facies	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Siliciclastics	1.943	25.612	6.500
Carbonates	0.364	2.100	0.738

Table 4. Mean total endowment of the Atlantic Region by lithology.

tual and their depositional style/facies unknown, plays have been categorized into siliciclastic, carbonate, and “other.” “Other” plays include both structurally defined and mixed clastic and carbonate plays. Within the Gulf of Mexico Mesozoic Province, siliciclastics contain the largest mean oil endowment, 3.078 Bbbl, as well as the largest mean gas endowment, 21.342 Tcf (table 3; figure 2).

In the Atlantic Region, siliciclastics are forecast to have the largest oil and gas total endowment, with a mean of 1.943 Bbbl and 25.612 Tcf (figure 3; table 4).

Total Endowment by Geologic Age

The total endowment of the Gulf of Mexico Region is found in plays ranging in age from the Triassic to the Pleistocene. Structurally defined plays, or plays that otherwise span geologic ages, are included in the “Span Ages” category (table 5; figure 4). These spanning plays account for 15 percent of the mean BOE total endowment.

Of Gulf of Mexico Region plays that fall into discrete geologic ages, the Miocene contains the largest total endowment (41 percent of the total mean BOE), followed by the Pleistocene (25 percent) and then the Pliocene (16 percent).

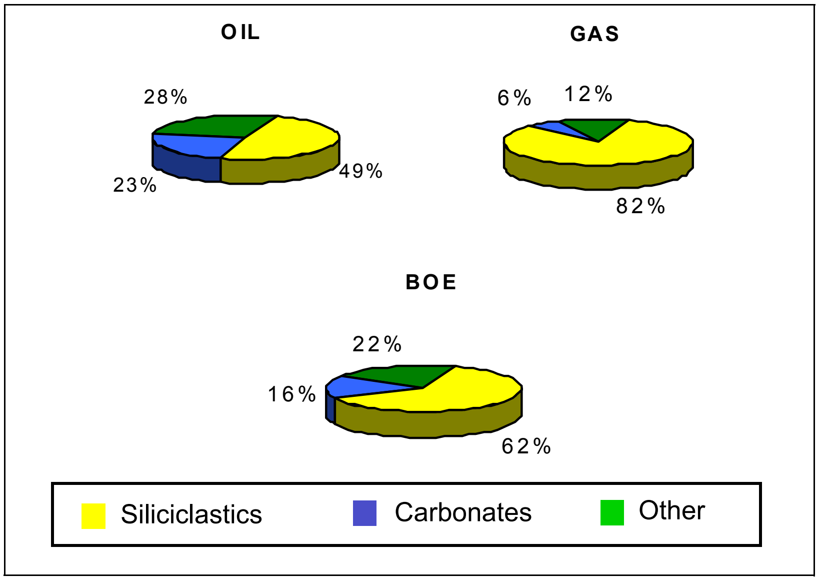

Figure 2. Mean total endowment of the Gulf of Mexico Mesozoic Province by lithology. The "other" category included structurally defined plays and plays containing both siliciclastic and carbonate reservoirs.

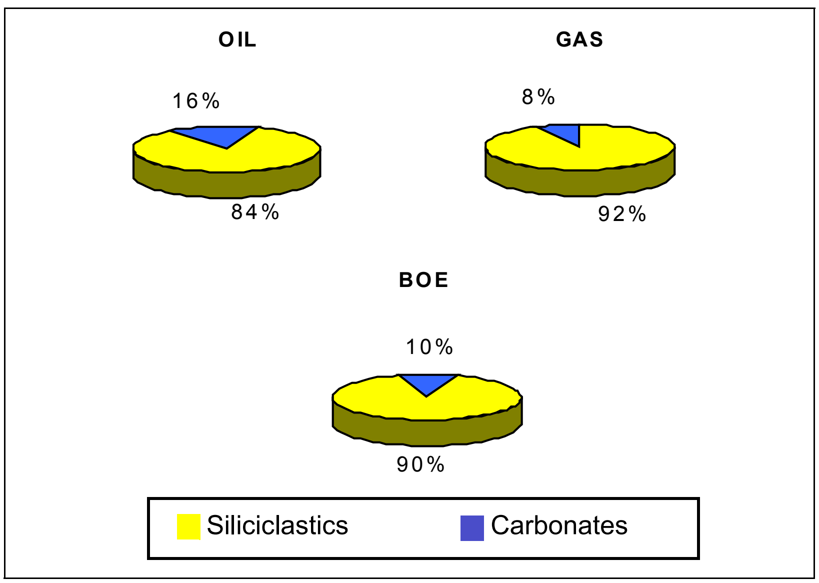

Figure 3. Mean total endowment of the Atlantic Region by lithology.

Mean Total Endowment by Geologic Age GOM Region	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Pleistocene	12.130	122.342	33.899
Pliocene	11.028	57.954	21.339
Miocene	22.728	190.395	56.606
Oligocene	0.025	0.851	0.177
Eocene	na	na	na
Paleocene	na	na	na
Upper Cretaceous	0.045	0.070	0.057
Lower Cretaceous	1.107	0.869	1.262
Upper Jurassic	1.132	12.690	3.391
Middle Jurassic	na	na	na
Lower Jurassic	na	na	na
Upper Triassic	na	na	na
Span Ages	12.969	42.550	20.540

Table 5. Mean total endowment for the Gulf of Mexico Region by geologic age. Note the large total endowment that occurs in plays that span ages.

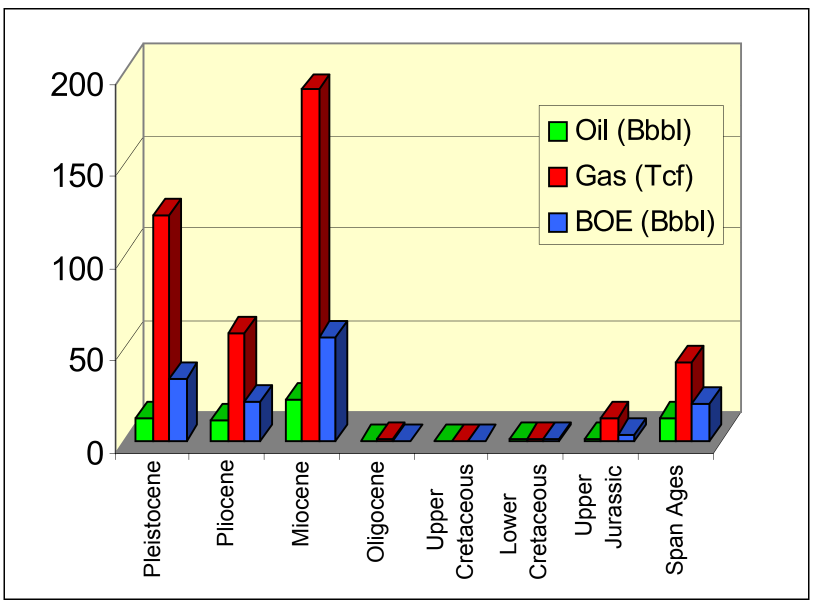

Figure 4. Mean total endowment of the Gulf of Mexico Region by geologic age. Series or systems without an endowment are not shown. The "Span Ages category includes structurally defined plays, or plays that otherwise span geologic ages. Such plays range in age from Triassic to Pleistocene.

Conclusions

Gulf of Mexico

Assuming existing and reasonably foreseeable technology, approximately 35 to 68 Bbo and 248 to 350 Tcfg (80 to 128 BBOE) of conventionally recoverable resources remain to be recovered or discovered within the Gulf of Mexico Region. Of these amounts, mean undiscovered conventionally recoverable resources (UCRR) are about 37 Bbo and 192 Tcfg (71 BBOE).

As of January 1, 1999, cumulative production was 10.908 Bbo and 132.677 Tcfg (34.515 BBOE), and remaining proved reserves totaled 3.358 Bbo and 30.034 Tcfg (8.703 BBOE). Thus, 75 percent of the current estimate of proved reserves has 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 4 over the field's life. In active fields discovered prior to January 1, 1999, reserves appreciation for 50 years is estimated to be 7.736 Bbo and 68.096 Tcfg (19.853 BBOE), a quantity of resources that exceeds the estimate of remaining proved reserves.

The mean total endowment for the Gulf of Mexico Region is approximately 60 Bbo and 428 Tcfg (136 BBOE). Forty-eight percent of this BOE total endowment is in the various reserves categories, with approximately 32 percent occurring as proved reserves. After nearly 50 years of exploration and development, about two-thirds of the mean BOE total endowment is represented by future reserves appreciation and UCRR.

In the Gulf of Mexico Region full-cycle, $18/bbl economic scenario, 47 percent (17 Bbbl) of the mean undiscovered conventionally recoverable oil and 52 percent (100 Tcf) of the mean undiscovered conventionally recoverable gas are economic. This increases to approximately 76 percent for undiscovered conventionally recoverable oil (28 Bbbl) and 73 percent for undiscovered conventionally recoverable gas (141 Tcf) in the full-cycle $30/bbl scenario.

Atlantic

Assuming existing and reasonably foreseeable technology, approximately 1 to 4 Bbo and 16 to 43 Tcfg (5 to 11 BBOE) of UCRR are forecast for the Atlantic Region. Mean UCRR are 2 Bbo and 28 Tcfg (7 BBOE). The Region contains no fields and, therefore, no reserves. For this reason, the Atlantic Region's total endowment equals its UCRR.

Only one uneconomic accumulation of hydrocarbon, which was mostly gas, has been discovered in the Atlantic Region. The last lease sale in the Region was held in 1983, and additional sales were cancelled in 1990. As of November, 2000, no oil or gas leases remain active in the Atlantic Region.

In the Atlantic Region full-cycle, $18/bbl economic scenario, 23 percent (<1 Bbbl) of the mean undiscovered conventionally recoverable oil and 24 percent (7 Tcf) of the mean undiscovered conventionally recoverable gas are economic. This increases to approximately 58 percent for undiscovered conventionally recoverable oil (1 Bbbl) and 46 percent for undiscovered conventionally recoverable gas (13 Tcf) in the full-cycle $30/bbl scenario.

United States OCS

From a National perspective, comparing the four Federal Regions (Alaska, Atlantic, Gulf of Mexico, and Pacific), the Gulf of Mexico Region is the largest in terms of total endowment, UCRR, and reserves. More BOE mean UCRR and more undiscovered conventionally recoverable gas are forecast to exist in the Gulf of Mexico Region than are forecast for the other Regions combined (71 BBOE *vs*. 68 BBOE, and 192 Tcfg *vs.* 170 Tcfg, respectively; refer to the MMS summary report, *Outer Continental Shelf Petroleum Assessment, 2000—Summary* located on the worldwide web at mms.gov/revaldiv/RedNatAssessment.htm). The Gulf of Mexico Region is also forecast to contain more mean undiscovered conventionally recoverable oil than any other Region, and undiscovered oil in the Gulf Region nearly equals the amount of forecast undiscovered oil in the other Regions combined (37 Bbl *vs.* 38 Bbl, respectively).

The Atlantic Region, with a mean total endowment of 7 BBOE, ranks last of the four OCS Regions.

Gulf of Mexico Region Economic Results

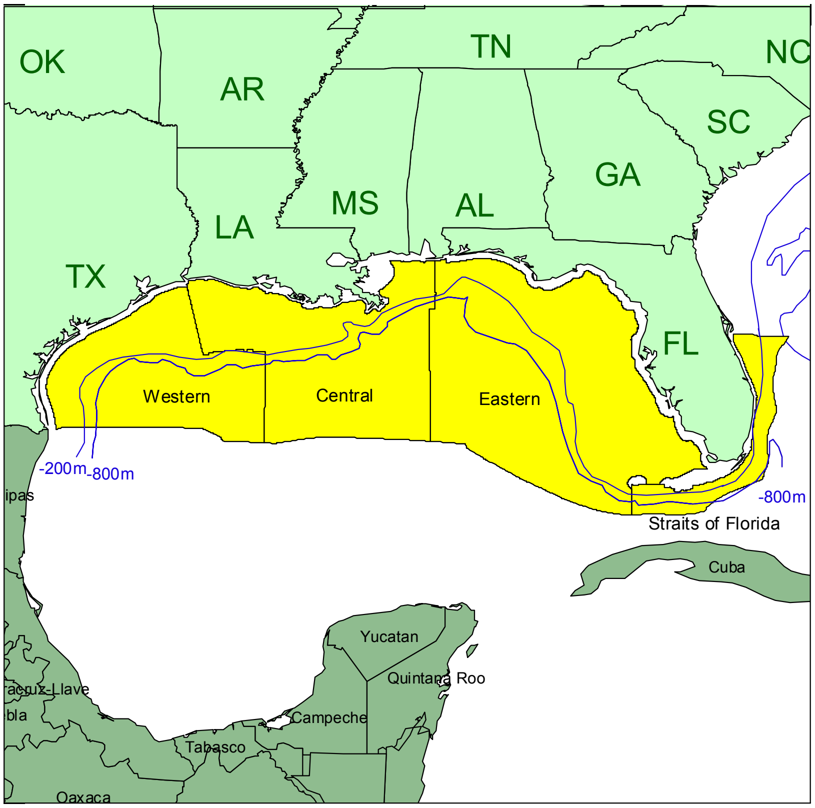

Figure 1. Map of the Gulf of Mexico Region (yellow) and its four planning areas---Western, Central, Eastern, and the Straits of Florida.

Total GOM Region

The Gulf of Mexico (GOM) Region includes submerged Federal lands located in offshore Texas, Louisiana, Mississippi, Alabama, and the west and southern coasts of Florida. To the east, the Region extends to the U.S.-Bahama international boundary, while to the south, the area extends to the U.S.-Mexico and U.S.-Cuba international boundaries (figure 1).

Water depths in the GOM Region range from very shallow to more than 3,000 m. The GOM Region was divided into five water depth areas to reflect differing royalty lease terms. Undiscovered economically recoverable resources (UERR) were evaluated for five water depth ranges: 0-200 m, 201-800 m, 801-1,600 m, 1,601-2,400 m, and greater than 2,400 m.

The GOM Region is well developed in the 0-200 m range, with an extensive infrastructure already in place. The 201-800 m range is undergoing significant development, with tie-backs to infrastructures and the installation of new deepwater structures. The 801-1,600 m range is also in the development process. All but the deepest of the water depth ranges have production. The deepest range will require new technologies for development. Significant amounts of undiscovered conventionally recoverable resources (UCRR) have been assessed for four out of the five water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at each of the five different water depth ranges. Assessment reserves and resources are listed in tables 1-6, which present the data from figure 2, for the five water depth areas, including an overall GOM Region total table.

The full-cycle and half-cycle UERR for both the $18.00/bbl and $30.00/bbl scenarios are shown in tables 7-12. Price-supply curves have been presented because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between UERR and product price, and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. Please note the entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are the mean curves.

The full-cycle and half-cycle price-supply curves are shown in figures 3-14 for the total GOM and each of the five water depth areas. An extended discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR) Detailed Discussion section.

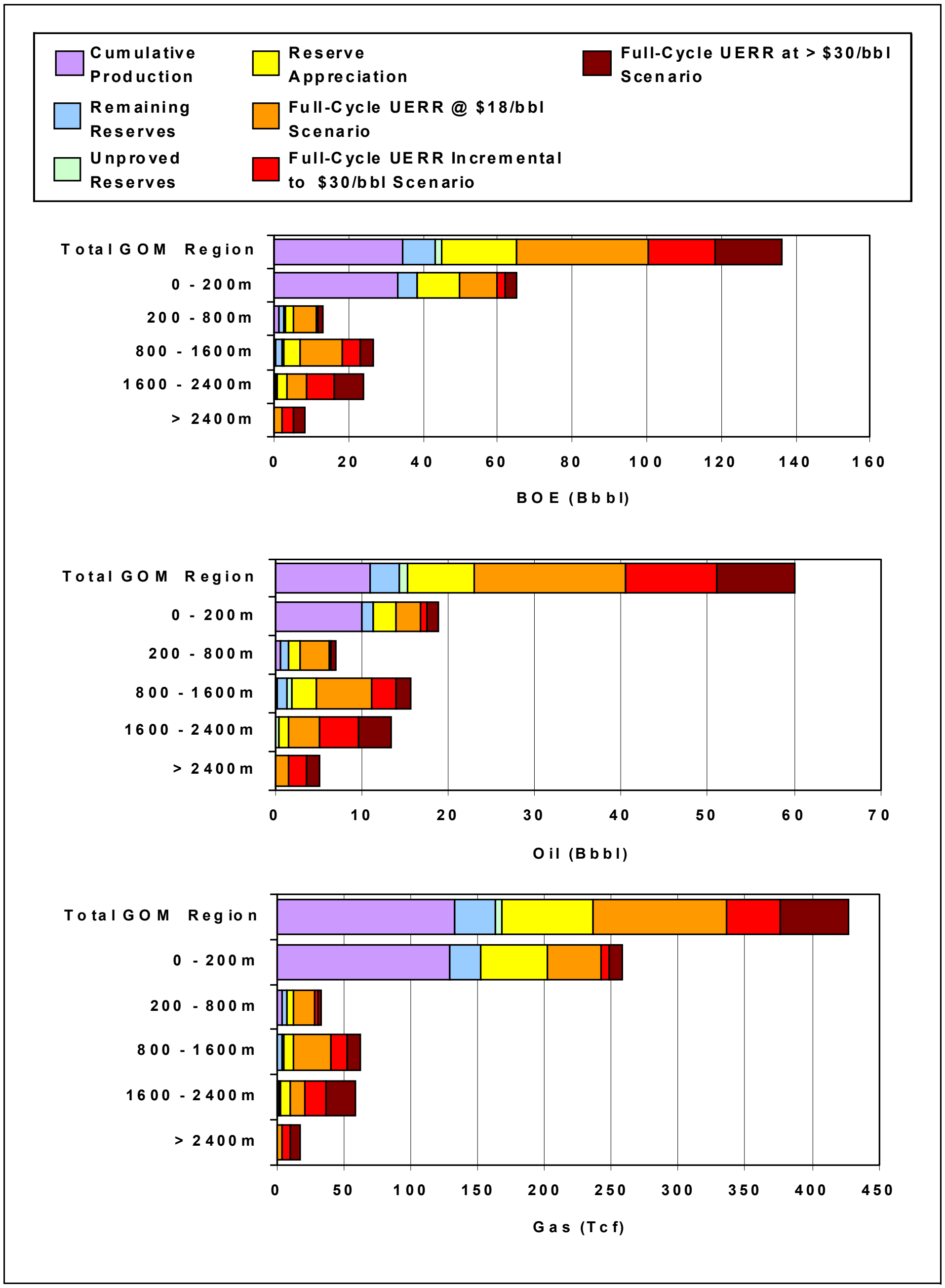

Figure 2. Gulf of Mexico Region mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	14.266	162.711	43.218
Cumulative production	10.908	132.677	34.515
Remaining proved	3.358	30.034	8.703
Unproved	0.995	5.102	1.903
Appreciation (P & U)	7.736	68.096	19.852
Undiscovered Conventionally Recoverable Resources			
95th percentile	22.821	145.088	49.851
Mean	37.126	191.627	71.223
5th percentile	56.054	246.600	97.602
Total Endowment			
95th percentile	45.818	380.998	114.825
Mean	60.123	427.537	136.197
5th percentile	79.051	482.510	162.576

Table 1. GOM reserves and resources total of all water depths.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	11.386	151.624	38.366
Cumulative production	10.006	128.736	32.912
Remaining proved	1.381	22.888	5.453
Unproved	0.031	1.014	0.211
Appreciation (P & U)	2.610	48.942	11.318
Undiscovered Conventionally Recoverable Resources			
95th percentile	4.383	54.045	13.999
Mean	4.912	56.724	15.005
5th percentile	5.788	59.958	16.457
Total Endowment			
95th percentile	18.410	255.626	63.895
Mean	18.939	258.305	64.901
5th percentile	19.815	261.538	66.352

Table 2. GOM reserves and resources 0-200 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.470	6.872	2.692
Cumulative production	0.674	3.389	1.277
Remaining proved	0.796	3.483	1.416
Unproved	0.088	0.369	0.154
Appreciation (P & U)	1.208	5.108	2.117
Undiscovered Conventionally Recoverable Resources			
95th percentile	3.517	18.814	6.864
Mean	4.144	21.046	7.889
5th percentile	4.807	23.438	8.978
Total Endowment			
95th percentile	6.283	31.163	11.828
Mean	6.911	33.394	12.853
5th percentile	7.574	35.787	13.942

Table 3. GOM reserves and resources 200-800 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.409	3.432	2.020
Cumulative production	0.228	0.490	0.315
Remaining proved	1.181	2.942	1.704
Unproved	0.455	1.540	0.729
Appreciation (P & U)	2.833	7.127	4.101
Undiscovered Conventionally Recoverable Resources			
95th percentile	9.929	45.446	18.016
Mean	10.882	50.096	19.796
5th percentile	11.867	59.558	22.464
Total Endowment			
95th percentile	14.626	57.546	24.865
Mean	15.578	62.196	26.645
5th percentile	16.563	71.658	29.314

Table 4. GOM reserves and resources 800-1,600 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.001	0.783	0.140
Cumulative production	<0.001	0.061	0.011
Remaining proved	0.001	0.722	0.129
Unproved	0.421	2.179	0.809
Appreciation (P & U)	1.085	6.920	2.316
Undiscovered Conventionally Recoverable Resources			
95th percentile	10.616	43.340	18.328
Mean	11.984	48.148	20.551
5th percentile	14.226	55.520	24.105
Total Endowment			
95th percentile	12.123	53.221	21.593
Mean	13.491	58.029	23.816
5th percentile	15.733	65.401	27.370

Table 5.GOM reserves and resources 1,600-2,400 m water depth.

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	3.315	12.594	5.556
Mean	5.147	16.967	8.166
5th percentile	10.763	29.031	15.928
Total Endowment			
95th percentile	3.315	12.594	5.556
Mean	5.147	16.967	8.166
5th percentile	10.763	29.031	15.928

Table 6. GOM reserves and resources > 2,400 m water depth.

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		13.968	84.530	29.009
Mean		17.467	100.260	35.307
5th percentile		21.851	114.075	42.149
Half-Cycle	1.00			
95th percentile		14.905	90.434	30.996
Mean		18.569	105.167	37.282
5th percentile		23.073	118.912	44.232
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		24.749	129.389	47.772
Mean		28.134	140.731	53.175
5th percentile		34.749	151.929	61.783
Half-Cycle	1.00			
95th percentile		25.171	133.790	48.977
Mean		28.811	143.986	54.431
5th percentile		35.643	155.311	63.278

Table 7. GOM total of all water depths economic assessment results.

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		2.205	38.544	9.063
Mean		2.726	40.236	9.885
5th percentile		3.400	41.756	10.830
Half-Cycle	1.00			
95th percentile		2.332	40.398	9.520
Mean		2.879	41.816	10.320
5th percentile		3.521	43.354	11.235
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		3.102	44.936	11.098
Mean		3.615	46.534	11.896
5th percentile		4.266	48.176	12.838
Half-Cycle	1.00			
95th percentile		3.217	45.648	11.339
Mean		3.689	47.641	12.166
5th percentile		4.306	49.742	13.157

Table 8. GOM 0-200 m water depth economic assessment results.

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		2.700	13.485	5.100
Mean		3.392	16.211	6.276
5th percentile		4.028	18.821	7.376
Half-Cycle	1.00			
95th percentile		2.764	13.863	5.230
Mean		3.432	16.497	6.368
5th percentile		4.056	19.122	7.459
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		3.070	15.859	5.892
Mean		3.686	18.295	6.941
5th percentile		4.319	20.614	7.987
Half-Cycle	1.00			
95th percentile		3.090	16.166	5.967
Mean		3.703	18.440	6.984
5th percentile		4.325	20.790	8.024

Table 9. GOM 200-800 m water depth economic assessment results.

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		5.394	21.351	9.194
Mean		6.453	28.714	11.562
5th percentile		7.543	38.979	14.479
Half-Cycle	1.00			
95th percentile		5.730	22.418	9.719
Mean		6.726	29.895	12.045
5th percentile		7.795	39.679	14.855
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		8.317	34.304	14.421
Mean		9.229	40.094	16.363
5th percentile		10.017	50.645	19.028
Half-Cycle	1.00			
95th percentile		8.415	35.163	14.671
Mean		9.361	40.701	16.603
5th percentile		10.250	50.876	19.303

Table 10. GOM 800-1,600 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.98			
95th percentile		0.744	1.188	0.956
Mean		3.536	11.308	5.548
5th percentile		5.879	20.451	9.518
Half-Cycle	0.99			
95th percentile		1.267	2.025	1.627
Mean		3.966	12.836	6.250
5th percentile		6.199	21.498	10.024
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		6.553	21.442	10.368
Mean		8.121	27.108	12.944
5th percentile		10.174	35.640	16.516
Half-Cycle	1.00			
95th percentile		6.878	22.357	10.857
Mean		8.389	28.175	13.403
5th percentile		10.402	36.706	16.934

Table 11. GOM 1,600-2,400 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.98			
95th percentile		0.366	0.624	0.477
Mean		1.485	3.895	2.178
5th percentile		3.709	7.403	5.026
Half-Cycle	0.99			
95th percentile		0.518	1.140	0.721
Mean		1.698	4.419	2.484
5th percentile		4.443	8.995	6.044
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.985	5.823	3.021
Mean		3.618	9.140	5.244
5th percentile		8.849	16.502	11.785
Half-Cycle	1.00			
95th percentile		2.076	6.097	3.160
Mean		3.735	9.483	5.423
5th percentile		9.039	16.971	12.058

Table 12. GOM >2,400 m water depth economic assessment results.

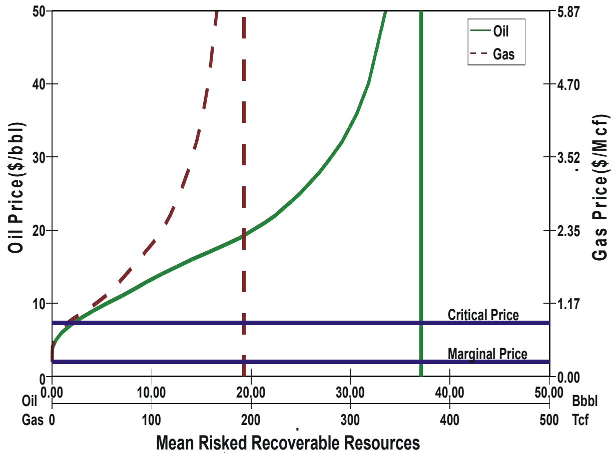

Figure 3. GOM full-cycle total of all water depths price-supply curve.

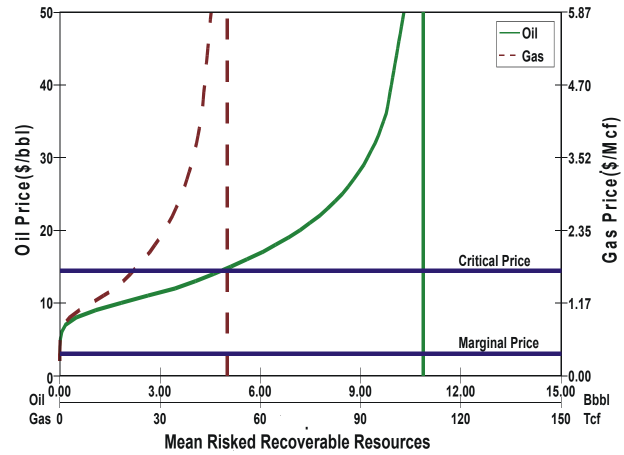

Figure 6.GOM full-cycle 800-1,600 m water depth price-supply curve.

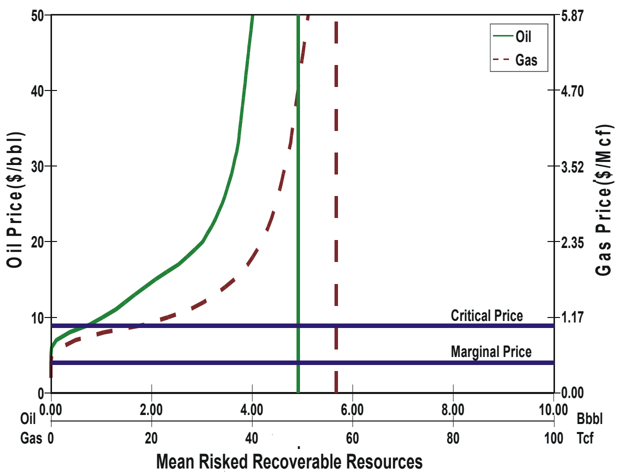

Figure 4. GOM full-cycle 0-200 m water depth price-supply curve.

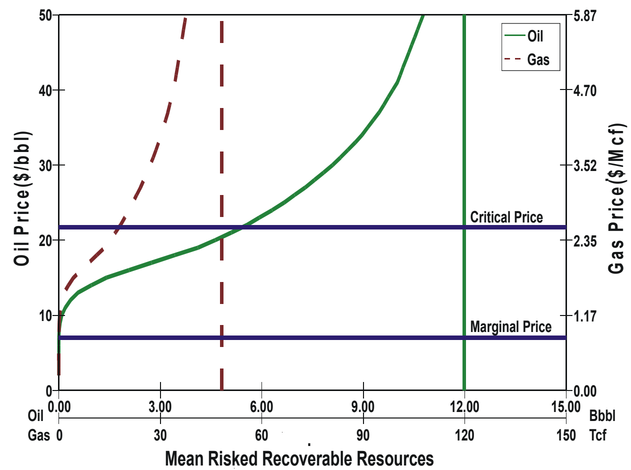

Figure 7. GOM full-cycle 1,600-2,400 m water depth price-supply curve.

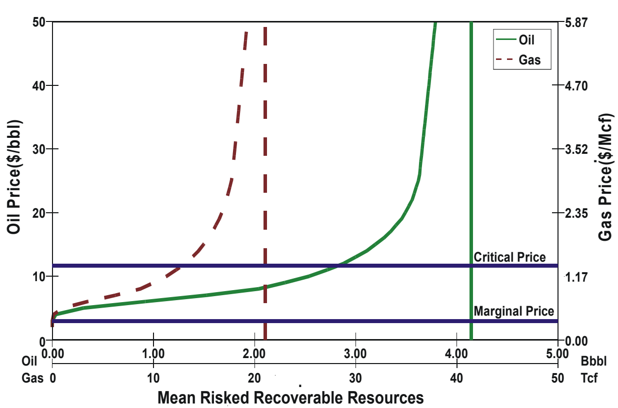

Figure 5. GOM full-cycle 200-800 m water depth price-supply curve.

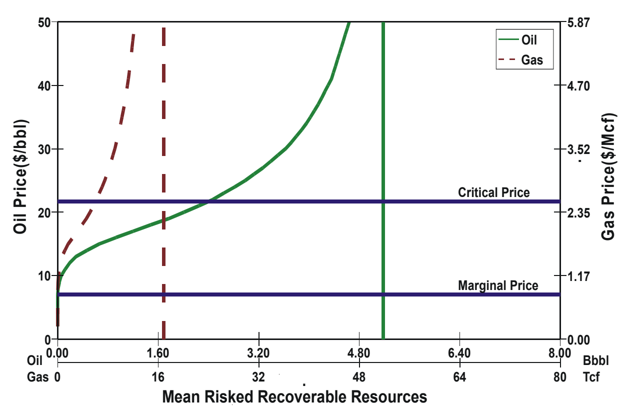

Figure 8. GOM full-cycle > 2,400 m water depth price-supply curve.

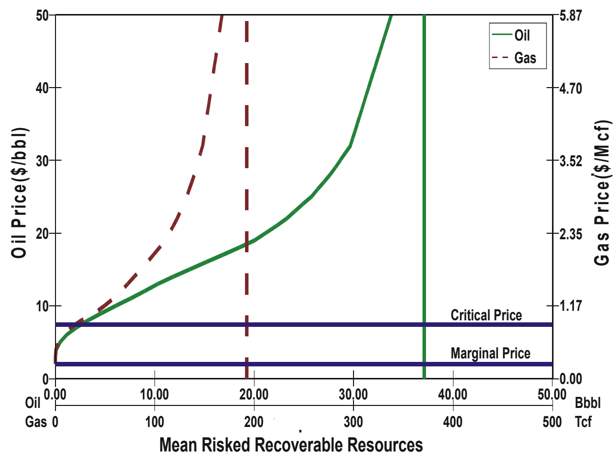

Figure 9. GOM half-cycle total of all water depths price-supply curve.

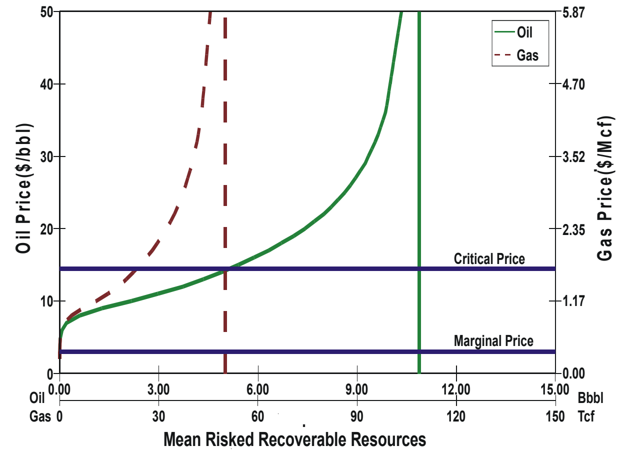

Figure 12. GOM half-cycle 800-1,600 m water depth price-supply curve.

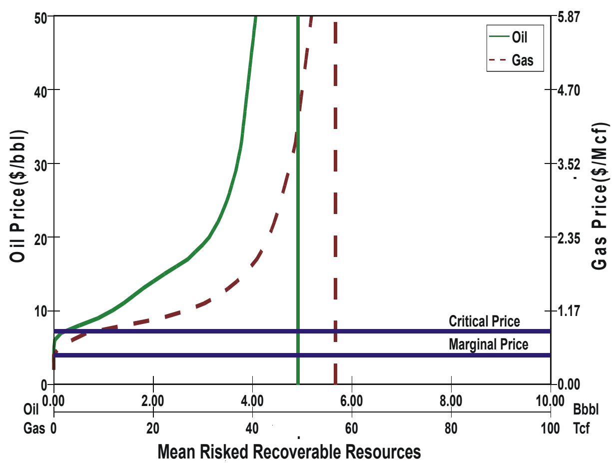

Figure 10. GOM half-cycle 0-200 m water depth price-supply curve.

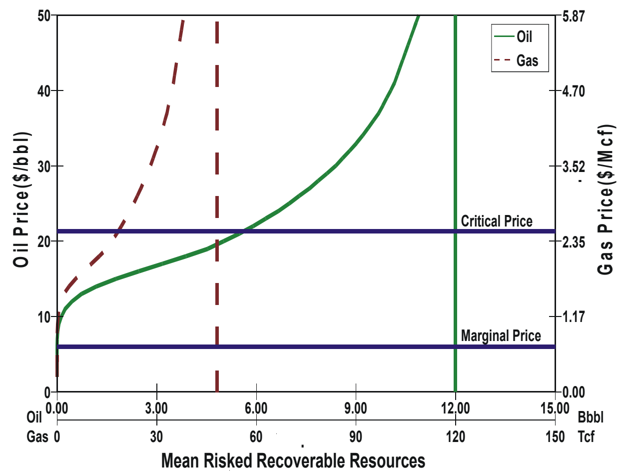

Figure 13. GOM half-cycle 1,600-2,400 m water depth price-supply curve.

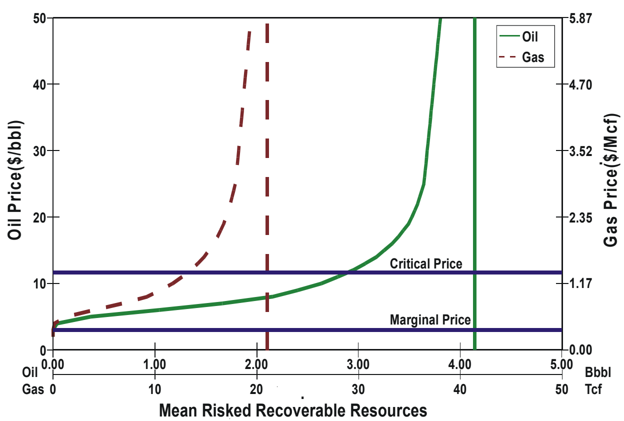

Figure 11. GOM half-cycle 200-800 m water depth price-supply curve.

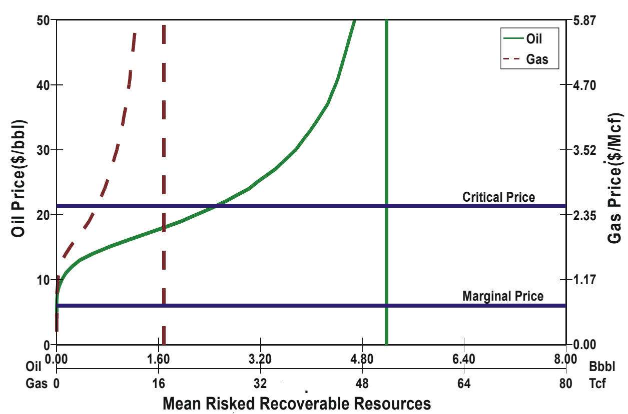

Figure 14. GOM half-cycle >2,400 m water depth price-supply curve.

Western Gulf of Mexico Planning Area Economic Results

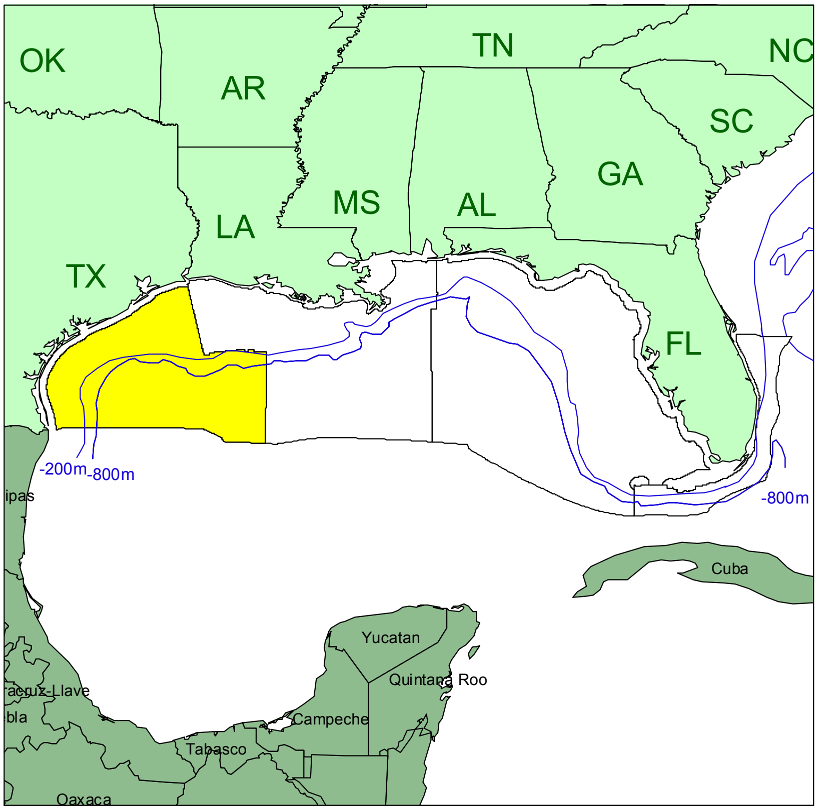

Figure 1. Map of the Western Gulf of Mexico Planning Area (yellow).

Western GOM Planning Area

The Western Gulf of Mexico (GOM) Planning Area includes submerged Federal lands located in offshore Texas and Louisiana. To the south, the area extends to the U.S.-Mexico international boundary (figure 1).

Undiscovered economically recoverable resources (UERR) were evaluated for five water depth ranges: 0-200 m, 201-800 m, 801-1,600 m, 1,601-2,400 m, and greater than 2,400 m. The Western GOM Planning Area is well developed in the 0-200 m range with an extensive infrastructure already in place. The 201-800 m range is less well developed, while the 801-1,600 m range is minimally developed. The three shallow-water depth ranges all contain production. Significant amounts of undiscovered conventionally recoverable resources (UCRR) have been assessed in all five water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at each of the five different water depths. Assessment reserves and resources have been provided in tables 1-6, which present the data from figure 2, including an overall Western GOM Planning Area total.

The full-cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in tables 7-12. These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the five water depth ranges, and for the total Western GOM Planning Area.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present estimates of mean UERR at any starting oil price up to $50/bbl. Please note that entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are the mean curves.

The full-cycle and half-cycle price-supply curves are shown in figures 3-14. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR), Detailed Discussion section.

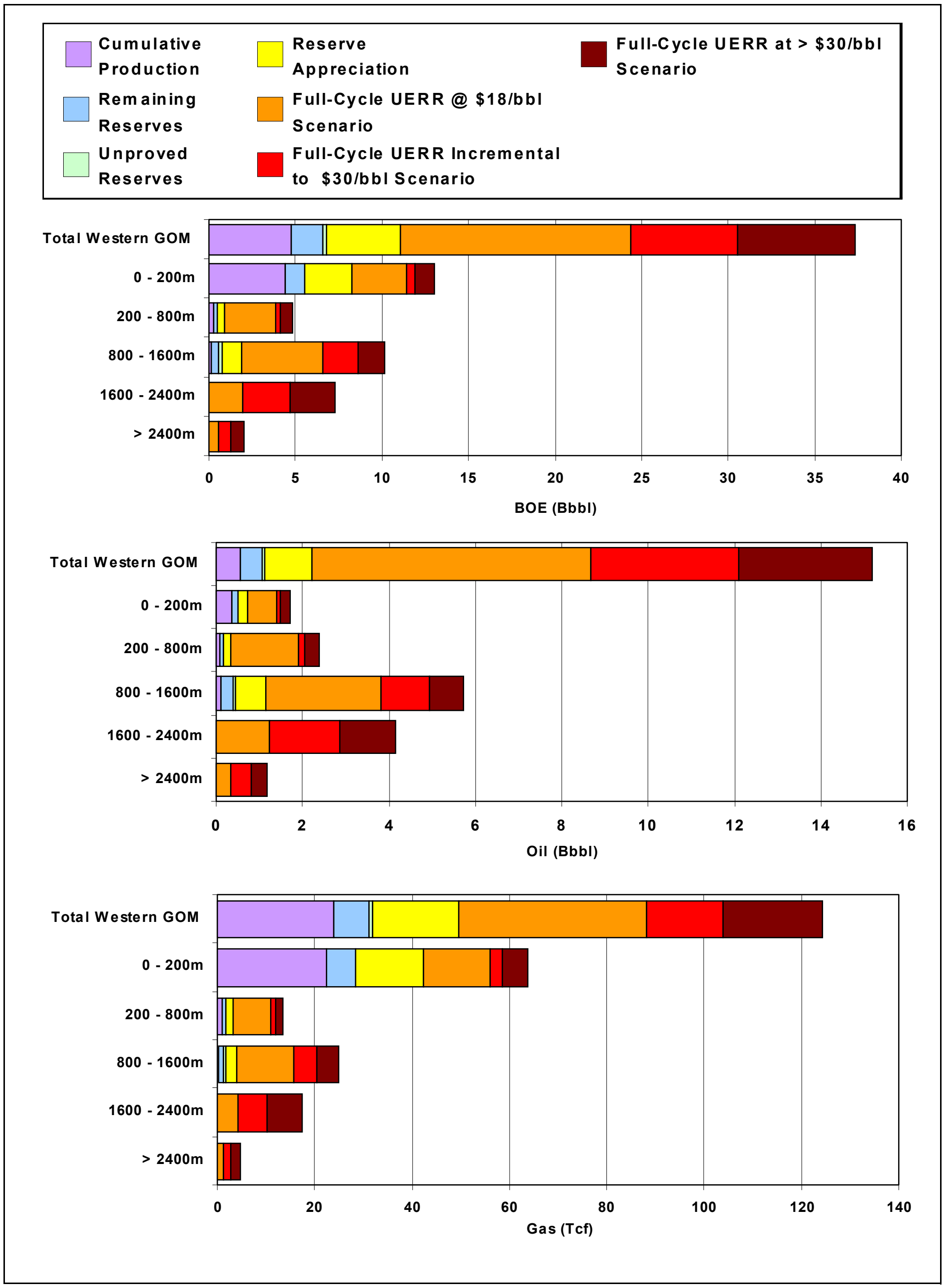

Figure 2. Western Gulf of Mexico Planning Area mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.054	31.189	6.603
Cumulative production	0.559	23.795	4.793
Remaining proved	0.495	7.393	1.810
Unproved	0.067	0.603	0.174
Appreciation (P & U)	1.091	17.881	4.273
Undiscovered Conventionally Recoverable Resources			
95th percentile	12.107	70.191	24.597
Mean	12.986	74.721	26.281
5th percentile	14.220	80.360	28.518
Total Endowment			
95th percentile	14.319	119.863	35.647
Mean	15.198	124.393	37.332
5th percentile	16.432	130.032	39.569

Table 1. Western GOM Planning Area reserves and resources total of all water depths.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.508	28.289	5.541
Cumulative production	0.378	22.518	4.385
Remaining proved	0.130	5.771	1.157
Unproved	<0.001	0.015	0.003
Appreciation (P & U)	0.222	14.042	2.720
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.848	19.481	4.315
Mean	0.979	21.377	4.783
5th percentile	1.120	24.199	5.426
Total Endowment			
95th percentile	1.578	61.827	12.579
Mean	1.709	63.723	13.047
5th percentile	1.850	66.545	13.690

Table 2. Western GOM Planning Area reserves and resources 0-200 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.163	1.773	0.479
Cumulative production	0.071	0.986	0.247
Remaining proved	0.092	0.787	0.232
Unproved	0.006	0.069	0.018
Appreciation (P & U)	0.160	1.515	0.429
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.760	9.053	3.371
Mean	2.071	10.212	3.888
5th percentile	2.437	11.409	4.467
Total Endowment			
95th percentile	2.089	12.409	4.297
Mean	2.399	13.568	4.813
5th percentile	2.766	14.765	5.393

Table 3. Western GOM Planning Area reserves and resources 200-800 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.383	1.127	0.583
Cumulative production	0.110	0.291	0.162
Remaining proved	0.273	0.836	0.421
Unproved	0.061	0.515	0.153
Appreciation (P & U)	0.710	2.313	1.121
Undiscovered Conventionally Recoverable Resources			
95th percentile	4.197	18.927	7.565
Mean	4.584	20.962	8.314
5th percentile	4.982	24.953	9.422
Total Endowment			
95th percentile	5.350	22.882	9.422
Mean	5.738	24.916	10.171
5th percentile	6.136	28.908	11.280

Table 4. Western GOM Planning Area reserves and resources 800-1,600 m water depth.

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	0.005	0.001
Appreciation (P & U)	<0.001	0.011	0.002
Undiscovered Conventionally Recoverable Resources			
95th percentile	3.750	15.707	6.544
Mean	4.167	17.456	7.273
5th percentile	4.806	20.093	8.382
Total Endowment			
95th percentile	3.750	15.723	6.547
Mean	4.167	17.472	7.276
5th percentile	4.806	20.109	8.385

Table 5. Western GOM Planning Area reserves and resources 1,600-2,400 m water depth.

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	0.989	4.151	1.727
Mean	1.180	4.733	2.022
5th percentile	1.615	5.814	2.649
Total Endowment			
95th percentile	0.989	4.151	1.727
Mean	1.180	4.733	2.022
5th percentile	1.615	5.814	2.649

Table 6. Western GOM Planning Area reserves and resources > 2,400 m water depth.

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		5.115	33.006	10.989
Mean		6.461	38.494	13.311
5th percentile		7.671	44.425	15.576
Half-Cycle	1.00			
95th percentile		5.552	34.476	11.687
Mean		6.806	40.365	13.989
5th percentile		7.944	46.460	16.211
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		9.019	49.986	17.913
Mean		9.872	54.104	19.499
5th percentile		10.886	59.227	21.424
Half-Cycle	1.00			
95th percentile		9.117	51.686	18.314
Mean		10.065	55.584	19.955
5th percentile		11.065	60.833	21.890

Table 7. Western GOM Planning Area total of all water depths economic assessment results.

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		0.535	12.507	2.761
Mean		0.679	13.744	3.124
5th percentile		0.842	14.960	3.504
Half-Cycle	1.00			
95th percentile		0.541	13.174	2.885
Mean		0.696	14.318	3.243
5th percentile		0.879	15.461	3.630
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.623	14.788	3.254
Mean		0.755	16.125	3.625
5th percentile		0.895	17.784	4.060
Half-Cycle	1.00			
95th percentile		0.647	15.201	3.352
Mean		0.759	16.756	3.741
5th percentile		0.898	18.619	4.211

Table 8. Western GOM Planning Area 0-200 m water depth economic assessment results.

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		1.273	6.306	2.395
Mean		1.583	7.647	2.943
5th percentile		1.878	8.876	3.458
Half-Cycle	1.00			
95th percentile		1.290	6.497	2.446
Mean		1.601	7.767	2.983
5th percentile		1.894	8.981	3.492
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.428	7.467	2.757
Mean		1.710	8.592	3.239
5th percentile		1.999	9.705	3.726
Half-Cycle	1.00			
95th percentile		1.436	7.533	2.776
Mean		1.716	8.652	3.255
5th percentile		2.003	9.774	3.742

Table 9. Western GOM Planning Area 200-800 m water depth economic assessment results.

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		2.226	8.763	3.785
Mean		2.656	11.827	4.761
5th percentile		3.114	16.003	5.961
Half-Cycle	1.00			
95th percentile		2.359	9.233	4.001
Mean		2.768	12.313	4.959
5th percentile		3.208	16.343	6.116
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		3.417	14.152	5.935
Mean		3.796	16.509	6.734
5th percentile		4.120	20.856	7.831
Half-Cycle	1.00			
95th percentile		3.464	14.466	6.038
Mean		3.851	16.760	6.833
5th percentile		4.213	20.967	7.944

Table 10. Western GOM Planning Area 800-1,600 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.98			
95th percentile		0.207	0.313	0.262
Mean		1.238	4.225	1.989
5th percentile		2.017	7.807	3.406
Half-Cycle	0.99			
95th percentile		0.349	0.556	0.447
Mean		1.395	4.818	2.252
5th percentile		2.126	8.302	3.603
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		2.360	7.862	3.759
Mean		2.849	10.154	4.656
5th percentile		3.486	12.716	5.749
Half-Cycle	1.00			
95th percentile		2.427	8.474	3.935
Mean		2.945	10.548	4.822
5th percentile		3.605	13.043	5.926

Table 11. Western GOM Planning Area 1,600-2,400 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.97			
95th percentile		0.057	0.094	0.074
Mean		0.335	1.138	0.538
5th percentile		0.565	2.202	0.957
Half-Cycle	0.99			
95th percentile		0.102	0.162	0.131
Mean		0.383	1.289	0.612
5th percentile		0.646	2.315	1.058
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.607	2.181	0.995
Mean		0.801	2.738	1.288
5th percentile		1.129	3.673	1.782
Half-Cycle	1.00			
95th percentile		0.643	2.252	1.043
Mean		0.828	2.841	1.333
5th percentile		1.156	3.761	1.825

Table 12. Western GOM Planning Area >2,400 m water depth economic assessment results.

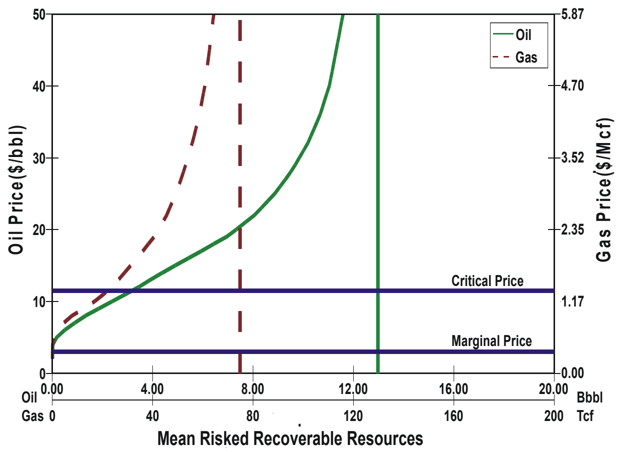

Figure 3. Western GOM Planning Area full-cycle total of all water depths price-supply curve.

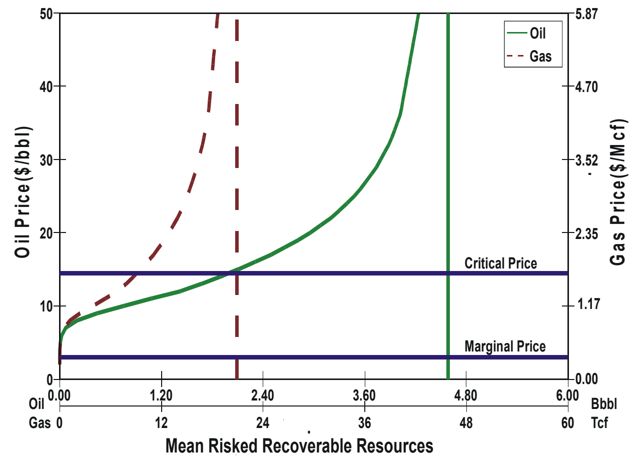

Figure 6. Western GOM Planning Area full-cycle 800-1,600 m water depth price-supply curve.

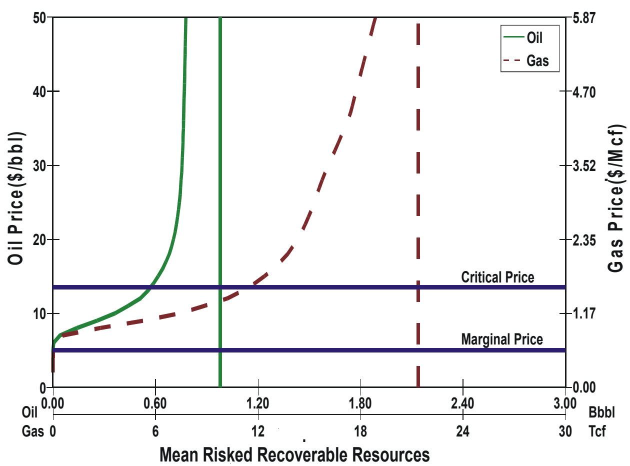

Figure 4. Western GOM Planning Area full-cycle 0-200 m water depth price-supply curve.

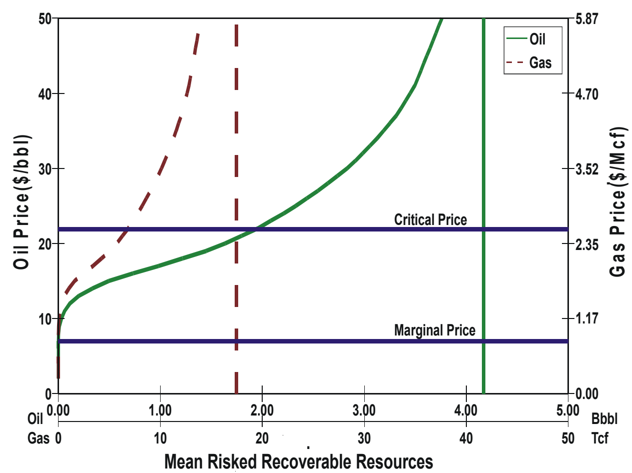

Figure 7. Western GOM Planning Area full-cycle 1,600-2,400 m water depth price-supply curve.

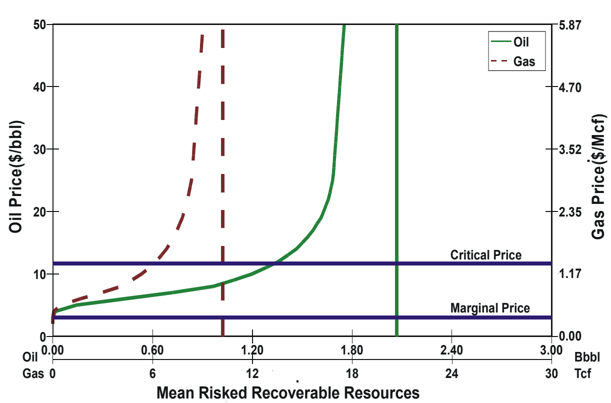

Figure 5. Western GOM Planning Area full-cycle 200-800 m water depth price-supply curve.

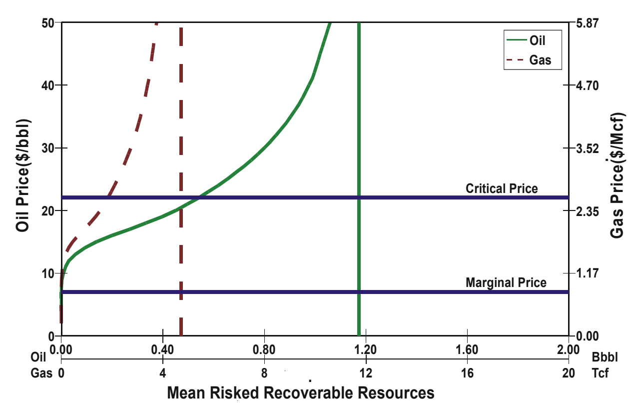

Figure 8. Western GOM Planning Area full-cycle > 2,400 m water depth price-supply curve.

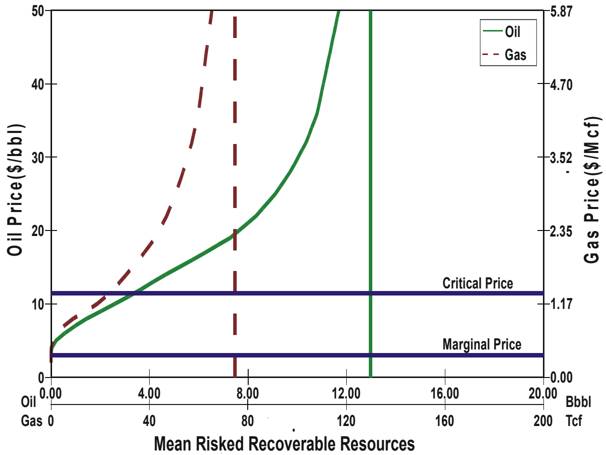

Figure 9. Western GOM Planning Area half-cycle total of all water depths price-supply curve.

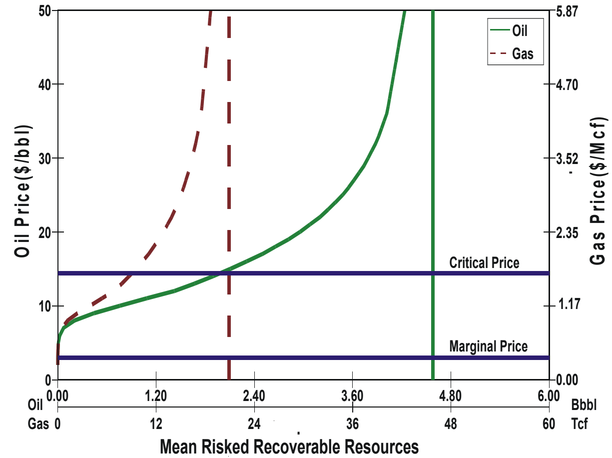

Figure 12. Western GOM Planning Area half-cycle 800-1,600 m water depth price-supply curve.

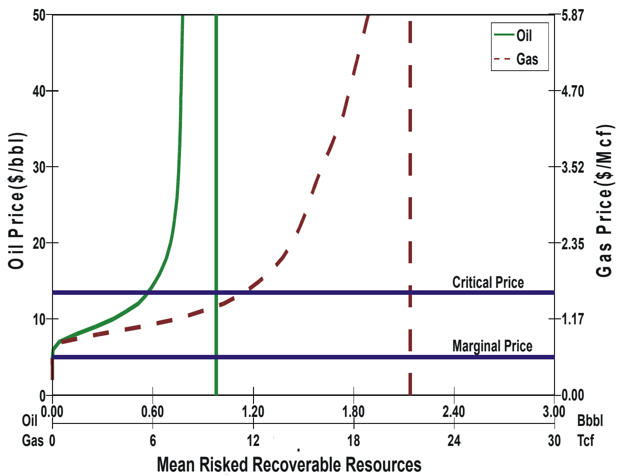

Figure 10. Western GOM Planning Area half-cycle 0-200 m water depth price-supply curve.

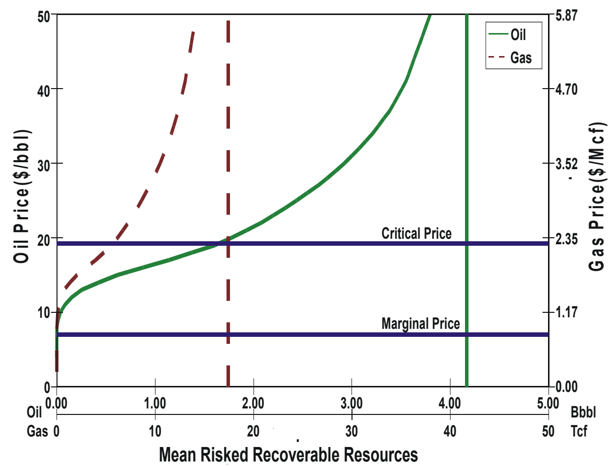

Figure 13. Western GOM Planning Area half-cycle 1,600-2,400 m water depth price-supply curve.

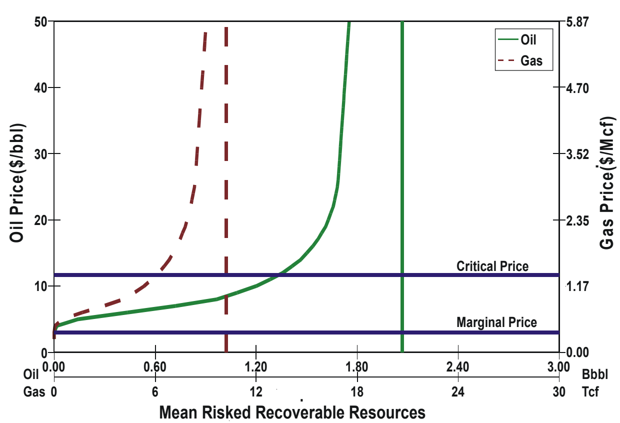

Figure 11. Western GOM Planning Area half-cycle 200-800 m water depth price-supply curve.

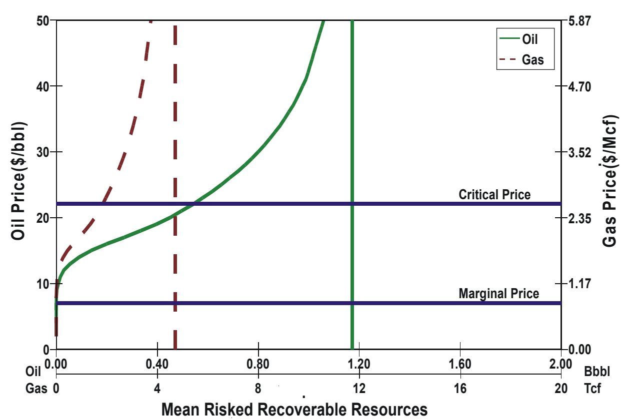

Figure 14. Western GOM Planning Area half-cycle >2,400 m water depth price-supply curve.

Central Gulf of Mexico Planning Area Economic Results

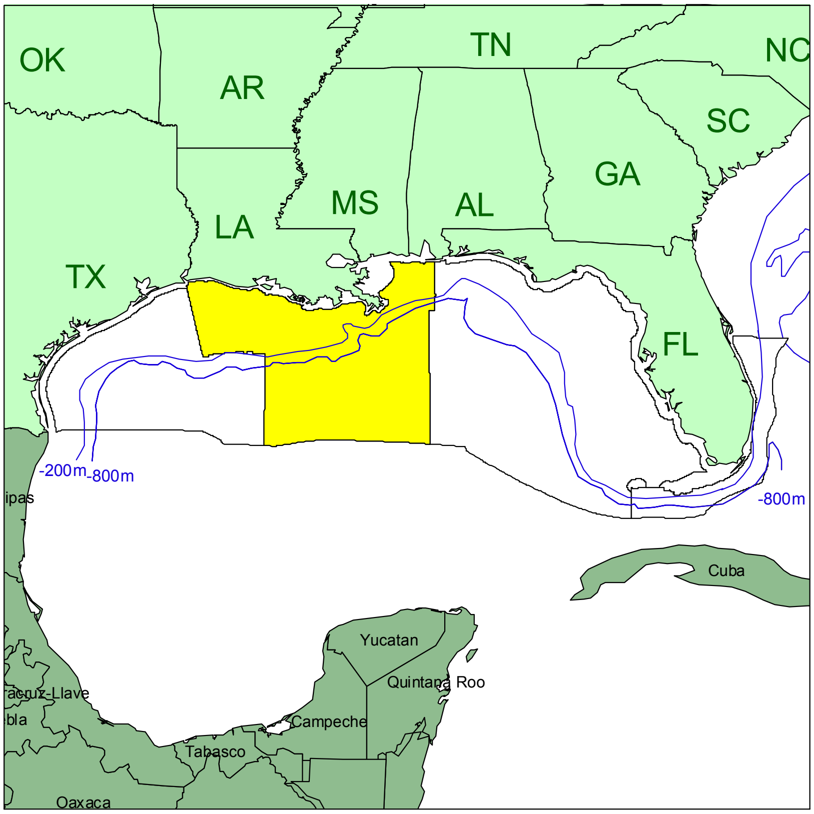

Figure 1. Map of the Central Gulf of Mexico Planning Area (yellow).

Central GOM Planning Area

The Central Gulf of Mexico (GOM) Planning Area includes submerged Federal lands located in offshore Louisiana, Mississippi, and Alabama. To the south, the area extends to the U.S.-Mexico international boundary (figure 1).

Undiscovered Economically Recoverable Resources (UERR) were evaluated for five water depth ranges: 0-200 m, 201-800 m, 801-1,600 m, 1,601-2,400 m, and greater than 2,400 m. The Central GOM Planning Area is extensively developed in the 0-200 m range with a network of infrastructures already in place. The 201-800 m range is undergoing significant development with tie-backs to infrastructures and the installation of new deepwater structures. The 801-1,600 m range is also in the development process, and production has been established in the 1,601 to 2,400 m range. The greater than 2,400 m water depths will require new technologies for development. Significant amounts of Undiscovered Conventionally Recoverable Resources (UCRR) have been assessed for all five water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at each of the five different water depths. Assessment reserves and resources have been provided in tables 1-6, which present the data from figure 2, including an overall Central GOM Planning Area total.

The full-cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in tables 7-12. These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the five water depth ranges, and for the total Central GOM Planning Area.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present the estimates of mean UERR at any starting oil price up to $50/bbl. Please note that entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are the mean curves.

The full-cycle and half-cycle price-supply curves are shown in figures 3-14. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR) Detailed Discussion section.

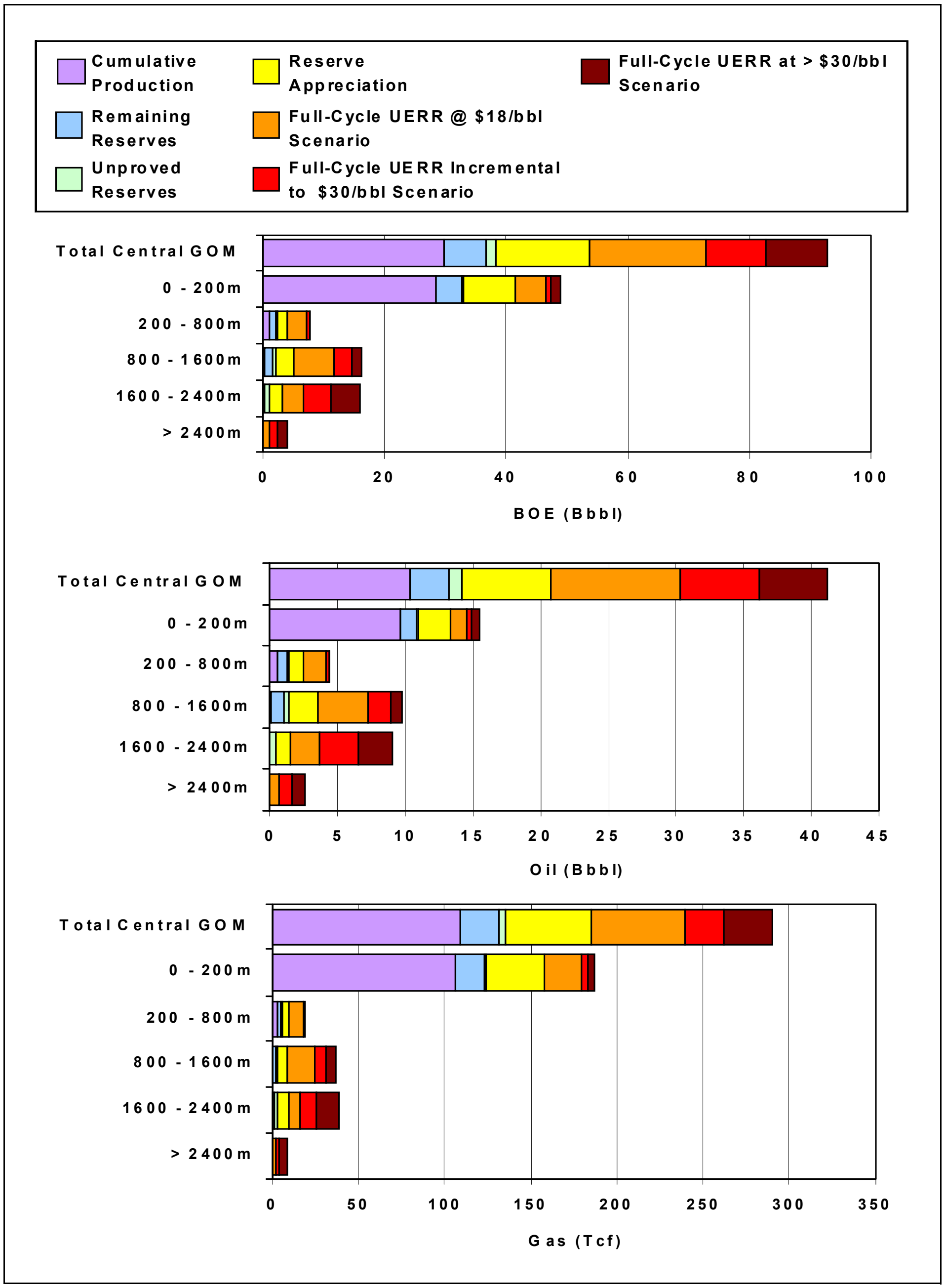

Figure 2. Central Gulf of Mexico Planning Area mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	13.212	131.518	36.614
Cumulative production	10.348	108.882	29.722
Remaining proved	2.864	22.636	6.891
Unproved	0.929	3.821	1.608
Appreciation (P & U)	6.644	49.556	15.462
Undiscovered Conventionally Recoverable Resources			
95th percentile	18.466	99.355	36.145
Mean	20.404	105.519	39.180
5th percentile	23.767	114.177	44.083
Total Endowment			
95th percentile	39.250	284.250	89.829
Mean	41.189	290.414	92.864
5th percentile	44.552	299.072	97.767

Table 1. Central GOM Planning Area reserves and resources total of all water depths.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	10.879	123.330	32.823
Cumulative production	9.628	106.218	28.528
Remaining proved	1.251	17.111	4.296
Unproved	0.031	0.423	0.106
Appreciation (P & U)	2.388	34.394	8.508
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.903	28.022	6.889
Mean	2.227	29.264	7.434
5th percentile	2.783	30.466	8.205
Total Endowment			
95th percentile	15.200	186.170	48.326
Mean	15.525	187.411	48.872
5th percentile	16.081	188.613	49.642

Table 2. Central GOM Planning Area reserves and resources 0-200 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.307	5.099	2.214
Cumulative production	0.603	2.403	1.030
Remaining proved	0.704	2.696	1.184
Unproved	0.083	0.300	0.136
Appreciation (P & U)	1.049	3.593	1.688
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.644	8.884	3.225
Mean	1.930	10.138	3.734
5th percentile	2.229	11.404	4.258
Total Endowment			
95th percentile	4.082	17.876	7.263
Mean	4.368	19.131	7.772
5th percentile	4.667	20.397	8.296

Table 3. Central GOM Planning Area reserves and resources 200-800 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.026	2.306	1.436
Cumulative production	0.118	0.199	0.153
Remaining proved	0.908	2.106	1.283
Unproved	0.394	1.025	0.577
Appreciation (P & U)	2.123	4.813	2.980
Undiscovered Conventionally Recoverable Resources			
95th percentile	5.713	25.817	10.307
Mean	6.206	28.686	11.310
5th percentile	6.743	34.246	12.836
Total Endowment			
95th percentile	9.256	33.962	15.299
Mean	9.749	36.830	16.302
5th percentile	10.286	42.390	17.829

Table 4. Central GOM Planning Area reserves and resources 800-1,600 m water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.001	0.783	0.140
Cumulative production	<0.001	0.061	0.011
Remaining proved	0.001	0.722	0.129
Unproved	0.421	2.073	0.790
Appreciation (P & U)	1.085	6.755	2.287
Undiscovered Conventionally Recoverable Resources			
95th percentile	6.606	26.219	11.271
Mean	7.522	29.339	12.742
5th percentile	8.992	34.180	15.074
Total Endowment			
95th percentile	8.112	35.830	14.488
Mean	9.028	38.950	15.959
5th percentile	10.499	43.791	18.291

Table 5. Central GOM Planning Area reserves and resources 1,600-2,400 m water depth.

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	1.826	6.596	2.999
Mean	2.554	8.218	4.017
5th percentile	4.740	12.803	7.018
Total Endowment			
95th percentile	1.826	6.596	2.999
Mean	2.554	8.218	4.017
5th percentile	4.740	12.803	7.018

Table 6. Central GOM Planning Area reserves and resources > 2,400 m water depth.

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		7.366	46.606	15.659
Mean		9.508	54.726	19.246
5th percentile		11.780	62.514	22.903
Half-Cycle	1.00			
95th percentile		7.907	49.453	16.707
Mean		10.091	57.549	20.331
5th percentile		12.479	65.404	24.117
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		13.369	71.337	26.062
Mean		15.369	77.467	29.154
5th percentile		18.148	85.500	33.362
Half-Cycle	1.00			
95th percentile		13.648	73.260	26.683
Mean		15.719	79.091	29.792
5th percentile		18.653	86.373	34.022

Table 7. Central GOM Planning Area total of all water depths economic assessment results.

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		1.093	20.194	4.686
Mean		1.282	21.605	5.126
5th percentile		1.483	22.849	5.549
Half-Cycle	1.00			
95th percentile		1.144	20.994	4.879
Mean		1.325	22.479	5.324
5th percentile		1.535	23.675	5.747
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.371	23.706	5.589
Mean		1.548	25.010	5.998
5th percentile		1.726	26.267	6.400
Half-Cycle	1.00			
95th percentile		1.378	24.171	5.679
Mean		1.563	25.395	6.082
5th percentile		1.739	26.630	6.478

Table 8. Central GOM Planning Area 0-200 m water depth economic assessment results.

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		1.390	6.995	2.635
Mean		1.741	8.406	3.236
5th percentile		2.046	9.871	3.803
Half-Cycle	1.00			
95th percentile		1.414	7.164	2.689
Mean		1.760	8.544	3.280
5th percentile		2.085	9.881	3.843
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.565	8.221	3.028
Mean		1.880	9.446	3.560
5th percentile		2.193	10.717	4.100
Half-Cycle	1.00			
95th percentile		1.581	8.251	3.049
Mean		1.887	9.513	3.579
5th percentile		2.196	10.781	4.114

Table 9. Central GOM Planning Area 200-800 m water depth economic assessment results.

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		3.125	12.235	5.302
Mean		3.737	16.633	6.697
5th percentile		4.332	22.633	8.359
Half-Cycle	1.00			
95th percentile		3.303	12.848	5.589
Mean		3.902	17.295	6.979
5th percentile		4.485	23.267	8.625
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		4.833	19.977	8.387
Mean		5.362	23.226	9.495
5th percentile		5.858	28.873	10.996
Half-Cycle	1.00			
95th percentile		4.939	20.168	8.528
Mean		5.437	23.573	9.632
5th percentile		5.917	29.317	11.134

Table 10. Central GOM Planning Area 800-1,600 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.98			
95th percentile		0.520	0.861	0.674
Mean		2.176	6.676	3.364
5th percentile		3.686	12.182	5.853
Half-Cycle	0.99			
95th percentile		0.881	1.462	1.141
Mean		2.446	7.579	3.794
5th percentile		3.903	12.723	6.166
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		3.983	12.803	6.261
Mean		5.054	16.063	7.912
5th percentile		6.338	21.441	10.153
Half-Cycle	1.00			
95th percentile		4.195	13.257	6.533
Mean		5.224	16.700	8.196
5th percentile		6.510	22.018	10.427

Table 11. Central GOM Planning Area 1,600-2,400 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.97			
95th percentile		0.154	0.424	0.230
Mean		0.618	1.554	0.894
5th percentile		1.414	3.169	1.978
Half-Cycle	0.99			
95th percentile		0.204	0.681	0.326
Mean		0.727	1.804	1.048
5th percentile		1.706	3.891	2.398
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.992	2.702	1.473
Mean		1.639	3.919	2.337
5th percentile		3.300	6.781	4.506
Half-Cycle	1.00			
95th percentile		1.047	2.864	1.557
Mean		1.700	4.069	2.424
5th percentile		3.388	6.680	4.576

Table 12. Central GOM Planning Area >2,400 m water depth economic assessment results.

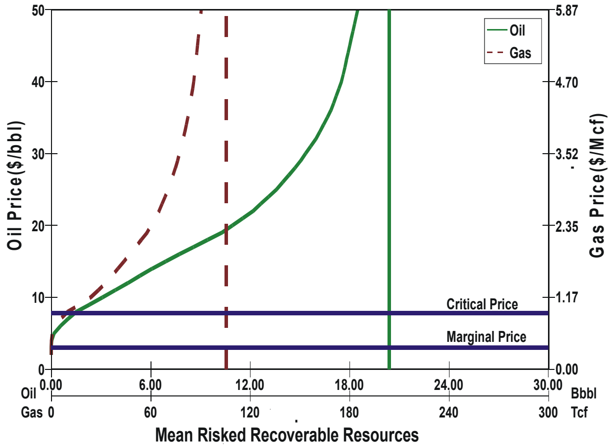

Figure 3. Central GOM Planning Area Full-Cycle Total of All Water Depths Price-Supply Curve.

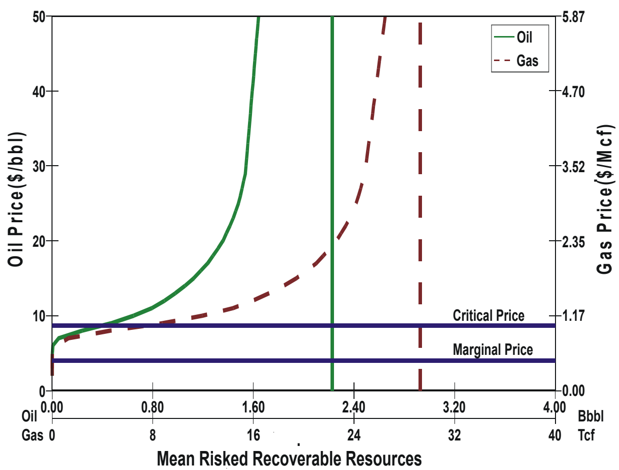

Figure 4. Central GOM Planning Area Full-Cycle 0-200 m Water Depth Price-Supply Curve.

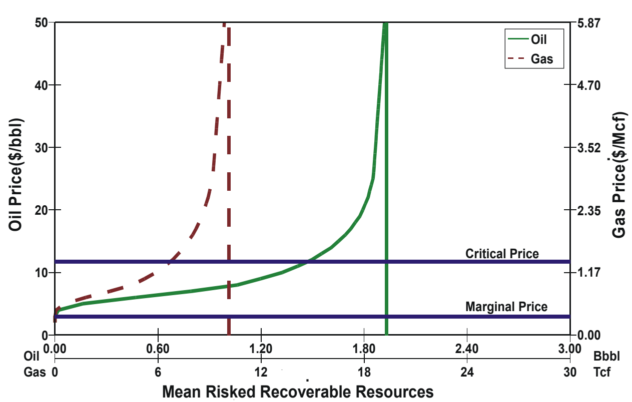

Figure 5. Central GOM Planning Area Full-Cycle 200-800 m Water Depth Price-Supply Curve.

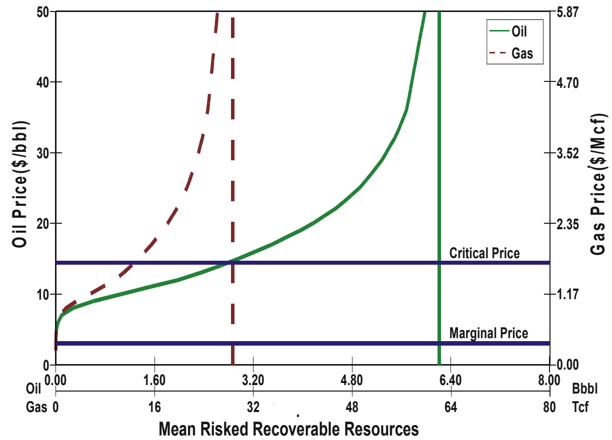

Figure 6. Central GOM Planning Area Full-Cycle 800-1,600 m Water Depth Price-Supply Curve.

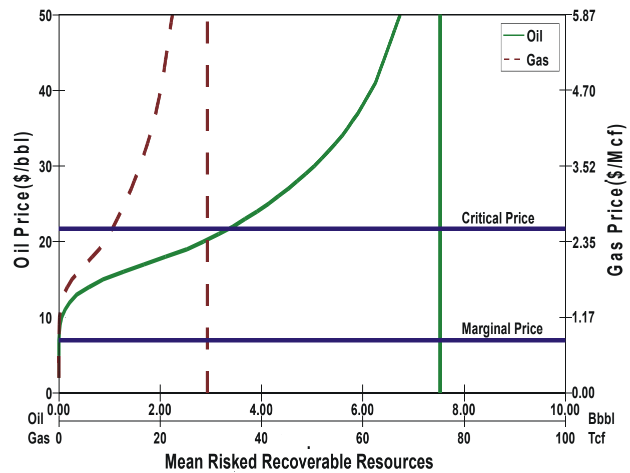

Figure 7. Central GOM Planning Area Full-Cycle 1,600-2,400 m Water Depth Price-Supply Curve.

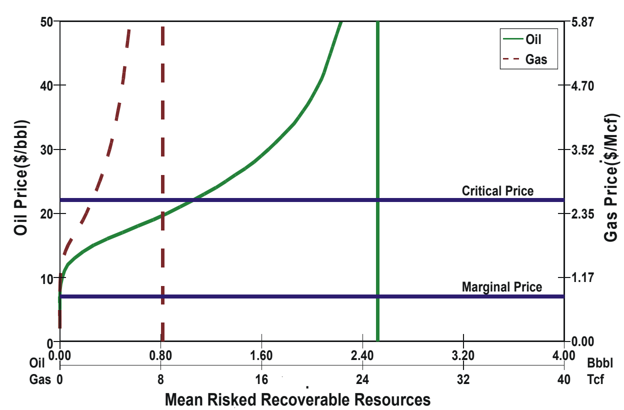

Figure 8. Central GOM Planning Area Full-Cycle > 2,400 m Water Depth Price-Supply Curve.

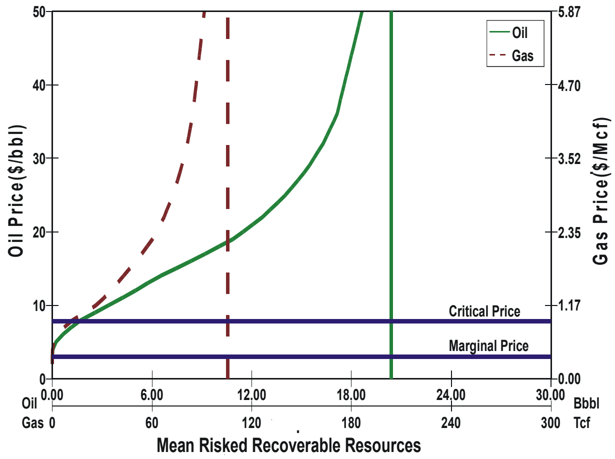

Figure 9. Central GOM Planning Area Half-Cycle Total of All Water Depths Price-Supply Curve.

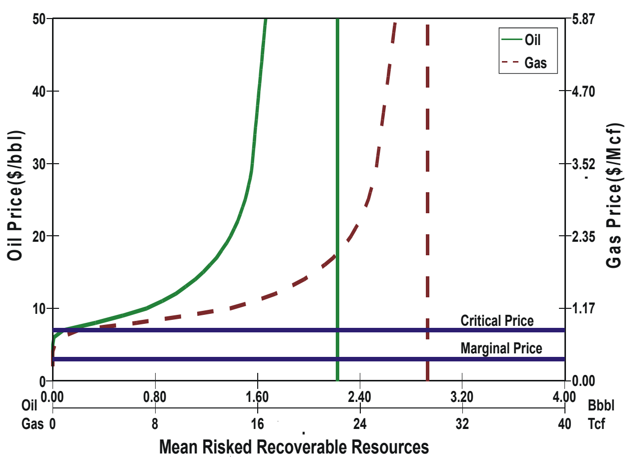

Figure 10. Central GOM Planning Area Half-Cycle 0-200 m Water Depth Price-Supply Curve.

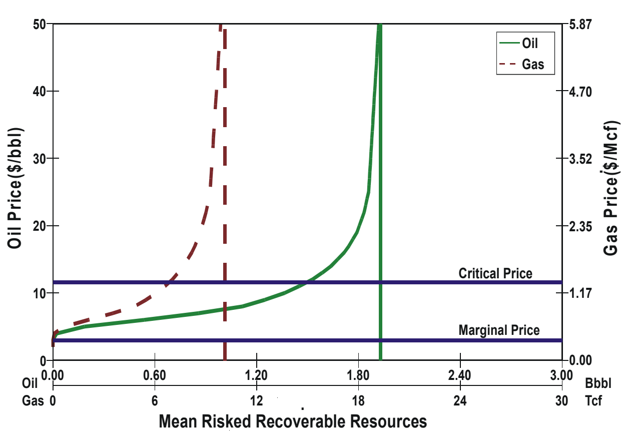

Figure 11. Central GOM Planning Area Half-Cycle 200-800 m Water Depth Price-Supply Curve.

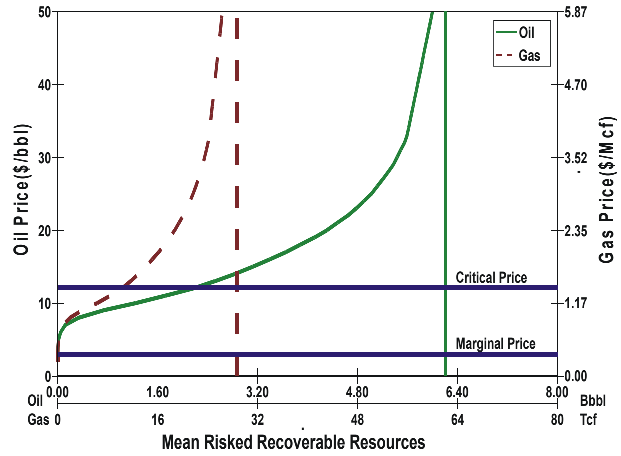

Figure 12. Central GOM Planning Area Half-Cycle 800-1,600 m Water Depth Price- Supply Curve.

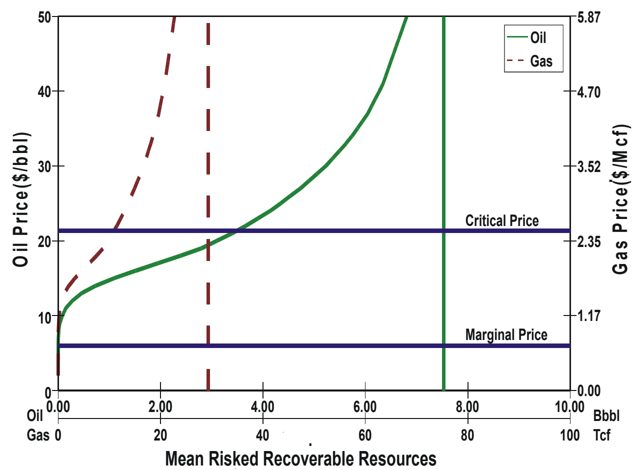

Figure 13. Central GOM Planning Area Half-Cycle 1,600-2,400 m Water Depth Price-Supply Curve.

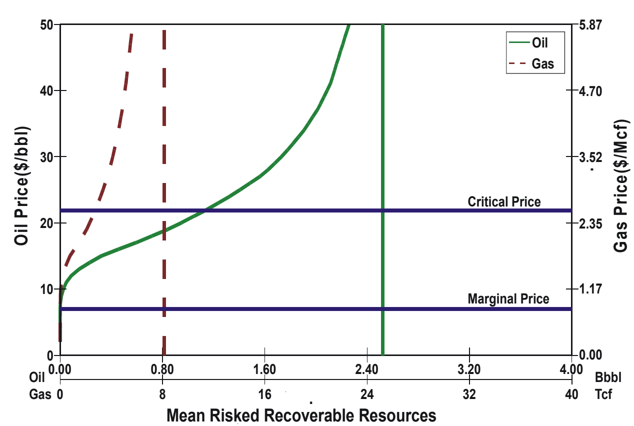

Figure 14. Central GOM Planning Area Half-Cycle >2,400 m Water Depth Price-Supply Curve.

Eastern Gulf of Mexico Planning Area Economic Results

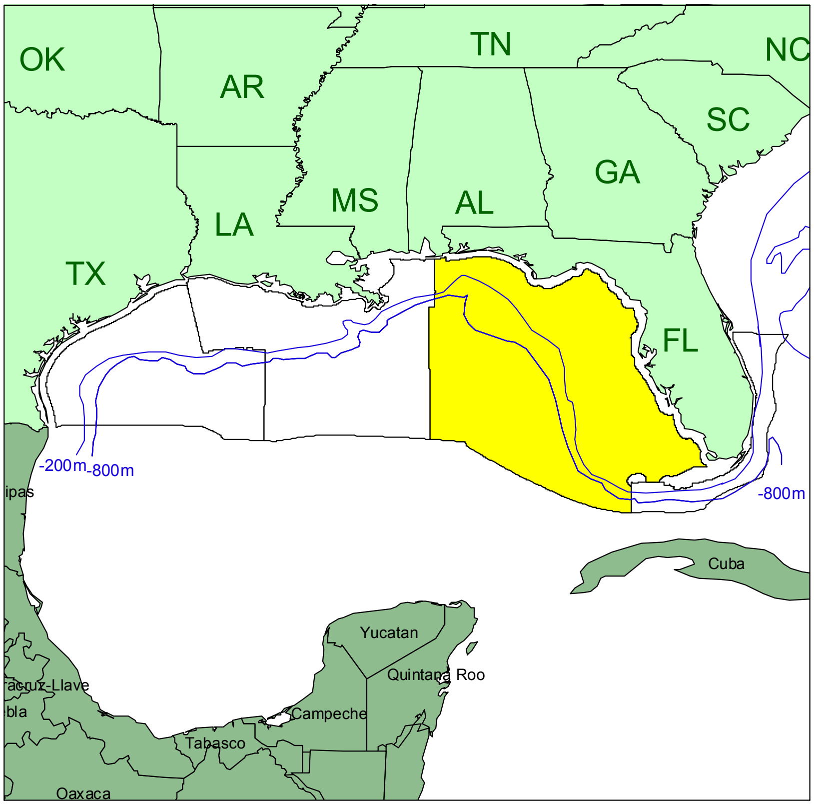

Figure 1. Map of Eastern Gulf of Mexico Planning Area (yellow).

Eastern GOM Planning Area

The Eastern Gulf of Mexico (GOM) Planning Area includes submerged Federal lands located offshore of Alabama and the west coast of Florida. The southern extent is the U.S.-Cuba international boundary (figure 1).

Undiscovered Economically Recoverable Resources (UERR) were evaluated for five water depth ranges: 0-200 m, 201-800 m, 801-1,600 m, 1,601-2,400 m, and greater than 2,400 m. As of the date of this study, the Eastern GOM Planning Area has no production in any of the water depth ranges; however, unproved and appreciated reserves exist in two of the five water depth ranges, as do significant amounts of undiscovered conventionally recoverable resources (UCRR).

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at each of the five different water depths. Assessment reserves and resources have been provided in tables 1-6, which present the data from figure 2, including an overall Eastern GOM Planning Area total.

The full-cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in tables 7-12. These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the five water depth ranges and for the total GOM Eastern Planning Area.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present the estimates of mean UERR at any starting oil price up to $50/bbl. Please note that entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are the mean curves. The full-cycle and half-cycle price-supply curves are shown in figures 3-14. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR) Detailed Discussion section.

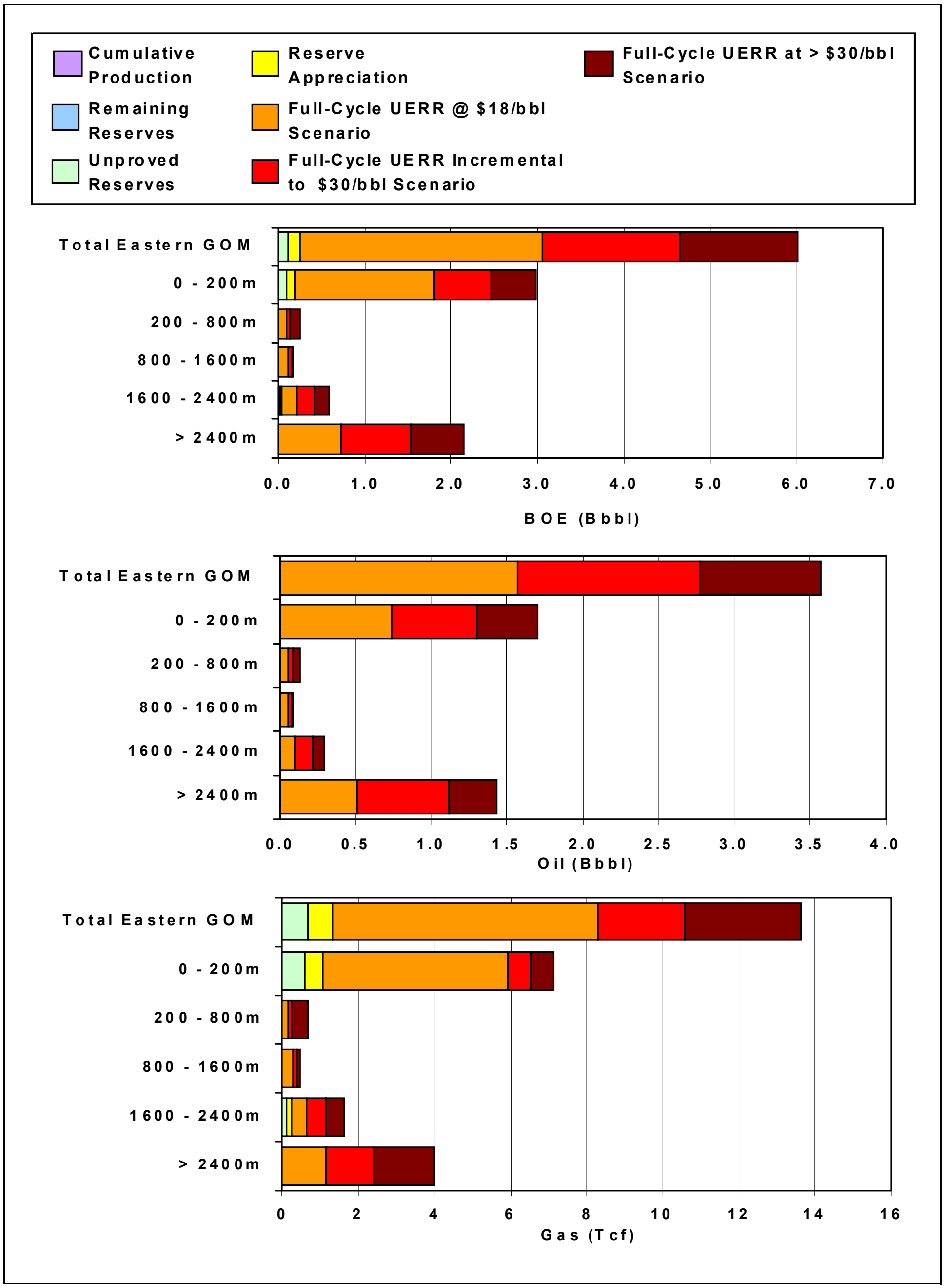

Figure 2. Eastern Gulf of Mexico Planning Area mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.005	0.001
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.005	0.001
Unproved	<0.001	0.678	0.121
Appreciation (P & U)	<0.001	0.659	0.117
Undiscovered Conventionally Recoverable Resources			
95th percentile	2.351	10.024	4.134
Mean	3.576	12.306	5.766
5th percentile	6.614	18.934	9.983
Total Endowment			
95th percentile	2.351	11.366	4.373
Mean	3.576	13.648	6.004
5th percentile	6.614	20.276	10.222

Table 1. Eastern GOM Planning Area reserves and resources total of all water depths.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.005	0.001
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.005	0.001
Unproved	<0.001	0.576	0.103
Appreciation (P & U)	<0.001	0.506	0.090
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.287	5.769	2.314
Mean	1.700	6.070	2.780
5th percentile	2.348	6.348	3.477
Total Endowment			
95th percentile	1.287	6.856	2.507
Mean	1.700	7.157	2.973
5th percentile	2.348	7.435	3.671

Table 2. Eastern GOM Planning Area reserves and resources 0-200 m water depth.

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	0.093	0.500	0.181
Mean	0.133	0.673	0.253
5th percentile	0.213	1.033	0.397
Total Endowment			
95th percentile	0.093	0.500	0.181
Mean	0.133	0.673	0.253
5th percentile	0.213	1.033	0.397

Table 3. Eastern GOM Planning Area reserves and resources 200-800 m water depth.

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	0.085	0.401	0.156
Mean	0.092	0.452	0.172
5th percentile	0.099	0.550	0.197
Total Endowment			
95th percentile	0.085	0.401	0.156
Mean	0.092	0.452	0.172
5th percentile	0.099	0.550	0.197

Table 4. Eastern GOM Planning Area reserves and resources 800-1,600 m water depth.

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	0.101	0.018
Appreciation (P & U)	<0.001	0.153	0.027
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.253	1.175	0.462
Mean	0.294	1.354	0.535
5th percentile	0.367	1.721	0.673
Total Endowment			
95th percentile	0.253	1.429	0.507
Mean	0.294	1.609	0.580
5th percentile	0.367	1.975	0.719

Table 5. Eastern GOM Planning Area reserves and resources 1,600-2,400 m water depth.

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	0.458	1.767	0.772
Mean	1.433	3.987	2.143
5th percentile	4.780	11.014	6.740
Total Endowment			
95th percentile	0.458	1.767	0.772
Mean	1.433	3.987	2.143
5th percentile	4.780	11.014	6.740

Table 6. Eastern GOM Planning Area reserves and resources > 2,400 m water depth.

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	5.716	1.547
Mean		1.572	6.946	2.808
5th percentile		3.832	10.698	5.735
Half-Cycle	1.00			
95th percentile		0.728	5.863	1.771
Mean		1.748	7.341	3.054
5th percentile		4.154	11.786	6.252
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.641	7.461	2.969
Mean		2.776	9.222	4.417
5th percentile		5.603	14.448	8.174
Half-Cycle	1.00			
95th percentile		1.736	7.588	3.087
Mean		2.887	9.431	4.565
5th percentile		5.839	14.682	8.451

Table 7. Eastern GOM Planning Area total of all water depths economic assessment results.

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		0.140	4.733	0.983
Mean		0.740	4.854	1.604
5th percentile		1.395	5.065	2.296
Half-Cycle	1.00			
95th percentile		0.347	4.754	1.192
Mean		0.846	5.010	1.737
5th percentile		1.480	5.255	2.415
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.873	5.082	1.777
Mean		1.301	5.438	2.269
5th percentile		1.916	5.685	2.927
Half-Cycle	1.00			
95th percentile		0.894	5.204	1.820
Mean		1.353	5.498	2.331
5th percentile		1.985	5.721	3.003

Table 8. Eastern GOM Planning Area 0-200 m water depth economic assessment results.

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		0.027	0.132	0.050
Mean		0.061	0.165	0.090
5th percentile		0.152	0.241	0.194
Half-Cycle	1.00			
95th percentile		0.027	0.136	0.052
Mean		0.063	0.169	0.094
5th percentile		0.158	0.261	0.204
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.049	0.154	0.077
Mean		0.089	0.255	0.134
5th percentile		0.170	0.633	0.282
Half-Cycle	1.00			
95th percentile		0.050	0.158	0.078
Mean		0.091	0.264	0.138
5th percentile		0.174	0.634	0.287

Table 9. Eastern GOM Planning Area 200-800 m water depth economic assessment results.

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		0.050	0.207	0.087
Mean		0.061	0.282	0.111
5th percentile		0.070	0.385	0.139
Half-Cycle	1.00			
95th percentile		0.054	0.218	0.092
Mean		0.063	0.293	0.116
5th percentile		0.073	0.399	0.143
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.076	0.327	0.134
Mean		0.083	0.387	0.152
5th percentile		0.091	0.489	0.177
Half-Cycle	1.00			
95th percentile		0.077	0.332	0.136
Mean		0.084	0.392	0.154
5th percentile		0.092	0.489	0.179

Table 10. Eastern GOM Planning Area 800-1,600 m water depth economic assessment results.

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		0.103	0.384	0.171
5th percentile		0.186	0.801	0.328
Half-Cycle	0.93			
95th percentile		0.000	0.000	0.000
Mean		0.114	0.434	0.192
5th percentile		0.201	0.829	0.348
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.166	0.685	0.288
Mean		0.215	0.884	0.372
5th percentile		0.293	1.225	0.511
Half-Cycle	1.00			
95th percentile		0.174	0.707	0.300
Mean		0.221	0.914	0.384
5th percentile		0.299	1.263	0.523

Table 11. Eastern GOM Planning Area 1,600-2,400 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.98			
95th percentile		0.047	0.078	0.061
Mean		0.506	1.166	0.714
5th percentile		2.154	4.089	2.881
Half-Cycle	0.99			
95th percentile		0.071	0.154	0.098
Mean		0.571	1.296	0.801
5th percentile		2.441	4.617	3.263
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.276	0.842	0.426
Mean		1.115	2.385	1.540
5th percentile		4.138	7.069	5.396
Half-Cycle	1.00			
95th percentile		0.288	0.889	0.447
Mean		1.145	2.457	1.582
5th percentile		4.217	7.328	5.520

Table 12. Eastern GOM Planning Area >2,400 m water depth economic assessment results.

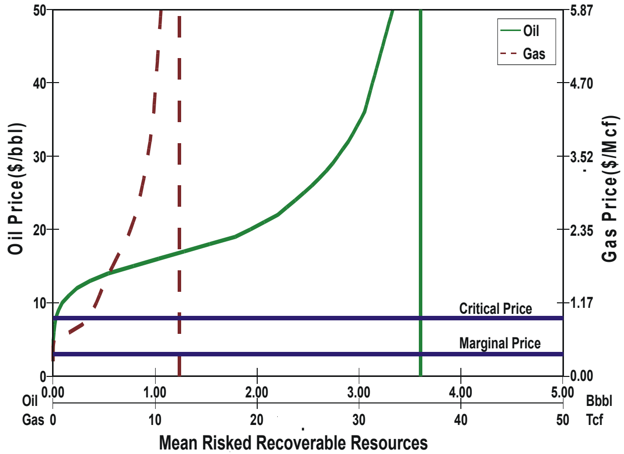

Figure 3. Eastern GOM Planning Area full-cycle total of all water depths price-supply curve.

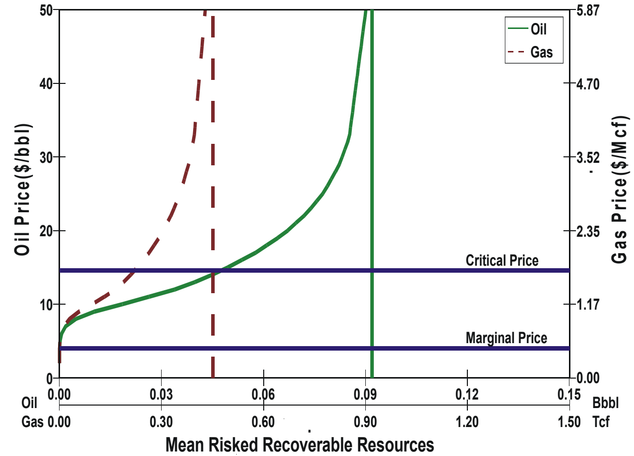

Figure 6. Eastern GOM Planning Area full-cycle 800-1,600 m water depth price-supply curve.

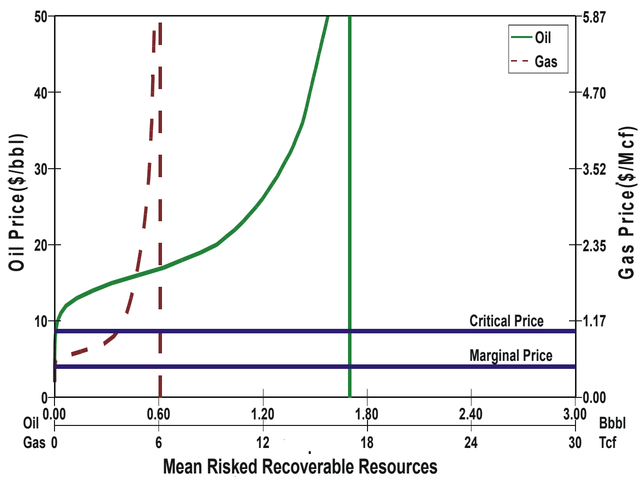

Figure 4. Eastern GOM Planning Area full-cycle 0-200 m water depth price-supply curve.

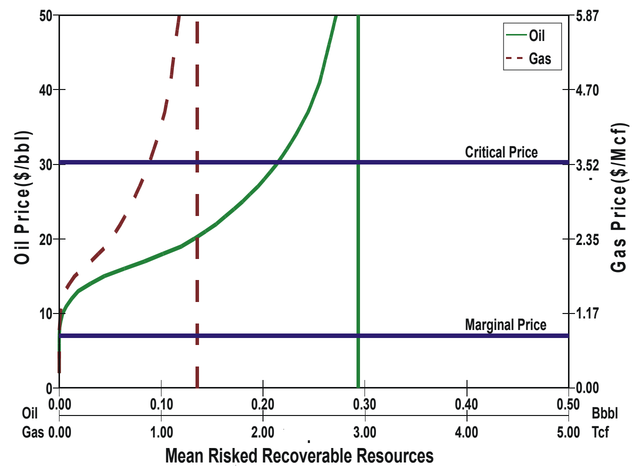

Figure 7. Eastern GOM Planning Area full-cycle 1,600-2,400 m water depth price-supply curve.

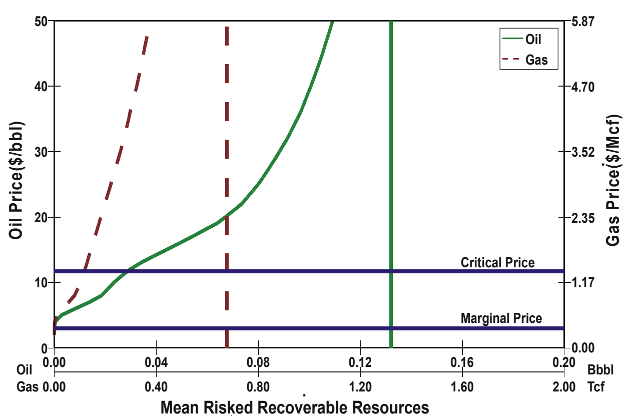

Figure 5. Eastern GOM Planning Area full-cycle 200-800 m water depth price-supply curve.

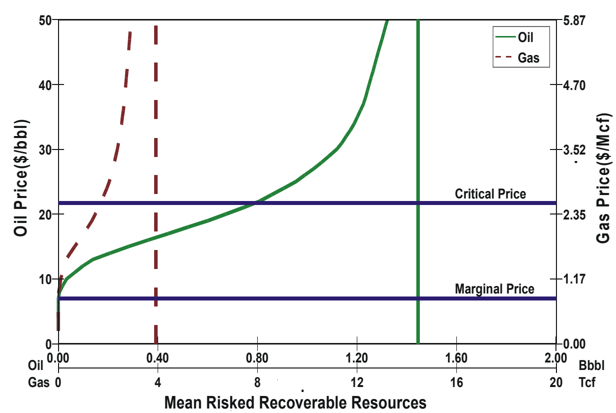

Figure 8. Eastern GOM Planning Area full-cycle > 2,400 m water depth price-supply curve.

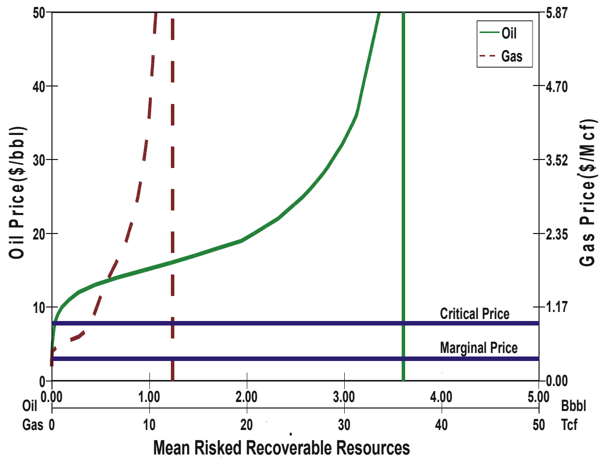

Figure 9. Eastern GOM Planning Area half-cycle total of all water depths price-supply curve.

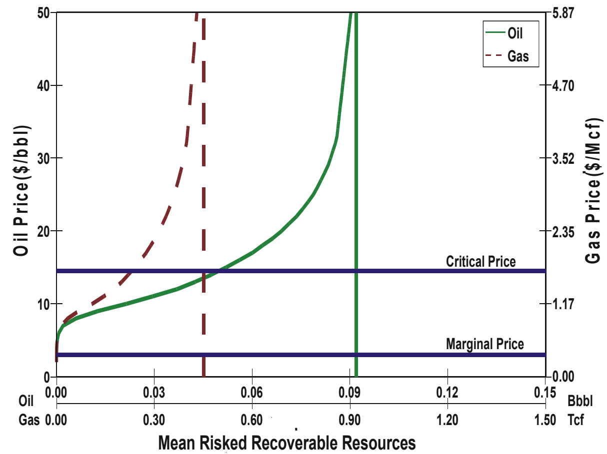

Figure 12. Eastern GOM Planning Area half-cycle 800-1,600 m water depth price-supply curve.

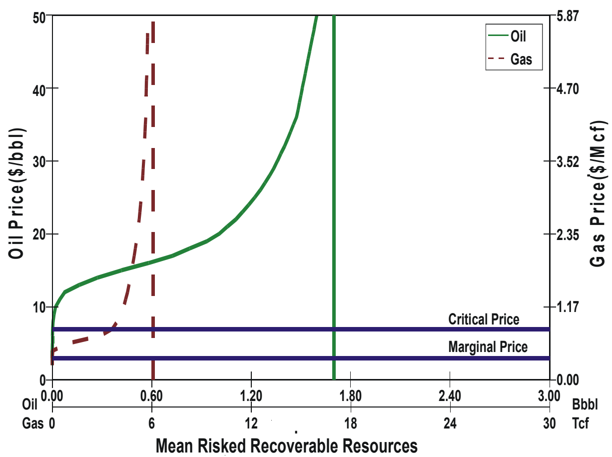

Figure 10. Eastern GOM Planning Area half-cycle 0-200 m water depth price-supply curve.

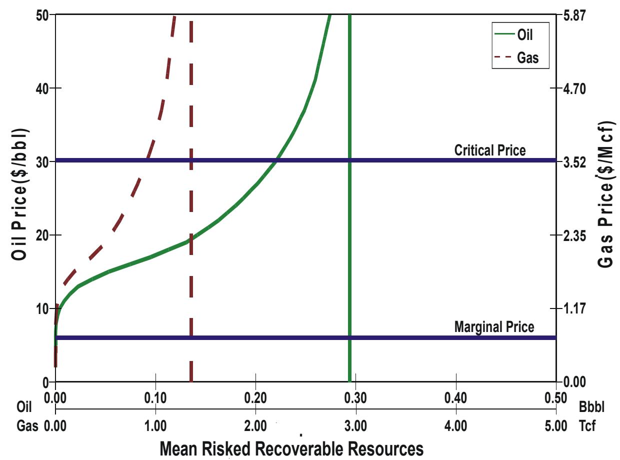

Figure 13. Eastern GOM Planning Area half-cycle 1,600-2,400 m water depth price-supply curve.

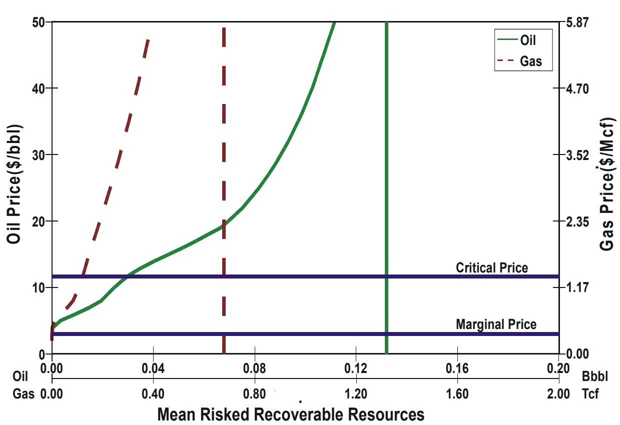

Figure 11. GOM Eastern Planning Area half-cycle 200-800 m water depth price-supply curve.

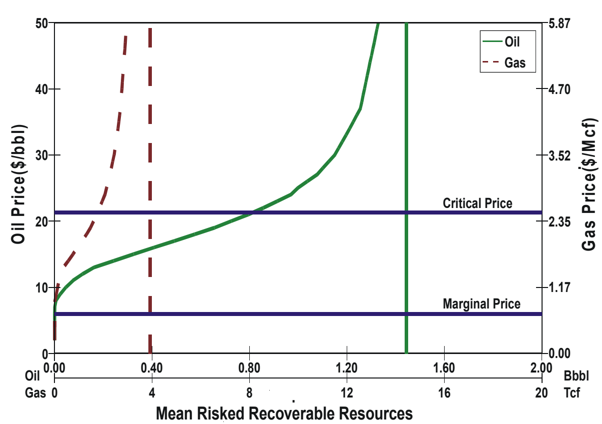

Figure 14. Eastern GOM Planning Area half-cycle >2,400 m water depth price-supply curve.

Straits of Florida Planning Area Economic Results

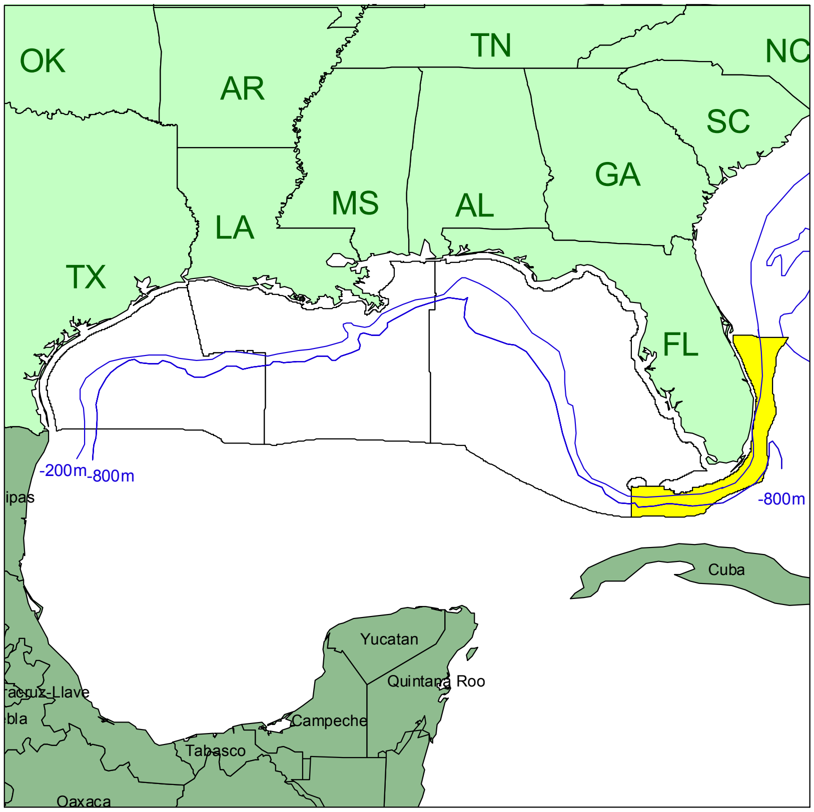

Figure 1. Map of the Straits of Florida Planning Area (yellow) in the Gulf of Mexico Region.

Straits of Florida Planning Area

The Straits of Florida Planning Area includes submerged Federal lands offshore central and southeastern Florida and extends to the U.S.-Cuba international boundary in the south and to the US-Bahama international boundary in the east (figure 1).

Undiscovered Economically Recoverable Resources (UERR) were evaluated for two water depth ranges, 0-200 m and 201-800 m. Reserves and resources were not assessed for greater than 800 m because of the limited extent of water greater than 800 m in depth in the planning area. The Straits of Florida Planning Area contains no production or production facilities and therefore no proved or unproved reserves. However, undiscovered conventionally recoverable resources (UCRR) have been assessed for the two water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at two different water depths. Assessment reserves and resources are listed in tables 1-3, which present the data from figure 2, including an overall Straits of Florida Planning Area total.

The full-cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in (tables 4-6). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the two water depth ranges and for the total Straits of Florida Planning Area.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present the estimates of mean UERR at any starting oil price up to $50/bbl. Please note that entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are the mean curves.

The full-cycle and half-cycle price-supply curves are shown in figures 3-8. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR), Detailed Discussion section.

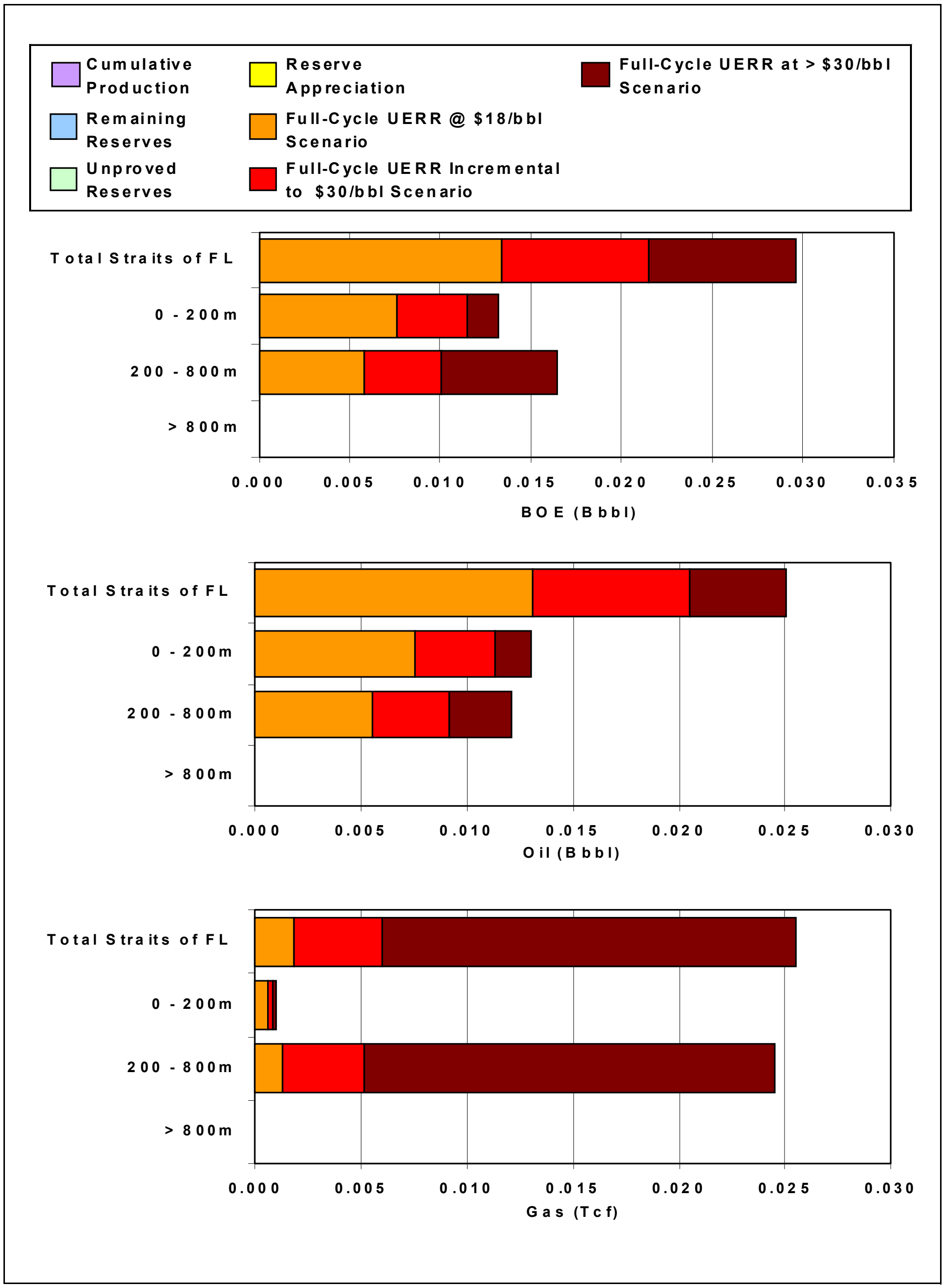

Figure 2. Straits of Florida Planning Area mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

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	0.015	0.019	0.018
Mean	0.025	0.026	0.030
5th percentile	0.045	0.030	0.051
Total Endowment			
95th percentile	0.015	0.019	0.018
Mean	0.025	0.026	0.030
5th percentile	0.045	0.030	0.051

Table 1. Straits of Florida Planning Area reserves and resources total of all water depths.

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	0.007	0.001	0.007
Mean	0.013	0.001	0.013
5th percentile	0.025	0.002	0.025
Total Endowment			
95th percentile	0.007	0.001	0.007
Mean	0.013	0.001	0.013
5th percentile	0.025	0.002	0.025

Table 2. Straits of Florida Planning Area reserves and resources 0-200 m water depth.

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	0.007	0.017	0.010
Mean	0.012	0.025	0.016
5th percentile	0.021	0.041	0.028
Total Endowment			
95th percentile	0.007	0.017	0.010
Mean	0.012	0.025	0.016
5th percentile	0.021	0.041	0.028

Table 3. Straits of Florida Planning Area reserves and resources 200-800 m water depth.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.65			
95th percentile		0.000	0.000	0.000
Mean		0.013	0.002	0.013
5th percentile		0.037	0.005	0.037
Half-Cycle	0.72			
95th percentile		0.000	0.000	0.000
Mean		0.014	0.002	0.015
5th percentile		0.037	0.006	0.038
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.010	0.002	0.010
Mean		0.020	0.006	0.022
5th percentile		0.041	0.013	0.043
Half-Cycle	1.00			
95th percentile		0.010	0.002	0.011
Mean		0.021	0.006	0.022
5th percentile		0.041	0.013	0.043

Table 4. Straits of Florida Planning Area total of all water depths economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.62			
95th percentile		0.000	0.000	0.000
Mean		0.008	0.001	0.008
5th percentile		0.021	0.002	0.021
Half-Cycle	0.68			
95th percentile		0.000	0.000	0.000
Mean		0.008	0.001	0.008
5th percentile		0.022	0.002	0.022
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.005	<0.001	0.005
Mean		0.011	0.001	0.012
5th percentile		0.023	0.002	0.023
Half-Cycle	1.00			
95th percentile		0.006	<0.001	0.006
Mean		0.011	0.001	0.012
5th percentile		0.023	0.002	0.024

Table 5. Straits of Florida Planning Area 0-200 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.65			
95th percentile		0.000	0.000	0.000
Mean		0.006	0.001	0.006
5th percentile		0.015	0.008	0.017
Half-Cycle	0.72			
95th percentile		0.000	0.000	0.000
Mean		0.006	0.001	0.006
5th percentile		0.016	0.008	0.017
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.004	<0.001	0.004
Mean		0.009	0.005	0.010
5th percentile		0.018	0.024	0.022
Half-Cycle	1.00			
95th percentile		0.004	<0.001	0.004
Mean		0.009	0.006	0.010
5th percentile		0.018	0.025	0.023

Table 6. Straits of Florida Planning Area 200-800 m water depth economic assessment results.

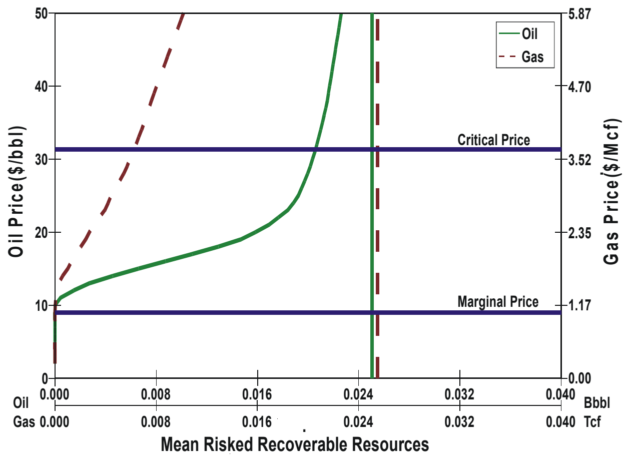

Figure 3. Straits of Florida Planning Area full-cycle total of all water depths price-supply curve.

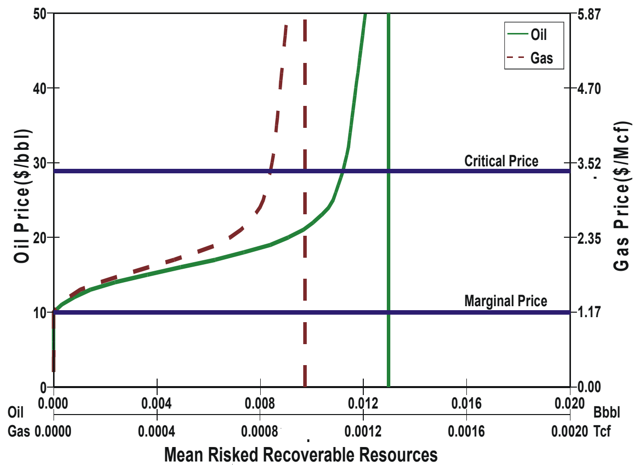

Figure 4. Straits of Florida Planning Area full-cycle 0-200 m water depth price-supply curve.

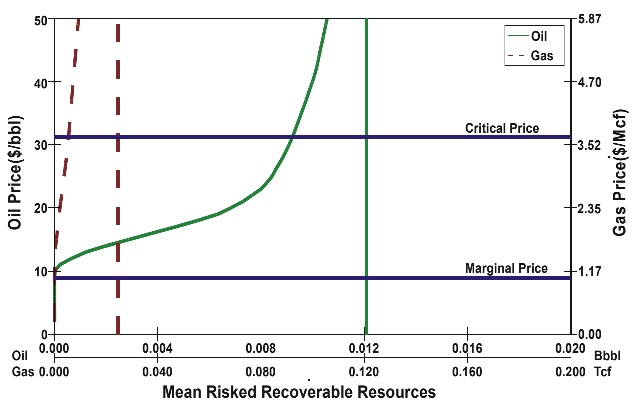

Figure 5. Straits of Florida Planning Area full-cycle 200-800 m water depth price-supply curve.

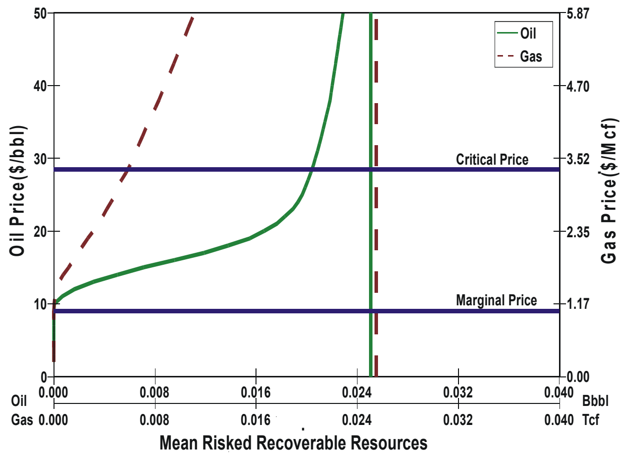

Figure 6. Straits of Florida Planning Area half-cycle total of all water depths price-supply curve.

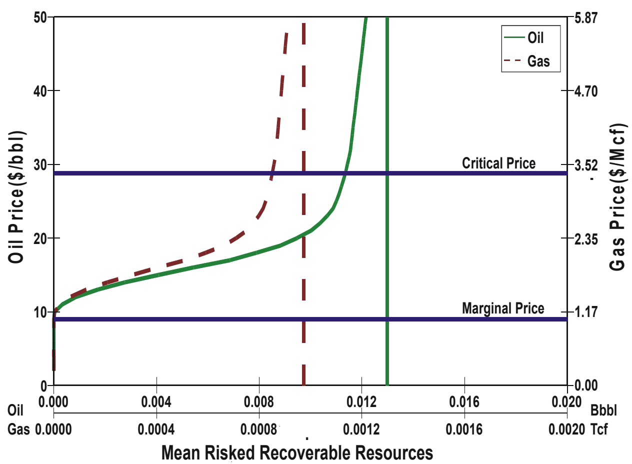

Figure 7. Straits of Florida Planning Area half-cycle 0-200 m water depth price-supply curve.

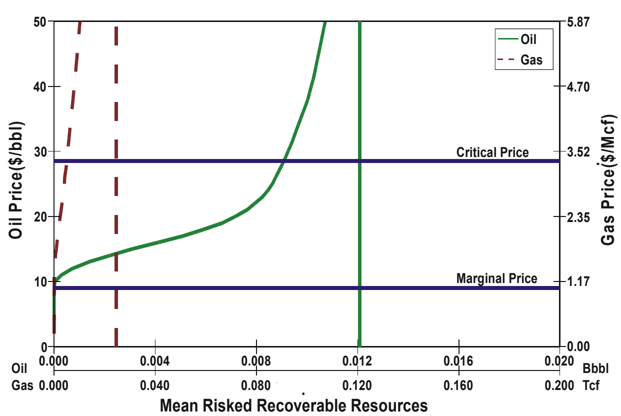

Figure 8. Straits of Florida Planning Area half-cycle 200-800 m water depth price-supply curve.

Atlantic Region Economic Results

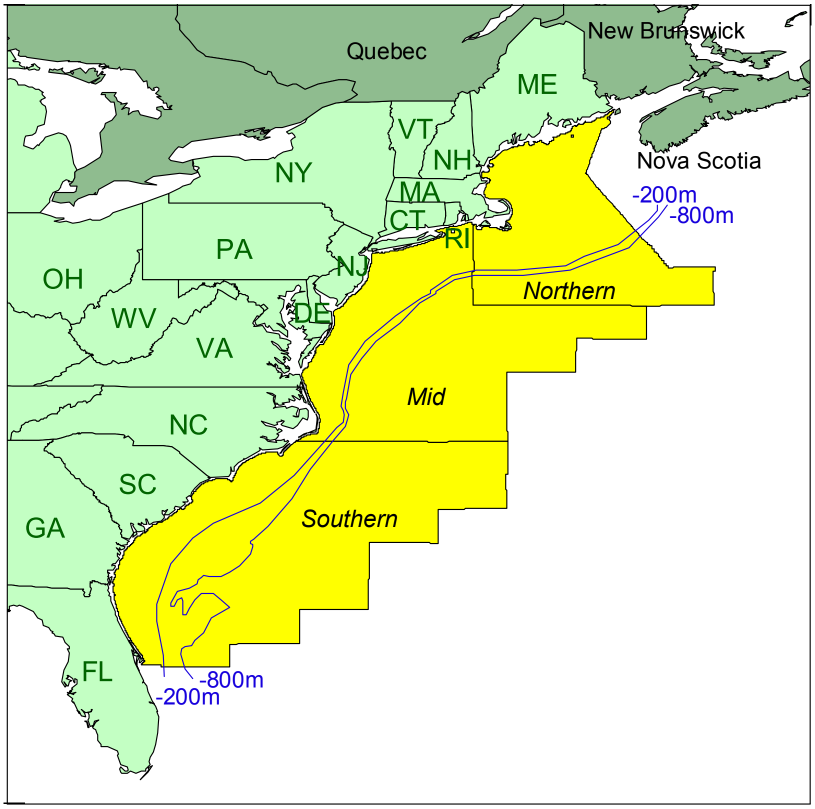

Figure 1. Map of Atlantic Region (yellow) and its three planning areas---northern, mid-, and southern.

Atlantic Region

The Atlantic Region includes submerged Federal lands from the U.S.-Canada international boundary south to central offshore Florida (figure 1).

Undiscovered Economically Recoverable Resources (UERR) were evaluated for three water depth ranges, 0-200 m, 201-800 m, and greater than 800 m. The Atlantic Region contains no production facilities and no infrastructure. As a result, the Region contains no proved or unproved reserves. However, undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at three different water depths. Assessment reserves and resources are listed in tables 1-4, which present the data from figure 2.

The full-cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in tables 5-8. These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present the estimates of mean UERR at any starting oil price up to $50/bbl. Please note 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 and half-cycle price-supply curves are shown in figures 3-10. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR) Detailed Discussion section.

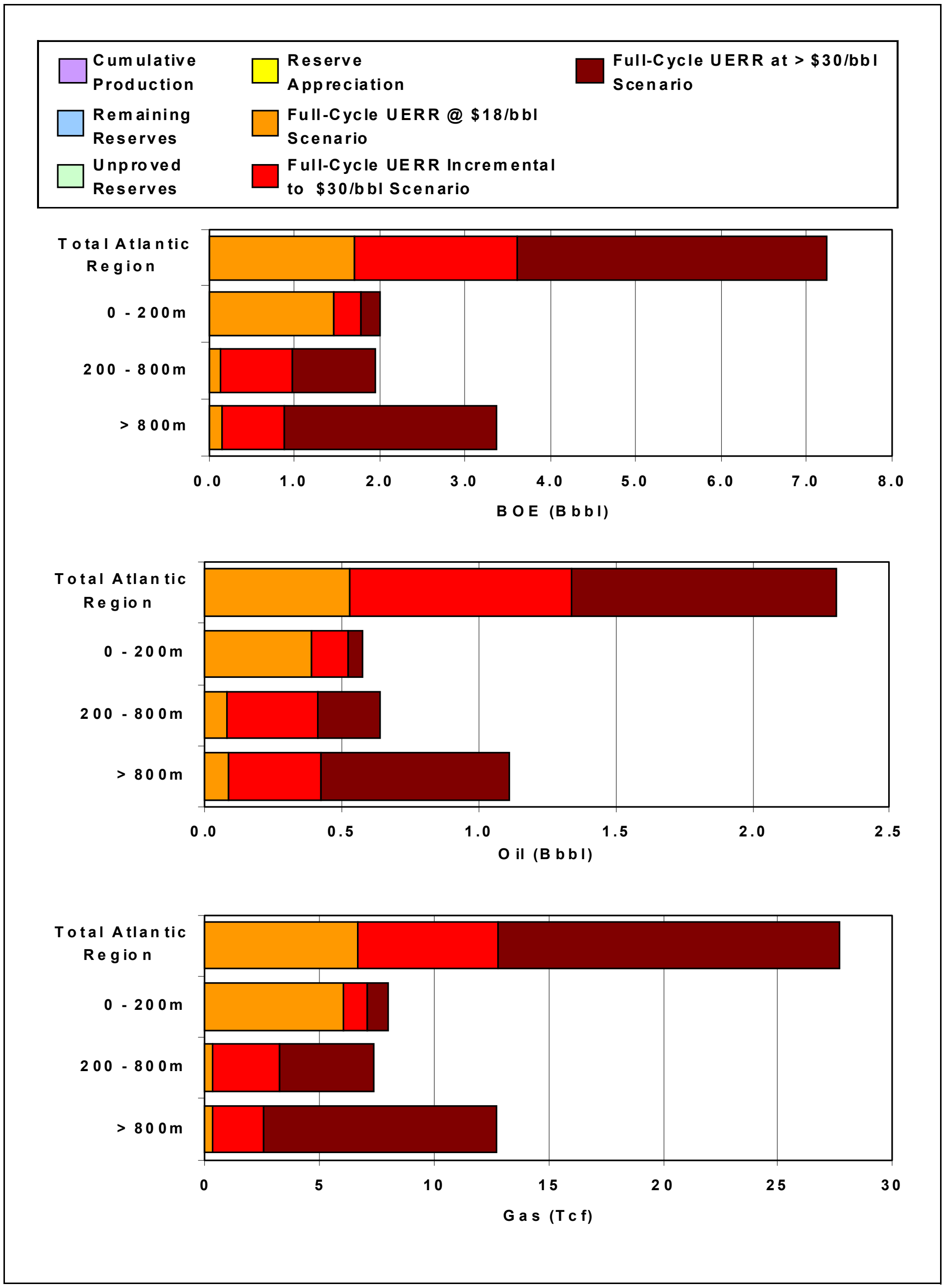

Figure 2. Atlantic Region mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

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	1.297	16.117	4.558
Mean	2.307	27.712	7.238
5th percentile	3.706	43.499	10.739
Total Endowment			
95th percentile	1.297	16.117	4.558
Mean	2.307	27.712	7.238
5th percentile	3.706	43.499	10.739

Table 1. Atlantic Region reserves and resources total of all water depths.

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	0.420	4.784	1.271
Mean	0.576	8.003	2.000
5th percentile	0.669	14.557	3.259
Total Endowment			
95th percentile	0.420	4.784	1.271
Mean	0.576	8.003	2.000
5th percentile	0.669	14.557	3.259

Table 2. Atlantic Region reserves and resources 0-200 m water depth.

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	0.447	5.957	1.507
Mean	0.637	7.363	1.947
5th percentile	0.973	9.173	2.605
Total Endowment			
95th percentile	0.447	5.957	1.507
Mean	0.637	7.363	1.947
5th percentile	0.973	9.173	2.605

Table 3. Atlantic Region reserves and resources 200-800 m water depth.

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	0.855	10.812	2.779
Mean	1.109	12.748	3.378
5th percentile	1.537	15.190	4.240
Total Endowment			
95th percentile	0.855	10.812	2.779
Mean	1.109	12.748	3.378
5th percentile	1.537	15.190	4.240

Table 4. Atlantic Region reserves and resources > 800 m water depth.

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		0.216	2.325	0.630
Mean		0.530	6.649	1.713
5th percentile		1.067	12.546	3.300
Half-Cycle	1.00			
95th percentile		0.280	3.059	0.824
Mean		0.602	7.310	1.903
5th percentile		1.178	13.280	3.541
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.823	7.939	2.235
Mean		1.338	12.780	3.612
5th percentile		1.920	19.205	5.338
Half-Cycle	1.00			
95th percentile		1.044	10.100	2.842
Mean		1.570	14.875	4.216
5th percentile		2.011	21.847	5.898

Table 5. Atlantic Region total of all water depths economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.99			
95th percentile		0.160	1.924	0.503
Mean		0.386	6.021	1.458
5th percentile		0.516	12.796	2.793
Half-Cycle	0.99			
95th percentile		0.188	2.340	0.605
Mean		0.419	6.391	1.556
5th percentile		0.549	13.015	2.865
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.355	3.881	1.045
Mean		0.523	7.066	1.780
5th percentile		0.612	13.622	3.036
Half-Cycle	1.00			
95th percentile		0.376	3.952	1.079
Mean		0.531	7.199	1.812
5th percentile		0.621	13.749	3.068

Table 6. Atlantic Region 0-200 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.25			
95th percentile		0.000	0.000	0.000
Mean		0.076	0.339	0.137
5th percentile		0.462	2.038	0.825
Half-Cycle	0.34			
95th percentile		0.000	0.000	0.000
Mean		0.091	0.465	0.174
5th percentile		0.462	2.830	0.965
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.97			
95th percentile		0.082	0.442	0.161
Mean		0.411	3.219	0.984
5th percentile		0.787	5.264	1.724
Half-Cycle	0.99			
95th percentile		0.256	2.287	0.663
Mean		0.467	3.870	1.155
5th percentile		0.799	5.894	1.848

Table 7. Atlantic Region 200-800 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.18			
95th percentile		0.000	0.000	0.000
Mean		0.087	0.351	0.149
5th percentile		0.560	2.781	1.054
Half-Cycle	0.26			
95th percentile		0.000	0.000	0.000
Mean		0.109	0.499	0.198
5th percentile		0.659	3.203	1.229
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.98			
95th percentile		0.041	0.386	0.109
Mean		0.422	2.568	0.879
5th percentile		0.957	5.787	1.987
Half-Cycle	1.00			
95th percentile		0.065	0.605	0.173
Mean		0.581	3.851	1.266
5th percentile		1.074	6.718	2.270

Table 8. Atlantic Region > 800 m water depth economic assessment results.

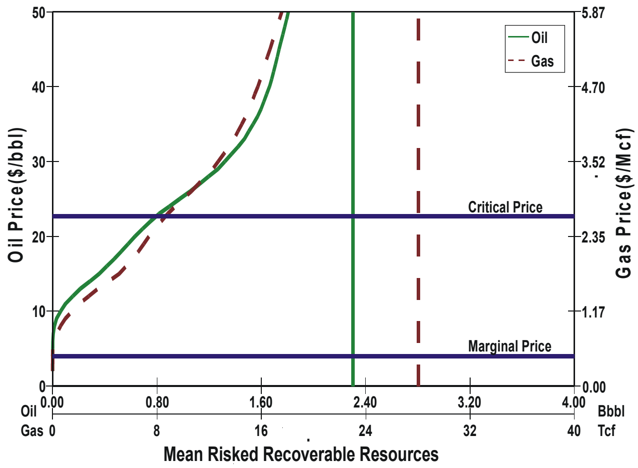

Figure 3. Atlantic Region full-cycle total of all water depths price-supply curve.

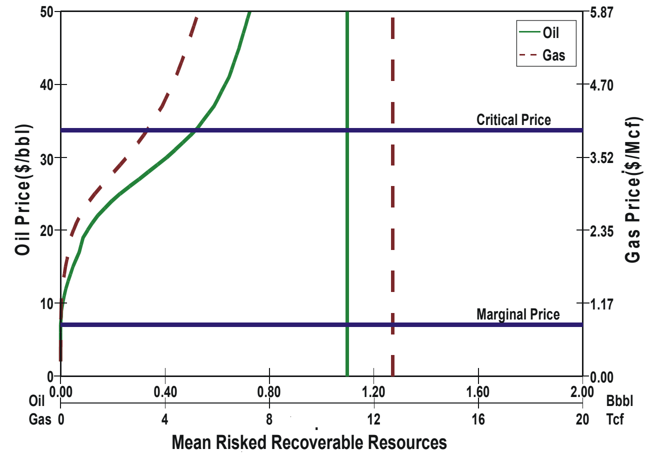

Figure 6. Atlantic Region full-cycle >800 m water depths price-supply curve.

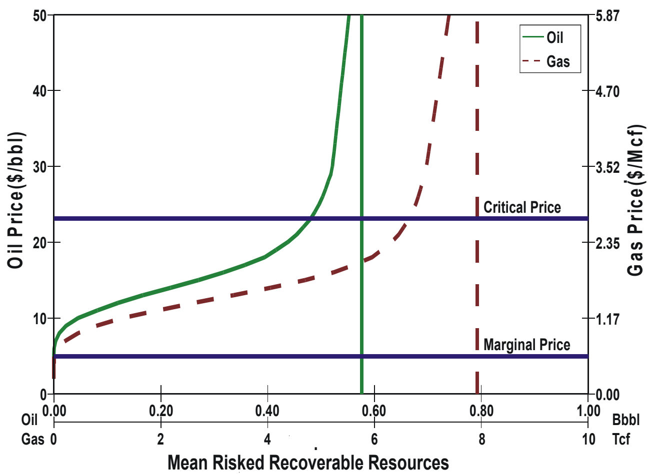

Figure 4. Atlantic Region full-cycle 0-200 m water depth price-supply curve.

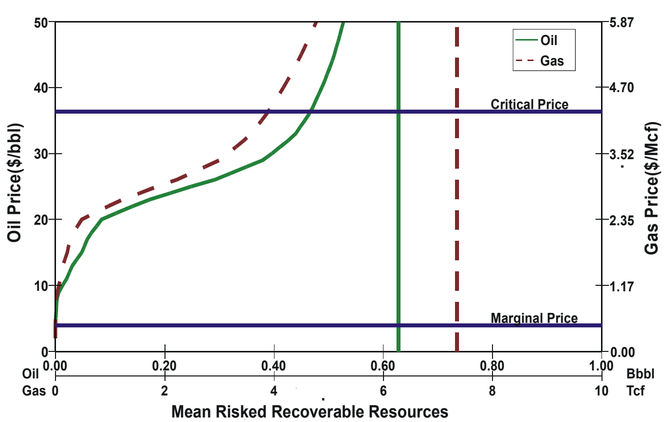

Figure 5. Atlantic Region full-cycle 200-800 m water depth price-supply curve.

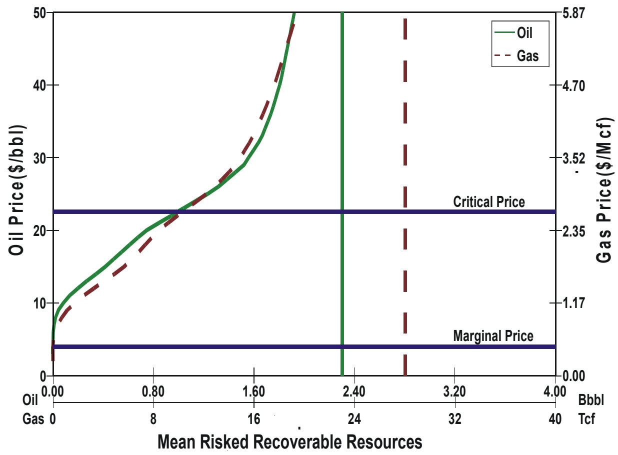

Figure 7. Atlantic Region half-cycle total of all water depths price-supply curve.

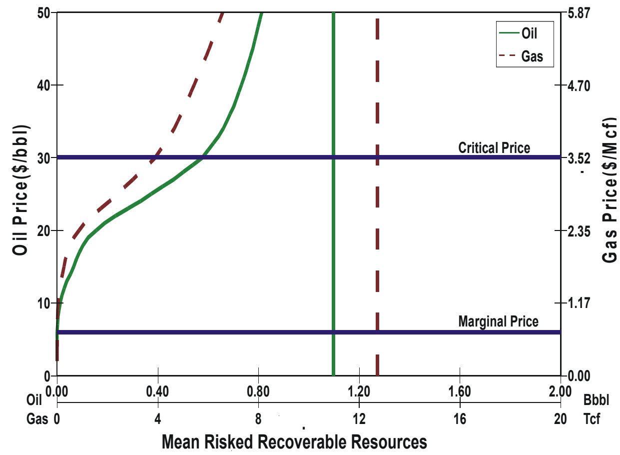

Figure 10. Atlantic Region half-cycle > 800 m water depths price-supply curve.

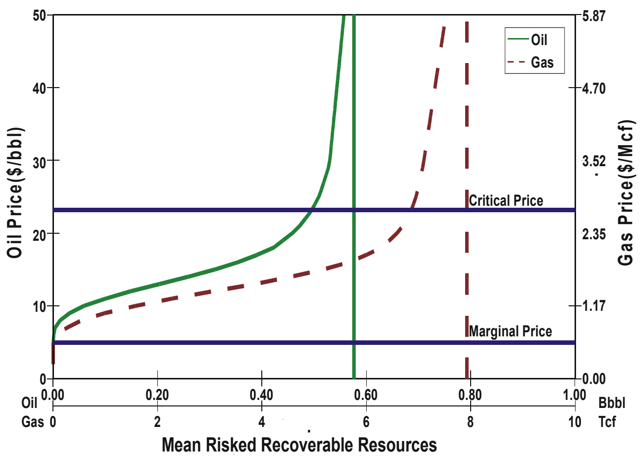

Figure 8. Atlantic Region half-cycle 0-200 m water depth price-supply curve.

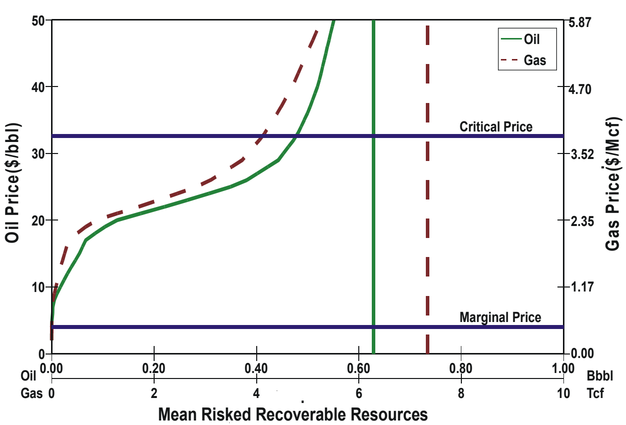

Figure 9. Atlantic Region half-cycle 200-800 m water depth price-supply curve.

South Atlantic Planning Area Economic Results

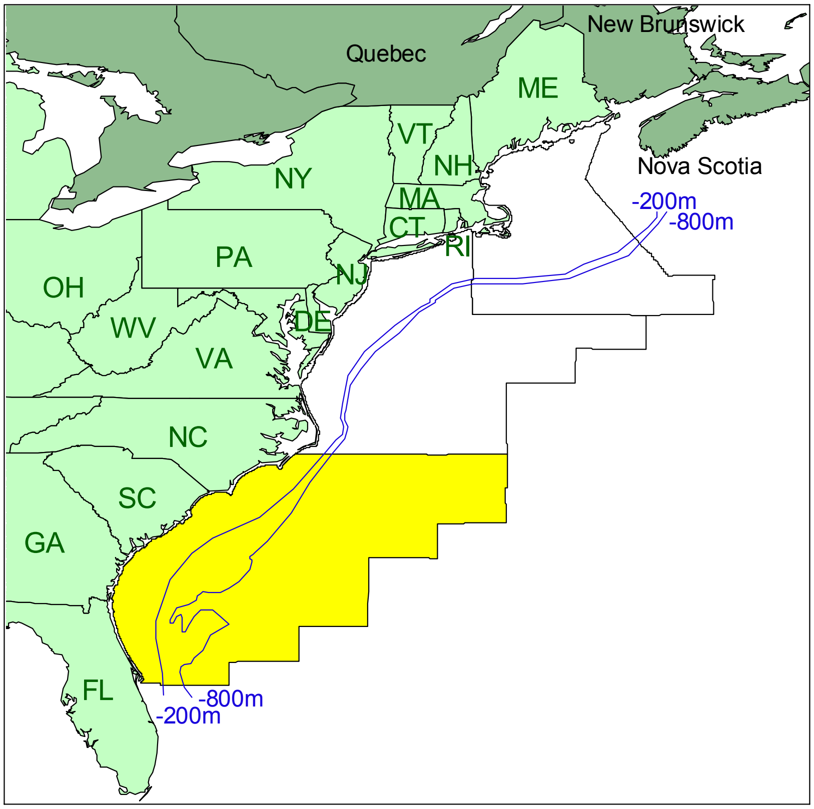

Figure 1. Map of South Atlantic Planning Area (yellow).

South Atlantic Planning Area

The South Atlantic Planning Area includes submerged Federal lands located in offshore southern North Carolina, South Carolina, Georgia, and northern Florida (figure 1).

Undiscovered Economically Recoverable Resources (UERR) were evaluated for three water depth ranges, 0-200 m, 201-800 m, and greater than 800 m. The South Atlantic Planning Area contains no production facilities and no infrastructure. As a result, this area contains no proved or unproved reserves; however, undiscovered conventionally recoverable resources (UCRR) are assessed for all three water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at each of the three different water depths. Assessment reserves and resources are listed in tables 1-4, which present the data from figure 2 and include the South Atlantic Area total.

The full- cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in tables 5-8. 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 South Atlantic Planning Area.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present the estimates of mean UERR at any starting oil price up to $50/bbl. Please note that entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are mean curves.

The full-cycle and half-cycle price-supply curves are shown in figures 3-10. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR) Detailed Discussion section.

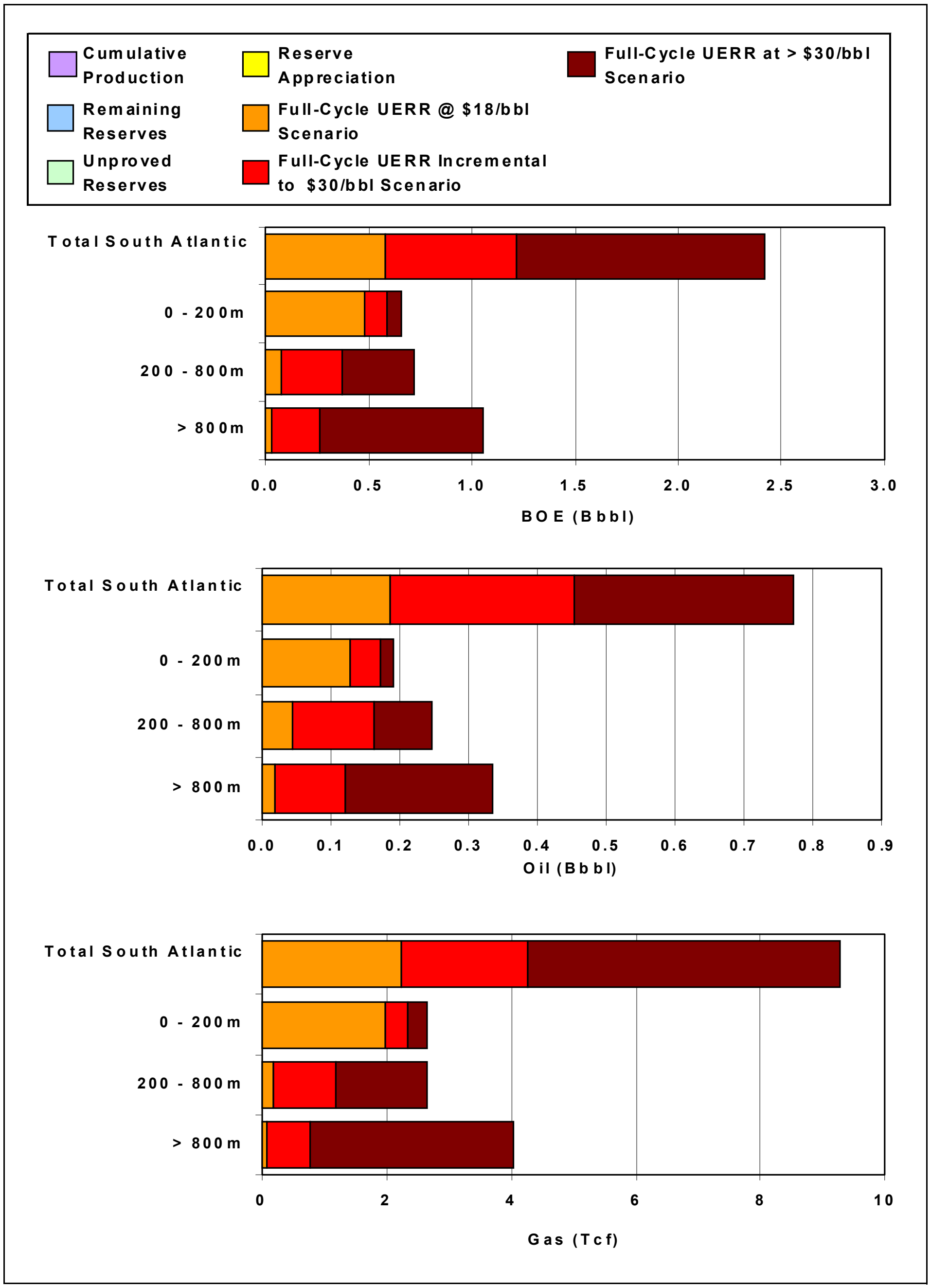

Figure 2. South Atlantic Planning Area mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

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	0.645	7.870	2.046
Mean	0.770	9.286	2.422
5th percentile	0.924	11.667	3.000
Total Endowment			
95th percentile	0.645	7.870	2.046
Mean	0.770	9.286	2.422
5th percentile	0.924	11.667	3.000

Table 1. South Atlantic Planning Area reserves and resources total of all water depths.

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	0.139	1.579	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.076
Total Endowment			
95th percentile	0.139	1.579	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.076

Table 2. South Atlantic Planning Area reserves and resources 0-200 m water depth.

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	0.162	2.090	0.533
Mean	0.247	2.642	0.717
5th percentile	0.437	3.503	1.060
Total Endowment			
95th percentile	0.162	2.090	0.533
Mean	0.247	2.642	0.717
5th percentile	0.437	3.503	1.060

Table 3. South Atlantic Planning Area reserves and resources 200-800 m water depth.

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	0.270	3.419	0.878
Mean	0.336	4.027	1.052
5th percentile	0.429	4.779	1.279
Total Endowment			
95th percentile	0.270	3.419	0.878
Mean	0.336	4.027	1.052
5th percentile	0.429	4.779	1.279

Table 4. South Atlantic Planning Area reserves and resources > 800 m water depth.

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		0.066	0.807	0.210
Mean		0.185	2.231	0.582
5th percentile		0.370	4.481	1.167
Half-Cycle	1.00			
95th percentile		0.089	1.050	0.275
Mean		0.209	2.453	0.646
5th percentile		0.401	4.689	1.236
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.272	2.705	0.753
Mean		0.454	4.273	1.214
5th percentile		0.672	6.569	1.841
Half-Cycle	1.00			
95th percentile		0.355	3.316	0.945
Mean		0.530	4.969	1.414
5th percentile		0.724	7.262	2.016

Table 5. South Atlantic Planning Area total of all water depths economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.99			
95th percentile		0.053	0.635	0.166
Mean		0.127	1.987	0.481
5th percentile		0.170	4.223	0.922
Half-Cycle	0.99			
95th percentile		0.062	0.772	0.199
Mean		0.138	2.109	0.513
5th percentile		0.181	4.295	0.945
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.117	1.281	0.345
Mean		0.173	2.332	0.587
5th percentile		0.202	4.495	1.002
Half-Cycle	1.00			
95th percentile		0.124	1.304	0.356
Mean		0.175	2.376	0.598
5th percentile		0.205	4.537	1.012

Table 6. South Atlantic Planning Area 0-200 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.25			
95th percentile		0.000	0.000	0.000
Mean		0.044	0.186	0.077
5th percentile		0.248	1.079	0.440
Half-Cycle	0.34			
95th percentile		0.000	0.000	0.000
Mean		0.051	0.240	0.094
5th percentile		0.251	1.255	0.475
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.97			
95th percentile		0.040	0.246	0.084
Mean		0.164	1.186	0.374
5th percentile		0.361	2.162	0.746
Half-Cycle	0.99			
95th percentile		0.091	0.758	0.226
Mean		0.183	1.416	0.435
5th percentile		0.386	2.296	0.794

Table 7. South Atlantic Planning Area 200-800 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.18			
95th percentile		0.000	0.000	0.000
Mean		0.018	0.080	0.033
5th percentile		0.133	0.577	0.235
Half-Cycle	0.26			
95th percentile		0.000	0.000	0.000
Mean		0.024	0.119	0.045
5th percentile		0.154	0.790	0.294
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.98			
95th percentile		0.013	0.126	0.036
Mean		0.122	0.778	0.260
5th percentile		0.257	1.758	0.570
Half-Cycle	1.00			
95th percentile		0.022	0.196	0.057
Mean		0.172	1.192	0.384
5th percentile		0.292	2.077	0.662

Table 8. South Atlantic Planning Area > 800 m water depth economic assessment results.

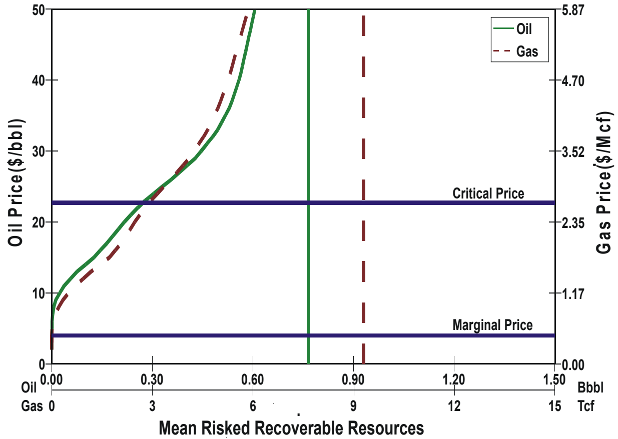

Figure 3. South Atlantic Planning Area full-cycle total of all water depths price-supply curve.

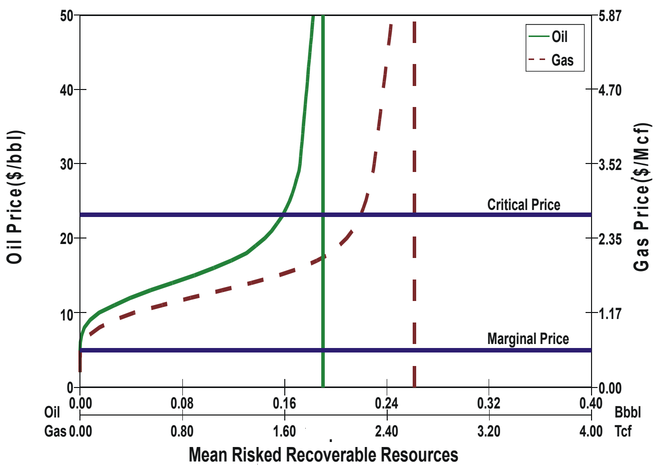

Figure 4. South Atlantic Planning Area full-cycle 0-200 m water depth price-supply curve.

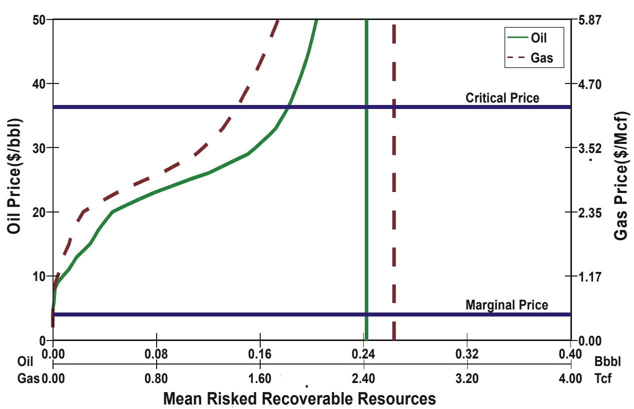

Figure 5. South Atlantic Planning Area full-cycle 200-800 m water depth price-supply curve.

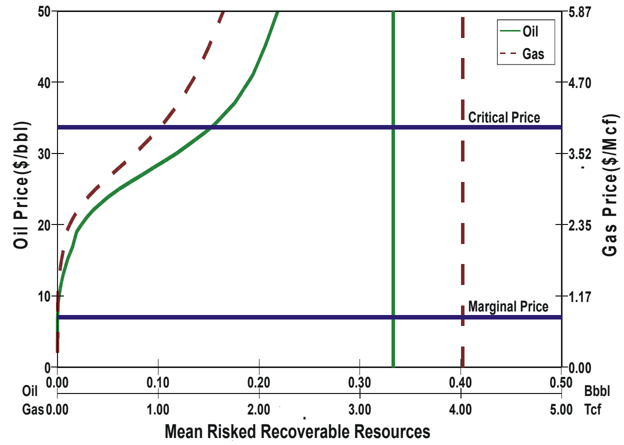

Figure 6. South Atlantic Planning Area full-cycle >800 m water depth price-supply curve.

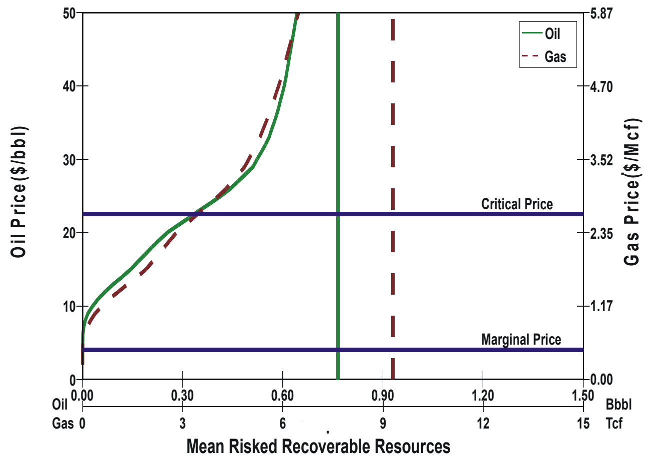

Figure 7. South Atlantic Planning Area half-cycle total of all water depths price-supply curve.

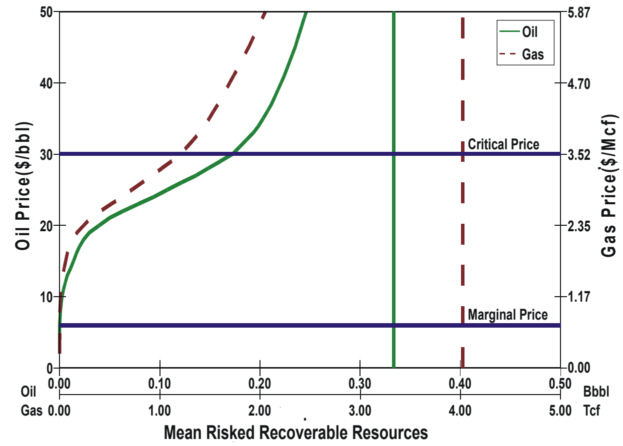

Figure 10. South Atlantic Planning Area half-cycle > 800 m water depth price-supply curve.

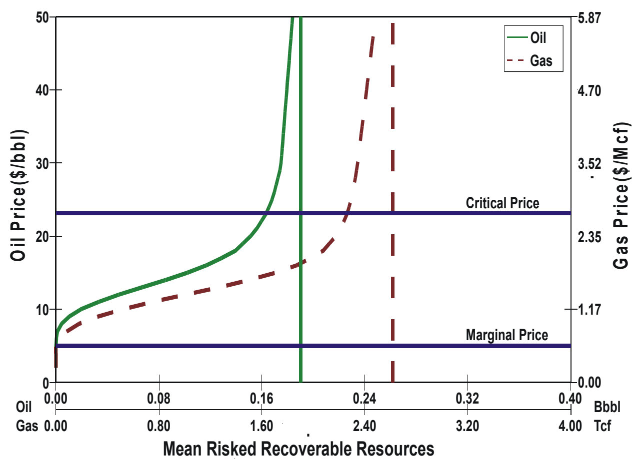

Figure 8. South Atlantic Planning Area half-cycle 0-200 m water depth price-supply curve.

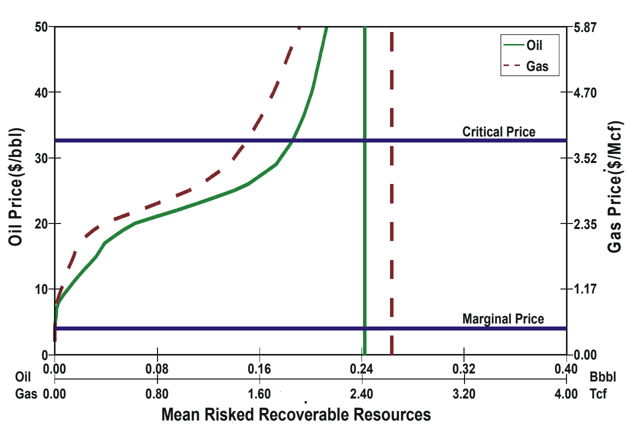

Figure 9. South Atlantic Planning Area half-cycle 200-800 m water depth price-supply curve.

Mid-Atlantic Planning Area Economic Results

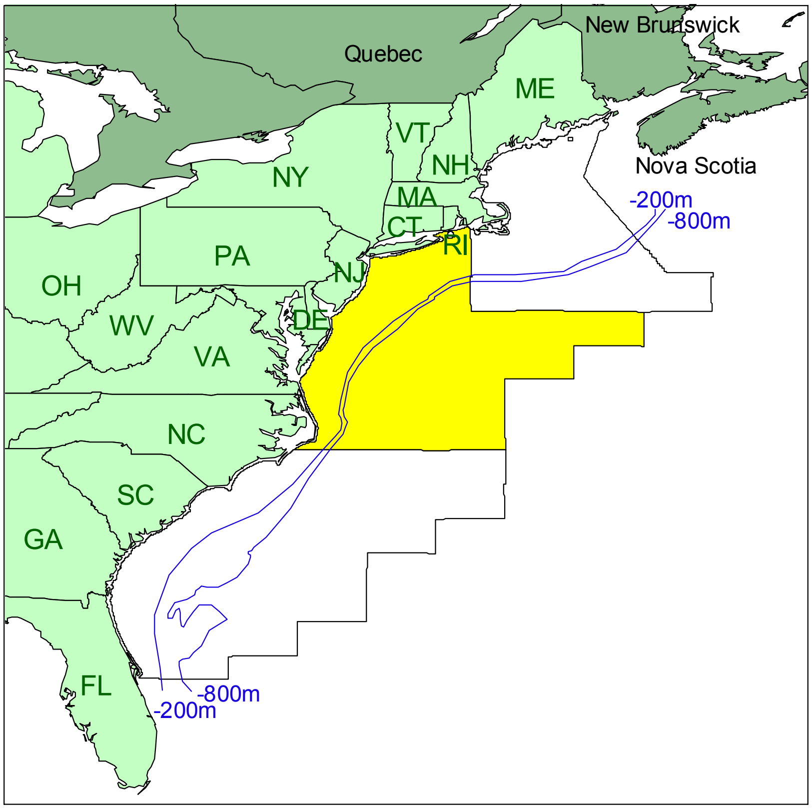

Figure 1. Map of the Mid-Atlantic Planning Area (yellow).

Mid-Atlantic Planning Area

The Mid-Atlantic Planning Area includes submerged Federal lands located in offshore Rhode Island, Connecticut, New York, New Jersey, Delaware, Maryland, Virginia, and northern North Carolina (figure 1).

Undiscovered Economically Recoverable Resources (UERR) were evaluated for three water depth ranges, 0-200 m, 201-800 m, and greater than 800 m. The Mid-Atlantic Planning Area contains no production facilities and no infrastructure. As a result, this area contains no proved or unproved reserves; however, undiscovered Conventionally Recoverable Resources (UCRR) are assessed for all three water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at each of the three different water depths. Assessment reserves and resources are listed in tables 1-4, which present the data from figure 2, and include the Mid-Atlantic Planning Area total.

The full-cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in tables 5-8. 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 Mid-Atlantic Planning Area.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present the estimates of mean UERR at any starting oil price up to $50/bbl. Please note that entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are mean curves.

The full-cycle and half-cycle price-supply curves are shown in figures 3-10. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR) Detailed Discussion section.

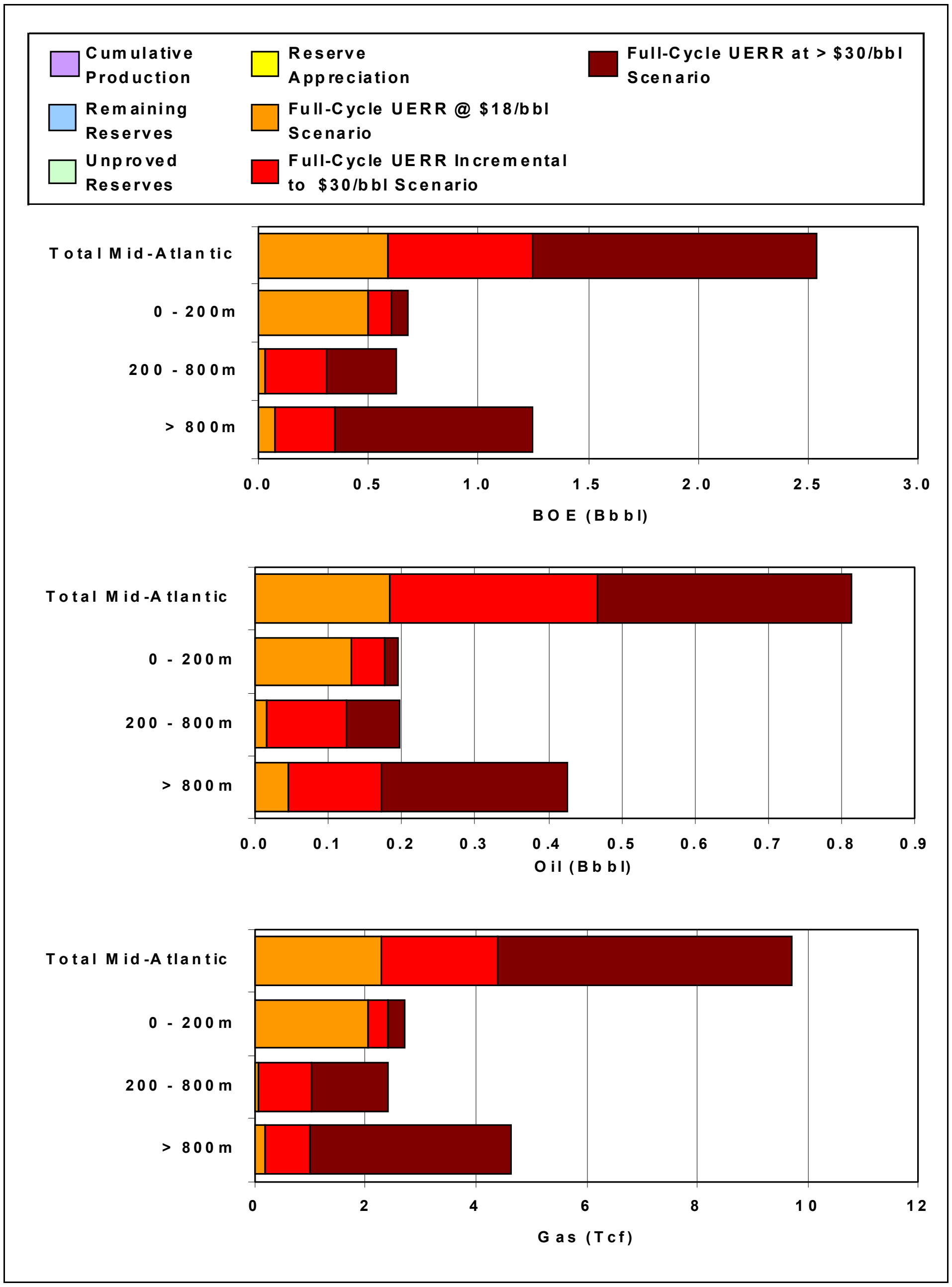

Figure 2. Mid-Atlantic Planning Area mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

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	0.678	8.200	2.138
Mean	0.813	9.718	2.543
5th percentile	1.014	11.933	3.137
Total Endowment			
95th percentile	0.678	8.200	2.138
Mean	0.813	9.718	2.543
5th percentile	1.014	11.933	3.137

Table 1. Mid-Atlantic Planning Area reserves and resources total of all water depths.

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	0.143	1.627	0.432
Mean	0.196	2.721	0.680
5th percentile	0.227	4.950	1.108
Total Endowment			
95th percentile	0.143	1.627	0.432
Mean	0.196	2.721	0.680
5th percentile	0.227	4.950	1.108

Table 2. Mid-Atlantic Planning Area reserves and resources 0-200 m water depth.

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	0.144	1.956	0.492
Mean	0.198	2.399	0.625
5th percentile	0.273	2.949	0.797
Total Endowment			
95th percentile	0.144	1.956	0.492
Mean	0.198	2.399	0.625
5th percentile	0.273	2.949	0.797

Table 3. Mid-Atlantic Planning Area reserves and resources 200-800 m water depth.

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	0.312	3.889	1.004
Mean	0.426	4.624	1.249
5th percentile	0.663	5.603	1.660
Total Endowment			
95th percentile	0.312	3.889	1.004
Mean	0.426	4.624	1.249
5th percentile	0.663	5.603	1.660

Table 4. Mid-Atlantic Planning Area reserves and resources > 800 m water depth.

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		0.070	0.784	0.210
Mean		0.184	2.283	0.590
5th percentile		0.411	4.332	1.182
Half-Cycle	1.00			
95th percentile		0.089	1.037	0.274
Mean		0.210	2.514	0.658
5th percentile		0.483	4.579	1.297
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.275	2.672	0.750
Mean		0.467	4.394	1.248
5th percentile		0.720	6.580	1.890
Half-Cycle	1.00			
95th percentile		0.359	3.412	0.966
Mean		0.547	5.115	1.457
5th percentile		0.762	7.354	2.070

Table 5. Mid-Atlantic Planning Area total of all water depths economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.18			
95th percentile		0.000	0.000	0.000
Mean		0.046	0.177	0.078
5th percentile		0.291	1.278	0.519
Half-Cycle	0.26			
95th percentile		0.000	0.000	0.000
Mean		0.057	0.244	0.100
5th percentile		0.322	1.444	0.579
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.98			
95th percentile		0.014	0.129	0.036
Mean		0.172	0.985	0.347
5th percentile		0.426	2.307	0.836
Half-Cycle	1.00			
95th percentile		0.022	0.202	0.058
Mean		0.229	1.437	0.484
5th percentile		0.463	2.665	0.938

Table 8. Mid-Atlantic Planning Area > 800 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.99			
95th percentile		0.055	0.654	0.171
Mean		0.131	2.047	0.496
5th percentile		0.176	4.351	0.950
Half-Cycle	0.99			
95th percentile		0.064	0.796	0.206
Mean		0.142	2.173	0.529
5th percentile		0.187	4.425	0.974
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.121	1.320	0.355
Mean		0.178	2.403	0.605
5th percentile		0.208	4.631	1.032
Half-Cycle	1.00			
95th percentile		0.128	1.344	0.367
Mean		0.181	2.448	0.616
5th percentile		0.211	4.675	1.043

Table 6. Mid-Atlantic Planning area 0-200 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.25			
95th percentile		0.000	0.000	0.000
Mean		0.016	0.077	0.030
5th percentile		0.105	0.448	0.185
Half-Cycle	0.34			
95th percentile		0.000	0.000	0.000
Mean		0.020	0.113	0.040
5th percentile		0.120	0.762	0.255
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.97			
95th percentile		0.018	0.089	0.034
Mean		0.126	1.033	0.309
5th percentile		0.213	1.653	0.507
Half-Cycle	0.99			
95th percentile		0.085	0.760	0.220
Mean		0.144	1.246	0.366
5th percentile		0.224	1.831	0.549

Table 7. Mid-Atlantic Planning Area 200-800 m water depth economic assessment results.

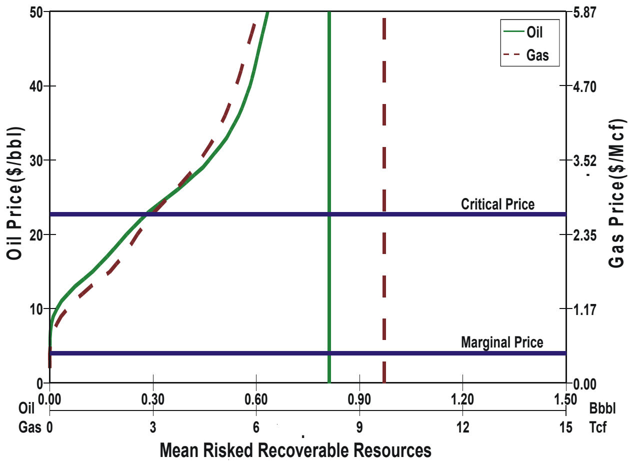

Figure 3. Mid-Atlantic Planning Area full-cycle total of all water depths price-supply curve.

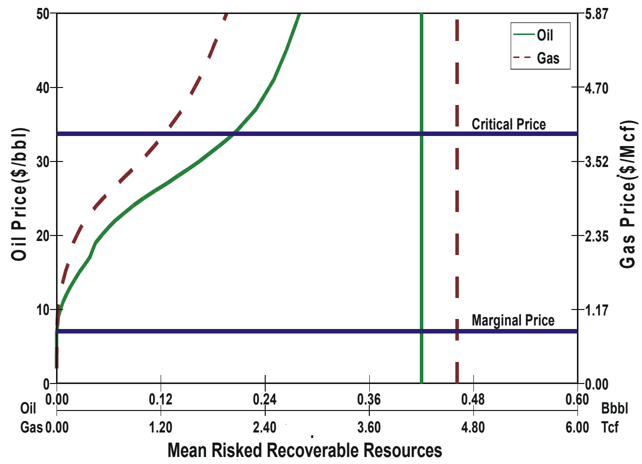

Figure 6. Mid-Atlantic Planning Area full-cycle >800 m water depth price-supply curve.

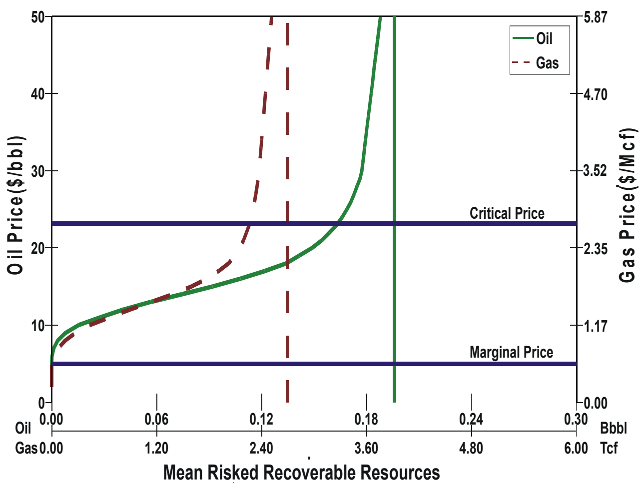

Figure 4. Mid-Atlantic Planning Area full-cycle 0-200 m water depth price-supply curve.

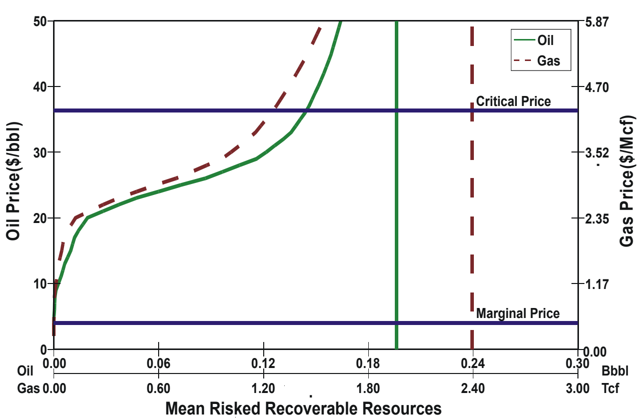

Figure 5. Mid-Atlantic Planning Area full-cycle 200-800 m water depth price-supply curve.

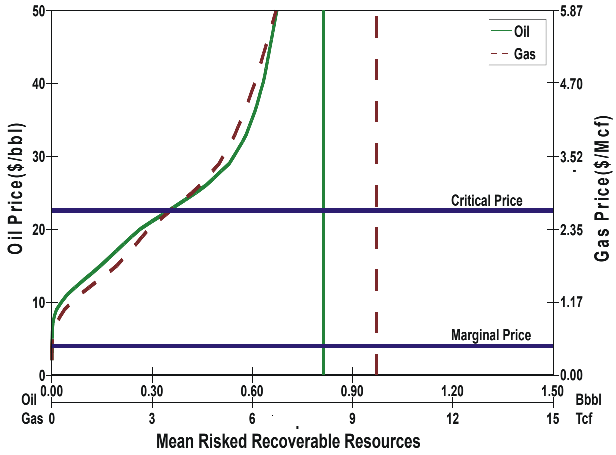

Figure 7. Mid-Atlantic Planning Area half-cycle total of all water depths price-supply curve.

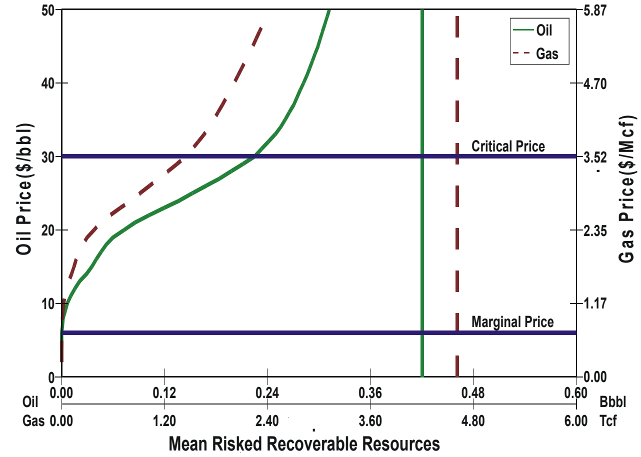

Figure 8. Mid-Atlantic Planning Area half-cycle 0-200 m water depth price-supply curve.

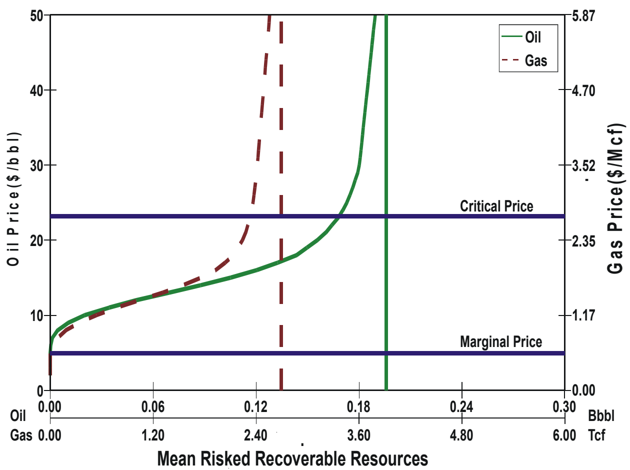

Figure 9. Mid-Atlantic Planning Area half-cycle 200-800 m water depth price-supply curve.

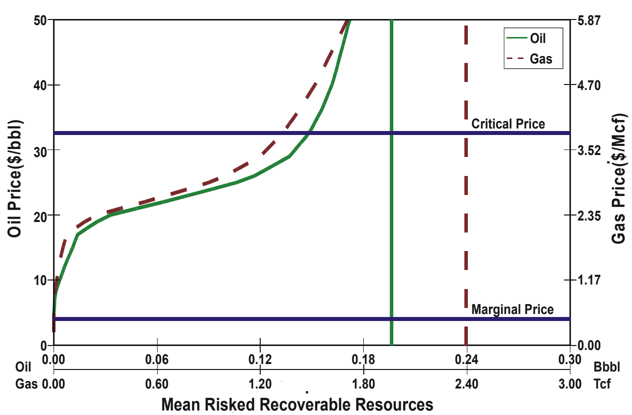

Figure 10. Mid-Atlantic Planning Area half-cycle > 800 m water depth price-supply curve.

North Atlantic Planning Area Economic Results

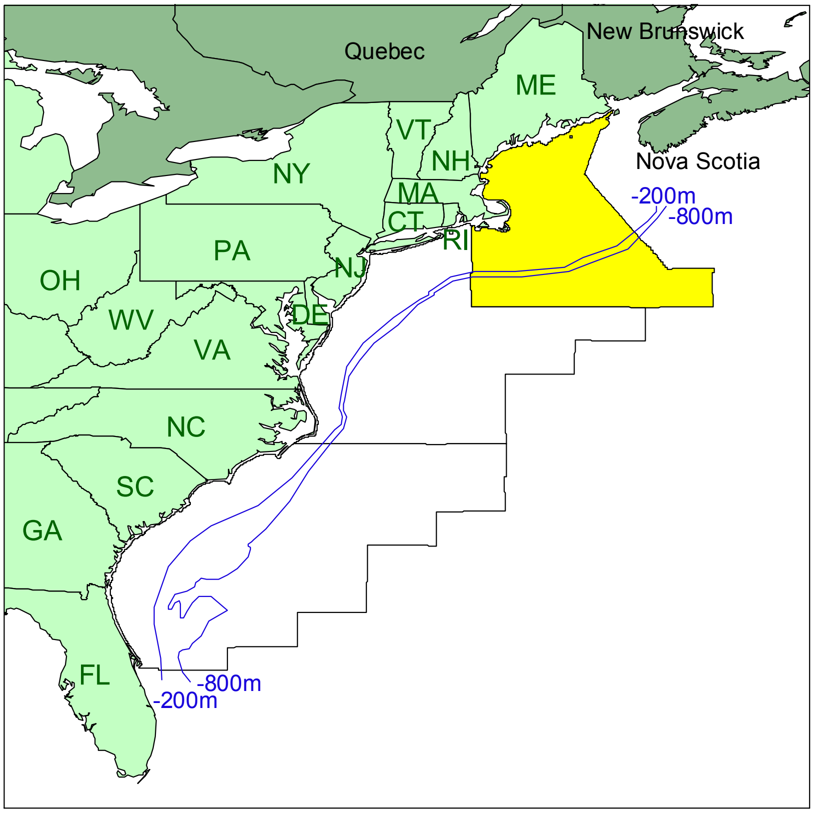

Figure 1. Map of North Atlantic Planning Area (yellow).

North Atlantic Planning Area

The North Atlantic Planning Area includes submerged Federal lands from offshore Massachusetts, New Hampshire, and Maine north to the U.S.-Canada International Boundary (figure 1).

Undiscovered Economically Recoverable Resources (UERR) were evaluated for three water depth ranges, 0-200 m, 201-800 m, and greater than 800 m. The North Atlantic Planning Area contains no production facilities and no infrastructure. As a result, this area contains no proved or unproved reserves; however, undiscovered conventionally recoverable resources (UCRR) are assessed for all three water depth ranges.

A horizontal stacked bar graph (figure 2) depicts the summation of the reserves and resources, yielding the mean total endowment of oil, gas, and BOE equivalent. The figure shows the potential at two economic scenarios at each of the three different water depths. Assessment reserves and resources have been provided in tables 1-4, which present the data from figure 2 and include an overall North Atlantic Planning Area total.

The full-cycle and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in tables 5-8. 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 North Atlantic Planning Area.

Price-supply curves have been provided because estimates of UERR are sensitive to price and technology assumptions. These curves describe a functional relationship between economically recoverable resources and product price, and present the estimates of mean UERR at any starting oil price up to $50/bbl. Please note that entire resource distributions are generated at each price level, but that all of the price-supply curves presented in this report are mean curves.

The full-cycle and half-cycle price-supply curves are shown in figures 3-10. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the Undiscovered Economically Recoverable Resources (UERR) Detailed Discussion section.

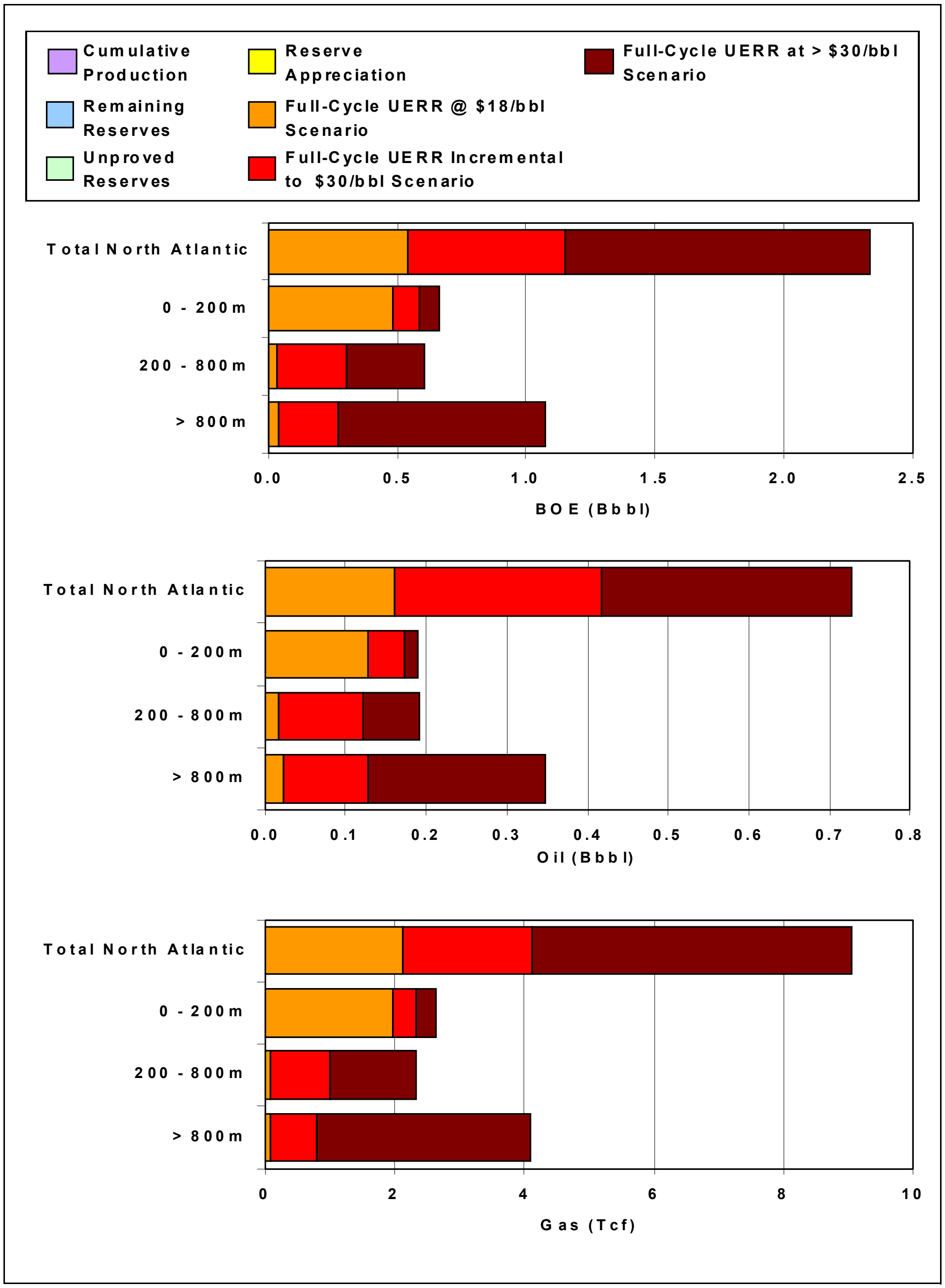

Figure 2. North Atlantic Planning Area mean total endowment and undiscovered economic recoverable resources (UERR) by water depth.

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	0.622	7.664	1.986
Mean	0.726	9.036	2.334
5th percentile	0.832	11.125	2.811
Total Endowment			
95th percentile	0.622	7.664	1.986
Mean	0.726	9.036	2.334
5th percentile	0.832	11.125	2.811

Table 1. North Atlantic Planning Area reserves and resources total of all water depths.

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	0.276	3.473	0.894
Mean	0.347	4.098	1.077
5th percentile	0.452	4.901	1.324
Total Endowment			
95th percentile	0.276	3.473	0.894
Mean	0.347	4.098	1.077
5th percentile	0.452	4.901	1.324

Table 4. North Atlantic Planning Area reserves and resources > 800 m water depth.

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	0.139	1.579	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.076
Total Endowment			
95th percentile	0.139	1.579	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.076

Table 2. North Atlantic Planning Area reserves and resources 0-200 m water depth.

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	0.140	1.891	0.477
Mean	0.192	2.322	0.605
5th percentile	0.268	2.844	0.774
Total Endowment			
95th percentile	0.140	1.891	0.477
Mean	0.192	2.322	0.605
5th percentile	0.268	2.844	0.774

Table 3. North Atlantic Planning Area reserves and resources 200-800 m water depth.

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		0.066	0.754	0.200
Mean		0.161	2.135	0.541
5th percentile		0.269	4.148	1.007
Half-Cycle	1.00			
95th percentile		0.089	0.966	0.260
Mean		0.182	2.343	0.599
5th percentile		0.314	4.349	1.088
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.265	2.531	0.715
Mean		0.418	4.113	1.150
5th percentile		0.574	6.171	1.672
Half-Cycle	1.00			
95th percentile		0.331	3.257	0.911
Mean		0.493	4.791	1.345
5th percentile		0.624	6.947	1.860

Table 5. North Atlantic Planning Area total of all water depths economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.18			
95th percentile		0.000	0.000	0.000
Mean		0.022	0.094	0.039
5th percentile		0.145	0.771	0.283
Half-Cycle	0.26			
95th percentile		0.000	0.000	0.000
Mean		0.029	0.136	0.053
5th percentile		0.175	0.921	0.339
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.98			
95th percentile		0.014	0.127	0.036
Mean		0.128	0.805	0.272
5th percentile		0.282	1.793	0.601
Half-Cycle	1.00			
95th percentile		0.022	0.199	0.058
Mean		0.180	1.223	0.398
5th percentile		0.315	2.136	0.695

Table 8. North Atlantic Planning Area > 800 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.99			
95th percentile		0.053	0.635	0.166
Mean		0.127	1.987	0.481
5th percentile		0.170	4.223	0.922
Half-Cycle	0.99			
95th percentile		0.062	0.772	0.199
Mean		0.138	2.109	0.513
5th percentile		0.181	4.295	0.945
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.117	1.281	0.345
Mean		0.173	2.332	0.587
5th percentile		0.202	4.495	1.002
Half-Cycle	1.00			
95th percentile		0.124	1.304	0.356
Mean		0.175	2.376	0.598
5th percentile		0.205	4.537	1.012

Table 6. North Atlantic Planning Area 0-200 m water depth economic assessment results.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.25			
95th percentile		0.000	0.000	0.000
Mean		0.016	0.076	0.030
5th percentile		0.103	0.449	0.183
Half-Cycle	0.34			
95th percentile		0.000	0.000	0.000
Mean		0.020	0.112	0.040
5th percentile		0.118	0.747	0.251
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.97			
95th percentile		0.018	0.089	0.034
Mean		0.122	1.000	0.300
5th percentile		0.213	1.578	0.493
Half-Cycle	0.99			
95th percentile		0.082	0.735	0.213
Mean		0.140	1.207	0.354
5th percentile		0.221	1.760	0.534

Table 7. North Atlantic Planning Area 200-800 m water depth economic assessment results.

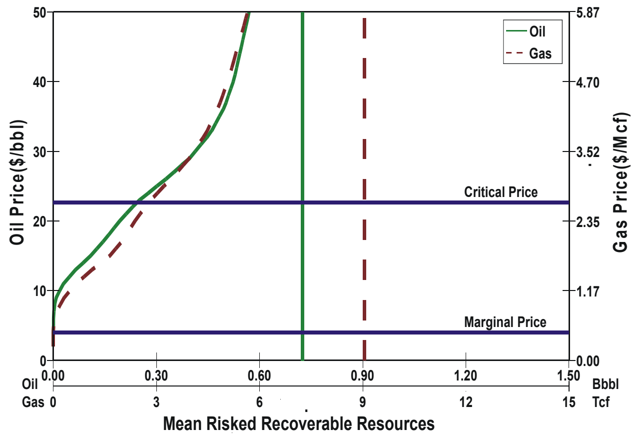

Figure 3. North Atlantic Planning Area full-cycle total of all water depths price-supply curve.

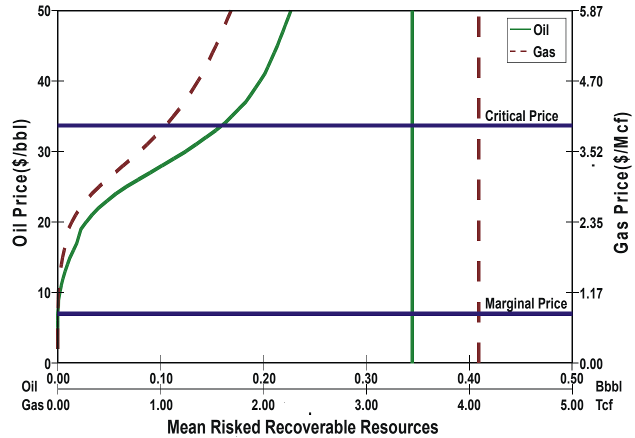

Figure 6. North Atlantic Planning Area full-cycle >800 m water depth price-supply curve.

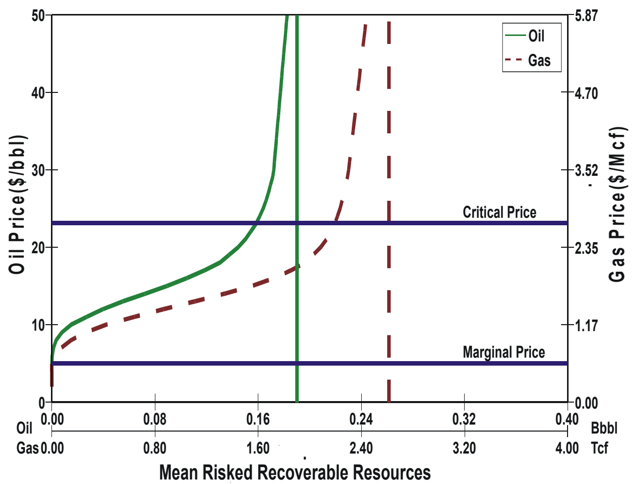

Figure 4. North Atlantic Planning Area full-cycle 0-200 m water depth price-supply curve.

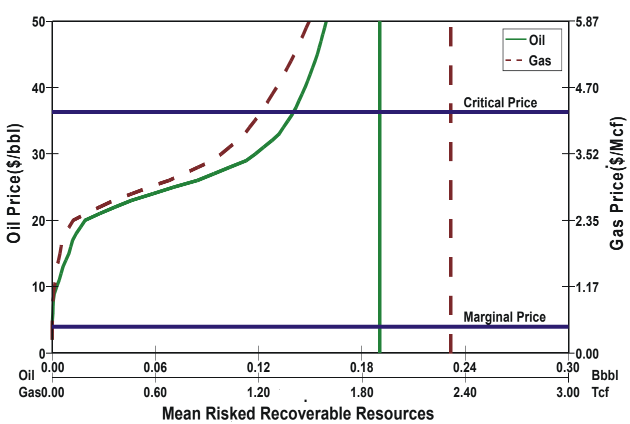

Figure 5. North Atlantic Planning Area full-cycle 200-800 m water depth price-supply curve.

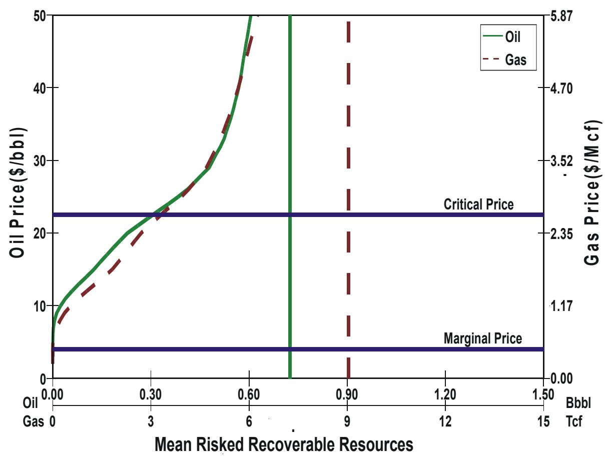

Figure 7. North Atlantic Planning Area half-cycle total of all water depths price-supply curve.

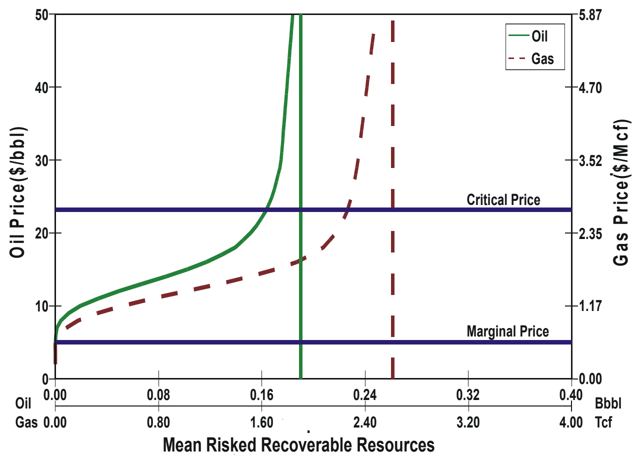

Figure 8. North Atlantic Planning Area half-cycle 0-200 m water depth price-supply curve.

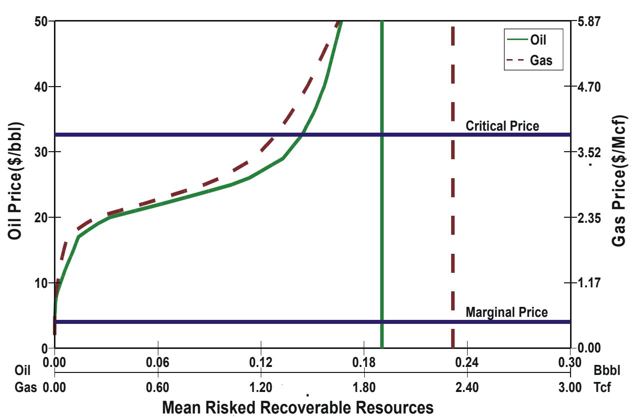

Figure 9. North Atlantic Planning Area half-cycle 200-800 m water depth price-supply curve.

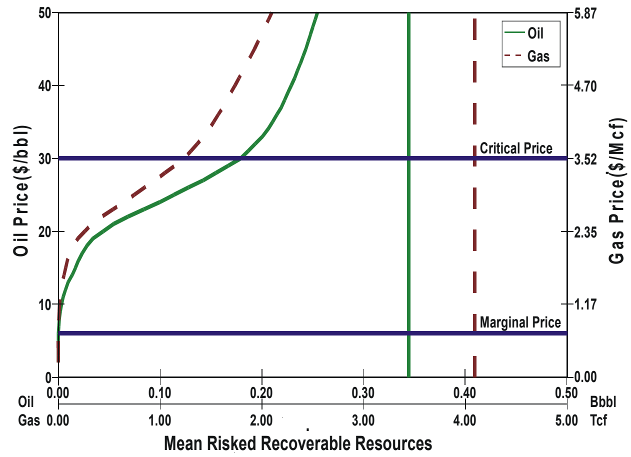

Figure 10. North Atlantic Planning Area half-cycle > 800 m water depth price-supply curve.

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 from Other OCS Regions

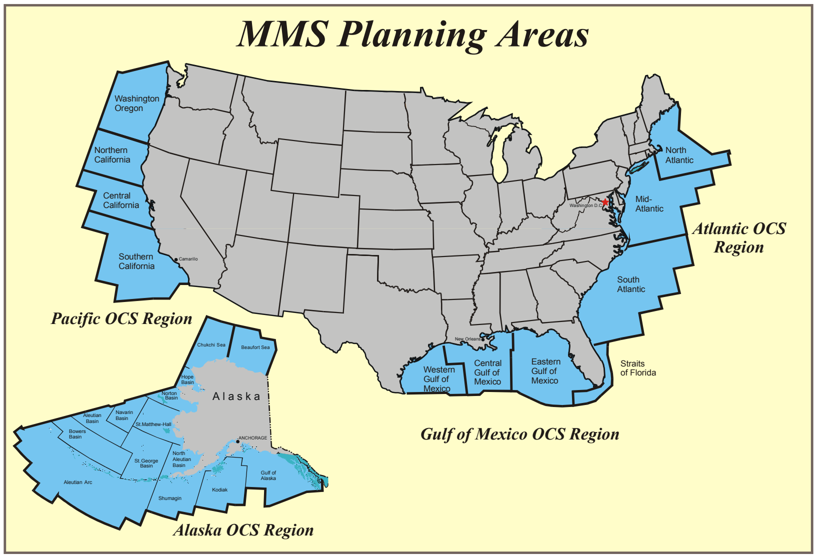

Figure 1. MMS Outer Continental Shelf Regions.

Region	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Alaska	24.9	122.6	46.7
Atlantic	2.3	28.0	7.3
Gulf of Mexico	37.1	192.7	71.4
Pacific	10.7	18.9	14.1
Total OCS	75.0	362.2	139.5

Table 1. Mean estimates of undiscovered conventionally recoverable resources (UCRR) for the United States OCS by MMS Region. Values from the Alaska and Pacific Regions are from Hunt and Dickerson (2001).

Region	$18 Oil (Bbbl)	$2.11 Gas (Tcf)	$30 Oil (Bbbl)	$3.52 Gas (Tcf)
Alaska	3.3	1.6	10.1	3.0
Atlantic	0.5	6.6	1.3	12.8
Gulf of Mexico	17.5	100.3	28.1	140.7
Pacific	5.3	8.3	7.2	11.6
Total OCS	26.6	116.8	46.7	168.1

Table 2. Mean estimates of undiscovered economically recoverable resources (UERR) for the United States OCS by MMS Region. Values from the Alaska and Pacific Regions are from Hunt and Dickerson (2001). The price of oil is in dollars per barrel and the price of gas is in dollars per Mcf.

To place this resource assessment of the Gulf of Mexico and Atlantic Regions in a national perspective, estimates of undiscovered conventionally recoverable resources (UCRR) and undiscovered economically recoverable resources (UERR) are compared to those of the other MMS Outer Continental Shelf (OCS) Regions (figure 1).

Table 1 illustrates that the Gulf of Mexico Region contains about half of the mean UCRR in the United States OCS in terms of oil, gas, and BOE. The Alaska Region contains the second-most, with about a third of the mean UCRR in these categories. The Atlantic Region contains the least amount of BOE mean UCRR, with only about 5 percent of the total.

Table 2 illustrates that the Gulf of Mexico Region also contains the largest amount of mean UERR of the four regions. In both the $18/$2.11 and the $30/$3.52 scenarios, the Gulf of Mexico Region provides roughly two-thirds of the economic undiscovered oil and over four-fifths of the economic undiscovered gas in the OCS. The Atlantic Region contains about 6 percent of the economic undiscovered gas at the $2.11 per Mcf scenario and 8 percent at the $3.52 per Mcf scenario.

MMS 1995 versus 2000 Assessment Results

	Gulf of Mexico Region (Including the Straits of Florida)			Atlantic Region (Excluding the Straits of Florida)		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Cumulative Production						
2000 Assessment	10.908	132.677	34.515	0.000	0.000	0.000
1995 Assessment	9.338	112.633	29.379	0.000	0.000	0.000
Difference in Cumulative	1.570	20.044	5.136	0.000	0.000	0.000
Remaining Proved Reserves						
2000 Assessment	3.358	30.034	8.703	0.000	0.000	0.000
1995 Assessment	2.516	29.258	7.722	0.000	0.000	0.000
Difference in Proved Reserves	0.842	0.776	0.981	0.000	0.000	0.000
Unproved Reserves						
2000 Assessment	0.995	5.102	1.903	0.000	0.000	0.000
1995 Assessment	0.639	3.603	1.280	0.000	0.000	0.000
Difference in Unproved Reserves	0.356	1.499	0.623	0.000	0.000	0.000
Reserves Appreciation						
2000 Assessment	7.736	68.096	19.853	0.000	0.000	0.000
1995 Assessment	2.507	31.028	8.028	0.000	0.000	0.000
Difference in Appreciation	5.229	37.068	11.825	0.000	0.000	0.000
Mean Risked UCRR						
2000 Assessment	37.126	191.627	71.223	2.307	27.712	7.238
1995 Assessment	8.344	95.661	25.366	2.271	27.480	7.161
Difference in Risked UCRR	28.782	95.966	45.857	0.036	0.232	0.077
Mean Risked UERR Half-Cycle $18/bbl.						
2000 $18/bbl $2.11/mcf	18.569	105.167	37.282	0.602	7.310	1.903
1995 $18/bbl $2.11/mcf	5.306	62.300	16.391	0.452	5.989	1.518
Difference in Risked UERR	13.263	42.867	20.891	0.150	1.321	0.385
Mean Risked UERR Half-Cycle $30/bbl.						
2000 $30/bbl $3.52/mcf	28.811	143.986	54.431	1.570	14.875	4.216
1995 $30/bbl $3.52/mcf	6.865	78.100	20.762	1.234	11.966	3.363
Difference in Risked UERR	21.946	65.886	33.669	0.336	2.909	0.853
Mean Total Endowment						
2000 Assessment	60.123	427.537	136.197	2.307	27.712	7.238
1995 Assessment	23.343	272.183	71.775	2.271	27.480	7.161
Difference in Mean Total Endowment	36.780	155.354	64.422	0.036	0.232	0.077

Table 1. Comparison of the results of the MMS's 1995 and 2000 resource assessments. UERR from 2000 and 1995 are half-cycle results. See text for a description of differences between the two assessments.

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 (Lore *et al.*, 1999), which incorporated data as of January 1995. Table 1 shows the estimates from the two assessments that are most appropriate for comparison.

Both assessments present estimates of undiscovered conventionally recoverable resources (UCRR) and undiscovered economically recoverable resources (UERR) under two scenarios.

The following sections describe major differences between the 1995 and 2000 assessments.

Deepwater Fans

The 1995 assessment treated the deepwater fans somewhat simplistically by defining each fan play by chronozone. Since then, MMS has reevaluated the fan plays to incorporate the interaction between deposition and structural setting. Because the structural regime found in the Gulf of Mexico is a linked system (i.e., updip extension leads to toe-of-slope contraction), plays can be refined to fit into a structural setting that relates them to their depositional and salt tectonic history. In so doing, a three-part breakup of the fan plays resulted (Bascle *et al.*, 2001).

Fan 1 Plays (F1)--The area of the F1 fan plays occurs between the present-day coast and the shelf edge. This is the major region of extension on the northern Gulf of Mexico shelf. Salt-withdrawal basins and down-to-the-south, listric growth

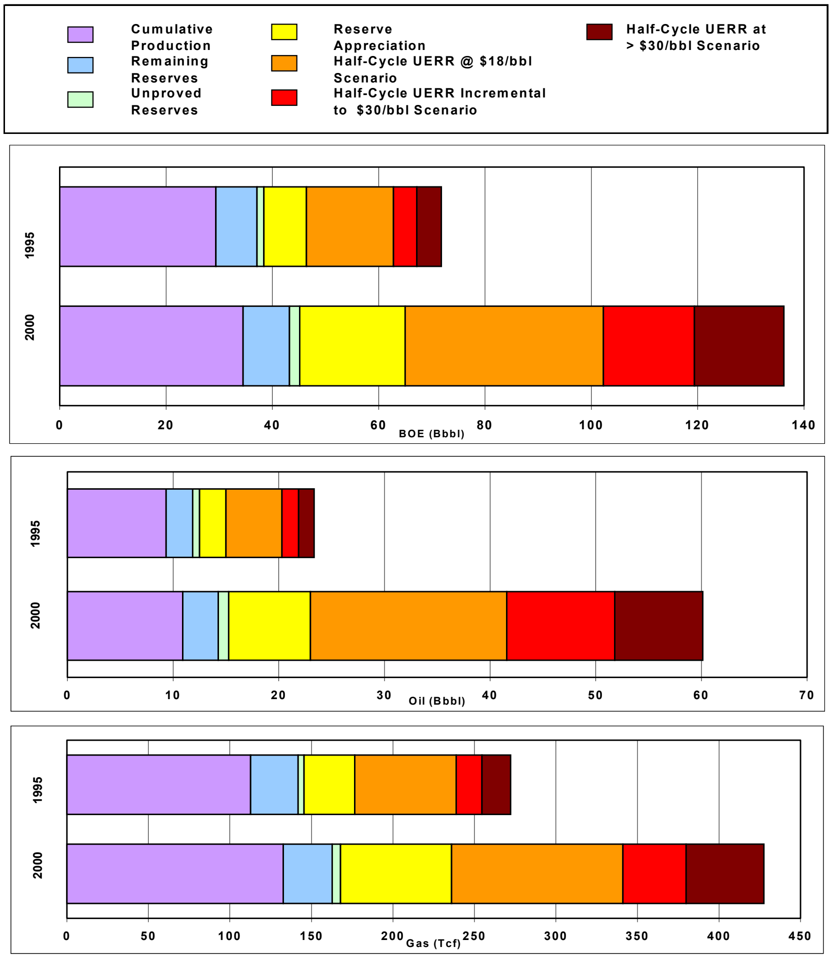

Figure 1. Gulf of Mexico Region comparison of 1995 and 2000 resource assessments.

faults that sole into salt decollements and extensive salt welds linking the isolated salt bodies are the primary structural features in this area.

Fan 2 Plays (F2)--The area of the F2 fan plays is located primarily on the present-day northern Gulf of Mexico slope. This area comprises the second part of the linked depositional and salt tectonic regime of the Gulf of Mexico, and contains a wide array of salt features. In the western and central Gulf of Mexico, F2 fans occur approximately from the present-day shelf edge to the farthest downdip limit of potential, allochthonous, tabular salt bodies. This downdip limit is defined by either (1) the Sigsbee Escarpment or (2) the downdip extent of the Perdido and Mississippi Fan Fold Belts, when they are outboard of the Sigsbee Escarpment. In the eastern Gulf, F2 fans continue to the southern extent of Louann Salt deposition, as defined by the downdip extent of the Salt Roller/High-Relief Salt Structure Play (UK5-UJ4 S1).

Abyssal Plain Fan Play (F3)--The F3 fan area covers the abyssal plain of the Gulf of Mexico in front of the Perdido and Mississippi Fan Fold Belts or in front of the Sigsbee Escarpment. Because this area is basinward of the depositional edge of the Jurassic Louann Salt, there are no salt-cored of salt-withdrawal structures. However, differential compaction and some faulting may affect the F3 fan intervals near "buried hill" structures that occur in parts of the area. There are no productive F3 fan plays yet in the Gulf of Mexico.

A more detailed discussion of the three-part breakup of the fan plays is provided in the Play Delineation Detailed Discussion section.

Addition of New Plays in the Deepwater GOM

Some of the largest additions of undiscovered conventionally recoverable resources (UCRR) in the 2000 assessment were from new established and conceptual plays described in the deepwater areas of the Gulf of Mexico Region. Additional seismic, drilling, and production data acquired since the 1995 assessment allowed for a more thorough and detailed assessment of prospects and analogs on the Outer Continental Slope and ultra-deep abyssal plain (~3,000 m). In addition, plays were assessed down to a depth of about 9,150 m (~30,000 feet)---a greater depth than was evaluated in the 1995 assessment.

Significant new deepwater plays in the 2000 assessment include the established and conceptual Mississippi Fan Fold Belt plays (UPL-LL X2, UK5-LK3 X5; UJ4 X2), the conceptual Perdido Fold Belt plays (UK5-LK3 X4, UJ4 X1), the various conceptual buried hills plays (UK5-LK3 BC2, UJ4 BC1, UK5-UJ4 BC3, UK5-LTR BC4), and the offshore Texas Lower Tertiary Clastic Gas- and Gas and Oil plays (LO-LL C1, LO-LL C2). Combined, these plays add about 16 Bbbl BOE in the mean case of UCRR, or about 22 percent of the total, to the Gulf of Mexico Region.

Data Aggregations

In this 2000 assessment, data aggregation are discussed at only the province and

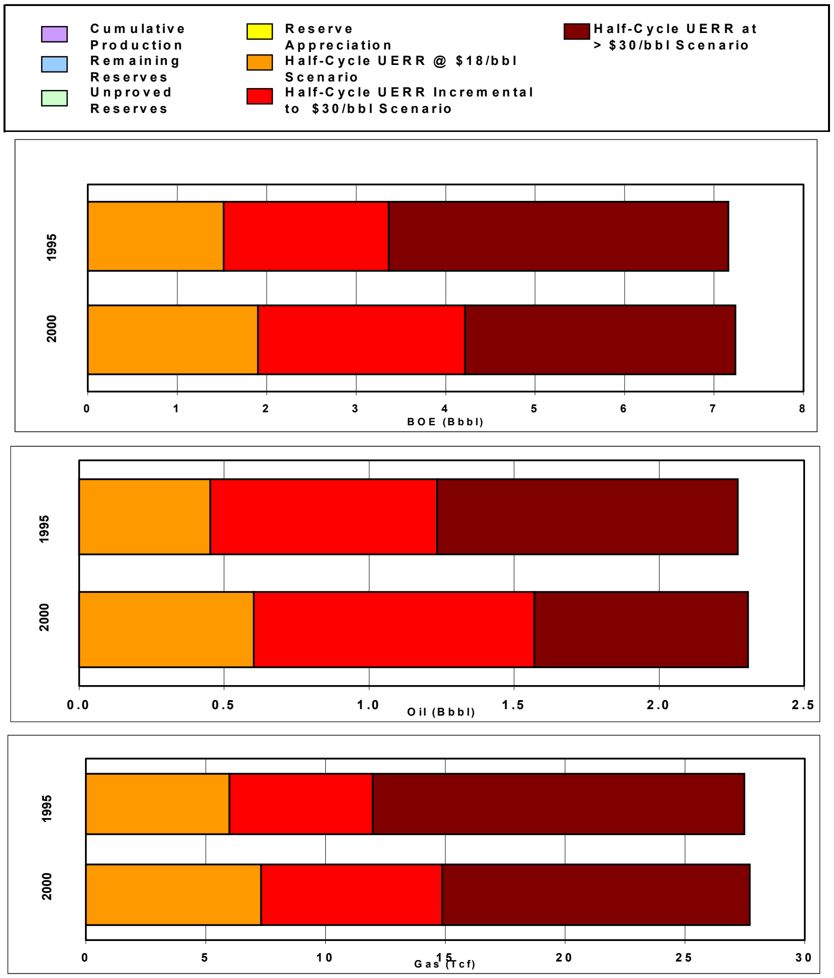

Figure 2. Atlantic Region comparison of 1995 and 2000 resource assessments.

region levels, and not at the chronozone, series, and systems levels as was done in the 1995 assessment. Chronozone, series, and systems levels were not discussed because a number of large, structurally defined plays that include sediments of multiple chronozones, series, or systems were added since the 1995 assessment. Because these new plays span geologic ages and include significant reserves and resources, aggregation of data from the remaining plays (plays defined by chronozone and facies) would be of limited comparative value with the 1995 assessment. For example, mean BOE UCRR of plays that span ages total 18 Bbbl, or 25 percent of mean BOE UCRR for the Gulf of Mexico Region; thus, a quarter of the mean BOE UCRR cannot be assigned to specific chronozones, series, or systems. For illustrative purposes, a general comparison of plays by facies and ages, which includes a "plays that span ages" category, is included in the Assessment Results section.

Provincial vs. Global Biozone Terminology

MMS currently uses provincial benthic foraminiferal biozones to define the Plio-Pleistocene and top of the Miocene boundaries in the Gulf of Mexico and Atlantic Regions. However, oil and gas exploration companies increasingly are relying on global nannoplanktic (coccolith) and planktic foraminiferal marker fauna, including planktic coiling changes and acmes, as well as extinction points, to define these boundaries (Simmons *et al.*, 1997; Picou *et al.*, 1999; Jones and Simmons, 1999). To avoid confusion over provincial vs. global biozonation, bounding benthic foraminiferal biozone names are now included, where appropriate, in the subtitle of each play.

Play Name Changes

On the basis of additional data and further review, certain plays from the 1995 assessment were either combined into one play or split into multiple plays. For example, several lower Cretaceous plays in this 2000 assessment were created from the one 1995 Lower Cretaceous Carbonate (LK CB) play. Significant changes to plays are discussed in the play write-ups.

In addition, to accommodate new plays in the 2000 assessment, several of the play code conventions were changed. For example, the designation for the upper Jurassic was changed from UU to UJ; the clastic designation was changed from CL to C; the carbonate designation was changed from CB to B (Biologic); and the caprock designation was changed from C to B. Finally, numbers were added to the end of all play codes, e.g. UPL A1 from UPL A.

Gulf of Mexico Region Assessment Comparisons

Figure 1 is a comparison of the mean results from the two assessments for the Gulf of Mexico Region. Comparing the risked mean total endowment estimates from the 1995 assessment to the 2000, the total endowment increased by 36.780 Bbo and 155.354 Tcfg (64.422 BBOE). Most of the increase in the total values is directly attributed to the following increase in the UCRR of 28.782 Bbo and 95.966 Tcfg (45.857 BBOE) from the 1995 assessment.

The 2000 estimate of the potential mean volumes of UERR at $30/bbl. increased by 21.946 Bbo and 65.886 Tcfg (33.669 BBOE) from the 1995 assessment. The 2000 estimate of the potential mean volumes of UERR at $18/bbl. increased by 13.263 Bbo and 42.867 Tcfg (20.891 BBOE) from the 1995 assessment.

In the 1995 assessment, 924 existing fields were studied and had estimates of reserves reported. In the 2000 assessment, 1,042 fields (984 proved, 58 unproved) were studied and had estimates of reserves reported.

Atlantic Region Assessment Comparisons

Figure 2 is a comparison of the mean results from the two assessments for the Atlantic Region. The 2000 mean estimates of UCRR increased by 0.036 Bbo and 0.232 Tcfg (0.077 BBOE). This is the result of reassessments in the Upper Jurassic and Middle Jurassic Carbonate plays in response to Panuke well discovery in the Scotian Basin. Contrasting the 1995 and 2000 assessments of UERR for the Atlantic Region, the potential volumes of mean economic resources increased by 0.150 Bbo and 1.321 Tcfg (0.385 BBOE) in the $18/bbl. scenario and 0.336 Bbo and 2.909 Tcfg (0.853 BBOE) in the $30/bbl. scenario.

Selected Previous Assessments

Estimates of the potential quantities of undiscovered hydrocarbon resources have been made periodically by numerous organizations, companies, government agencies, and individuals. Many of these have been published. Most of these assessments, however, have dealt with the entire United States and provide little additional regional detail, beyond possibly breaking out the lower 48 states onshore/offshore and Alaska onshore/offshore. Table 1 and figure 1 compare seven 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). Two of the seven estimates are by the USGS and the remaining five are by the MMS. These estimates were selected for comparison because of their relative similarities in methodologies. A more inclusive comparison of estimates with more variable methodologies is presented and discussed in Lore *et al.* (1999).

The overall range of the estimates of undiscovered economically recoverable resources has been expansive. During the 25-year interval represented in table 1, estimates of undiscovered economically recoverable resources for the Gulf of Mexico Region range from 5.3 to 17.5 Bbo and 50.0 to 100.3 Tcfg. The largest estimates occur in this study. In the Atlantic Region, the range is from 0.2 to 6.2 Bbo and 4.4 to 23.7 Tcfg.

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 750 fields containing proved and unproved reserves of 6 Bbo and 63 Tcfg discovered during the 25-year period covered by the estimates.

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												
USGS Circ. 725	Dec-74	4.1	32.1	2.3	35.3	2.4	27.0	*	*	6.3	50.0	1, 3, 4, 9
USGS Circ. 860	Dec-79	5.6	49.7	1.7	35.6	1.0	26.7	*	*	8.1	71.8	1, 3, 4, 10
MMS (Cooke)	Jul-84	5.9	62.5	3.4	43.7	*	*	*	*	6.0	59.8	2, 6, 11
MMS (Cooke)	Jan-87	6.9	75.2	3.9	45.8	0.5	5.8	0.1	1.2	5.7	64.4	2, 5, 6, 8, 11
MMS (Cooke)	Jan-90	7.8	88.9	3.0	40.2	0.5	5.8	*	*	6.4	64.9	2, 5, 6, 8, 11
MMS (Lore, et al.)	Jan-95	9.3	112.6	2.5	29.3	2.5	31.0	3.6	5.3	5.3	62.3	2, 6, 7, 11, 12
MMS (Lore, et al.)	Jan-99	10.9	132.7	3.4	30.0	7.7	68.1	1.0	5.1	17.5	100.3	2, 6, 7, 11, 12
Atlantic Region												
USGS Circ. 725	Dec-74	*	*	*	*	*	*	*	*	3.3	10.0	1, 4, 9
USGS Circ. 860	Dec-79	*	*	*	*	*	*	*	*	6.2	23.7	1, 4, 10
MMS (Cooke)	Jul-84	*	*	*	*	*	*	*	*	0.7	12.2	3, 6, 11
MMS (Cooke)	Jan-87	*	*	*	*	*	*	*	*	0.2	4.4	3, 5, 6, 8, 11
MMS (Cooke)	Jan-90	*	*	*	*	*	*	*	*	0.2	4.4	3, 5, 6, 8, 11
MMS (Lore, et al.)	Jan-95	*	*	*	*	*	*	*	*	0.5	6.0	3, 6, 7, 11, 12
MMS (Lore, et al.)	Jan-99	*	*	*	*	*	*	*	*	3.3	6.6	3, 6, 7, 11, 12

1. Includes state waters
2. Includes Straits of Florida planning area
3. Excludes Straits of Florida planning area
4. Includes NGL with oil
5. Primary case
6. Half-cycle evaluation
7. Most likely values
8. Appreciation is mean estimate
9. 0-200 meters water depth
10. 0-2,500 meters water depth
11. No water depth limit reported
12. $18/bbl scenario

Table 1. Comparison of selected estimates of reserves and undiscovered economically recoverable resources.

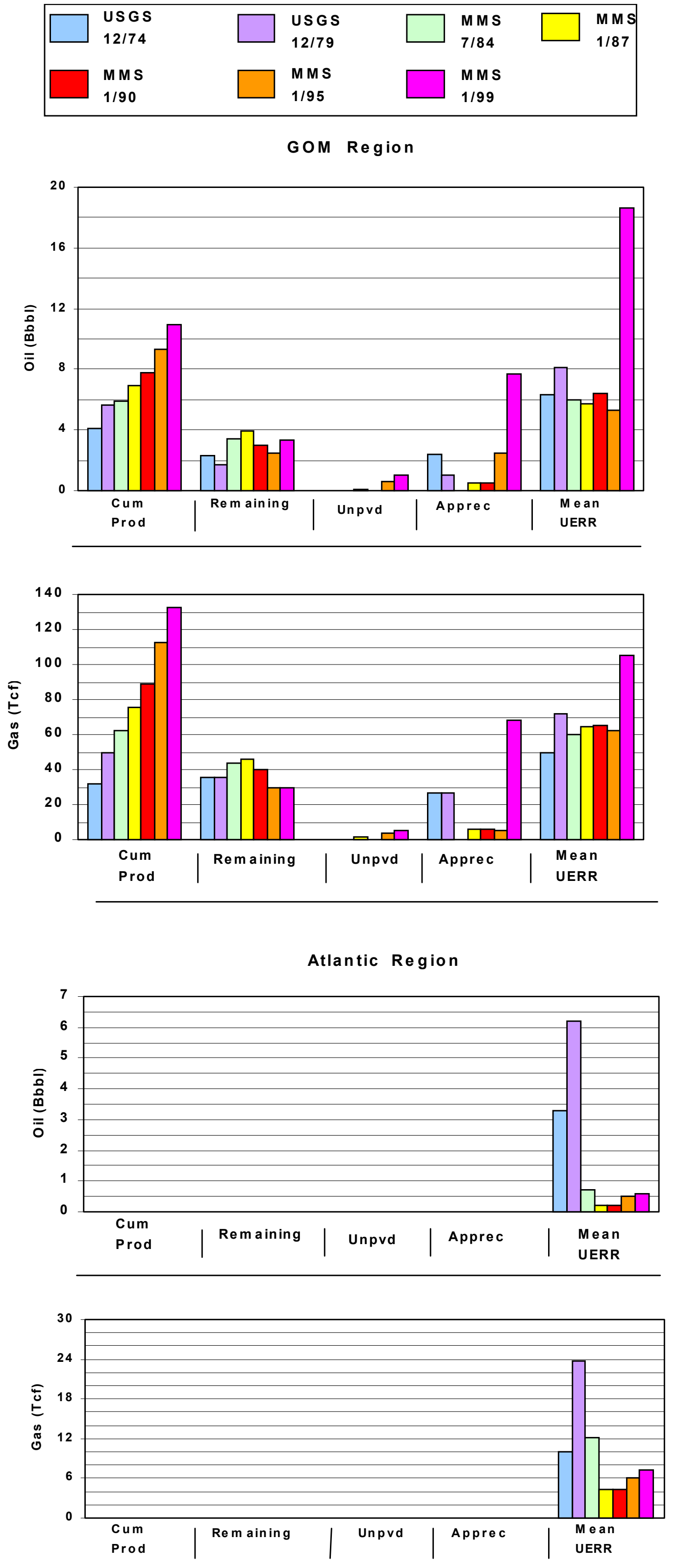

Figure 1. Comparison of selected estimates of reserves and undiscovered economically recoverable resources in the Gulf of Mexico and Atlantic Regions. Refer to table 1 for a listing of differences in methodologies between the estimates.

GOM Chronozone, Series, and System Aggregations

Region	Province	System	Series	Chronozone Name	Chronozone Number
Gulf of Mexico	**Cenozoic**	Quaternary	Pleistocene	UPL	01
				MPL	05
				LPL	07
		Tertiary	Pliocene	UP	09
				LP	10
			Miocene	UM3	11
				UM1	13
				MM9	14
				MM7	16
				MM4	19
				LM4	23
				LM2	25
				LM1	26
			Oligocene	UO	27
				MO	29
				LO	30
			Eocene	UE	31
				ME	33
				LE	34
			Paleocene	UL	35
				LL	37
	Mesozoic	Cretaceous	Upper	UK5	38
				UK2	41
			Lower	LK8	43
				LK6	45
				LK3	48
		Jurassic	Upper	UJ4	51
			Middle	MJ	55
			Lower	LJ	56
		Triassic	Upper	UTR	57
			Middle	MTR	58
			Lower	LTR	59

Figure 1. MMS chronostratigraphic chart for the Gulf of Mexico illustrating potential play data aggregation levels. Chronozones are after Reed et al., (1987).

In the MMS 1995 assessment (Lore *et al*., 1999), Gulf of Mexico play level data were aggregated to the chronozone, series, system, province, and region levels (figure 1). However, because a number of new plays in the 2000 assessment span these geologic age divisions, play level data are now aggregated only to the province and region levels. This was done because significant resources are contained in the plays that span chronozones, series, and systems, and the assessment methodology employed does not allow for geologically meaningful assignment of resources to these levels.

For example, the Cenozoic Mississippi Fan Fold Belt Play (UPL-LL X2) with 6.432 mean BOE in undiscovered conventionally recoverable resources spans 15 chronozones, four series, and two systems (figure 1).

The data tables in this report contain chronozone, series, and system aggregations, which should be used only with the understanding that these levels represent incomplete aggregations and that meaningful comparisons with previous assessments can not be made using these numbers.

The MMS *Atlas of Gulf of Mexico Gas and Oil Sands* (Bascle *et al.,* 2001), which documents reserves in the northern Gulf of Mexico, contains data meaningfully aggregated to the chronozone, series, and system levels.

Gulf of Mexico Region

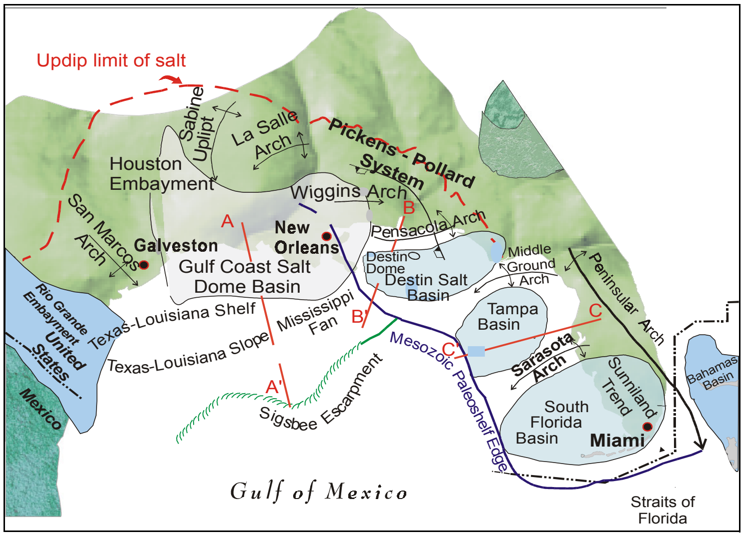

Figure 1. Physiographic map of the northern Gulf of Mexico.

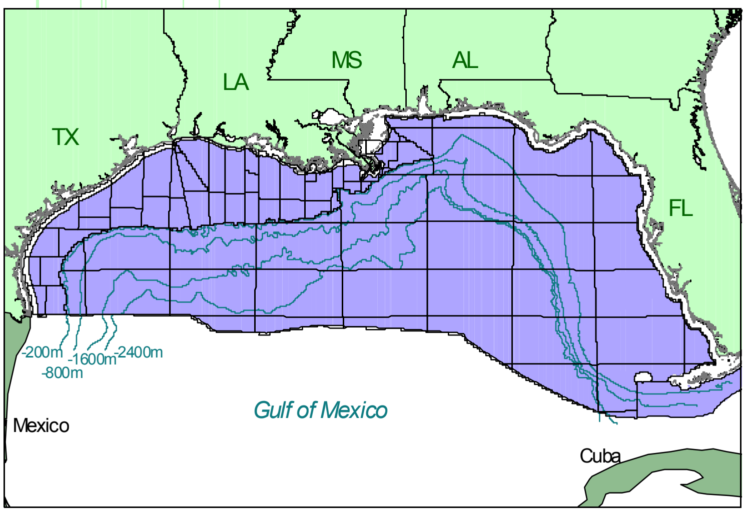

Figure 2. Extent of plays assessed in the northern Gulf of Mexico.

Gulf of Mexico Region 2453 Pools 10235 Sands	Minimum	Mean	Maximum
Water depth (feet)	9	287	7620
Subsea depth (feet)	950	8097	22612
Number of sands per pool	1	4	44
Porosity	10%	29%	39%
Water saturation	16%	28%	75%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Region Description

The Gulf of Mexico Region includes the area of the northern Gulf of Mexico extending from the U.S.-Mexico and U.S.-Cuba international boundaries to the Federal waters adjacent to the State waters of Texas, Louisiana, Mississippi, Alabama, and Florida. The Region also includes the Straits of Florida located on the southern and southeastern coasts of Florida adjacent to the U.S.-Bahamas international boundary (figure 1). The sedimentary section in the Gulf of Mexico Region attains a thickness upwards of 50,000 feet, while water depths range from about 10 to 10,000 feet. Figure 2 illustrates that all areas of the Gulf of Mexico Region were reviewed for the 2000 assessment.

The Gulf of Mexico Basin initially formed during the Late Triassic to Middle Jurassic rifting episode that occurred when South America/Africa separated from North America. This breakup event formed a series of northeast-southwest-trending rifts offset by northwest-southeast-trending transfer faults/zones. The rift grabens were active depocenters receiving lacustrine and alluvial deposits. During the Middle Jurassic, marine water sporadically entered the incipient Gulf of Mexico Basin, resulting in the deposition of thick evaporative deposits of the Louann Salt. Subsequently, a series of transgressions and regressions led to the deposition of high-energy siliciclastics and carbonates that prograded the shelf edge in the northeastern Gulf Basin. Thick reef complexes developed on this shelf edge during the Cretaceous, and interfingered with carbonates and siliciclastics in back-reef areas.

During the Late Cretaceous through the Tertiary, uplift of the North American continent and the subsequent Laramide Orogeny provided the source for large amounts of clastic sediments deposited in the western, then central, areas of the

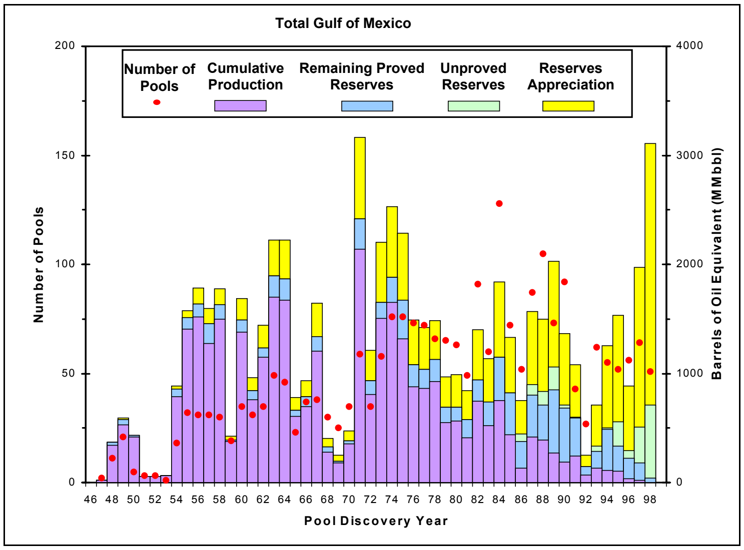

Figure 3. Exploration history graph showing reserves addition and number of pool discoveries by year.

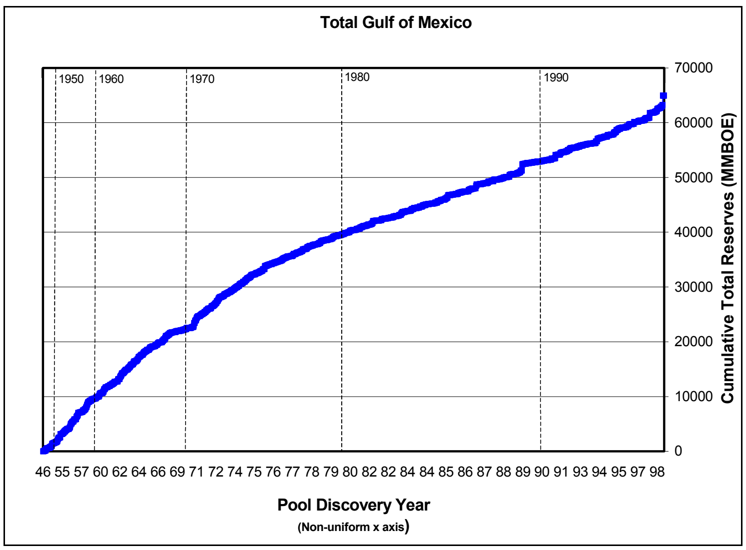

Figure 4. Plot of pools showing cumulative reserves by discovery order (non-uniform x axis). Note the increase in pool sizes beginning in the mid 1990's and reflecting deepwater discoveries.

Gulf of Mexico Basin. During the Quaternary, periods of continental glaciation produced an increased clastic sediment load to the central and western basin areas, resulting in the present-day Texas and Louisiana shelf and slope. 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 relative sea level transgressions and regressions. This sediment loading also led to deformation of the Jurassic-aged Louann Salt, producing the variety of autochthonous and allochthonous salt structures found in the northern Gulf of Mexico today. In deepwater areas of the Gulf, downdip compressional folding resulting from updip extensional faulting and salt tectonics produced large fold belts underneath and in front of the modern Sigsbee Escarpment (figure 1). These fold belts are productive in the Cenozoic section and contain the largest structural closures in the northern Gulf of Mexico.

Discoveries

The Gulf of Mexico Region contains total reserves of 22.997 Bbo and 235.910 Tcfg (64.974 BBOE), of which 10.908 Bbo and 132.677 Tcfg (34.515 BBOE) have been produced. The Region contains 10,235 producible sands in 2,453 pools (table 1). Total reserves were in decline during the late 1980's and early 1990's, but during the middle 1990's, a number of large discoveries, especially in the deepwater Gulf of Mexico, has reversed this trend (figures 3 and 4).

Assessment Results

In the previous assessment, (Lore *et al.*, 1999; data as of January 1, 1995) uncertainty about the presence of reservoir-quality sands beyond the Sigsbee Escarpment resulted in the 3,000-meter water depth contour being used as the geo-

Gulf of Mexico Region Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2369	14.266	162.711	43.218
Cumulative production	--	10.908	132.677	34.515
Remaining proved	--	3.358	30.034	8.703
Unproved	84	0.995	5.102	1.903
Appreciation (P & U)	--	7.736	68.096	19.853
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	22.821	145.088	49.851
Mean	2870	37.126	191.627	71.223
5th percentile	--	56.054	246.600	97.602
Total Endowment				
95th percentile	--	45.818	380.998	114.825
Mean	5323	60.123	427.537	136.197
5th percentile	--	79.051	482.510	162.576

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment

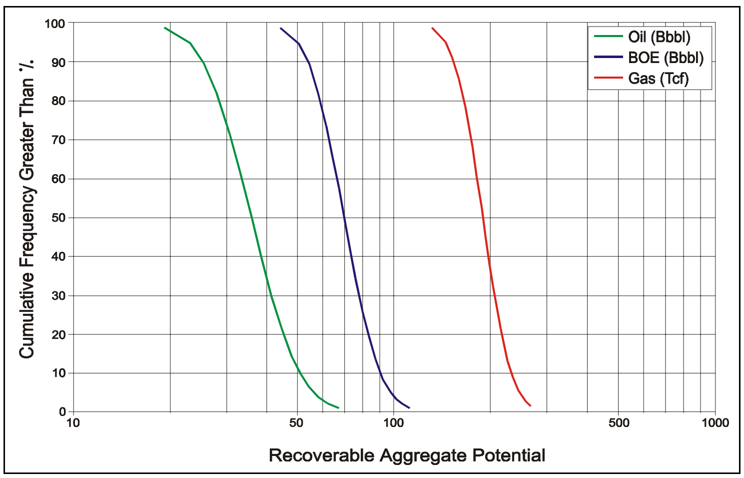

Figure 5. Cumulative probability distribution for undiscovered conventionally recoverable resources.

graphical cutoff for play assessments in the Gulf of Mexico Region. However, new seismic data, well data, and production data from the deepwater areas of the Gulf have allowed for a more thorough and detailed assessment of deepwater prospects. Consequently, the amount of undiscovered conventionally recoverable resources (UCRR) increased by 46 BBOE over those in the previous assessment.

Ninety-two individual plays within the Gulf of Mexico have been identified, of which 87 were assessed. Four identified plays were not assessed because of either source rock issues or reservoir quality questions. A fifth play, the Cenozoic Fan 3 (UPL-LL F3) play, was not assessed at the time of this report.

The mean total endowment of assessed plays is forecast at 60.123 Bbo and 427.537 Tcfg (136.197 BBOE) (table 2). Twenty-five percent of this BOE mean total endowment has been produced. The 95th- and 5th-percentile estimates of UCRR in the Gulf of Mexico Region are 22.821 to 56.054 Bbo and 145.088 to 246.600 Tcfg, respectively (figure 5). At mean levels, UCRR are forecast at 37.126 Bbo and 191.627 Tcfg (71.223 BBOE). These undiscovered resources may occur in as many as 2,870 pools.

The largest undiscovered pool is forecast as the largest pool in the Gulf of Mexico Region (over 3,500 MMBOE). The next four undiscovered pools occupy positions 2, 3, 5, and 7 on the pool rank plot. The mean mean size of undiscovered pools is 34 MMBOE compared with the 26 MMBOE mean mean size of discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 31 MMBOE.

The potential for significant additional discoveries in the Gulf of Mexico Region is excellent, despite almost 50 years of extensive drilling in the area. The potential that does exist in the area, however, is dependent upon deeper drilling, discoveries

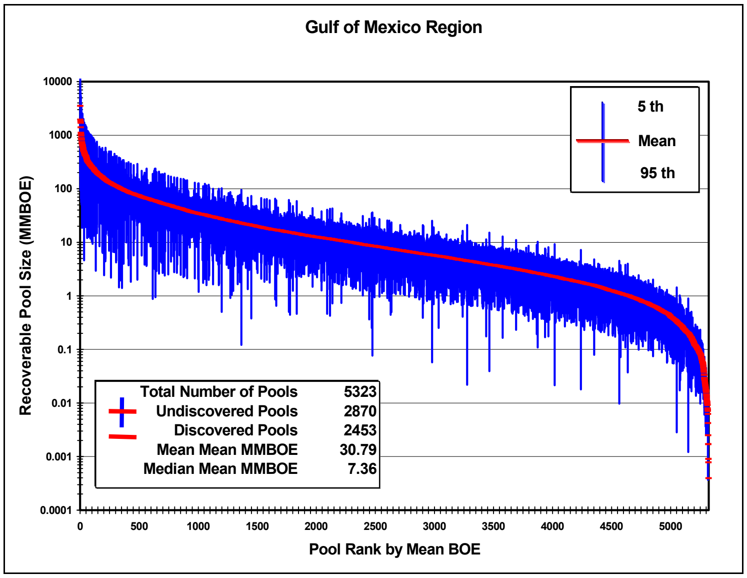

Figure 6. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars) in the Gulf of Mexico Region.

being made in deeper water, or discoveries being made below salt.

Reference

Lore, G.L., K.M. Ross, B.J. Bascle, L.D. Nixon, and R.J. Klazynski. 1999. Assessment of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1995: Minerals Management Service OCS Report MMS 99-0034, CD-ROM.

Gulf of Mexico Cenozoic Province

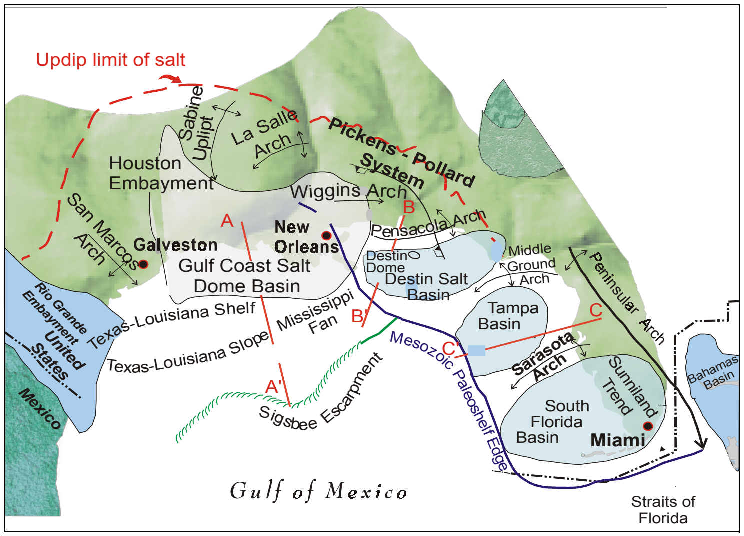

Figure 1. Physiographic map of the northern Gulf of Mexico.

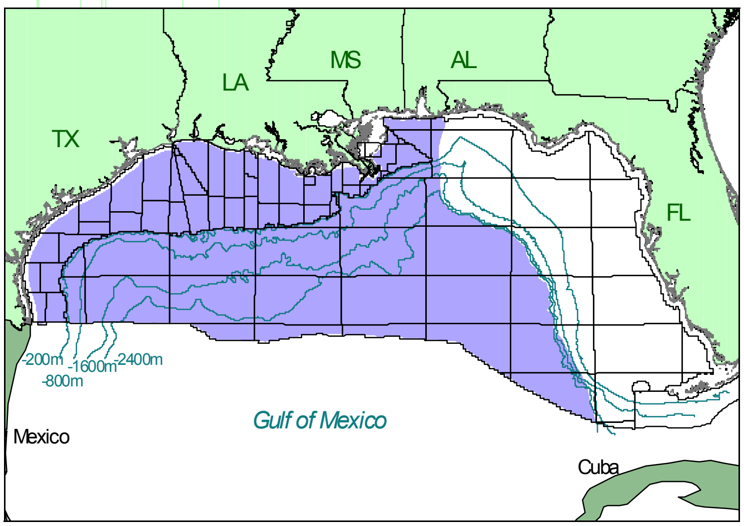

Figure 2. Extent of plays assessed in the Gulf of Mexico Cenozoic Province.

Province Description

The Gulf of Mexico Cenozoic Province covers an area extending from the U.S.-Mexico international boundary to the Federal waters adjacent to the State waters of Texas, Louisiana, Mississippi, and Alabama (figure 1). The Cenozoic sedimentary section attains a thickness upwards of 50,000 feet, while 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.

A general uplift of the North American continent and the subsequent Laramide Orogeny during the Late Cretaceous and Early Tertiary provided large amounts of clastic sediment that were transported into the northwestern Gulf of Mexico. Quaternary continental glaciation resulted in additional large volumes of sediment being supplied to the basin. 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 sea level transgressions and regressions.

These relative sea level changes created various depositional styles and environments. During periods when subsidence was rapid and sediment supply was limited, transgressions resulted in a backstepping, retrogradational style of deposition. When basin subsidence and the sediment supply filled accommodation space as it became available, upbuilding, aggradational depositional styles developed. When sedimentation was rapid and subsidence slower, sediments built outward across the shelf in a progradational style. Rapidly falling relative sea levels and high sedimentation rates resulted in sediments spilling out onto the outer shelf and upper slope as

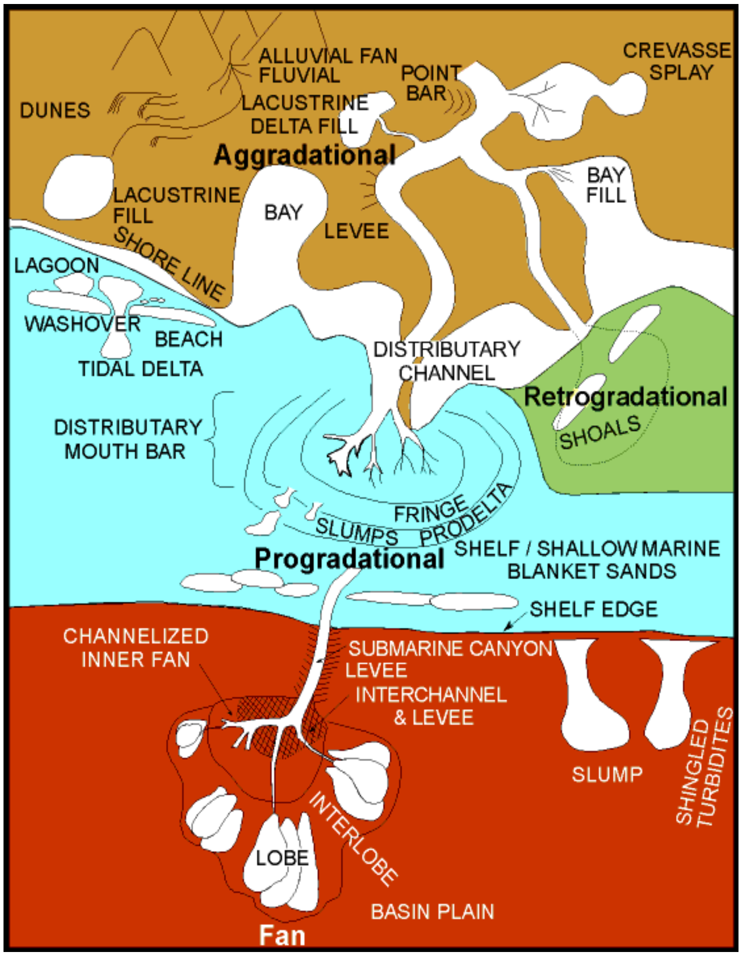

Figure 3. Map diagram illustrating the relationships between depositional environments and depositional styles.

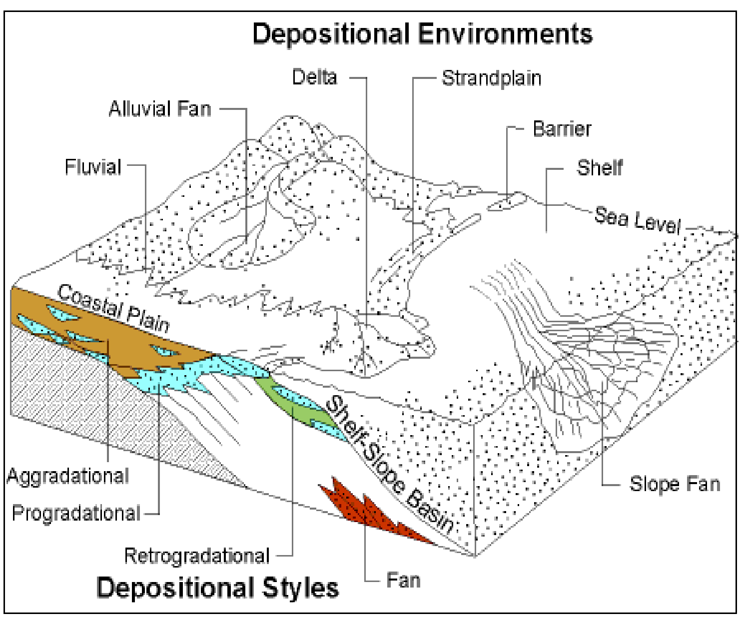

Figure 4. Block diagram illustrating relationship between depositional environments and depositional styles.

deep-sea fan systems.

These basic depositional styles were applied to the Cenozoic Province and its depositional environments (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). Chronostratigraphy, coupled with the distinct depositional styles and environments of this model --- recognized by a combination of electric log curve characteristics, ecozone data, and seismic character --- are the 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).

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. Progradational sediments are historically the most productive because of 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.

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 bodies in late Miocene sediments flowed downdip because of the influence of gravity and sediment loading, resulting in large sheets of salt that themselves

Province	System	Series	Chronozone Name	Chronozone Number	Biozone
Cenozoic	Quaternary	Pleistocene	UPL	01	*Sangamon fauna*
					Trimosina "A" 1st
					Trimosina "A" 2nd
					Hyalinea "B" / Trimosina "B"
			MPL	05	*Angulogerina "B" 1st*
					Angulogerina "B" 2nd
			LPL	07	*Lenticulina 1*
					Valvulineria "H"
	Tertiary	Pliocene	UP	09	*Buliminella 1*
			LP	10	*Textularia "X"*
		Miocene	UM3	11	*Robulus "E" / Bigenerina "A"*
					Cristellaria "K"
			UM1	13	*Discorbus 12*
			MM9	14	*Bigenerina 2*
					Textularia "W"
			MM7	16	*Bigenerina humblei*
					Cristellaria "I"
					Cibicides opima
			MM4	19	*Amphistegina "B"*
					Robulus 43
					Cristellaria 54 / Eponides 14
					Gyroidina "K"
			LM4	23	*Discorbus "B"*
					Marginulina "A"
			LM2	25	*Siphonina davisi*
			LM1	26	*Lenticulina hanseni*
		Oligocene	UO	27	*Discorbis Zone / Robulus "A"*
					Heterostegina texana
			MO	29	*Camerina "A"*
			LO	30	*Textularia warreni*
		Eocene	UE	31	*Hantkenina alabamensis*
					Camerina moodybranchensis
			ME	33	*Discorbis yeguaensis*
			LE	34	*Globorotalia wilcoxensis*
		Paleocene	UL	35	*Globorotalia velascoensis*
					Cristellaria longiforma
			LL	37	*Globorotalia uncinata*

Figure 5. Gulf of Mexico Cenozoic Province chronostratigraphic/biostratigraphic chart. Chronozones are after Reed et al. (1987).

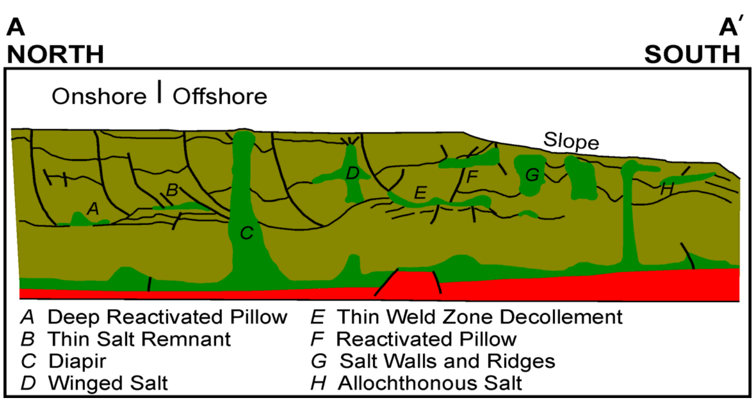

Figure 6. Cross section A-A′ (refer to figure 1 for location) illustrating various salt structures in the Gulf of Mexico (modified from Brooks, 1993).

were deformed by subsequent sediment loading. The recognition that salt exists as lenses, winged salt diapirs, 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

The Cenozoic Province contains total reserves of 22.997 Bbo and 230.677 Tcfg (64.042 BBOE), of which 10.907 Bbo and 131.946 Tcfg (34.385 BBOE) have been produced. The first reserves were discovered in the Province in 1947 (figures 7 and 8), and 1042 proved and unproved fields were included for this assessment. The Province contains 10,213 producible sands in 2,435 pools (table 1), and 2,354 of these pools contain proved reserves (table 2).

Assessment Results

Sixty-nine individual plays have been identified within the Gulf of Mexico Cenozoic Province. All but one of the plays were assessed. The Cenozoic Fan 3 (UPL-LL F3) play had not been assessed as of January 1, 1999.

From the 68 assessed plays in the Gulf of Mexico Cenozoic Province, the mean total endowment is estimated at 53.780 Bbo and 401.325 Tcfg (125.190 BBOE) (table 2). Twenty-seven percent of this BOE mean total endowment has been produced.

The 95th- and 5th-percentile forecasts of risked undiscovered conventionally recoverable resources (UCRR) in the Cenozoic Province are 25.754 to 36.390 Bbo and 145.264 to 198.661 Tcfg, respectively (figure 8). At mean levels, undiscovered resources are 30.783 Bbo and 170.648 Tcfg (61.148 BBOE). These undiscovered resources might occur in as many as 2,532 pools (figure 9). The largest undiscovered Cenozoic

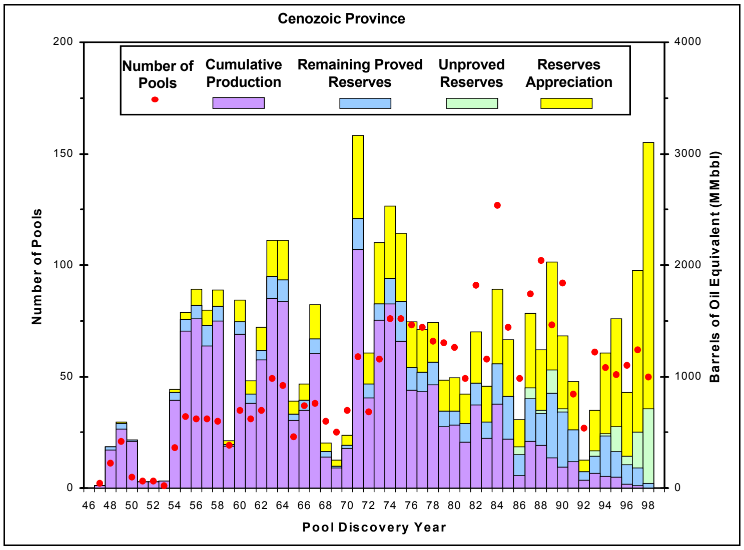

Figure 7. Exploration history graph showing reserves addition and number of pool discoveries by year.

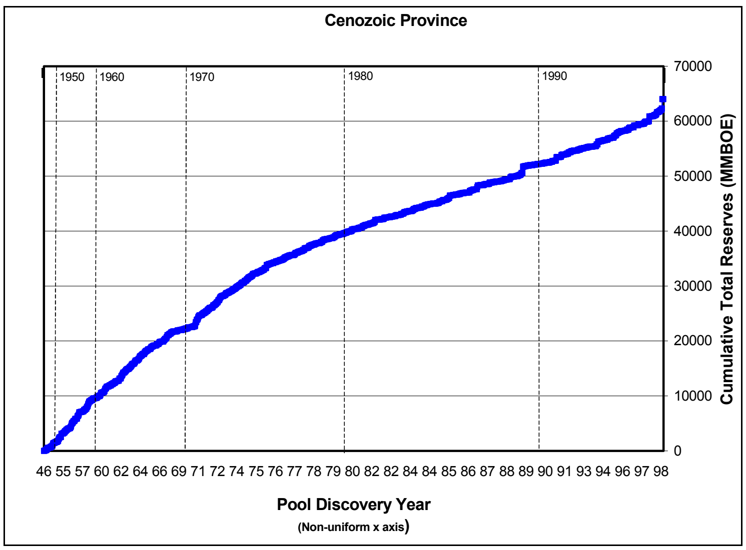

Figure 8. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

Cenozoic Province			
2435 Pools 10213 Sands	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	9	289	7620
Subsea depth (feet)	950	8012	22572
Number of sands per pool	1	4	44
Porosity	14%	29%	39%
Water saturation	16%	28%	75%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

pool, with a mean size of 1,952 MMBOE, is forecast as the largest pool in the Province. The next four undiscovered pools are in positions 2, 4, 5, and 6 on the pool rank plot. The mean mean size of undiscovered pools is 24 MMBOE compared with the 26 MMBOE mean size of discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 25 MMBOE.

The potential for significant additional Cenozoic 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, however, is primarily dependent upon deeper drilling, or upon discoveries being made in deepwater or subsalt. The greatest hydrocarbon potential of the Province lies in deepwater fan deposits.

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Cenozoic Province Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2354	14.266	160.457	42.817
Cumulative production	--	10.907	131.946	34.385
Remaining proved	--	3.358	28.510	8.431
Unproved	81	0.995	4.477	1.792
Appreciation (P & U)	--	7.736	65.743	19.434
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	25.754	145.264	52.708
Mean	2532	30.783	170.648	61.148
5th percentile	--	36.390	198.661	70.393
Total Endowment				
95th percentile	--	48.751	375.941	116.750
Mean	4967	53.780	401.325	125.190
5th percentile	--	59.387	429.338	134.435

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

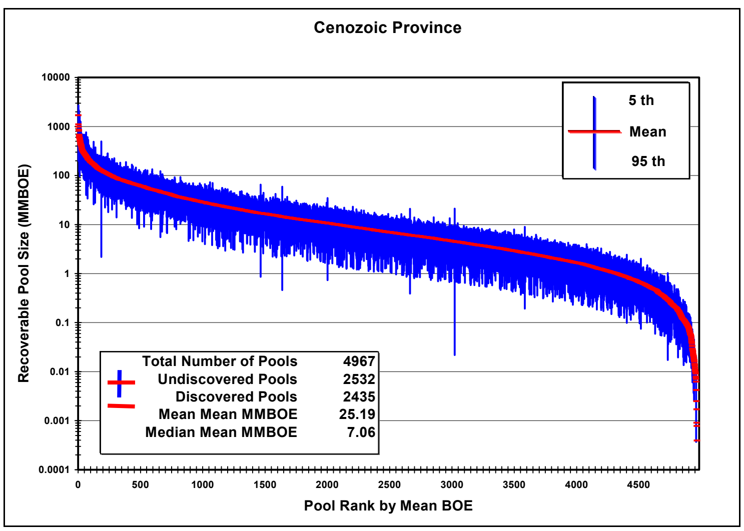

Figure 9. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars) in the Gulf of Mexico Cenozoic Province.

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Gulf of Mexico Mesozoic Province

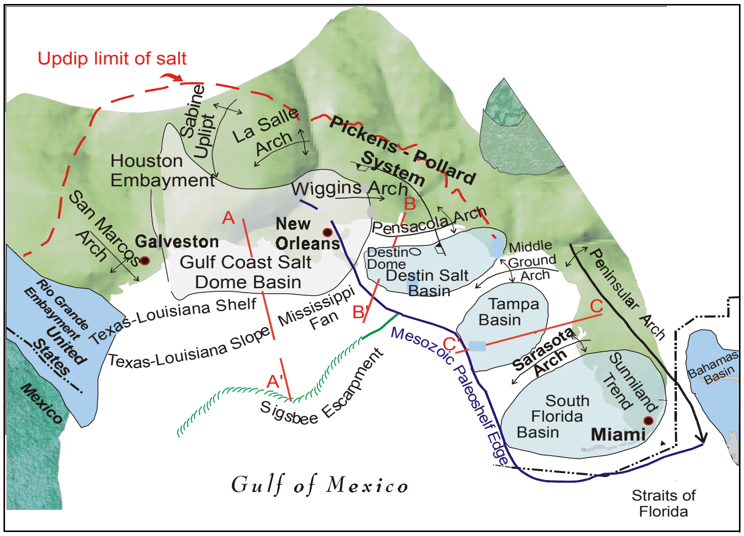


Figure 1. Physiographic map of the northern Gulf of Mexico.

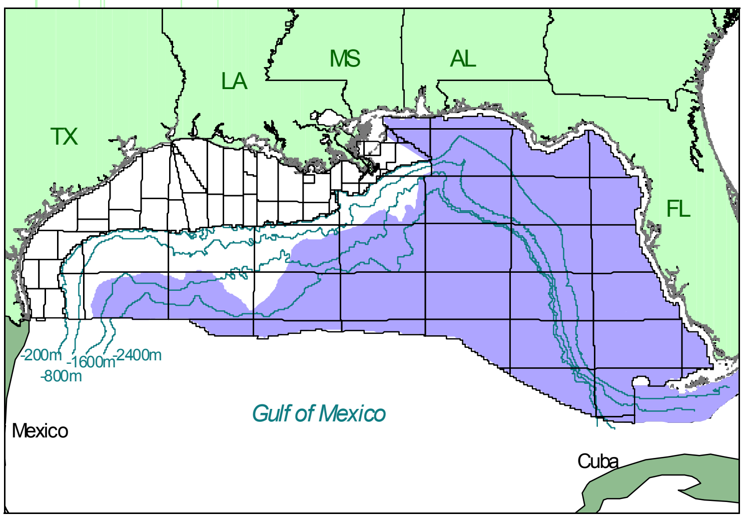
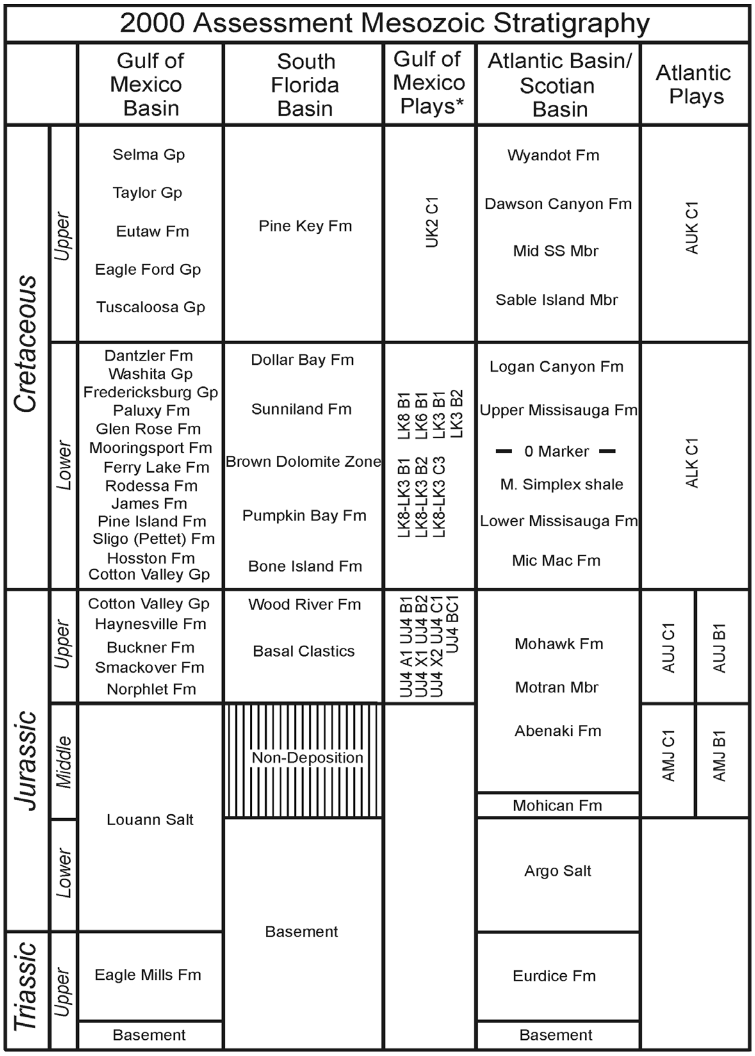


Figure 2. Extent of plays assessed in the Gulf of Mexico Mesozoic Province.

Province Description

The Gulf of Mexico Mesozoic Province covers an area extending from the U.S.-Mexico and U.S.-Cuba international boundaries in the deepwater Gulf of Mexico to the Federal waters adjacent to the State waters of Mississippi, Alabama, and Florida (figure 1). The Mesozoic sedimentary section attains a thickness exceeding 20,000 feet in the South Florida Basin and eastern portion of the Gulf of Mexico Basin. Water depths range from approximately 10 to over 10,000 feet. Figure 2 illustrates the overall extent of the plays assessed within the Mesozoic Province.

The Mesozoic Province initially formed during the Late Triassic to Middle Jurassic rifting episode that created the Gulf of Mexico. This breakup event formed a series of northeast-southwest-trending rifts offset by northwest-southeast-trending transfer faults/zones. The Wiggins Arch and parts of the Sarasota Arch (figure 1) represent Paleozoic remnants from this rifting stage. The rift grabens were active depocenters receiving lacustrine and alluvial deposits. During the Middle Jurassic, marine water sporadically entered the incipient Gulf of Mexico Basin, resulting in the deposition of thick evaporative deposits of the Louann Salt. During the Late Jurassic (Oxfordian), a widespread marine transgression deposited an organic-rich carbonate mudstone that became a major hydrocarbon source rock for the Gulf of Mexico. A series of transgressions and regressions led to the deposition of high-energy siliciclastics and carbonates, which caused progradation of the shelf edge in the northeastern Gulf Basin. During the Cretaceous, thick reef complexes developed along the shelf edge. These reef complexes interfingered with carbonates and siliciclastics in back-reef areas. In deepwater areas of the Gulf, downdip compressional folding caused by Mesozoic- and Cenozoic-



Rock unit positions do not imply age relationships between basins.
* Does not include plays that span ages.

Figure 3. Mesozoic stratigraphy including a comparison of formations in the Gulf of Mexico and South Florida Basins.

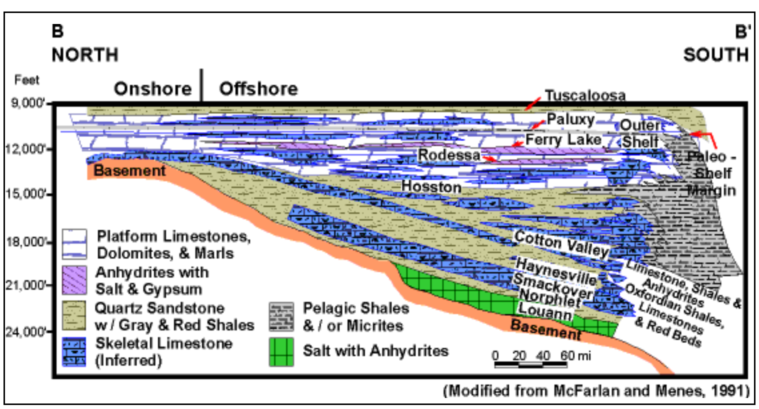


Figure 4. Cross-section B-B' (refer to figure 1 for location) illustrating the stratigraphic and lithologic relationships of the formations overlying the basement from onshore in the Florida panhandle southward to offshore Federal waters in the Gulf of Mexico.

aged updip extensional faulting and salt tectonics produced large fold belts underneath and in front of the modern Sigsbee Escarpment (figure 1). These fold belts are productive in the Cenozoic section, but the folded Mesozoic section remains untested.

Figures 3, 4, and 5, provide the Mesozoic stratigraphy of groups and formations from the onshore to the offshore Federal OCS in the Gulf of Mexico. Maximum thicknesses attained by upper Jurassic sediments exceed 5,000 feet, lower Cretaceous sediments 10,000 feet, and upper Cretaceous sediments 5,000 feet. Detailed paleontological analysis provided the basis for the Mesozoic chronostratigraphic chart (figure 6).

Three prospective chronozones have been identified in the Gulf of Mexico Mesozoic Province: upper Jurassic (UJ), lower Cretaceous (LK), and upper Cretaceous (UK). Potential traps are related to fold structures, faults (normal and growth), drape over deeper structures, and permeability pinchouts against nonporous shales, evaporites, carbonates, and basement rocks. Primary exploration targets in the Mesozoic Province to date have been the upper Jurassic siliciclastic Norphlet Formation and the lower Cretaceous carbonate James Formation.

In offshore Federal waters of the south Florida shelf, 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 figures 3 and 5. In the deepwater Gulf of Mexico, horst blocks of the rifted basement (“buried hills”) and associated sediments are forecast to contain the greatest reservoir potential.

Discoveries

The Mesozoic Province contains total reserves of <0.001 Bbo and 5.232 Tcfg (0.931 BBOE), of which <0.001 Bbo and 0.730 Tcfg (0.130 BBOE) have been produced. The first reserves were discovered in

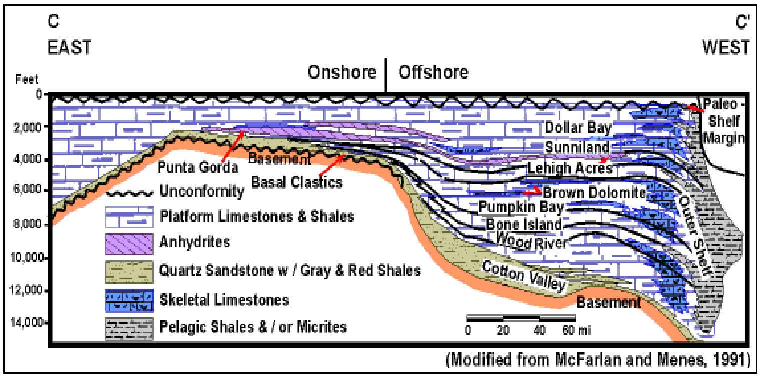


Figure 5. Cross-section C-C' (refer to figure 1 for location) illustrating the stratigraphic and lithologic relationships of the formations overlying the basement from onshore south Florida westward into offshore Federal waters in the Gulf of Mexico.

Province	System	Series	Chronozone Name	Chronozone Number	Biozone
Mesozoic	Cretaceous	Upper	UK5	38	*Globotruncana mayaroensis* *Globotruncana fornicata* *Globotruncana concavata*
			UK2	41	*Planulina eaglefordnsis* *Rotalipora cushmani*
		Lower	LK8	43	*Lenticulina washitaensis* *Cythereis fredericksburgensis*
			LK6	45	*Eocytheropteron trinitiensis* *Orbitolina texana* *Rehacythereis? aff. R. glabrella*
			LK3	48	*Choffatella decipiens* *Schulerìdea acuminata*
	Jurassic	Upper	UJ4	51	*Epistomina uhligi* *Epistomina mosquensis* *Pseudocyclammina jaccardi*
		Middle	MJ	55	
		Lower	LJ	56	
	Triassic	Upper	UTR	57	
		Middle	MTR	58	
		Lower	LTR	59	

Figure 6. Chronostratigraphic chart illustrating the chronostratigraphy and biostratigraphy of the Mesozoic Province in the Gulf of Mexico Region. Chronozones are after Reed et al. (1987).

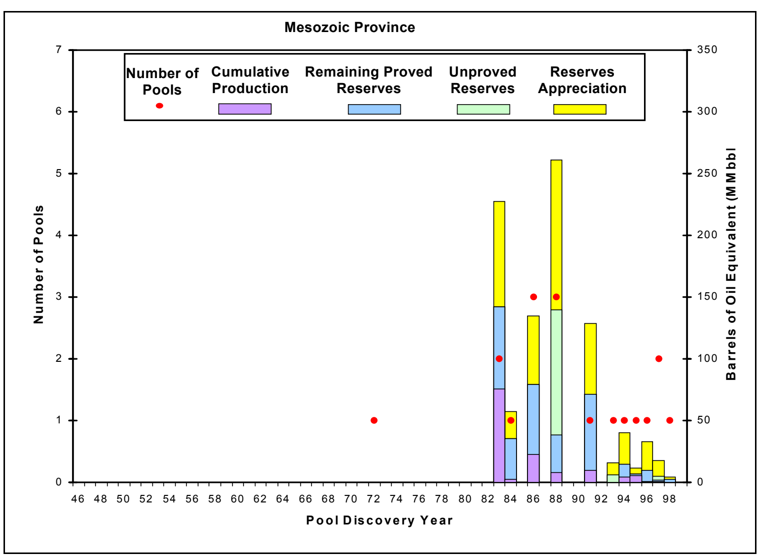


Figure 7. Exploration history graph showing reserves addition and number of pool discoveries by year.

the Province in 1972 (figures 7 and 8). The Province contains 22 producible sands in 18 pools (table 1), and 15 of these pools contain proved reserves (table 2).

Assessment Results

Twenty-three individual plays were identified within the Gulf of Mexico Mesozoic Province. Nineteen of these plays were assessed. Four plays were unassessed because of poor reservoir potential, lack of source rock potential, or lack of hydrocarbon migration routes.

The mean total endowment for the 19 assessed plays in the Mesozoic Province is estimated at 6.342 Bbo and 26.211 Tcfg (11.006 BBOE) (table 2). Only a little more than 1 percent of this BOE mean total endowment has been produced.

The 95th- and 5th-percentile forecasts of undiscovered conventionally recoverable resources (UCRR) in the Mesozoic Province are 0.728 to 20.023 Bbo and 4.023 to 57.101 Tcfg, respectively (table 2; figure 9). Mean UCRR are 6.342 Bbo and 20.979 Tcfg (10.075 BBOE). These undiscovered resources might occur in as many as 338 pools. The largest undiscovered Mesozoic pool, with a mean size of 3,538 MMBOE, is also forecast to be the largest pool in the Province. The next four undiscovered pools are in positions 2, 3, 4, and 5 on the pool rank plot (figure 10). The mean mean size of undiscovered pools is 111 MMBOE compared with the 52 MMBOE mean size of discovered pools. The mean mean size of all pools, including both discovered and undiscovered, is 108 MMBOE.

The potential for significant additional Mesozoic discoveries on the shelf and slope of the Gulf of Mexico is high; however, plays with the greatest potential have the highest risk. The combined Mesozoic sections in the fold belts are forecast to contain the most UCRR, but reservoir quality, depth of burial, and water depth are problematic.

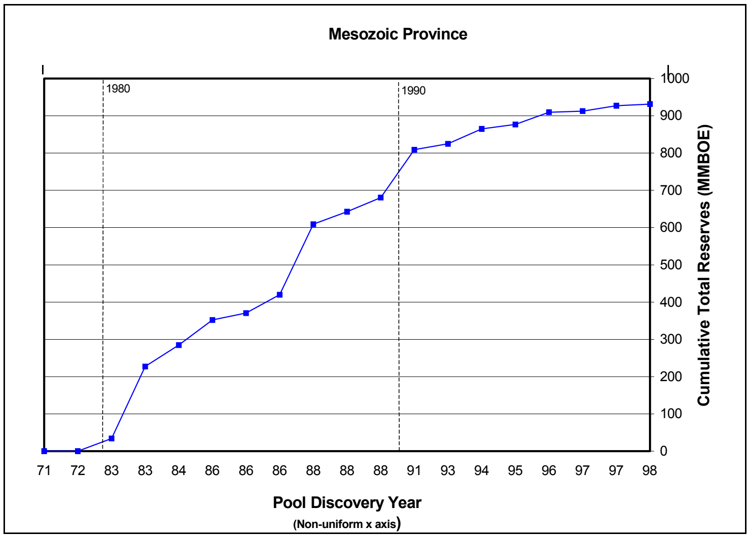


Figure 8. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

Mesozoic Province 18 Pools 22 Sands	Minimum	Mean	Maximum
Water depth (feet)	37	86	288
Subsea depth (feet)	8656	19618	22612
Number of sands per pool	1	1	3
Porosity	10%	13%	20%
Water saturation	19%	36%	52%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Mesozoic Province Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	15	<0.001	2.254	0.401
Cumulative production	–	<0.001	0.730	0.130
Remaining proved	–	<0.001	1.524	0.271
Unproved	3	<0.001	0.625	0.111
Appreciation (P & U)	–	<0.001	2.353	0.419
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.728	4.023	1.499
Mean	338	6.342	20.979	10.075
5th percentile	–	20.023	57.101	29.708
Total Endowment				
95th percentile	–	0.728	9.255	2.430
Mean	356	6.342	26.211	11.006
5th percentile	–	20.023	62.333	30.639

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

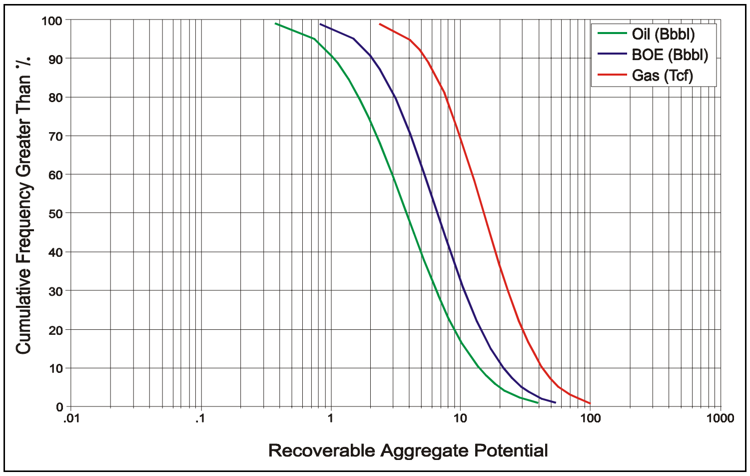


Figure 9. Cumulative probability distribution for undiscovered conventionally recoverable resources.

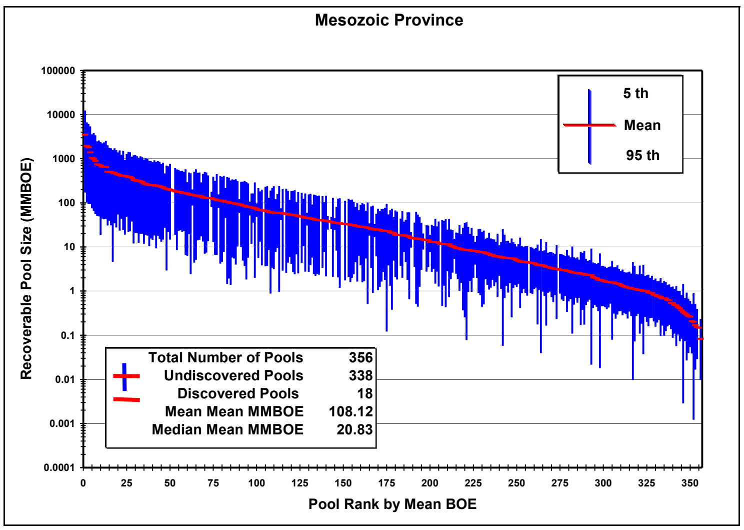


Figure 10. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars) in the Gulf of Mexico Mesozoic Province.

Upper Pleistocene Caprock (UPL B1) Play

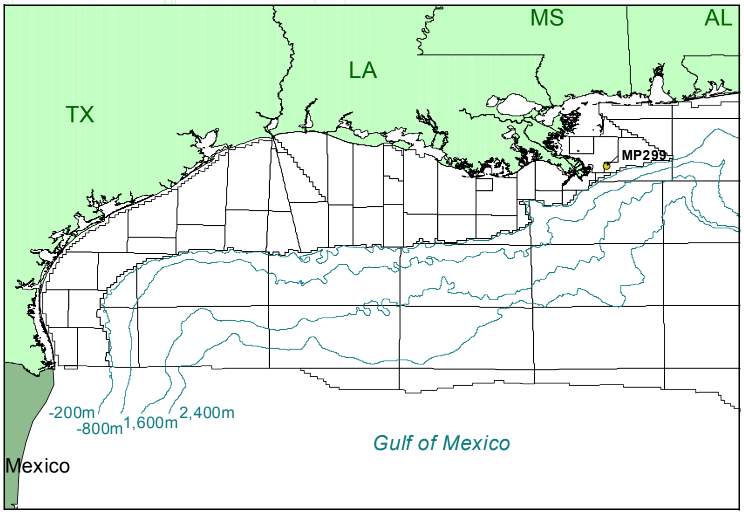


Figure 1. Play location.

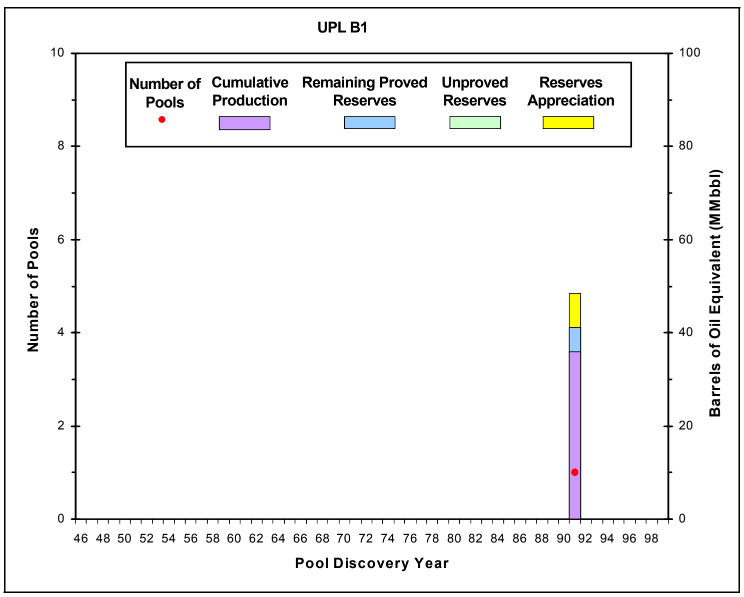


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UPL B1 Play 1 Pool 1 Sand	Minimum	Mean	Maximum
Water depth (feet)	209	209	209
Subsea depth (feet)	1500	1500	1500
Number of sands per pool	1	1	1
Porosity	35%	35%	35%
Water saturation	30%	30%	30%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pleistocene Caprock (UPL B1) play is confined to caprock overlying the salt diapir that provides structure for the Main Pass 299 field (figure 1). The pool's one reservoir (table 1; refer to the Methodology section for a discussion of reservoirs and pools) consists of vugular limestone. The caprock itself is a product of diagenesis, and its age is unknown. Therefore, for cataloging purposes, the caprock is correlated to the surrounding UPL sediments.

Discoveries

The UPL B1 oil play contains proved reserves of 0.047 Bbo and 0.008 Tcfg (0.048 BBOE), of which 0.035 Bbo and 0.005 Tcfg (0.036 BBOE) have been produced. The play's reserves were discovered in 1991 in Freeport-McMoRan Inc.'s CAPROCK reservoir (figures 2 and 3). Estimates of reserves and production can be found in table 2.

Assessment Results

Because the UPL B1 play is thought unlikely to contain significant new resources, undiscovered conventionally recoverable resources were not assessed for this play .

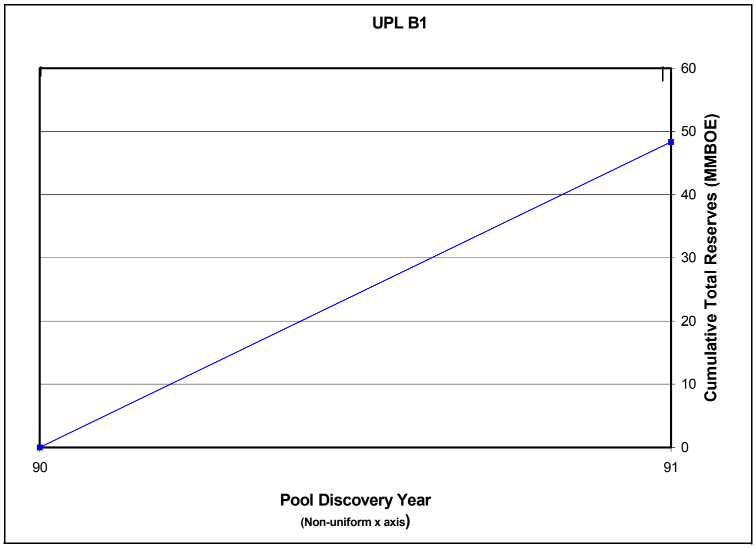


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UPL B1 Play 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	--	0.035	0.005	0.036
Remaining proved	--	0.005	0.002	0.005
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.007	0.001	0.007
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.000	0.000	0.000
Mean	0	0.000	0.000	0.000
5th percentile	--	0.000	0.000	0.000
Total Endowment				
95th percentile	--	0.047	0.008	0.048
Mean	1	0.047	0.008	0.048
5th percentile	--	0.047	0.008	0.048

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Upper Pleistocene Aggradational (UPL A1) Play

Hyalinea "B" through Sangamon Fauna

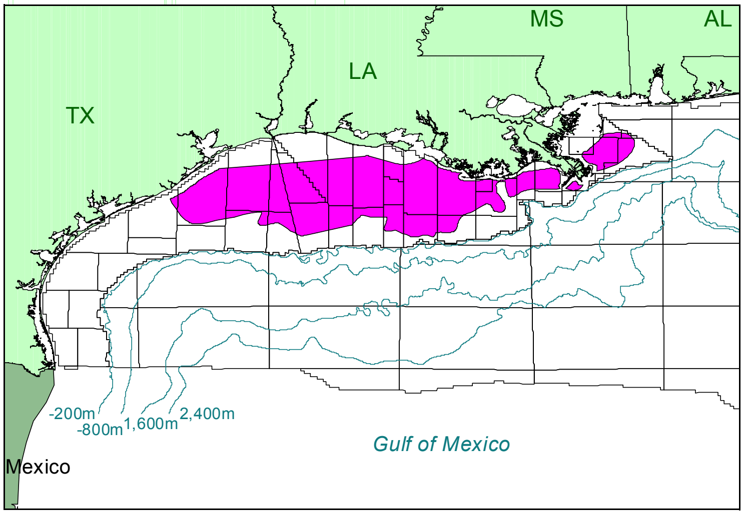


Figure 1. Play location.

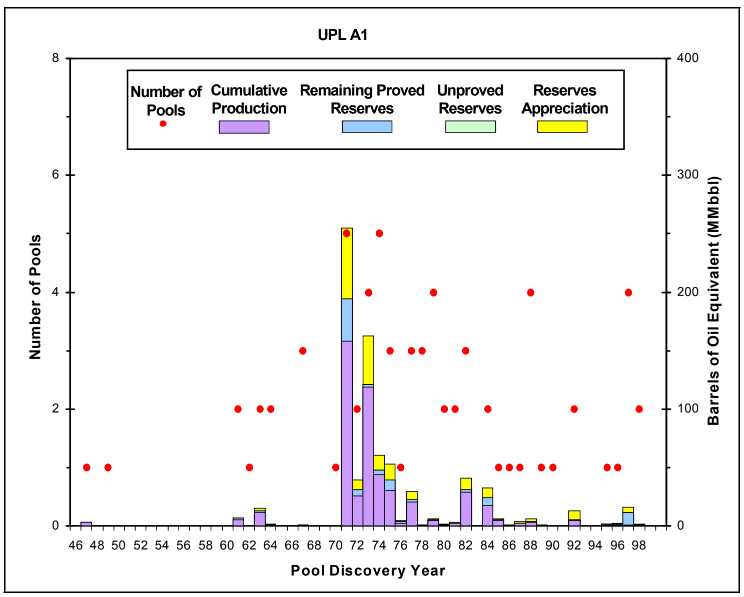


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UPL A1 Play 71 Pools 205 Sands	Minimum	Mean	Maximum
Water depth (feet)	18	165	338
Subsea depth (feet)	983	2621	5082
Number of sands per pool	1	3	15
Porosity	23%	33%	39%
Water saturation	16%	27%	45%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pleistocene Aggradational (UPL A1) 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 to the Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play extends onshore into Texas in the Brazos and Galveston Areas and into Louisiana from the Ship Shoal to Main Pass Areas. Otherwise, the updip limit for the UPL A1 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 P1) play.

Play Characteristics

The UPL A1 play is characterized by stacked, blocky, sand-dominated successions representing sediment buildup on fluvial channel/levee complexes, crevasse splays, and point bars; deltaic distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches and barrier islands; and shallow marine shelf delta fringes and slumps. Additionally, retrogradational, reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the UPL A1 play.

Anticlines, salt diapirs, and growth faults are major structural features in the play. Minor structural features include normal faults and shale diapir-like structures. Seals are pro-

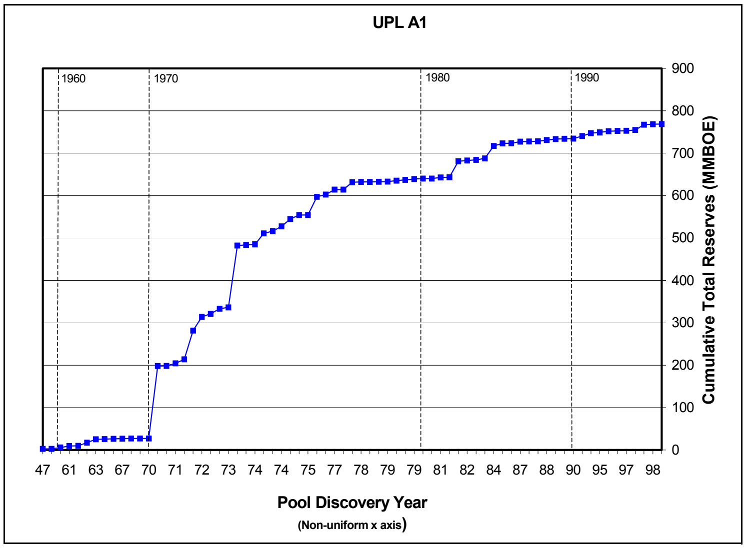


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UPL A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	71	0.109	2.659	0.582
Cumulative production	--	0.088	2.277	0.493
Remaining proved	--	0.021	0.382	0.089
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.033	0.862	0.187
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.001	0.090	0.018
Mean	11	0.003	0.133	0.027
5th percentile	--	0.012	0.183	0.038
Total Endowment				
95th percentile	--	0.143	3.611	0.787
Mean	82	0.145	3.654	0.796
5th percentile	--	0.154	3.704	0.807

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

vided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UPL A1 gas play contains total reserves of 0.142 Bbo and 3.521 Tcfg (0.769 BBOE), of which 0.088 Bbo and 2.277 Tcfg (0.493 BBOE) have been produced. The play contains 205 producible sands in 71 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Ship Shoal 32 field in 1947 (figure 2). Discoveries were infrequent and small until the 1970's. The maximum yearly total reserves of 254 MMBOE were added in 1971 with the discovery of five pools, including the largest pool in the play in the Eugene Island 330 field, with 171 MMBOE in mean total reserves (figures 2 and 3). Over 98 percent of the play's cumulative production and 95 percent of its total reserves come from pools discovered before 1990, reflecting the maturity of the play. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 71 discovered pools contain 315 reservoirs, of which 250 are nonassociated gas, 50 are undersaturated oil, and 15 are saturated oil. Cumulative production has consisted of 82 percent gas and 18 percent oil.

Of the 12 aggradational plays in the Gulf of Mexico, the UPL A1 play contains the third largest amount of BOE total reserves and has the third largest amount of BOE cumulative production.

Assessment Results

The marginal probability of hydrocarbons for the UPL A1 play is 1.00. The play contains a mean total endowment of 0.145 Bbo and 3.654 Tcfg (0.796 BBOE) (table 2). Sixty-two percent of this BOE mean total

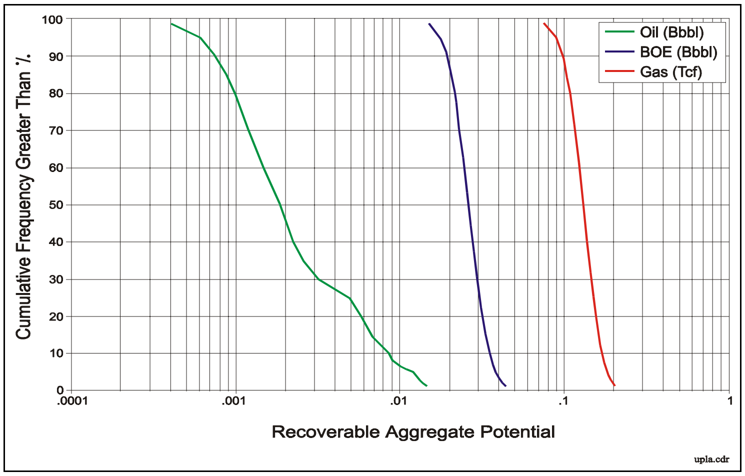


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

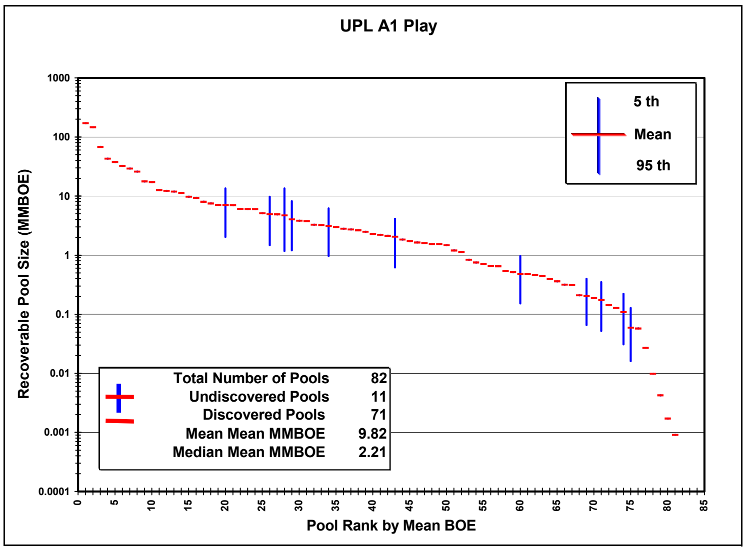


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of <.001 to 0.012 Bbo and 0.090 to 0.183 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.003 Bbo and 0.133 Tcfg (0.027 BBOE). These undiscovered resources might occur in as many as 11 pools. The largest undiscovered pool, with a mean size of 7 MMBOE, is forecast as the 20th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 26, 28, 29 and 34 on the pool rank plot. For all the undiscovered pools in the UPL A1 play, the mean mean size is 2 MMBOE, which is smaller than the 11 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 10 MMBOE.

The UPL A1 play is supermature with BOE mean UCRR contributing only 3 percent to the UPL A1 play's BOE mean total endowment. Small gas discoveries will continue to be made by drilling shallow seismic amplitudes as economics warrant.

Upper Pleistocene Progradational (UPL P1) Play

Hyalinea "B" through Sangamon Fauna

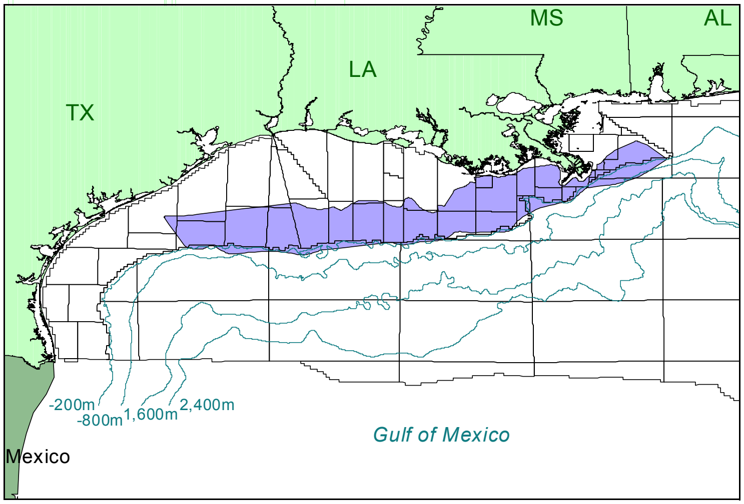


Figure 1. Play location.

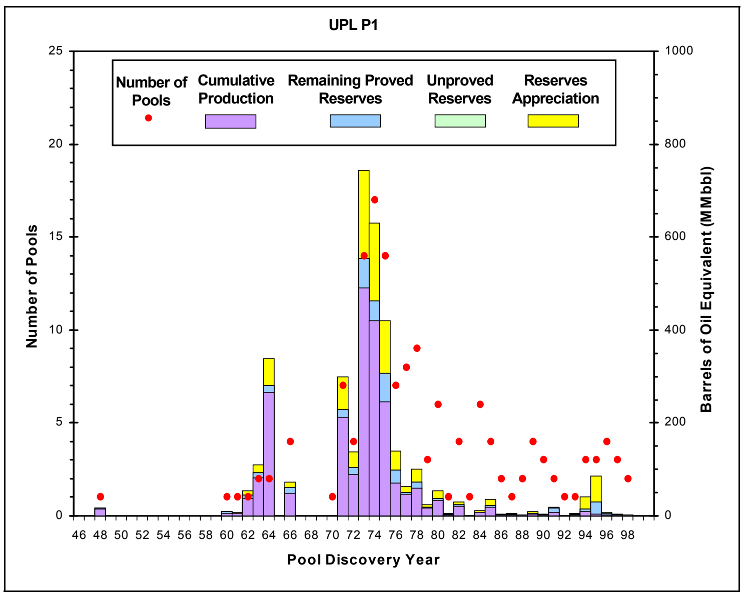


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UPL P1 Play 149 Pools 637 Sands	Minimum	Mean	Maximum
Water depth (feet)	39	244	922
Subsea depth (feet)	950	3969	8235
Number of sands per pool	1	4	20
Porosity	20%	32%	38%
Water saturation	16%	26%	55%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pleistocene Progradational (UPL P1) play is the second largest play in the Gulf of Mexico Region on the basis of gas total reserves and gas mean total endowment. 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 Brazos 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 A1) play. The UPL P1 play also extends onshore into Louisiana near the Mississippi River Delta. To the northeast and west, the UPL P1 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 1 (UPL F1) play.

Play Characteristics

Sediments in the UPL P1 play represent major regressive episodes of outbuilding of both the shelf and slope. Retrogradational reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the UPL P1 play.

Almost half of the fields in this play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are associated with growth fault anticlines and normal faults, while some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts or facies

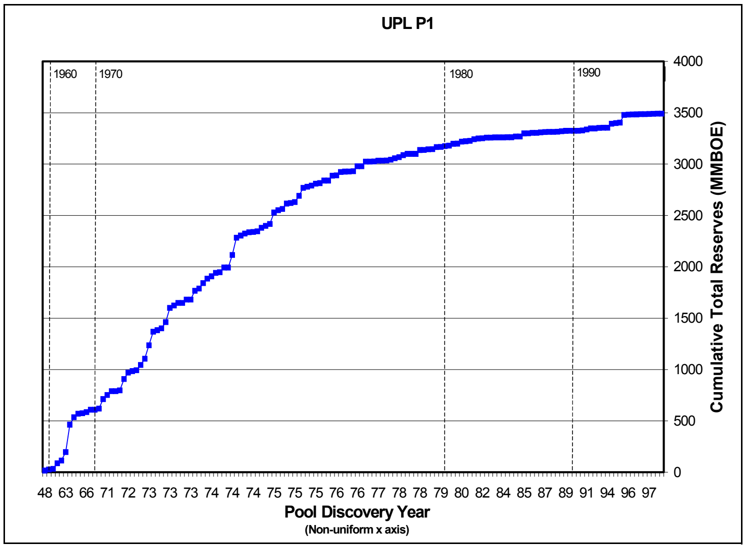


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UPL P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	149	0.333	12.686	2.590
Cumulative production	–	0.253	11.105	2.229
Remaining proved	–	0.079	1.581	0.361
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	0.117	4.411	0.902
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.052	1.658	0.364
Mean	66	0.116	1.873	0.449
5th percentile	–	0.210	2.092	0.567
Total Endowment				
95th percentile	–	0.501	18.755	3.856
Mean	215	0.565	18.970	3.941
5th percentile	–	0.659	19.189	4.059

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UPL P1 gas play contains total reserves of 0.449 Bbo and 17.097 Tcfg (3.492 BBOE), of which 0.253 Bbo and 11.105 Tcfg (2.229 BBOE) have been produced. The play contains 637 producible sands in 149 pools, and all 149 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves discovered in the play occurred in the South Timbalier 52 field in 1948 (figure 2). Discoveries peaked in the mid-1970's when maximum yearly total reserves of 744 MMBOE were added in 1973 with the discovery of 14 pools. The largest pool in the play was found in 1964 in the Eugene Island 292 field, with 267 MMBOE in total reserves (figures 2 and 3). Over 95 percent of the play's total reserves and 98 percent of its cumulative production have come from pools discovered before 1990, reflecting the maturity of the play. Twenty-two pools have been discovered in the 1990's; the most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 149 discovered pools contain 1,302 reservoirs, of which 977 are nonassociated gas, 244 are undersaturated oil, and 81 are saturated oil. Cumulative production has consisted of 89 percent gas and 11 percent oil.

Of the 87 assessed Gulf of Mexico Region plays, the UPL P1 play contains the second largest amount of BOE gas total reserves (7% of total gas reserves for the Region) and has produced the second largest amount of BOE cumulative production (8% of total BOE cumulative production in the Region).

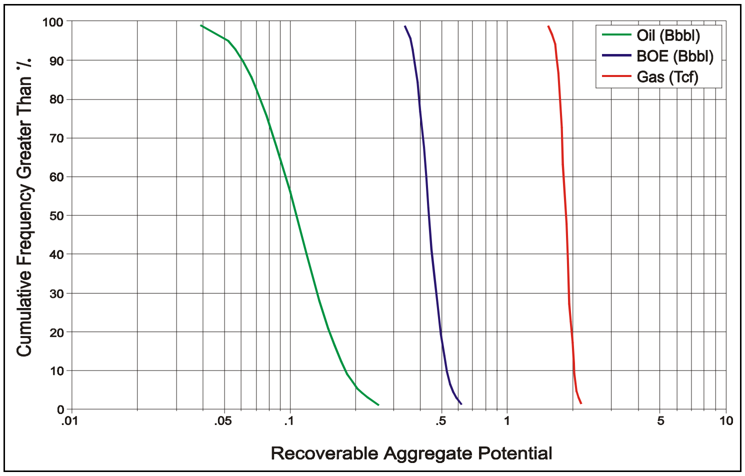


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

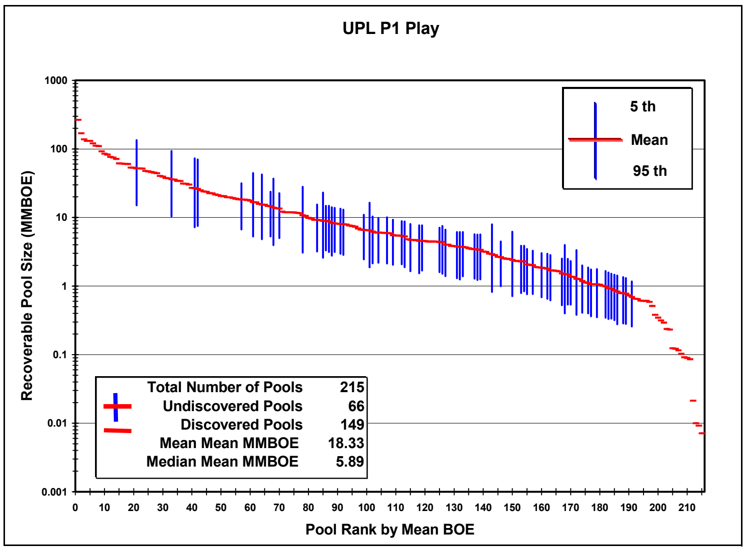


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Assessment Results

The marginal probability of hydrocarbons for the UPL P1 play is 1.00. This play has a mean total endowment of 0.565 Bbo and 18.970 Tcfg (3.941 BBOE) (table 2). Fifty-seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that mean undiscovered conventionally recoverable resources (UCRR) have a range of 0.052 to 0.210 Bbo and 1.658 to 2.092 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The mean UCRR resources are estimated at 0.116 Bbo and 1.873 Tcfg (0.449 BBOE). Of the 13 progradational plays in the Gulf of Mexico Region, the UPL P1 is forecast to contain the most UCRR. These undiscovered resources might occur in as many as 66 pools. The largest undiscovered pool, with a mean size of 52 MMBOE, is forecast as the 21st largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 33, 41, 42, and 57 on the pool rank plot. For all the undiscovered pools in the UPL P1 play, the mean mean size is 7 MMBOE, which is smaller than the 23 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 18 MMBOE.

The UPL P1 is a super-mature play with BOE mean UCRR contributing 11 percent to the play's BOE mean total endowment. Recently, shallow gas sands (1,000 to 3,000 feet subsea) have become an attractive target for several exploration companies. This trend is noted for being largely ignored by exploration companies until lately because the gas was considered too underpressured to be economic. The shallow gas creates good seismic hydrocarbon indicators (bright spots) and the sands are characterized by very high porosity and permeability. Faulted traps are frequently associated with hydrocarbon seeps at the seafloor. With 3D seismic data, drilling risks are very low.

Upper Pleistocene Fan 1 (UPL F1) Play

Hyalinea "B" through Sangamon Fauna

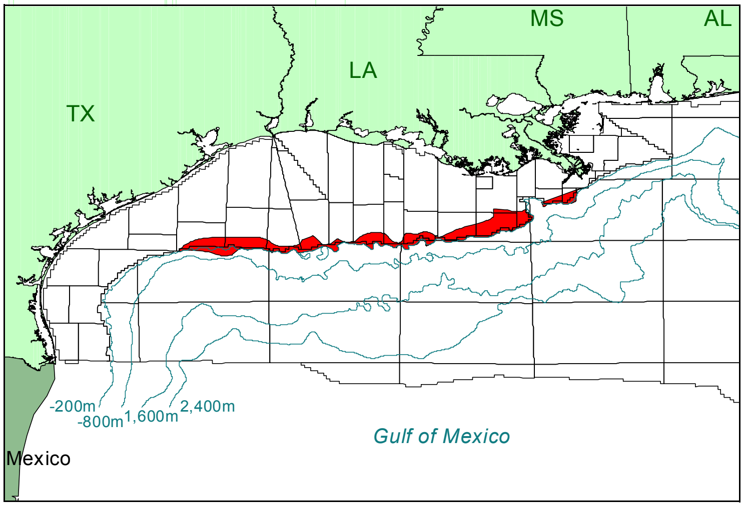


Figure 1. Play location.

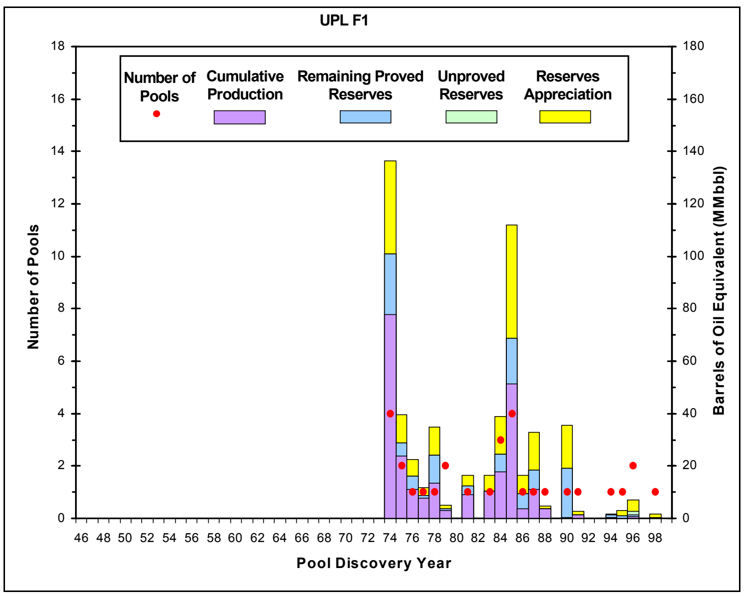


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UPL F1 Play 30 Pools 118 Sands	Minimum	Mean	Maximum
Water depth (feet)	164	419	930
Subsea depth (feet)	3825	6492	12152
Number of sands per pool	1	4	17
Porosity	23%	31%	35%
Water saturation	18%	27%	46%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pleistocene Fan 1 (UPL F1) play occurs within the *Hyalinea* "B," *Trimosina* "B," *Trimosina* "A" 2nd occurrence and *Trimosina* "A" 1st occurrence biozones, and Sangamon Fauna. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and listric faulting located on the modern Gulf of Mexico Region shelf. This play extends in a narrow band along the shelf margin from the Galveston/East Breaks Areas offshore Texas to the South Pass/Mississippi Canyon Areas near the present-day Mississippi River Delta (figure 1).

Updip, the play grades into deposits of the Upper Pleistocene Progradational (UPL P1) play. To the east and west, the UPL F1 play is limited by a lack of sediment influx at the edges of the UPL depocenter. The southern extension of the play is limited by the structural boundary of the Upper Pleistocene Fan 2 (UPL F2) play.

Play Characteristics

The UPL F1 play is characterized by deepwater turbidites deposited basinward of the UPL1 shelf margin on the UPL upper and lower slopes, in topographically low areas between salt structure highs, and on the abyssal plain. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps. These deep-sea fan facies are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Fields in UPL F1 are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops, normal faults, and growth

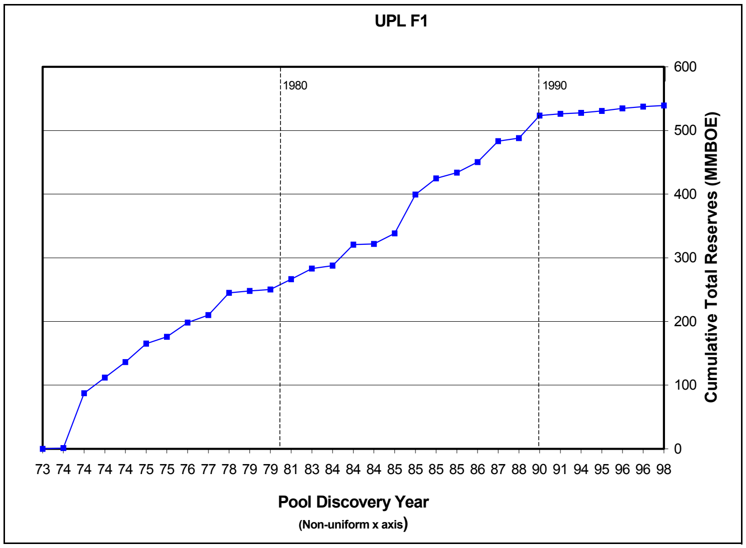


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UPL F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	28	0.130	1.256	0.353
Cumulative production	--	0.090	0.874	0.246
Remaining proved	--	0.039	0.382	0.107
Unproved	2	<0.001	0.011	0.002
Appreciation (P & U)	--	0.069	0.645	0.184
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.030	0.667	0.157
Mean	20	0.049	0.764	0.185
5th percentile	--	0.071	0.888	0.217
Total Endowment				
95th percentile	--	0.229	2.579	0.696
Mean	50	0.248	2.676	0.724
5th percentile	--	0.270	2.800	0.756

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

fault anticlines. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UPL F1 mixed oil and gas play contains total reserves of 0.199 Bbo and 1.912 Tcfg (0.539 BBOE), of which 0.090 Bbo and 0.874 Tcfg (0.246 BBOE) have been produced. The play contains 118 producible sands in 30 pools of which 28 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1974 in the High Island 571A field (figure 2). Maximum yearly total reserves of 136 MMBOE were also added in 1974 when three additional pools were discovered, including the largest discovered pool in the play in the High Island A573 field, with 86 MMBOE in total reserves (figures 2 and 3). Ninety percent of the play's total reserves and 99 percent of its cumulative production have come from pools discovered before 1990. The most recent prior to this study's cutoff date of January 1, 1999, was in 1998.

The 30 discovered pools contain 240 reservoirs, of which 132 are nonassociated gas, 86 are undersaturated oil, and 22 are saturated oil. Cumulative production has consisted of 63 percent gas and 37 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UPL F1 play is 1.00. The play contains a mean total endowment of 0.248 Bbo and 2.676 Tcfg (0.724 BBOE) (table 2). Thirty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCCR) have a range of 0.030 to 0.071 Bbo and 0.667 to 0.888 Tcfg at the 95th and

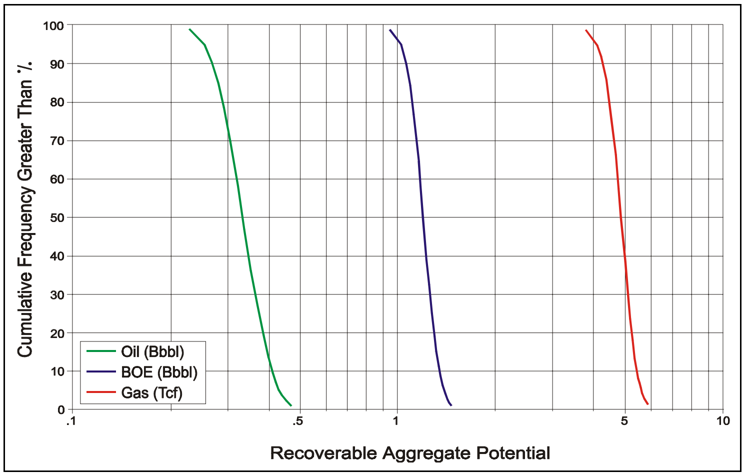


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

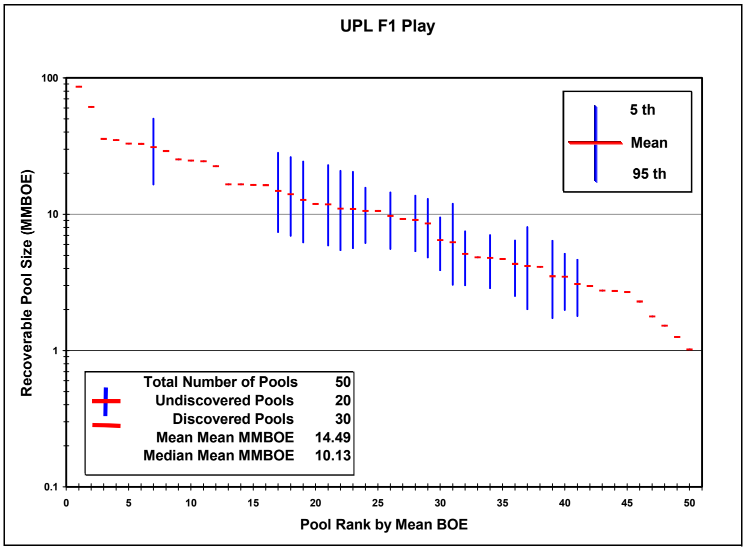


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

5th percentiles, respectively (figure 4). The mean UCRR are estimated at 0.049 Bbo and 0.764 Tcfg (0.185 BBOE). These undiscovered resources might occur in as many as 20 pools. The largest undiscovered pool, with a mean size of 31 MMBOE, is forecast as the 7th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 17, 18, 19, and 21 on the pool rank plot. For all the undiscovered pools in the UPL F1 play, the mean mean size is 9 MMBOE, which is smaller than the 18 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 14 MMBOE.

The UPL F1 is a relatively well-explored fan play with BOE mean UCRR contributing 25 percent to the play's BOE mean total endowment. Future discoveries will continue to be made against salt structures in more subtle structural and stratigraphic traps.

Upper Pleistocene Fan 2 (UPL F2) Play

Hyalinea "B" through Sangamon Fauna

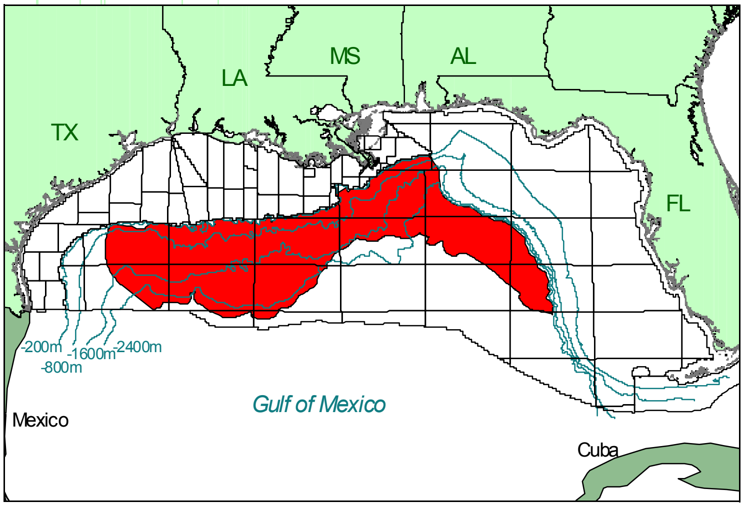


Figure 1. Play location.

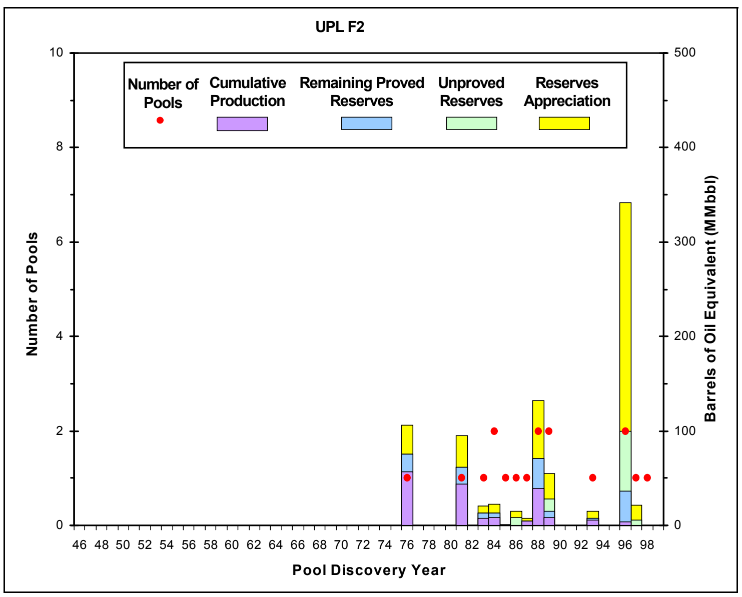


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UPL F2 Play 17 Pools 74 Sands	Minimum	Mean	Maximum
Water depth (feet)	663	1520	3153
Subsea depth (feet)	3312	7668	12856
Number of sands per pool	1	4	22
Porosity	27%	32%	35%
Water saturation	16%	25%	44%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pleistocene Fan 2 (UPL F2) play occurs within the *Hyalinea* "B," *Trimosina* "B," *Trimosina* "A" 2nd occurrence and *Trimosina* "A" 1st occurrence biozones, and Sangamon Fauna. The play is also defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The play encompasses an area from the central East Breaks and Alaminos Canyon Areas to the southern Viosca Knoll and western Desoto Canyon Areas east of the Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the UPL F2 play is bounded by the Upper Pleistocene Fan 1 (UPL F1) play. The UPL F2 play does not extend farther to the west because of a lack of sediment influx at the edge of the UPL depocenter. To the east, the play onlaps the Cretaceous carbonate slope. Downdip in the western and central Gulf of Mexico Regions, the UPL F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt Plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps deposited on the UPL

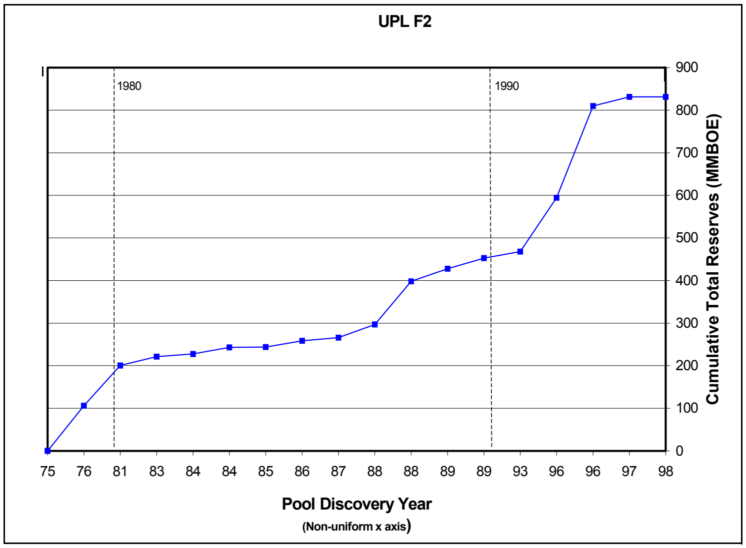


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UPL F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	13	0.098	1.134	0.300
Cumulative production	–	0.051	0.724	0.180
Remaining proved	–	0.047	0.410	0.120
Unproved	4	0.020	0.388	0.089
Appreciation (P & U)	–	0.155	1.612	0.442
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.659	6.135	1.848
Mean	98	0.971	7.790	2.357
5th percentile	–	1.475	11.149	3.235
Total Endowment				
95th percentile	–	0.932	9.270	2.679
Mean	115	1.244	10.925	3.188
5th percentile	–	1.748	14.284	4.066

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

upper and lower slopes, in topographically low areas between salt structure highs, and on the abyssal plain. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Most of the fields in UPL F2 play are structurally associated with salt bodies with hydrocarbons trapped on salt flanks or in sediments draped over salt tops. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UPL F2 mixed oil and gas play contains total reserves of 0.273 Bbo and 3.135 Tcfg (0.831 BBOE), of which 0.051 Bbo and 0.724 Tcfg (0.180 BBOE) have been produced. The play contains 74 producible sands in 17 pools, of which 13 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1976 in the Garden Banks 236 field (figure 2). Maximum yearly total reserves of 342 MMBOE were added in 1996 when two pools were discovered, including the largest pool in the play in the Garden Banks 516 field (Sorano) with 215 MMBOE in total reserves (figures 2 and 3). Fifty-four percent of the play's total reserves and 95 percent of its cumulative production have come from pools discovered before 1990. The most recent discovery prior to this study's cutoff date of January 1, 1999, was in 1998.

The 17 discovered pools contain 153 reservoirs, of which 50 are nonassociated gas, 89 are undersaturated oil, and 14 are saturated oil. Cumulative production has consisted of 72 percent gas and 28 percent oil.

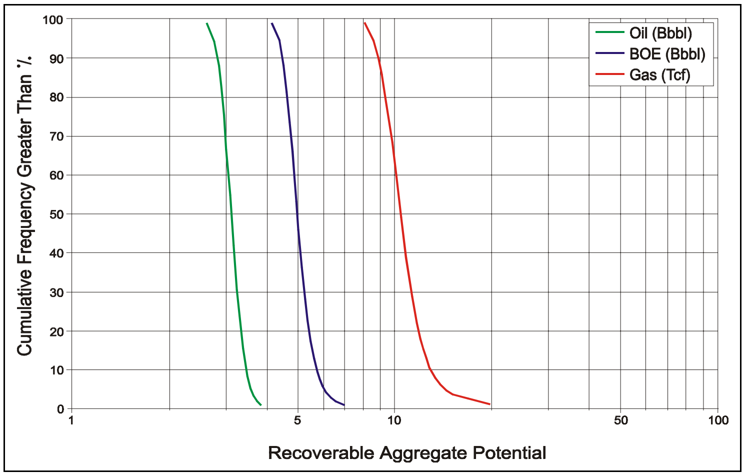


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

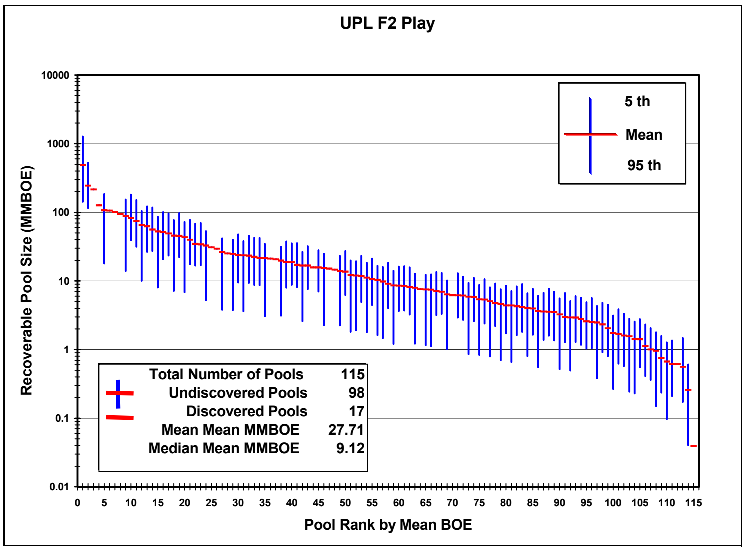


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Assessment Results

The marginal probability of hydrocarbons for the UPL F2 play is 1.00. This play has a mean total endowment of 1.244 Bbo and 10.925 Tcfg (3.188 BBOE) (table 2). Six percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.659 to 1.475 Bbo and 6.135 to 11.149 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.971 Bbo and 7.790 Tcfg (2.357 BBOE). These undiscovered resources might occur in as many as 98 pools. The largest undiscovered pool, with a mean size of 493 MMBOE, is also forecast to be the largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 2, 5, 9, and 10 on the pool rank plot. For all the undiscovered pools in the UPL F2 play, the mean mean size is 24 MMBOE, which is smaller than the 49 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 28 MMBOE.

The UPL F2 is an immature play with BOE mean UCRR projected to add 74 percent to the play's BOE mean total endowment. Exploration potential continues to exist around salt in deep structural and stratigraphic traps, as well as in structures located underneath salt overhangs and allochthonous salt sheets.

Middle Pleistocene Caprock (MPL B1) Play

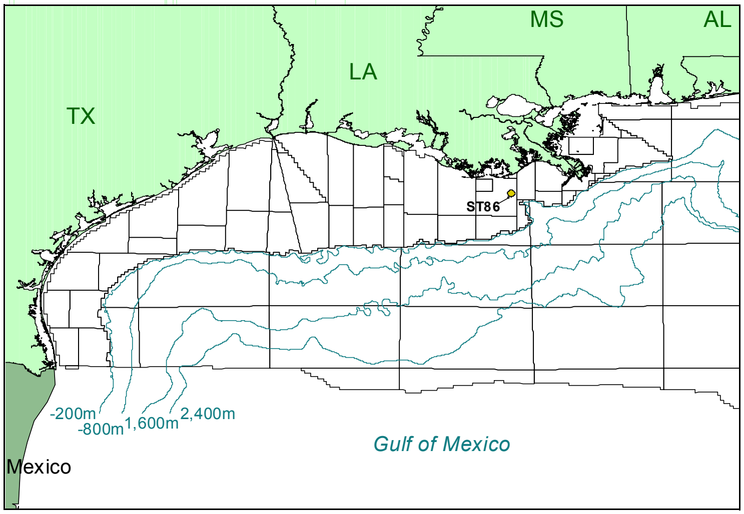


Figure 1. Play location.

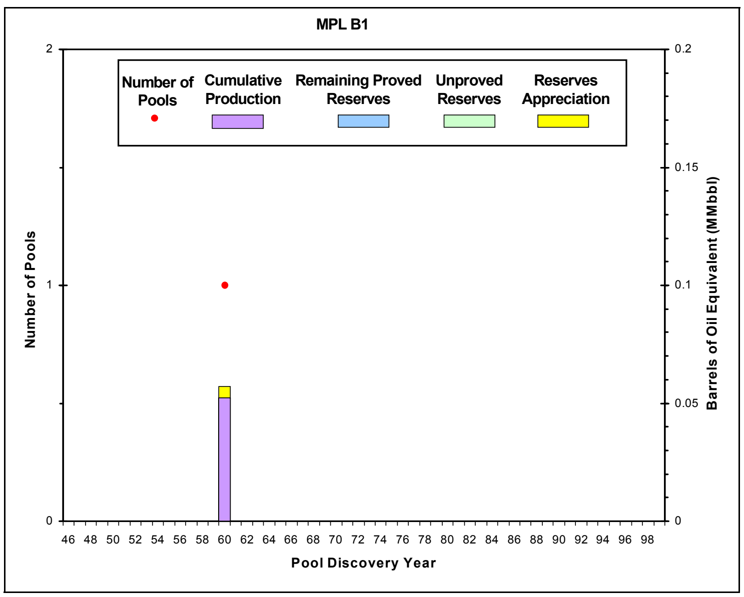


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MPL B1 Play 1 Pool 1 Sand	Minimum	Mean	Maximum
Water depth (feet)	94	94	94
Subsea depth (feet)	4070	4070	4070
Number of sands per pool	1	1	1
Porosity	29%	29%	29%
Water saturation	24%	24%	24%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Pleistocene Caprock (MPL B1) play is confined to caprock overlying the salt diapir that provides structure for the South Timbalier 86 field (figure 1). The pool's one reservoir (table 1; refer to the Methodology section for a discussion of reservoirs and pools) consists of porous crystalline limestone. The caprock itself is a product of diagenesis, and its age is unknown. Therefore, for cataloging purposes, the caprock is correlated to the surrounding MPL sediments.

Discoveries

The MPL B1 oil play contains proved reserves of <0.001 Bbo and <0.001 Tcfg (<0.001 BBOE), all of which have been produced. The play's reserves were discovered in 1960 in Murphy Exploration and Production's Zone 3 reservoir (figure 2). Estimates for reserves and production can be found in table 2.

Assessment Results

Because the MPL B1 play is thought unlikely to contain significant new resources, undiscovered conventionally recoverable resources were not assessed for this play .

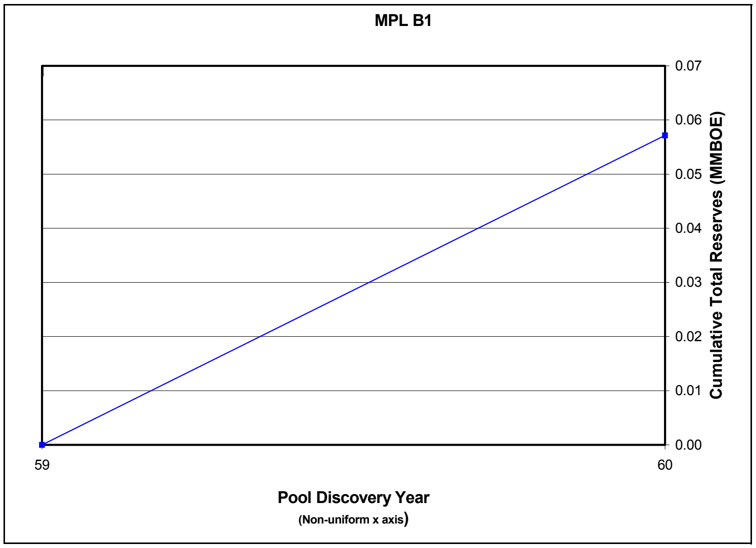


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MPL B1 Play 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	--	0.000	0.000	0.000
Mean	0	0.000	0.000	0.000
5th percentile	--	0.000	0.000	0.000
Total Endowment				
95th percentile	--	<0.001	<0.001	<0.001
Mean	1	<0.001	<0.001	<0.001
5th percentile	--	<0.001	<0.001	<0.001

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Middle Pleistocene Aggradational (MPL A1) Play

Angulogerina "B" biozone

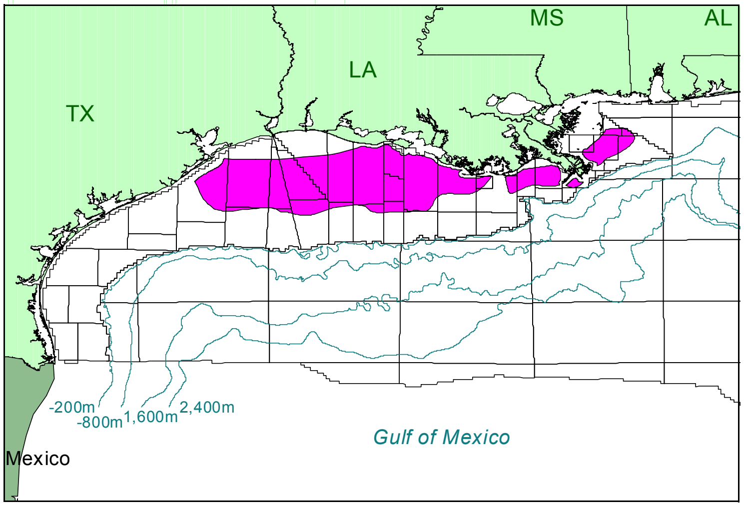


Figure 1. Play location.

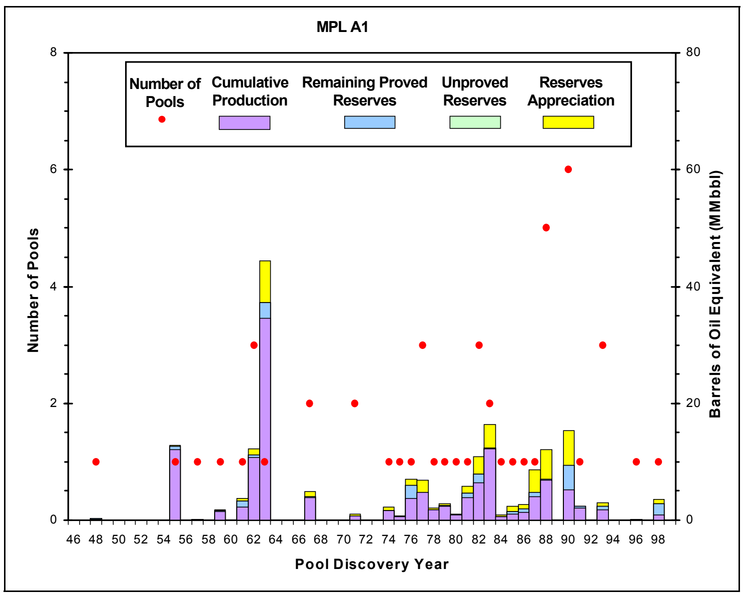


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MPL A1 Play 49 Pools 94 Sands	Minimum	Mean	Maximum
Water depth (feet)	17	85	177
Subsea depth (feet)	2125	3760	5874
Number of sands per pool	1	2	5
Porosity	27%	32%	37%
Water saturation	16%	25%	51%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Pleistocene Aggradational (MPL A1) play occurs within the *Angulogerina* "B" biozone. This play extends from the northeastern Galveston Area offshore Texas to the Chandeleur Area 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 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 P1) play.

Play Characteristics

The MPL A1 is characterized by stacked, blocky, sand-dominated successions representing sediment buildup in fluvial channel/levee complexes, crevasse splays, and point bars; deltaic distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches, and barrier islands; and in shallow marine shelf delta fringes and slumps. Additionally, retrogradational reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the MPL A1 play.

Just under half of the fields in the play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other less common structures in the play include growth fault anticlines and normal faults. Some fields also contain hydrocarbon accumulations trapped by permeability barriers,

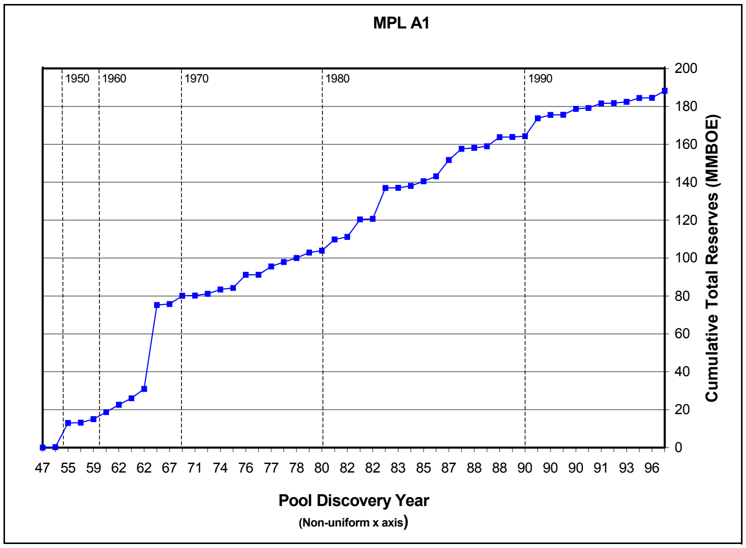


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MPL A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	49	0.017	0.730	0.147
Cumulative production	–	0.015	0.636	0.128
Remaining proved	–	0.002	0.094	0.018
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	<0.001	0.229	0.041
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	<0.001	0.075	0.015
Mean	20	0.002	0.100	0.020
5th percentile	–	0.004	0.124	0.025
Total Endowment				
95th percentile	–	0.017	1.035	0.203
Mean	69	0.020	1.060	0.208
5th percentile	–	0.022	1.083	0.213

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MPL A1 play is predominantly a gas play, with total reserves of 0.017 Bbo and 0.959 Tcfg (0.188 BBOE), of which 0.015 Bbo and 0.636 Tcfg (0.128 BBOE) have been produced. The play contains 94 producible sands in 49 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1948 in the Ship Shoal 32 field (figure 2). Maximum yearly total reserves were added in 1963 with the discovery of the largest pool in the play, East Cameron 245 field containing 44 MMBOE in total reserves. Pool discoveries were sparse until the mid-1970's when pools began to be discovered at an average rate of about two per year (figures 2 and 3). Pool discoveries prior to 1990 account for over 92 percent of the play's cumulative production and 87 percent of the play's total reserves. The most recent discovery prior to this study's cutoff date of January 1, 1999, was in 1998.

The 49 discovered pools contain 124 reservoirs, of which 103 are nonassociated gas and 21 are undersaturated oil. Cumulative production has consisted of 88 percent gas and 12 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MPL A1 play is 1.00. The play contains a mean total endowment of 0.020 Bbo and 1.060 Tcfg (0.208 BBOE) (table 2). Sixty-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of <0.001 to 0.004 Bbo and

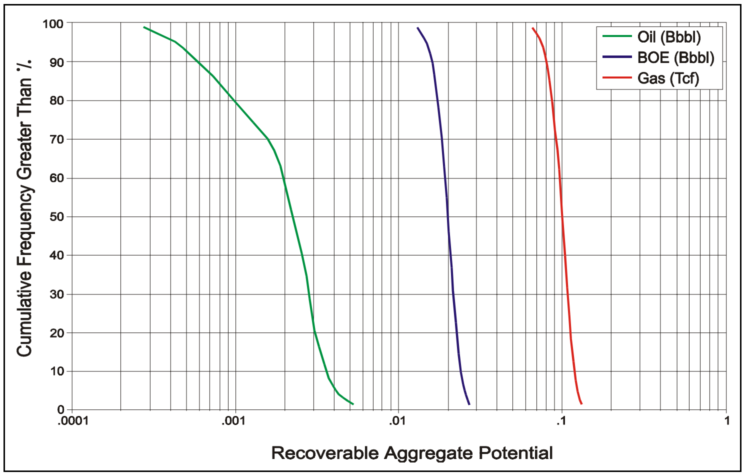


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

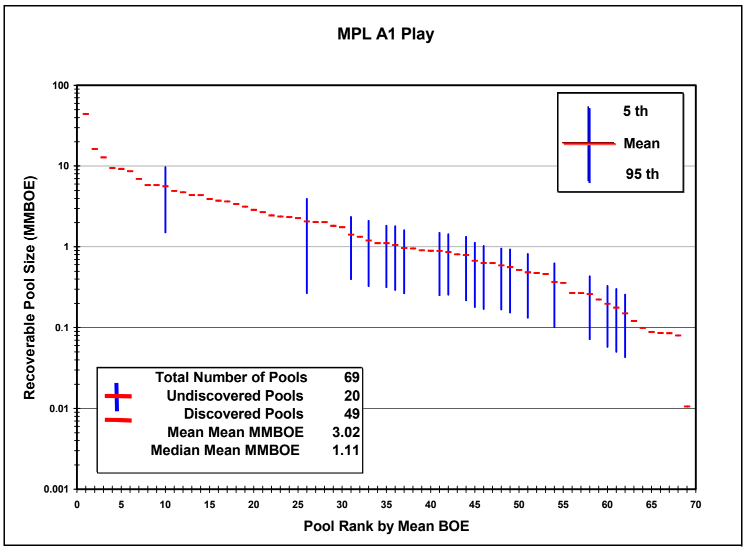


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

0.075 to 0.124 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.002 Bbo and 0.100 Tcfg (0.020 BBOE). These undiscovered resources might occur in as many as 20 pools. The largest undiscovered pool, with a mean size of 6 MMBOE, is forecast as the 10th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 26, 31, 33, and 35 on the pool rank plot. For all the undiscovered pools in the MPL A1 play, the mean mean size is 1 MMBOE, which is smaller than the 4 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 3 MMBOE.

The MPL A1 is a supermature play with BOE mean UCRR contributing only 10 percent to the play's BOE mean total endowment.

Middle Pleistocene Progradational (MPL P1) Play

Angulogerina "B" biozone

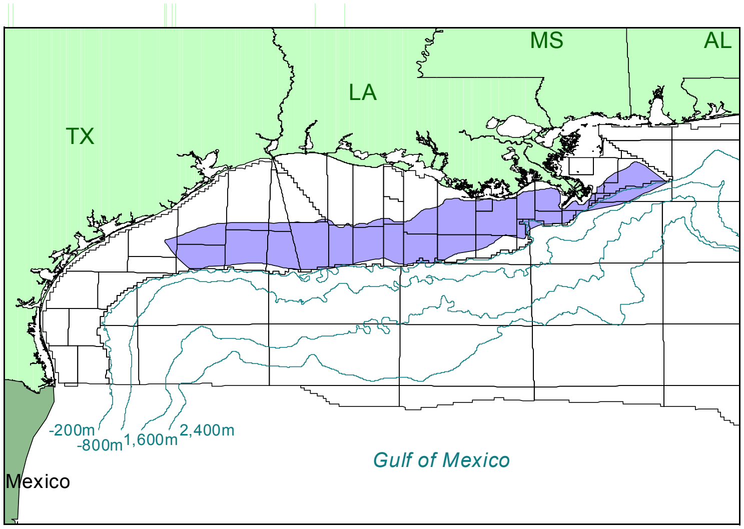


Figure 1. Play location.

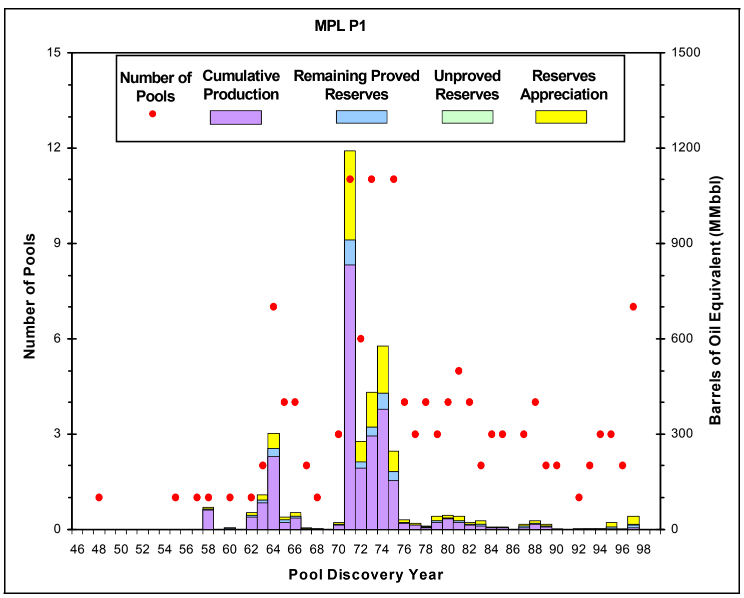


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MPL P1 Play 150 Pools 750 Sands	Minimum	Mean	Maximum
Water depth (feet)	39	197	740
Subsea depth (feet)	2102	5487	11238
Number of sands per pool	1	5	26
Porosity	22%	31%	38%
Water saturation	16%	27%	59%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Pleistocene Progradational (MPL P1) play is the third largest play in the Gulf of Mexico Region on the basis of BOE cumulative production and BOE total reserves. The MPL P1 play occurs at the *Angulogerina* "B" biozone and extends from the Brazos Area offshore Texas to the Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play grades into the nearshore sediments of the Middle Pleistocene Aggradational (MPL A1) play and 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 1 (MPL F1) play.

Play Characteristics

Sediments in the MPL P1 play represent major regressive episodes of outbuilding on both the shelf and the slope. In addition, retrogradational reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the MPL P1 play.

Almost half of the fields in this play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are structurally associated with growth fault anticlines and normal faults, while some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinch-outs or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-

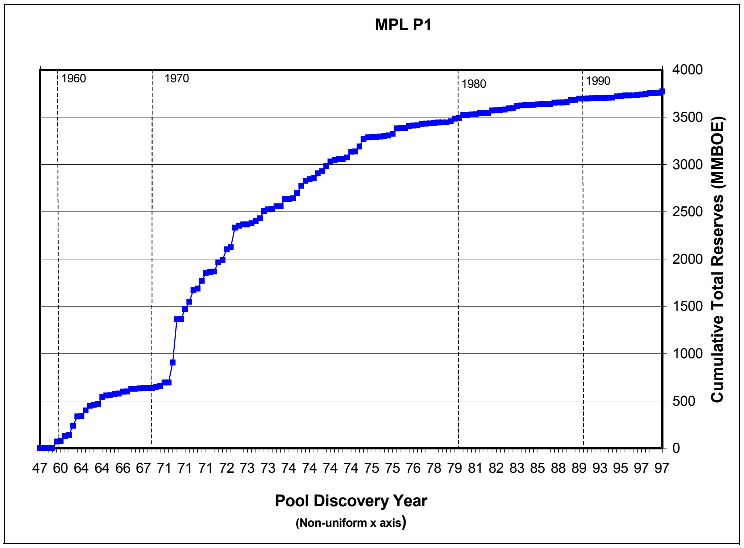


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MPL P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	148	0.750	11.865	2.862
Cumulative production	–	0.670	10.504	2.539
Remaining proved	–	0.080	1.362	0.322
Unproved	2	<0.001	0.022	0.004
Appreciation (P & U)	–	0.235	3.778	0.907
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.049	1.564	0.341
Mean	48	0.078	1.786	0.396
5th percentile	–	0.116	2.012	0.456
Total Endowment				
95th percentile	–	1.034	17.229	4.114
Mean	198	1.064	17.451	4.169
5th percentile	–	1.102	17.677	4.229

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

outs, overlying shales).

Discoveries

The MPL P1 play is a mixed gas and oil play, with total reserves of 0.986 Bbo and 15.665 Tcfg (3.773 BBOE), of which 0.670 Bbo and 10.504 Tcfg (2.539 BBOE) have been produced. The play contains 750 producible sands in 150 pools, and 148 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1948 in the South Timbalier 52 field (figure 2). Almost half of the pools were discovered between 1970 and 1976. Maximum yearly total reserves of 1,193 MMBOE were added in 1971 with the discovery of 11 pools, including the largest pool in the play in the Eugene Island 330 field with 457 MMBOE in total reserves (figures 2 and 3). Pool discoveries before 1990 account for over 99 percent of the play's cumulative production and 98 percent of the play's total reserves, reflecting the maturity of the play. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1997.

The 150 discovered pools contain 1,638 reservoirs, of which 1,093 are nonassociated gas, 402 are undersaturated oil, and 143 are saturated oil. Cumulative production has consisted of 74 percent gas and 26 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MPL P1 play is 1.00. This play is the eleventh largest in the Gulf of Mexico, on the basis of a mean total endowment of 1.064 Bbo and 17.451 Tcfg (4.169 BBOE) (table 2). Sixty-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.049 to 0.116 Bbo and 1.564 to 2.012 Tcfg at the 95th and

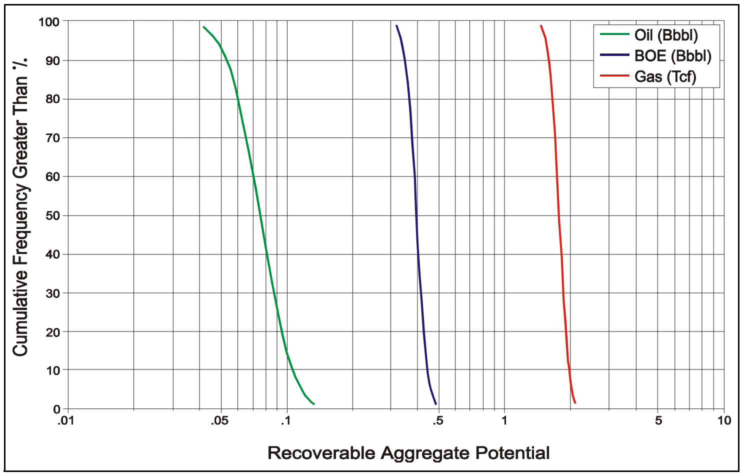


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

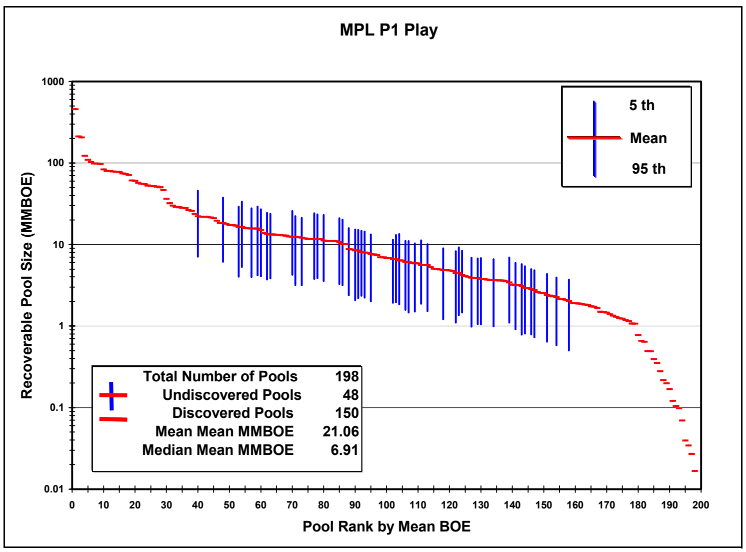


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.078 Bbo and 1.786 Tcfg (0.396 BBOE). These undiscovered resources might occur in as many as 48 pools. The largest undiscovered pool, with a mean size of 22 MMBOE, is forecast as the 40th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 48, 53, 54, and 57 on the pool rank plot. For all the undiscovered pools in the MPL P1 play, the mean mean size is 8 MMBOE, which is substantially less than the 25 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 21 MMBOE.

The MPL P1 is a supermature play with BOE mean UCRR expected to contribute only 9 percent to the play's BOE mean total endowment. Small pools will continue to be drilled as economics warrant.

Middle Pleistocene Fan 1 (MPL F1) Play

***Angulogerina* "B" biozone**

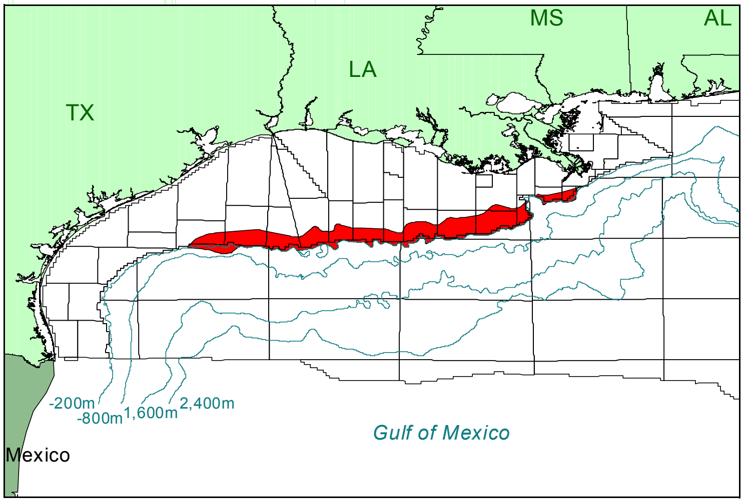


Figure 1. Play location.

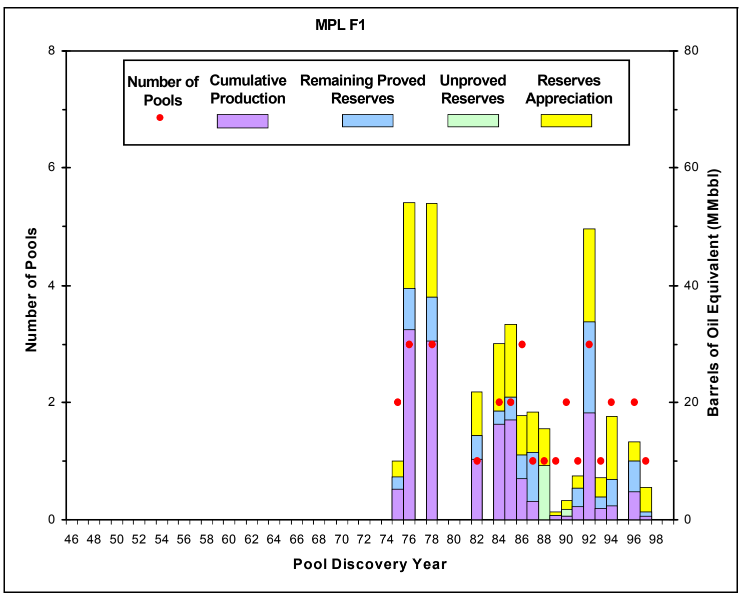


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MPL F1 Play 31 Pools 83 Sands	Minimum	Mean	Maximum
Water depth (feet)	165	384	958
Subsea depth (feet)	4918	8399	13001
Number of sands per pool	1	3	9
Porosity	25%	30%	35%
Water saturation	16%	30%	48%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Pleistocene Fan (MPL F1) play occurs at the *Angulogerina* "B" biozone. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and listric faulting located on the modern Gulf of Mexico Region shelf. The MPL F1 play extends in a narrow band from the Galveston/East Breaks Areas offshore Texas to the South Pass/Mississippi Canyon Areas near 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 *Angulogerina* "B" biozone and sediments of the Middle Pleistocene Progradational (MPL P1) play. To the west, the play is bounded by a lack of sediment influx at the edge of the MPL depocenter. Downdip, the MPL F1 play is limited by the structural boundary of the Middle Pleistocene Fan 2 (MPL F2) play.

Play Characteristics

The MPL F1 play is characterized by deepwater turbidites deposited basinward of the MPL shelf margin on the MPL upper and lower slope, in topographically low areas between salt structure highs, and on the abyssal plain. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps. These deep-sea fan facies are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Over one-third of the fields in the MPL F1 play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Less common trapping

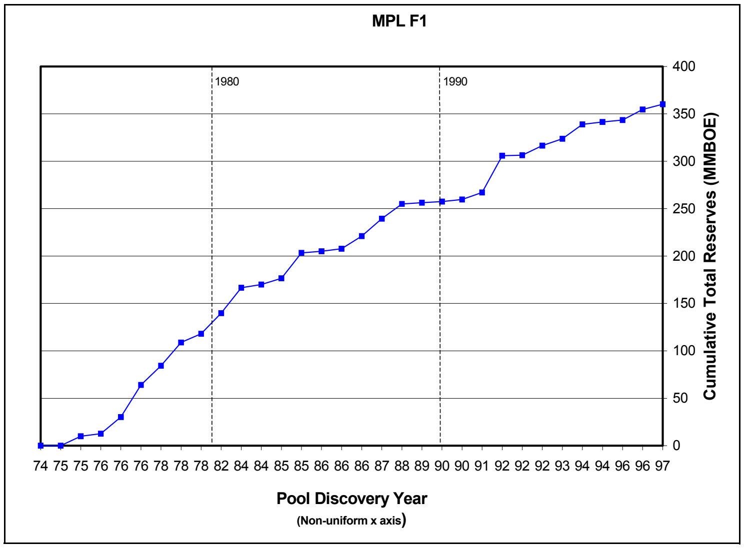


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MPL F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	29	0.071	0.856	0.223
Cumulative production	--	0.054	0.561	0.153
Remaining proved	--	0.017	0.295	0.070
Unproved	2	0.008	0.016	0.010
Appreciation (P & U)	--	0.042	0.476	0.127
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.026	0.563	0.134
Mean	22	0.046	0.849	0.197
5th percentile	--	0.076	1.346	0.296
Total Endowment				
95th percentile	--	0.146	1.911	0.494
Mean	53	0.166	2.197	0.557
5th percentile	--	0.196	2.694	0.656

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

structures in the play are growth fault anticlines and normal faults. In addition, a few fields contain hydrocarbon accumulations trapped by permeability barriers and updip pinchouts or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MPL F1 mixed oil and gas play contains total reserves of 0.120 Bbo and 1.348 Tcfg (0.360 BBOE), of which 0.054 Bbo and 0.561 Tcfg (0.153 BBOE) have been produced. The play contains 83 producible sands in 31 pools of which 29 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1975 in the Eugene Island 342 field (figure 2). Maximum yearly total reserves of 54 MMBOE were added in 1976 with the discovery of three pools. The largest discovered pool in the play was found in 1992 in the East Cameron 338 field with 39 MMBOE in total reserves (figures 2 and 3). Eighty percent of the play's cumulative production and seventy-one percent of the play's total reserves are from pools discovered before 1990. The most recent discovery prior to this study's cutoff date of January 1, 1999, was in 1997.

The 31 discovered pools contain 127 reservoirs, of which 65 are nonassociated gas, 40 are undersaturated oil, and 22 are saturated oil. Cumulative production has consisted of 65 percent gas and 35 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MPL F1 play is 1.00. The play contains a mean total endowment of 0.166 Bbo and 2.197 Tcfg (0.557 BBOE) (table 2). Twenty-seven percent of this BOE mean total

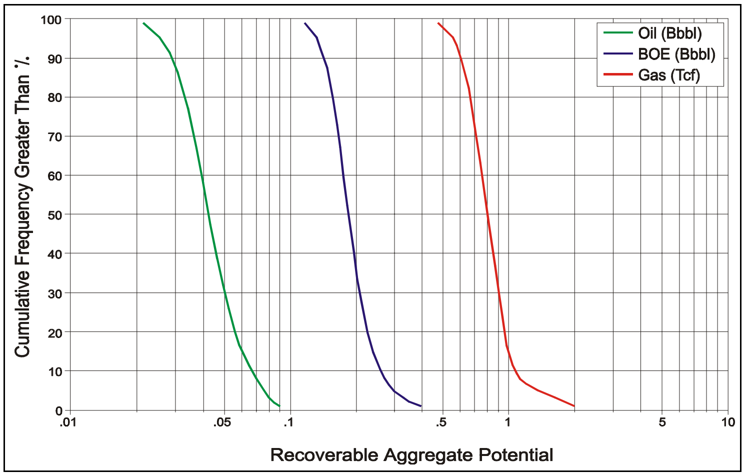


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

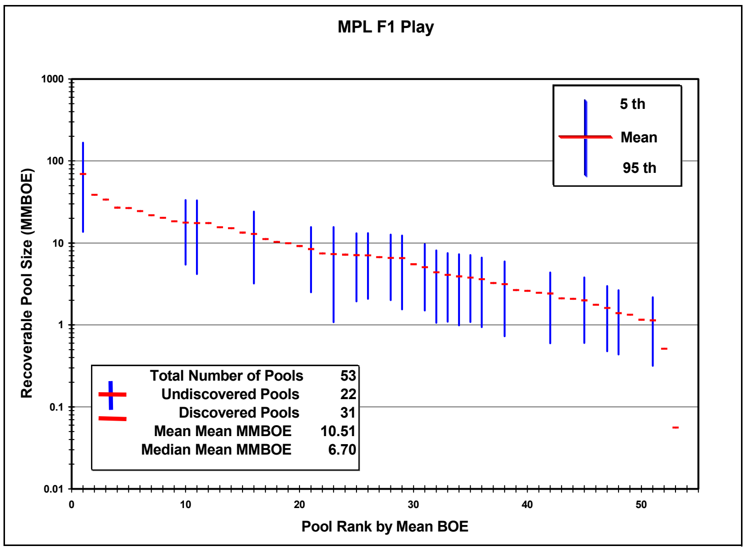


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.026 to 0.076 Bbo and 0.563 to 1.346 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The mean UCRR are estimated at 0.046 Bbo and 0.849 Tcfg (0.197 BBOE). These undiscovered resources might occur in as many as 22 pools. The largest undiscovered pool, with a mean size of 69 MMBOE, is also forecast to be the largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 10, 11, 16, and 21 on the pool rank plot. For all the undiscovered pools in the MPL F1 play, the mean mean size is 9 MMBOE, which is smaller than the 12 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 11 MMBOE.

The MPL F1 is a relatively well-explored fan play. BOE mean UCRR contribute 35 percent to the play's BOE mean total endowment. Future discoveries will continue to be made around salt structures in structural and stratigraphic traps. Of note is that the largest pool in the play is forecast yet to be discovered.

Middle Pleistocene Fan 2 (MPL F2) Play

***Angulogerina* "B" biozone**

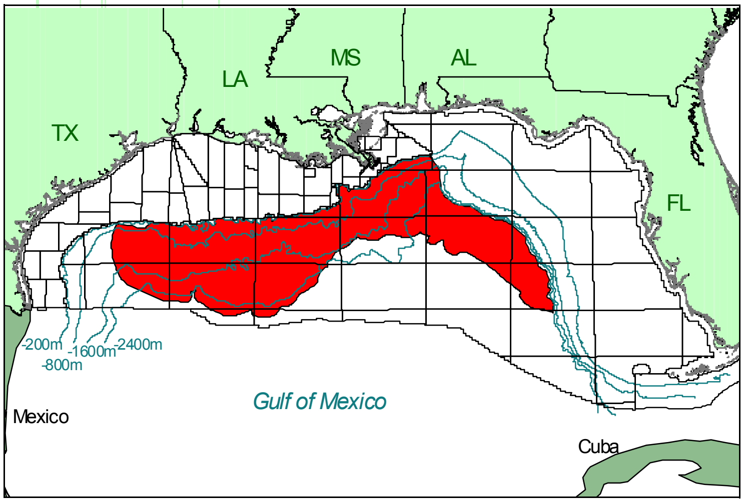


Figure 1. Play location.

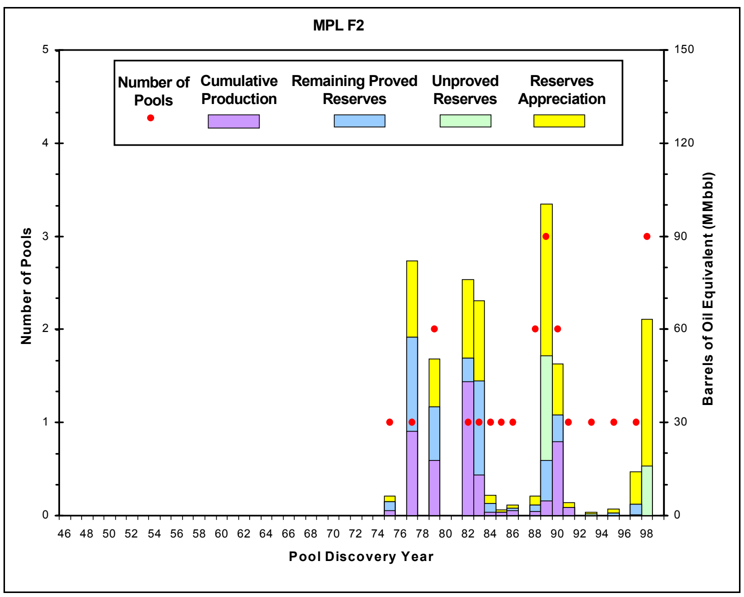


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MPL F2 Play 23 Pools 61 Sands	Minimum	Mean	Maximum
Water depth (feet)	663	1332	2953
Subsea depth (feet)	4414	9629	15916
Number of sands per pool	1	3	13
Porosity	27%	31%	36%
Water saturation	16%	26%	35%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Pleistocene Fan 2 (MPL F2) play occurs within the *Angulogerina* "B" biozone and is defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The MPL F2 play extends from the central East Breaks and Alaminos Canyon Areas to the southern Viosca Knoll and western Desoto Canyon Areas east of the Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the MPL F2 play is bounded by the Middle Pleistocene Fan 1 (MPL F1) play. The MPL F2 play does not extend farther to the west because of a lack of sediment influx at the edge of the MPL depocenter. To the east, the play onlaps the Cretaceous carbonate slope. Downdip in the western and central Gulf of Mexico Regions, the play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps that were deposited on the MPL upper and lower slope in topographically low areas between salt structure highs and on the abyssal plain. These

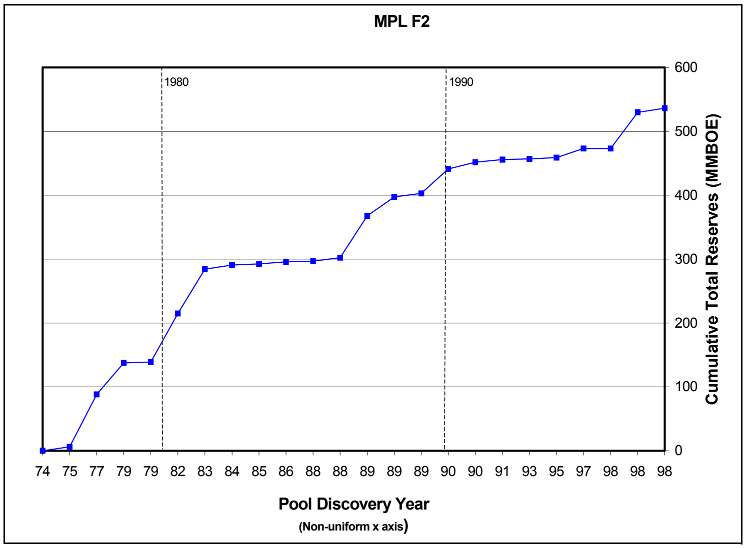


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MPL F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	18	0.087	0.969	0.259
Cumulative production	--	0.050	0.496	0.139
Remaining proved	--	0.037	0.473	0.121
Unproved	5	0.022	0.160	0.050
Appreciation (P & U)	--	0.071	0.877	0.227
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.179	1.506	0.480
Mean	67	0.236	2.259	0.638
5th percentile	--	0.314	3.155	0.824
Total Endowment				
95th percentile	--	0.359	3.512	1.016
Mean	90	0.415	4.265	1.174
5th percentile	--	0.493	5.161	1.360

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Over half of the fields in the MPL F2 play are structurally associated with salt bodies, mostly of intermediate and deep depths, with hydrocarbons trapped on salt flanks or in sediments draped over salt. Some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MPL F2 mixed oil and gas play contains total reserves of 0.179 Bbo and 2.006 Tcfg (0.536 BBOE), of which 0.050 Bbo and 0.496 Tcfg (0.139 BBOE) have been produced. The play contains 61 producible sands in 23 pools, of which 18 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1975 in the Mississippi Canyon 148 field (figure 2). Maximum yearly total reserves of 100 MMBOE were added in 1989 with the discovery of three pools. The largest discovered pool in the play was found in 1977 in the Mississippi Canyon 354 field (Zinc) with 82 MMBOE in total reserves (figures 2 and 3). Eighty-one percent of the play's cumulative production and seventy-five percent of total reserves are from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 23 discovered pools contain 87 reservoirs, of which 36 are nonassociated gas, 50 are undersaturated oil, and 1 is saturated oil. Cumulative production has consisted

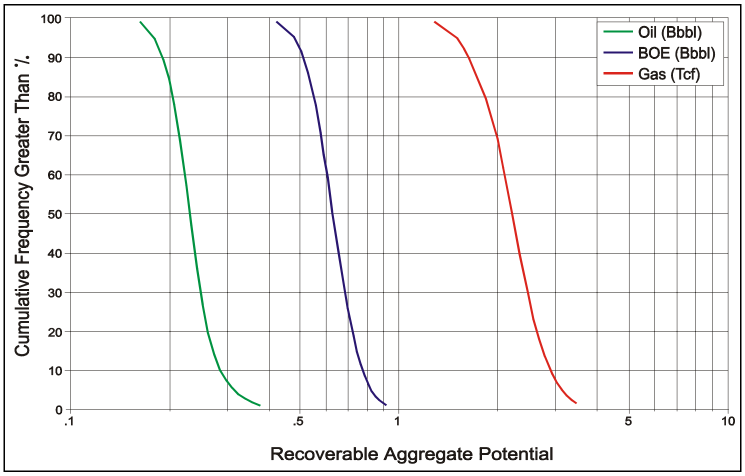


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

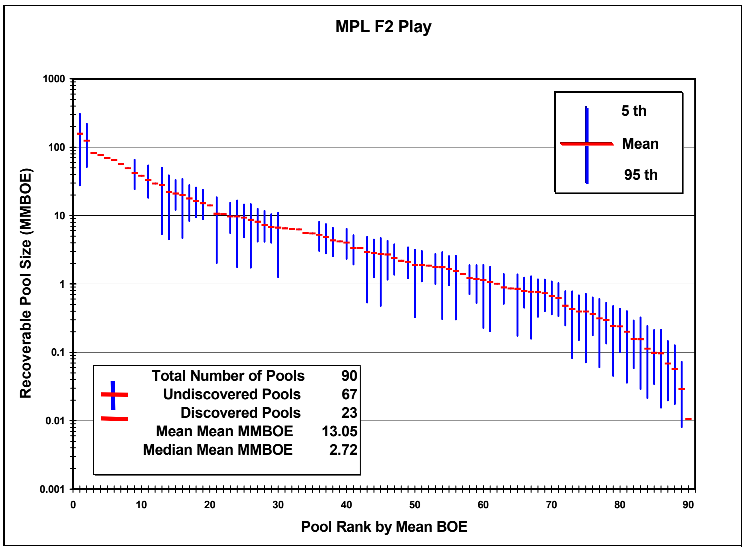


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

of 64 percent gas and 36 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MPL F2 play is 1.00. The play has a mean total endowment of 0.415 Bbo and 4.265 Tcfg (1.174 BBOE) (table 2). Twelve percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.179 to 0.314 Bbo and 1.506 to 3.155 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are forecast at 0.236 Bbo and 2.259 Tcfg (0.638 BBOE). These undiscovered resources might occur in as many as 67 pools. The largest undiscovered pool, with a mean size of 158 MMBOE, is also forecast as the largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 2, 9, 11, and 13 on the pool rank plot. For all the undiscovered pools in the MPL F2 play, the mean mean size is 9 MMBOE, which is smaller than the 23 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 13 MMBOE.

BOE mean UCRR are projected to increase the play's BOE mean total endowment by 54 percent. Discoveries in the MPL F2 play are expected to be numerous, though relatively small (figure 4). Exploration potential continues to exist around salt in deep structural and stratigraphic traps, as well as in structures located below salt overhangs and salt sheets.

Lower Pleistocene Aggradational (LPL A1) Play

Valvulineria "H" and *Lenticulina* 1 biozones

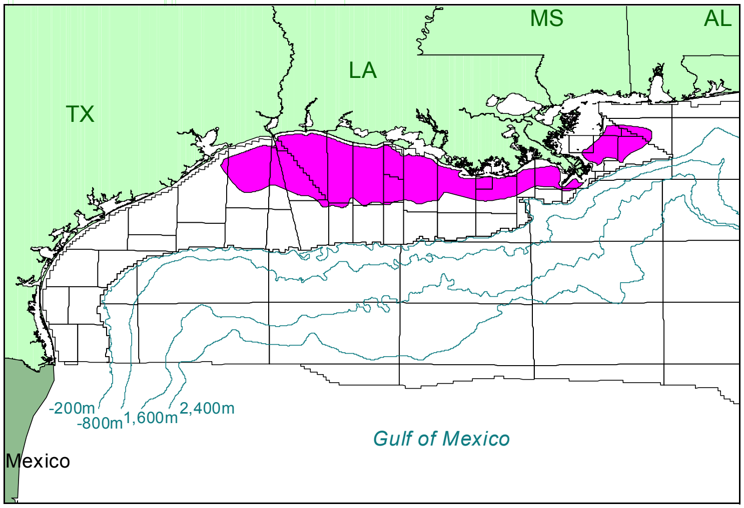


Figure 1. Play location.

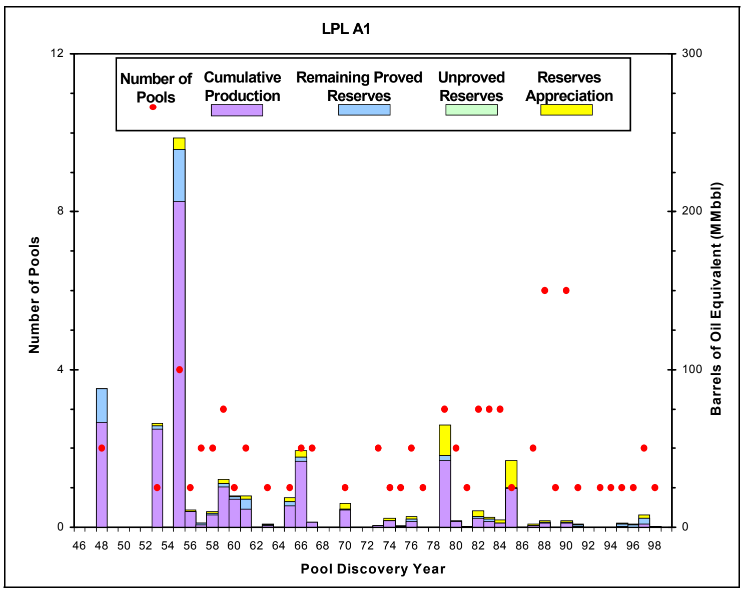


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LPL A1 Play 71 Pools 226 Sands	Minimum	Mean	Maximum
Water depth (feet)	12	73	204
Subsea depth (feet)	1625	4697	7709
Number of sands per pool	1	3	21
Porosity	22%	32%	37%
Water saturation	16%	27%	54%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pleistocene Aggradational (LPL A1) 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 aggradational sand deposition ends at the edges of the LPL depocenter. Downdip, the play grades into the sediments of the Lower Pleistocene Progradational (LPL P1) play.

Play Characteristics

The LPL A1 play is characterized by stacked, blocky, sand-dominated successions representing sediment buildup in fluvial channel/levee complexes, crevasse splays, and point bars; in deltaic distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches, and barrier islands; and in shallow marine shelf delta fringes and slumps. Additionally, retrogradational reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the LPL A1 play.

Many of the fields in the play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other common structures include simple anticlines and growth fault anticlines. Some fields also contain hydrocarbon accumulations trapped by permeability barriers and updip pinchouts or facies changes. Seals are provided by the juxtaposition of reservoir sands with

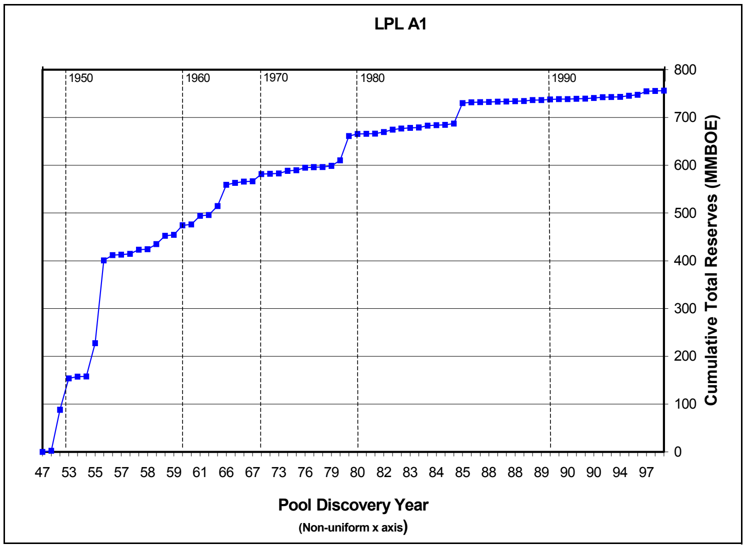


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LPL A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	70	0.365	1.738	0.675
Cumulative production	--	0.319	1.475	0.582
Remaining proved	--	0.046	0.263	0.093
Unproved	1	<0.001	0.001	<0.001
Appreciation (P & U)	--	0.013	0.384	0.081
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.004	0.181	0.041
Mean	16	0.017	0.248	0.061
5th percentile	--	0.036	0.313	0.084
Total Endowment				
95th percentile	--	0.382	2.304	0.797
Mean	87	0.395	2.371	0.817
5th percentile	--	0.414	2.436	0.840

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LPL A1 mixed oil and gas play contains total reserves of 0.378 Bbo and 2.123 Tcfg (0.756 BBOE), of which 0.319 Bbo and 1.475 Tcfg (0.582 BBOE) have been produced. The play contains 226 producible sands in 71 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Eugene Island 45 field in 1948 (figure 2). Maximum yearly total reserves of 247 MMBOE were added in 1955 when four pools were discovered, including the largest pool in the play, West Delta 30 field with 173 MMBOE in total reserves (figures 2 and 3). Ninety-nine percent of the play's cumulative production and ninety-seven percent of its total reserves come from pools discovered before 1990, indicative of the maturity of the play. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1998.

The 71 discovered pools contain 449 reservoirs, of which 205 are nonassociated gas, 224 are undersaturated oil, and 20 are saturated oil. Cumulative production has consisted of 55 percent oil and 45 percent gas.

Assessment Results

The marginal probability of hydrocarbons for the LPL A1 play is 1.00. The play has a mean total endowment of 0.395 Bbo and 2.371 Tcfg (0.817 BBOE) (table 2). Seventy-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.004 to 0.036 Bbo and 0.181 to 0.313 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at

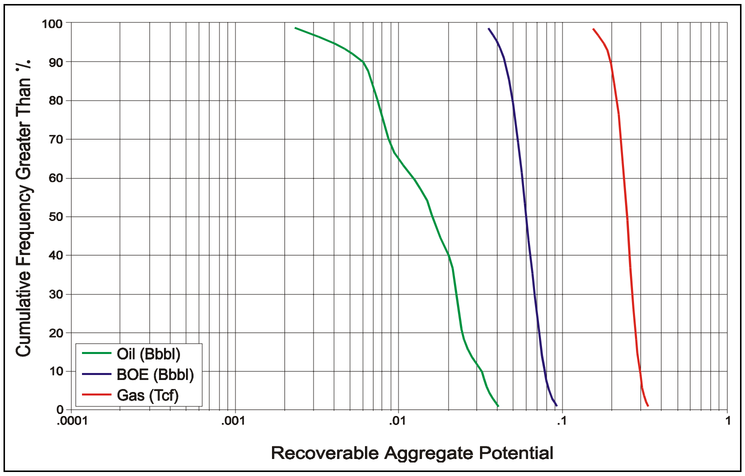


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

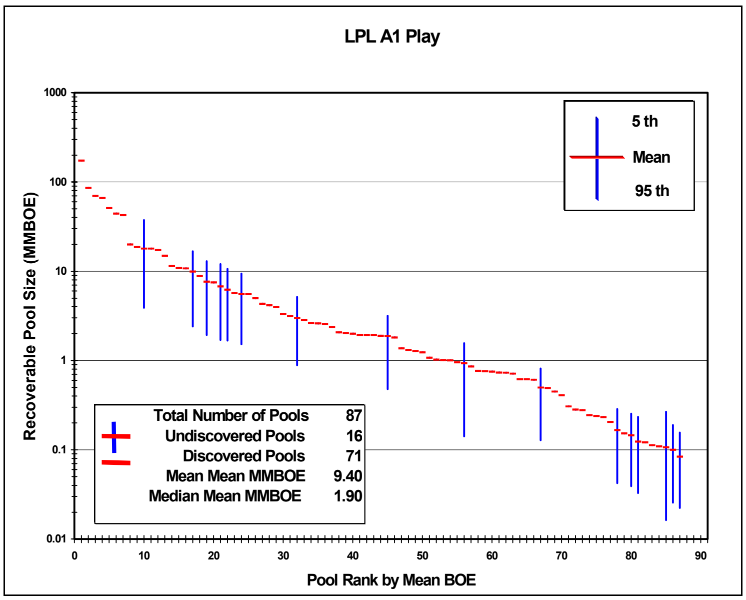


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

0.017 Bbo and 0.248 Tcfg (0.061 BBOE). These UCRR might occur in as many as 16 pools. The largest undiscovered pool, with a mean size of 18 MMBOE, is forecast as the 10th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 17, 19, 21, and 22 on the pool rank plot. For all the undiscovered pools in the LPL A1 play, the mean mean size is 4 MMBOE, which is smaller than the 11 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 9 MMBOE.

The LPL A1 is a super-mature play with BOE mean UCRR contributing only 7 percent to the LPL A1 play's BOE mean total endowment.

Lower Pleistocene Progradational (LPL P1) Play

Valvulineria "H" and *Lenticulina* 1 biozones

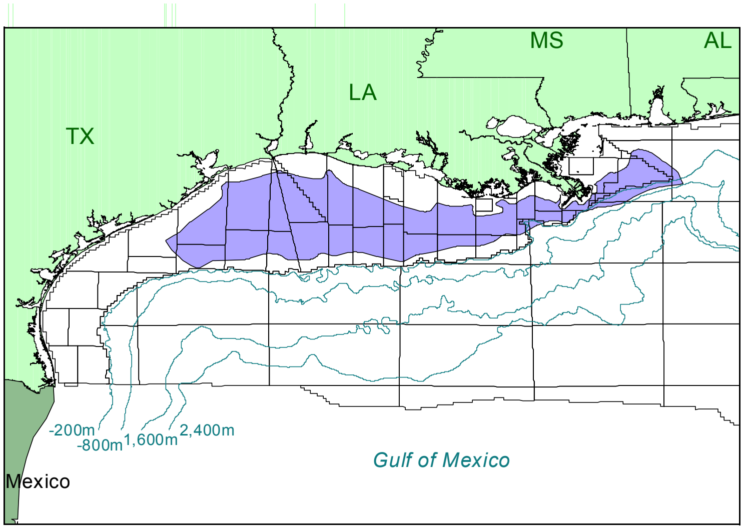


Figure 1. Play location.

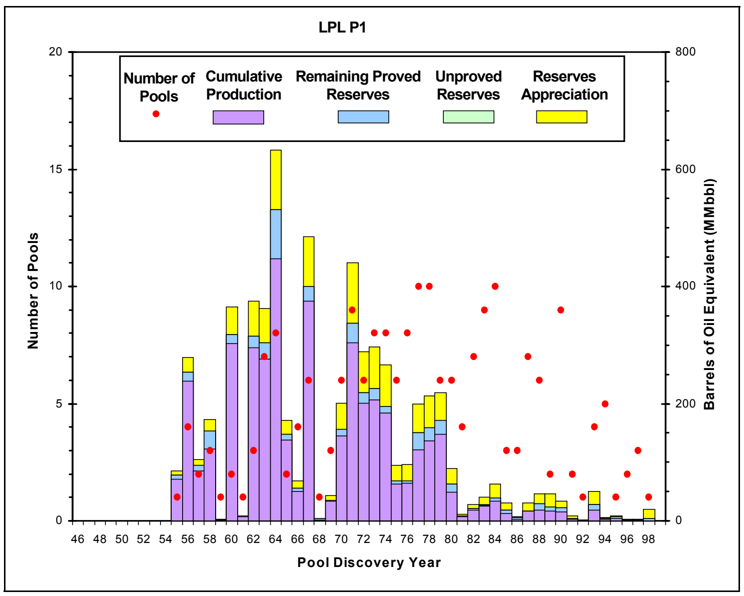


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LPL P1 Play 210 Pools 1359 Sands	Minimum	Mean	Maximum
Water depth (feet)	39	150	519
Subsea depth (feet)	2550	6928	12838
Number of sands per pool	1	6	39
Porosity	22%	30%	36%
Water saturation	16%	26%	50%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pleistocene Progradational (LPL P1) play is the largest play in the Gulf of Mexico Region on the basis of BOE total reserves and BOE cumulative production. The play occurs within the *Valvulineria* "H" and *Lenticulina* 1 biozones and extends from the eastern Brazos Area offshore Texas to the western 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 A1) play and also extends onshore in some areas near the Mississippi River Delta. The play does not extend farther to the west or northeast because of a lack of sediment influx at the edges of the LPL depocenter. Downdip, the play grades into the deposits of the Lower Pleistocene Fan 1 (LPL F1) play.

Play Characteristics

Sediments in the LPL P1 play represent major regressive episodes of outbuilding on both the shelf and slope. Additionally, retrogradational reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the LPL P1 play.

Almost half of the fields in this play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are associated with normal faults and growth fault anticlines. Some fields also contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally

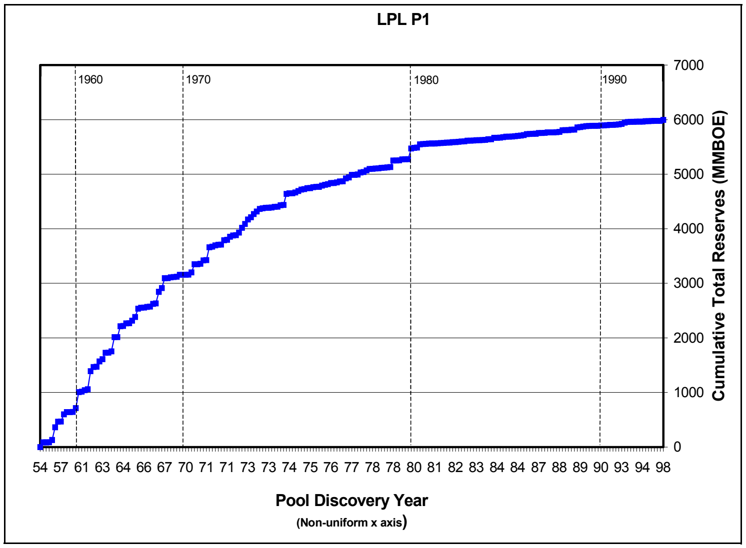


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LPL P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	209	1.551	18.139	4.778
Cumulative production	--	1.397	16.086	4.259
Remaining proved	--	0.154	2.053	0.520
Unproved	1	<0.001	0.008	0.002
Appreciation (P & U)	--	0.342	4.919	1.217
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.049	1.258	0.287
Mean	55	0.076	1.469	0.338
5th percentile	--	0.110	1.680	0.393
Total Endowment				
95th percentile	--	1.942	24.323	6.284
Mean	265	1.969	24.534	6.335
5th percentile	--	2.003	24.745	6.390

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

(e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LPL P1 play is a mixed gas and oil play, with total reserves of 1.893 Bbo and 23.065 Tcfg (5.997 BBOE), of which 1.397 Bbo and 16.086 Tcfg (4.259 BBOE) have been produced. The play contains 1,359 producible sands in 210 pools, and 209 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first LPL P1 reserves were discovered in 1955 in the Ship Shoal 154 field (figure 2). Maximum yearly total reserves of 632 MMBOE were added in 1964 with the discovery of eight pools. The largest pool in the play was discovered in 1962 in the South Timbalier 172 field, with 330 MMBOE in total reserves (figures 2 and 3). Discoveries before 1990 account for 99 percent of the cumulative production and 98 percent of the total reserves in the LPL P1 play, indicating the maturity of the play. Throughout the play's history, pool discoveries have averaged about five per year. The most recent discovery, prior to this study's cutoff date of January 1, 1999, occurred in 1998.

The 210 discovered pools contain 3,209 reservoirs, of which 1,840 are nonassociated gas, 1,140 are undersaturated oil, and 229 are saturated oil. Cumulative production has consisted of 67 percent gas and 33 percent oil.

Of the 87 assessed Gulf of Mexico Region plays, the LPL P1 play is the largest on the basis of BOE total reserves. It contains the largest amount of gas total reserves (10 % of gas total reserves in the Gulf of Mexico Region) and the second-largest amount of oil total reserves (8% of oil total reserves in the Region). The play has also produced the largest amount of gas (12% of gas cumulative production in the Region) and the second largest amount of oil (13% of oil production in

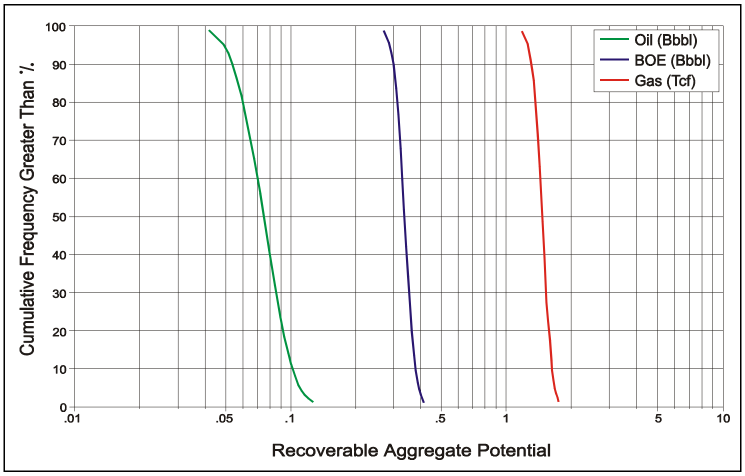


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

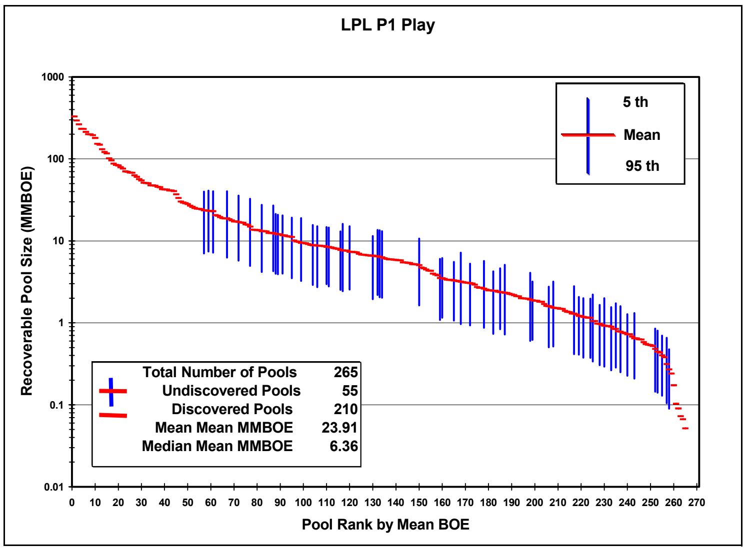


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

the Region). Additionally, the play is the largest of the 13 Gulf of Mexico progradational plays, containing 17 percent of progradational BOE total reserves.

Assessment Results

The marginal probability of hydrocarbons for the LPL P1 play is 1.00. This play is the fourth largest in the Gulf of Mexico, on the basis of a mean total endowment of 1.969 Bbo and 24.534 Tcfg (6.335 BBOE) (table 2). Sixty-seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.049 to 0.110 Bbo and 1.258 to 1.680 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.076 Bbo and 1.469 Tcfg (0.338 BBOE). These undiscovered resources might occur in as many as 55 pools, the largest of which has a mean size of 24 MMBOE. The five largest undiscovered pools in the play occupy positions 57, 59, 61, 67 and 72 on the pool rank plot (figure 5). For all the undiscovered pools in the LPL P1 play, the mean mean size is 6 MMBOE, which is smaller than the 29 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 24 MMBOE.

The LPL P1 is a supermature play, with BOE mean UCRR contributing only 5 percent to the LPL P1 play's BOE mean total endowment. Limited exploration potential exists downdip in deep sections around salt structures where the LPL P1 play may not have been adequately tested.

Lower Pleistocene Fan 1 (LPL F1) Play

***Lenticulina* 1 and *Valvulineria* "H" biozones**

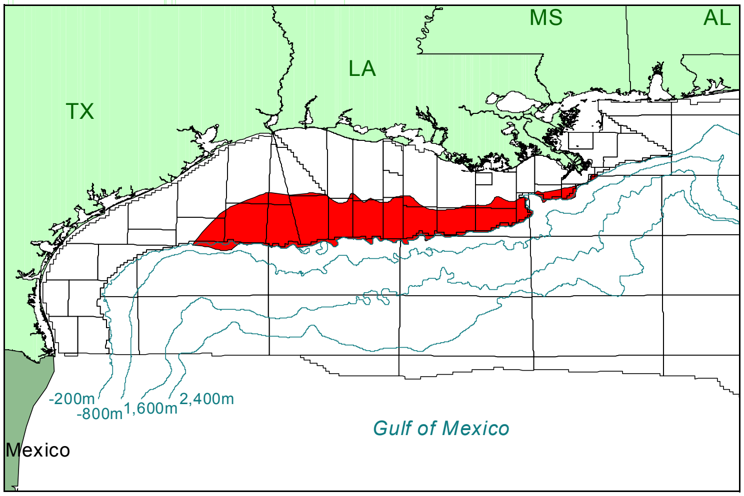


Figure 1. Play location.

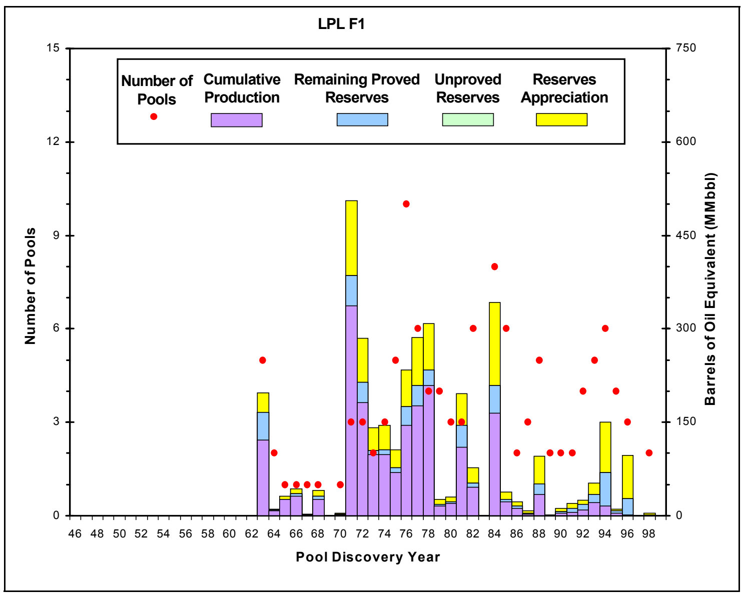


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LPL F1 Play 118 Pools 543 Sands	Minimum	Mean	Maximum
Water depth (feet)	95	255	930
Subsea depth (feet)	5715	9608	16267
Number of sands per pool	1	5	26
Porosity	20%	29%	35%
Water saturation	16%	26%	51%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pleistocene Fan 1 (LPL F1) play occurs within the *Lenticulina* 1 and *Valvulineria* "H" biozones. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The LPL F1 play extends from the Galveston/East Breaks Areas offshore Texas to the South Pass/Mississippi Canyon Areas near 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 P1) play. The LPL F1 play does not extend farther to the west because of a lack of sediment influx into offshore Texas during LPL time. To the northeast, the play grades into sediments of the LPL P1 play. The southern limit of the play is the structural boundary of the Lower Pleistocene Fan 2 (LPL F2) play.

Play Characteristics

The LPL F1 play is characterized by deepwater turbidites deposited basinward of the LPL shelf margin on the upper and lower slopes, in topographically low areas between salt structure highs, and on the abyssal plain. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Almost one-third of the fields in the LPL F1 play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over

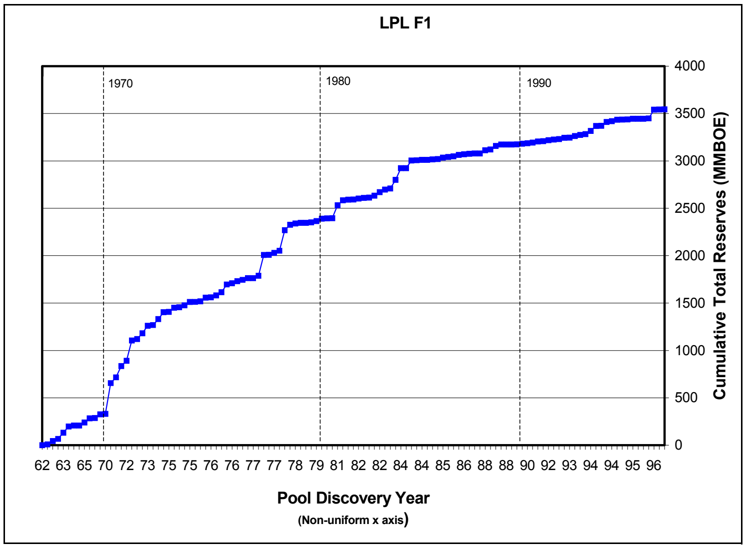


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LPL F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	115	0.703	10.087	2.498
Cumulative production	--	0.561	8.176	2.016
Remaining proved	--	0.142	1.910	0.482
Unproved	3	<0.001	0.018	0.003
Appreciation (P & U)	--	0.308	4.129	1.043
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.192	3.375	0.823
Mean	52	0.265	3.872	0.954
5th percentile	--	0.376	4.343	1.101
Total Endowment				
95th percentile	--	1.203	17.608	4.367
Mean	170	1.276	18.105	4.498
5th percentile	--	1.387	18.576	4.645

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

diapir tops. Another third of the fields are associated with simple anticlines and growth fault anticlines. Less common trapping structures in the play are normal faults, and a few fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LPL F1 mixed oil and gas play contains total reserves of 1.011 Bbo and 14.233 Tcfg (3.544 BBOE), of which 0.561 Bbo and 8.176 Tcfg (2.016 BBOE) have been produced. The play contains 543 producible sands in 118 pools of which 115 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools).

The first reserves in the play were discovered 1963 in the South Timbalier 219 field (figure 2). Pool discoveries peaked in 1976 at 10, and have averaged about three per year throughout the play's history. Maximum total reserves of 505 MMBOE were found in 1971 in 3 pools, including the largest pool in the play in the Eugene Island 330 field, with 325 MMBOE in total reserves (figures 2 and 3). The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998. Ninety-seven percent of the cumulative production and 90 percent of total reserves from this play are from pools discovered before 1990.

The 118 discovered pools contain 1,097 reservoirs, of which 664 are nonassociated gas, 332 are undersaturated oil, and 101 are saturated oil. Cumulative production has consisted of 72 percent gas and 28 percent oil.

Of the 87 assessed plays in the Gulf of Mexico, the LPL F1 play is the fourth largest on the basis of BOE total reserves. Of the 14 F1 plays, the

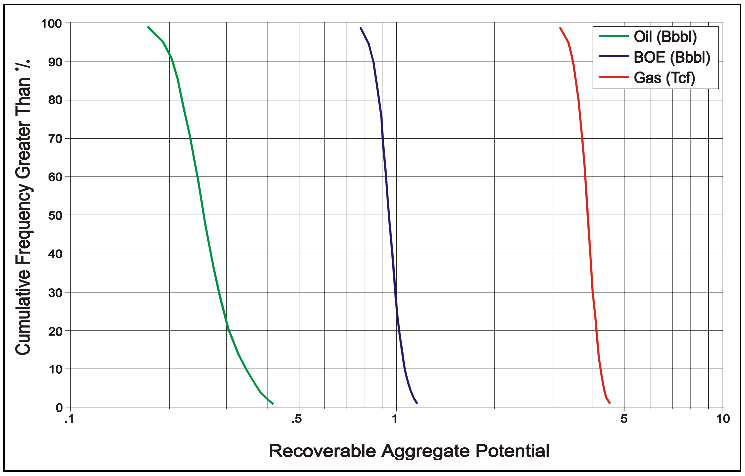


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

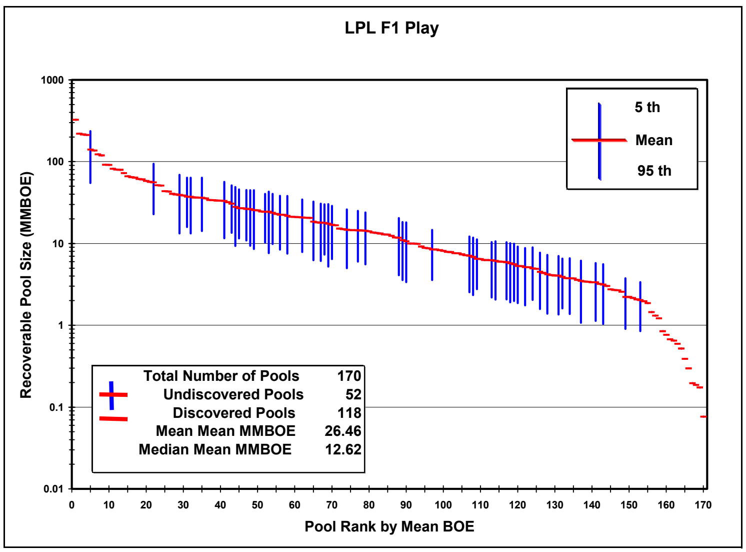


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

LPL F1 play is the largest, containing 35 percent of F1 BOE total reserves and accounting for 40 percent of F1 BOE cumulative production.

Assessment Results

The marginal probability of hydrocarbons for the LPL F1 play is 1.00. This play has a mean total endowment of 1.276 Bbo and 18.105 Tcfg (4.498 BBOE) (table 2). Forty-five percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.192 to 0.376 Bbo and 3.375 to 4.343 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.265 Bbo and 3.872 Tcfg (0.954 BBOE). These undiscovered resources might occur in as many as 52 pools. The largest undiscovered pool, with a mean size of 140 MMBOE, is forecast as the fifth largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 22, 29, 31, and 32 on the pool rank plot. For all the undiscovered pools in the LPL F1 play, the mean mean size is 18 MMBOE, which is smaller than the 30 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 26 MMBOE.

BOE mean UCRR contribute only 21 percent to the LPL F1 play's BOE mean total endowment, but the play is forecast to contain a billion BOE in UCRR. Future discoveries will continue be made in structural and stratigraphic traps around salt structures, and by deeper drilling within existing fields.

Lower Pleistocene Fan 2 (LPL F2) Play

***Lenticulina* 1 and *Valvulineria* "H" biozones**

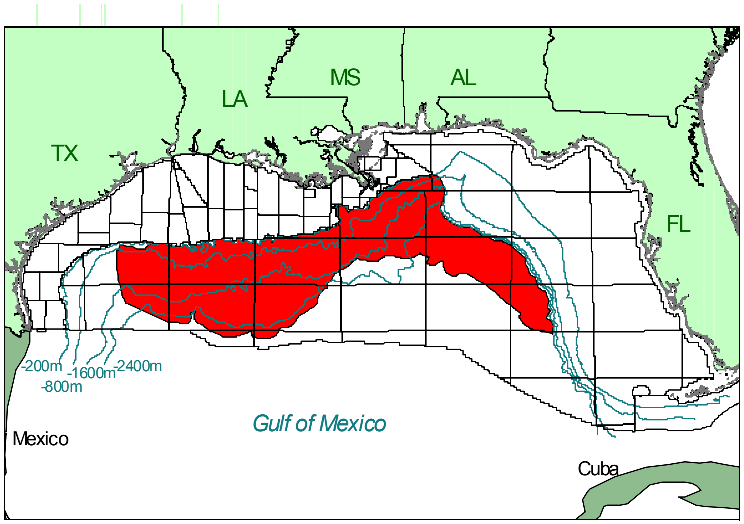


Figure 1. Play location.

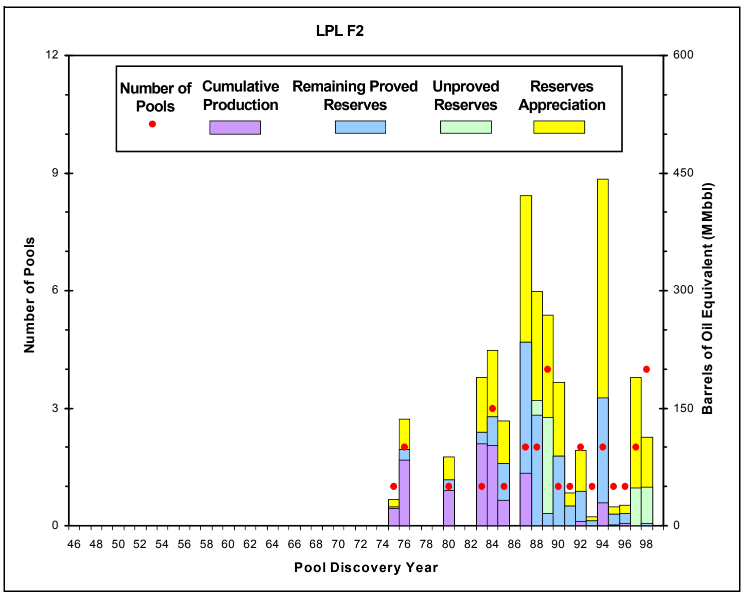


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LPL F2 Play 32 Pools 121 Sands	Minimum	Mean	Maximum
Water depth (feet)	663	2259	6845
Subsea depth (feet)	5990	11187	17368
Number of sands per pool	1	4	11
Porosity	27%	31%	36%
Water saturation	16%	24%	43%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pleistocene Fan 2 (LPL F2) play contains the third largest BOE mean total endowment of any play in the Gulf of Mexico Region. The play occurs within the *Lenticulina* 1 and *Valvulineria* "H" biozones and is defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The LPL F2 play extends from the central East Breaks and Alaminos Canyon Areas to the southwestern Destin Dome and western Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1).

The LPL F2 play is bounded updip by the Lower Pleistocene Fan 1 (LPL F1) play. The LPL F2 play does not extend farther to the west because of a lack of sediment influx at the edge of the LPL depocenter. To the east, the play onlaps the Cretaceous carbonate slope. Downdip in the western and central Gulf of Mexico Regions, the LPL F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf of Mexico Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes,

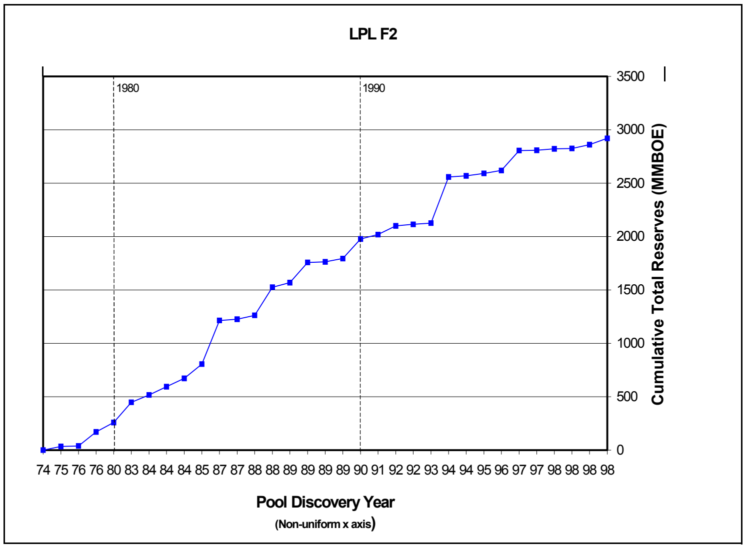


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LPL F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	23	0.791	2.678	1.268
Cumulative production	--	0.308	1.051	0.495
Remaining proved	--	0.483	1.627	0.773
Unproved	9	0.152	0.469	0.235
Appreciation (P & U)	--	0.931	2.733	1.418
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	2.360	9.038	4.043
Mean	128	2.699	10.247	4.522
5th percentile	--	3.301	11.815	5.372
Total Endowment				
95th percentile	--	4.234	14.918	6.964
Mean	160	4.573	16.127	7.443
5th percentile	--	5.175	17.695	8.293

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

lobe fringes, and slumps deposited on the LPL upper and lower slopes, in topographically low areas between salt structure highs and on the abyssal plain. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Over half of the fields in the LPL F2 play are structurally associated with salt bodies, mostly of intermediate and deep depths, with hydrocarbons trapped on salt flanks or in sediments draped over salt. Some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LPL F2 mixed oil and gas play contains total reserves of 1.874 Bbo and 5.880 Tcfg (2.921 BBOE), of which 0.308 Bbo and 1.051 Tcfg (0.495 BBOE) have been produced. The play contains 121 producible sands in 32 pools, of which 23 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered the Mississippi Canyon 194 field (Cognac) in 1975 (figure 2). Pool discoveries peaked at four in both 1989 and in 1998 and have averaged about three pools every two years throughout the play's history. Substantial reserves have been added almost every year since the initial discovery, with a maximum of 443 MMBOE found in 1994 in two pools. One of these pools, the Green Canyon 244 pool (Troika), is the largest in the play with 432 MMBOE in total reserves. Other significant pool discoveries were made in the Garden Banks 426 field (Auger) with 409 MMBOE in total reserves and in the Green Canyon 205 field (Genesis) with 263 MMBOE in total reserves

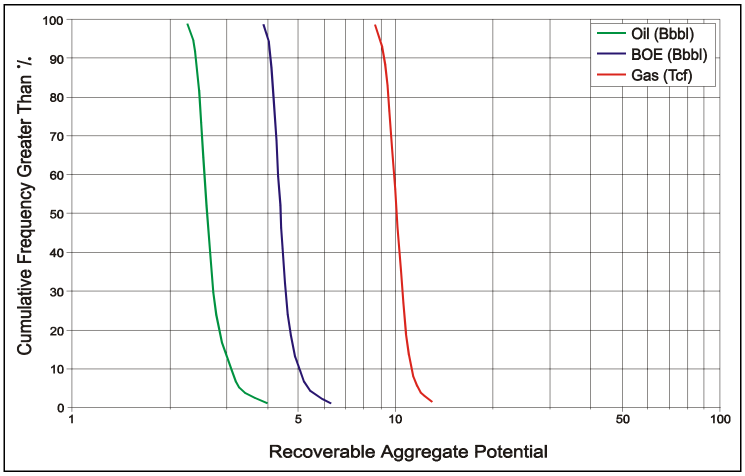


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

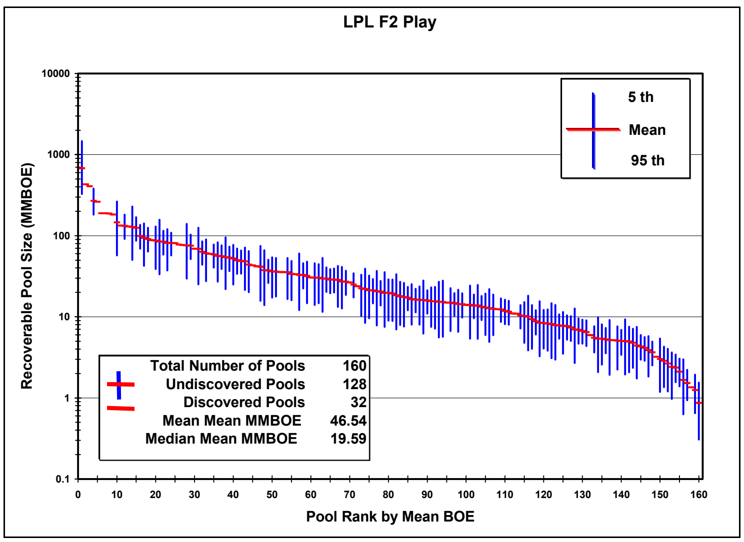


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

(figures 2 and 3). The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998. Ninety-two percent of the cumulative production from this play has occurred from pools discovered prior to 1990, and 61 percent of the remaining total reserves is estimated to be in pools discovered before 1990.

The 32 discovered pools contain 196 reservoirs, of which 61 are nonassociated gas, 120 are undersaturated oil, and 15 are saturated oil. Cumulative production has consisted of 62 percent oil and 38 percent gas.

Of the 87 assessed plays in the Gulf of Mexico Region, the LPL F2 contains the largest amounts of total oil reserves with 8 percent of oil in the Region. The LPL F2 play is also the largest of the 13 fan 2 plays on the basis of BOE cumulative production.

Assessment Results

The marginal probability of hydrocarbons for the LPL F2 play is 1.00. This play is the third largest in the Gulf of Mexico Region on the basis of a mean total endowment of 4.573 Bbo and 16.127 Tcfg (7.443 BBOE) (table 2). Seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 2.360 to 3.301 Bbo and 9.038 to 11.815 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 2.699 Bbo and 10.247 Tcfg (4.522 BBOE). These undiscovered resources might occur in as many as 128 pools. The largest undiscovered pool, with a mean size of 680 MMBOE, is also forecast to be the largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 4, 10, 12, and 14 on the pool rank plot. For all the undiscovered pools in the LPL F2 play, the mean mean size is 35 MMBOE, which is substantially smaller than the 91 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 47 MMBOE.

Of all 87 assessed Gulf of Mexico plays, the LPL F2 play is forecast to contain the fifth-most mean UCRR with 4.522 BBOE, or 61 percent of the play's BOE mean total endowment. Seven pools with 100 MMBOE or more are forecast as remaining to be discovered (figure 5). The LPL F2 play covers a vast area with relatively few well penetrations, although hydrocarbons have been encountered in significant portions of this deepwater area. Exceptions are the southernmost portions of the Garden Banks and Green Canyon Areas, and most of the sparsely explored Keathley Canyon Area.

Upper Pliocene Aggradational (UP A1) Play

***Buliminella* 1 biozone**

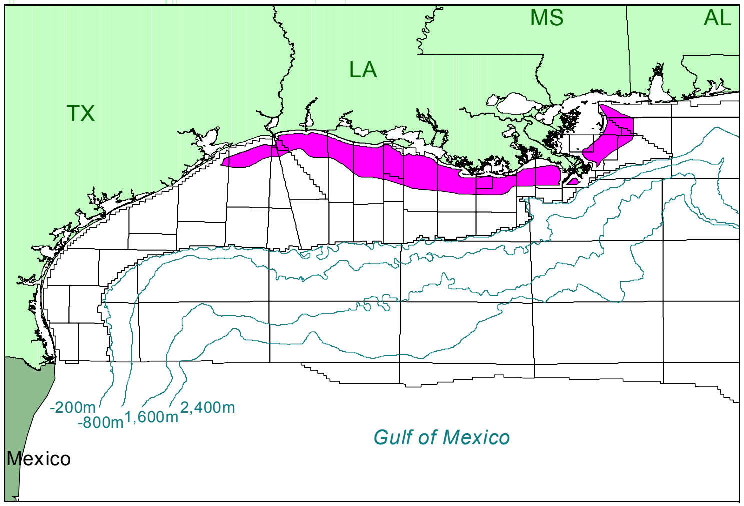


Figure 1. Play location.

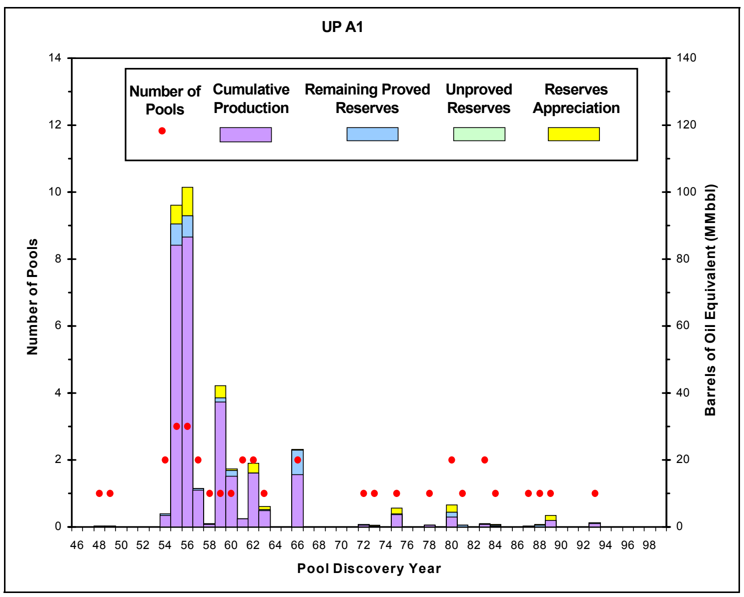


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UP A1 Play 36 Pools 135 Sands	Minimum	Mean	Maximum
Water depth (feet)	13	57	177
Subsea depth (feet)	1971	6415	13015
Number of sands per pool	1	4	16
Porosity	25%	30%	36%
Water saturation	16%	26%	50%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pliocene Aggradational (UP A1) play occurs within the *Buliminella* 1 biozone. This play extends from the northeastern Galveston Area offshore Texas to the Mobile Area 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 Mobile Area at the edges of the UP depocenter. Downdip, the play grades into the sediments of the Upper Pliocene Progradational (UP P1) play.

Play Characteristics

The UP A1 play is characterized by stacked, blocky, sand-dominated successions representing sediment buildup in fluvial channel/levee complexes, crevasse splays, and point bars; in deltaic distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches and barrier islands; and in shallow marine shelf delta fringes and slumps. Additionally, retrogradational, reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the UP A1 play.

Many of the fields in play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other common structures include simple anticlines and growth fault anticlines. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-

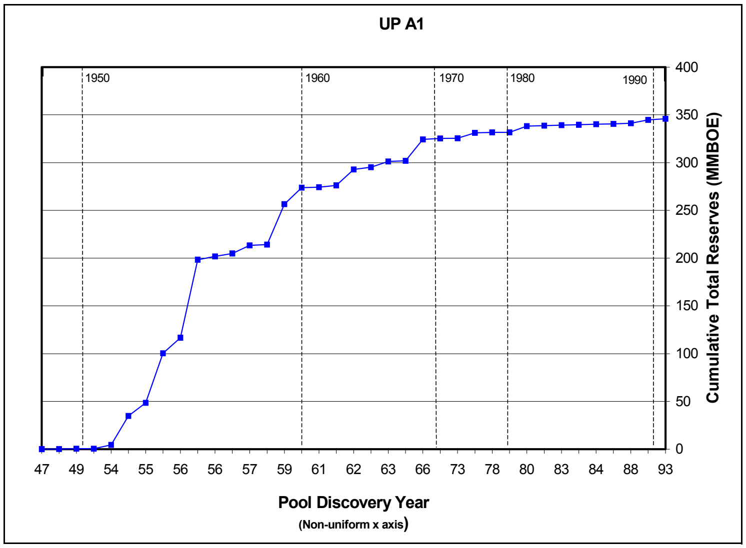


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UP A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	36	0.140	0.992	0.317
Cumulative production	–	0.129	0.900	0.289
Remaining proved	–	0.011	0.092	0.027
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	0.009	0.113	0.029
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.003	0.037	0.010
Mean	7	0.006	0.056	0.016
5th percentile	–	0.009	0.075	0.022
Total Endowment				
95th percentile	–	0.152	1.143	0.356
Mean	43	0.155	1.162	0.362
5th percentile	–	0.158	1.181	0.367

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

outs, overlying shales).

Discoveries

The UP A1 mixed gas and oil play contains total reserves of 0.149 Bbo and 1.106 Tcfg (0.346 BBOE), of which 0.129 Bbo and 0.900 Tcfg (0.289 BBOE) have been produced. The play contains 135 producible sands in 36 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). 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 1966, during which 19 pools and over 85 percent of the play's total reserves were found. Maximum yearly total reserves of 101 MMBOE were added in 1956 with the discovery of three pools, including the largest pool in the play, the Main Pass 41 field with 82 MMBOE in total reserves (figures 2 and 3). Almost all of the play's cumulative production and total reserves come from pools discovered before 1990, reflecting the maturity of the play. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1993.

The 36 discovered pools contain 349 reservoirs, of which 97 are nonassociated gas, 225 are undersaturated oil, and 27 are saturated oil. Cumulative production has consisted of 55 percent gas and 45 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UP A1 play is 1.00. The play contains a mean total endowment of 0.155 Bbo and 1.162 Tcfg (0.362 BBOE) (table 2). Eighty percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.003 to 0.009 Bbo and 0.037 to 0.075 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.006 Bbo and 0.056 Tcfg (0.016

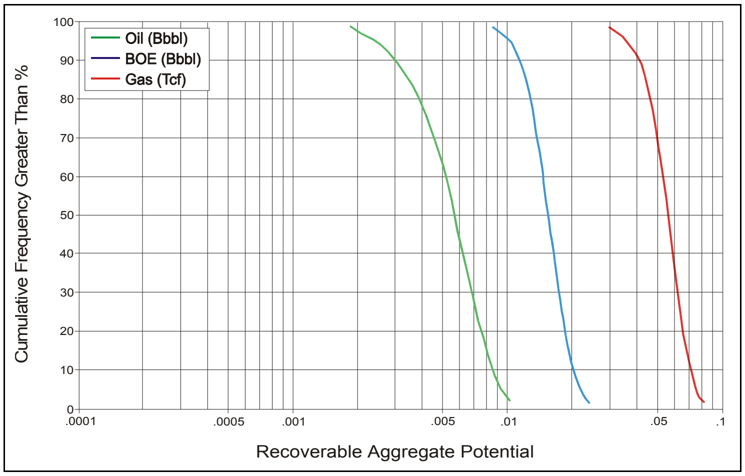


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

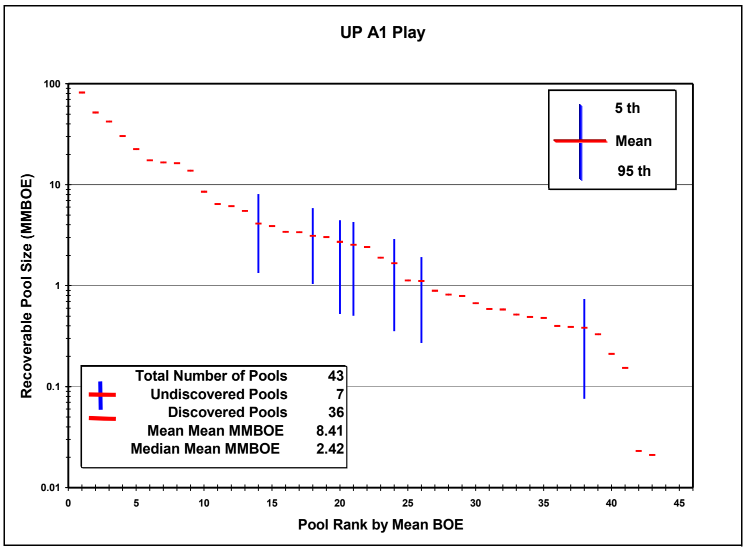


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

BBOE). These undiscovered resources might occur in as many as seven pools. The largest undiscovered pool, with a mean size of 4 MMBOE, is forecast as the 14th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 18, 20, 21, and 24 on the pool rank plot. For all the undiscovered pools in the UP A1 play, the mean mean size is 2 MMBOE, which is smaller than the 10 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 8 MMBOE.

The UP A1 is a super-mature play with BOE mean UCRR contributing only 4 percent to the play's BOE mean total endowment.

Upper Pliocene Progradational (UP P1) Play

Buliminella 1 biozone

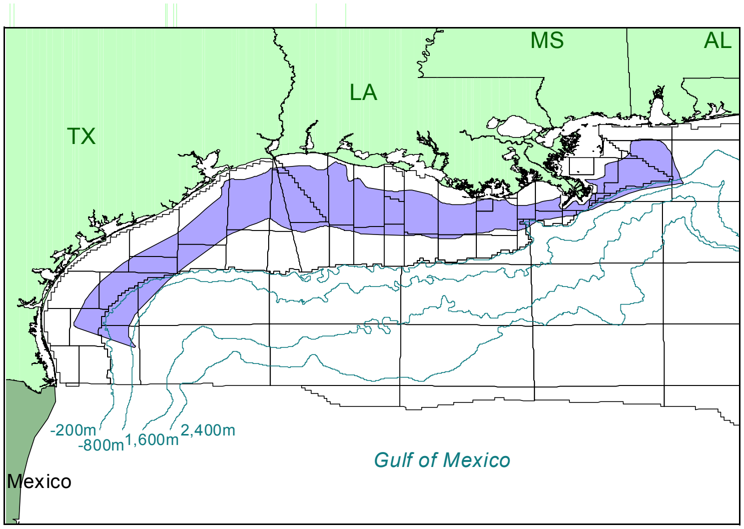


Figure 1. Play location.

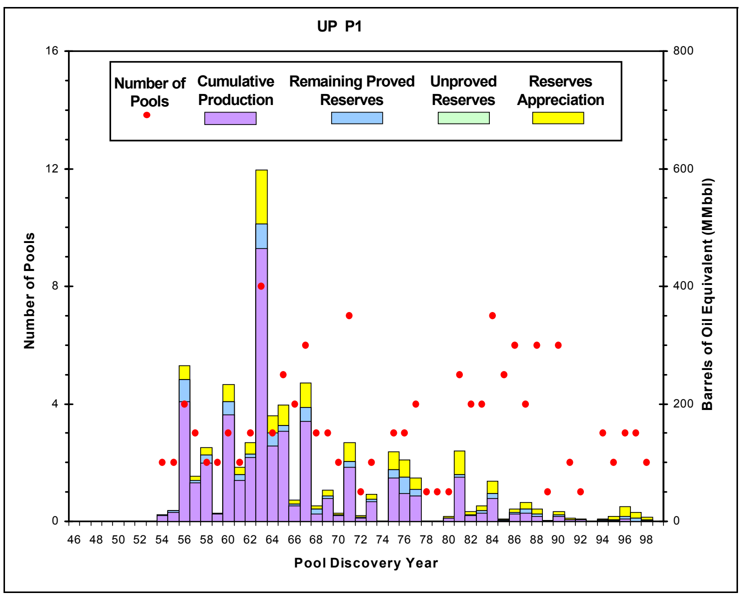


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UP P1 Play 144 Pools 722 Sands	Minimum	Mean	Maximum
Water depth (feet)	22	131	856
Subsea depth (feet)	1115	8123	13703
Number of sands per pool	1	5	33
Porosity	23%	29%	36%
Water saturation	16%	27%	49%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pliocene Progradational (UP P1) play has the fifth-most BOE cumulative production of any play in the Gulf of Mexico Region. The play occurs within the *Buliminella* 1 biozone and extends from the North Padre Island and Port Isabel Areas offshore Texas to the Destin Dome Area offshore Alabama (figure 1).

Updip, the play grades into the deposits of the Upper Pliocene Aggradational (UP A1) play. To the northeast and southwest, the UP P1 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 1 (UP F1) 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 thin at the edges of the depocenter.

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 located primarily in Federal waters.

Play Characteristics

Sediments in the UP P1 play represent major regressive episodes of outbuilding of both the shelf and the slope. Additionally, retrogradational, reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the UP P1 play.

Over one-third of the fields in

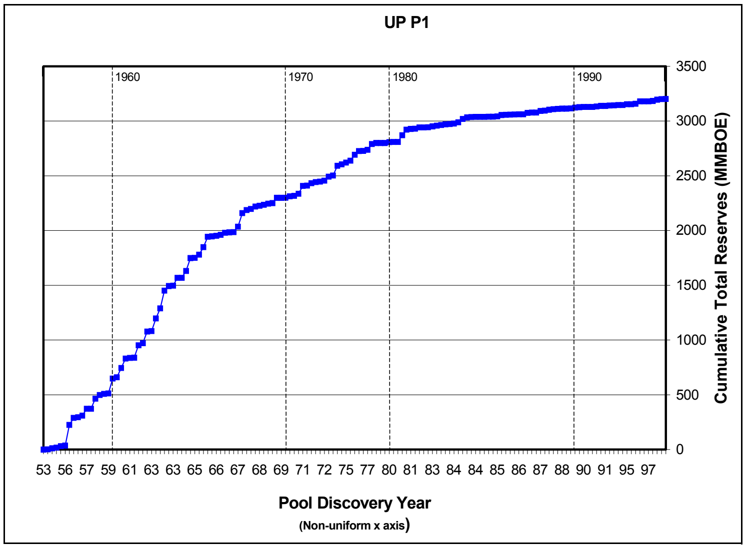


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UP P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	143	1.000	8.979	2.598
Cumulative production	–	0.868	7.864	2.267
Remaining proved	–	0.132	1.115	0.330
Unproved	1	<0.001	0.005	0.001
Appreciation (P & U)	–	0.207	2.229	0.603
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.051	0.821	0.212
Mean	36	0.083	1.008	0.263
5th percentile	–	0.121	1.199	0.319
Total Endowment				
95th percentile	–	1.258	12.034	3.414
Mean	180	1.290	12.221	3.465
5th percentile	–	1.328	12.412	3.521

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

this play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are associated with normal faults, and growth fault anticlines. Some fields also contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UP P1 mixed gas and oil play contains total reserves of 1.207 Bbo and 11.213 Tcfg (3.202 BBOE), of which 0.868 Bbo and 7.864 Tcfg (2.267 BBOE) have been produced. The play contains 722 producible sands in 144 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the South Timbalier 52 field in 1954 (figure 2). Maximum yearly total reserves of 597 MMBOE were added in 1963 with the discovery of eight pools. The largest pool in the play was discovered in 1956 in the South Timbalier 135 field with 189 MMBOE in total reserves (figures 2 and 3). Over 75 percent of the play's cumulative production and over 70 percent of the play's total reserves were from pools that were discovered in the 1960's or earlier. Ninety-nine percent of the play's cumulative production and ninety-seven percent of the play's total reserves are from pools discovered before 1990, reflecting the play's maturity. An average of about three pools was discovered each year from 1955 to 1998.

The 144 discovered pools contain 2,074 reservoirs, of which 1,022 are nonassociated gas, 877 are undersaturated oil, and 175 are saturated oil. Cumulative production has consisted of 62 percent gas and

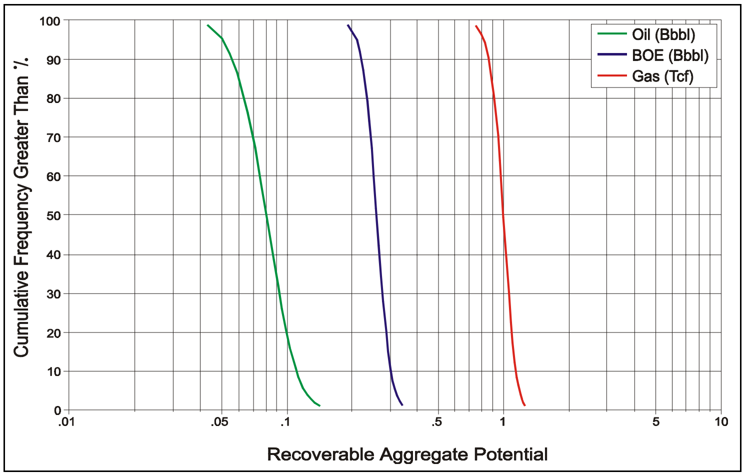


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

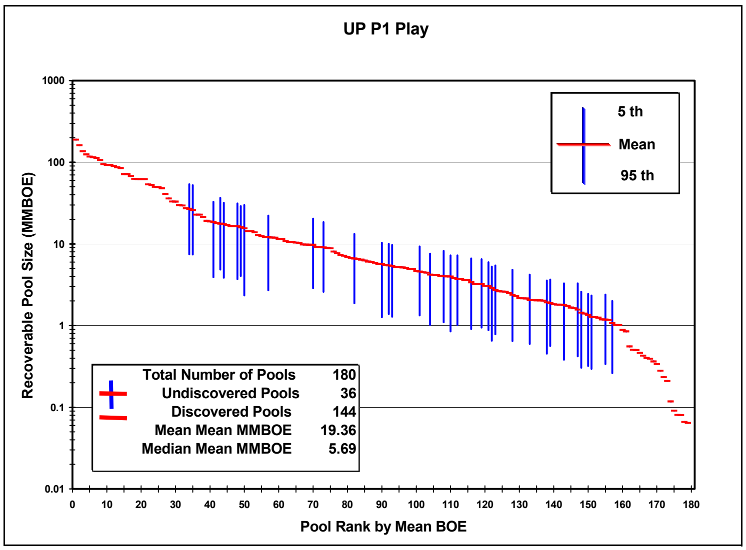


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

38 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UP P1 play is 1.00. The play contains a mean total endowment of 1.290 Bbo and 12.221 Tcfg (3.465 BBOE) (table 2). Sixty-five percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.051 to 0.121 Bbo and 0.821 to 1.199 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.083 Bbo and 1.008 Tcfg (0.263 BBOE). These undiscovered resources might occur in as many as 36 pools. The largest undiscovered pool, with a mean size of 27 MMBOE, is modeled as the 34th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 35, 41, 43, and 44 on the pool rank plot. For all the undiscovered pools in the UP P1 play, the mean mean size is 7 MMBOE, which is substantially smaller than the 22 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 19 MMBOE.

The UP P1 is a super-mature play with BOE mean UCRR contributing only 7 percent to the UP P1 play's BOE mean total endowment. Limited exploration potential in this play exists in deep sections around salt structures where the UP P1 play may not be adequately tested.

Upper Pliocene Fan 1 (UP F1) Play

Buliminella 1 biozone

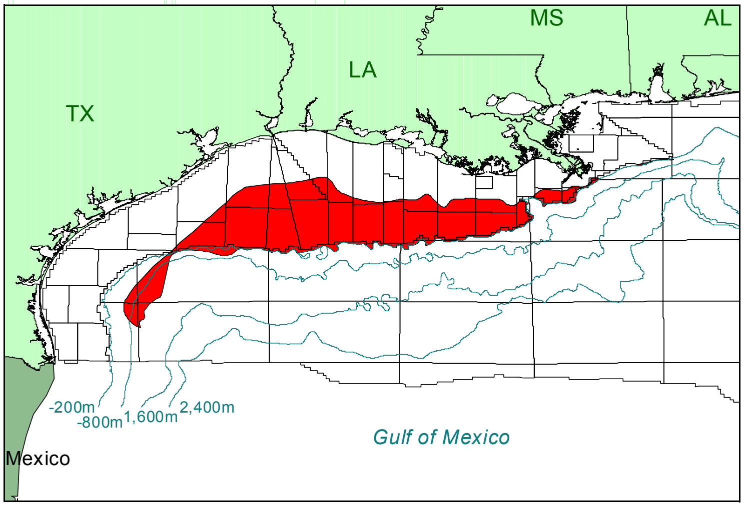


Figure 1. Play location.

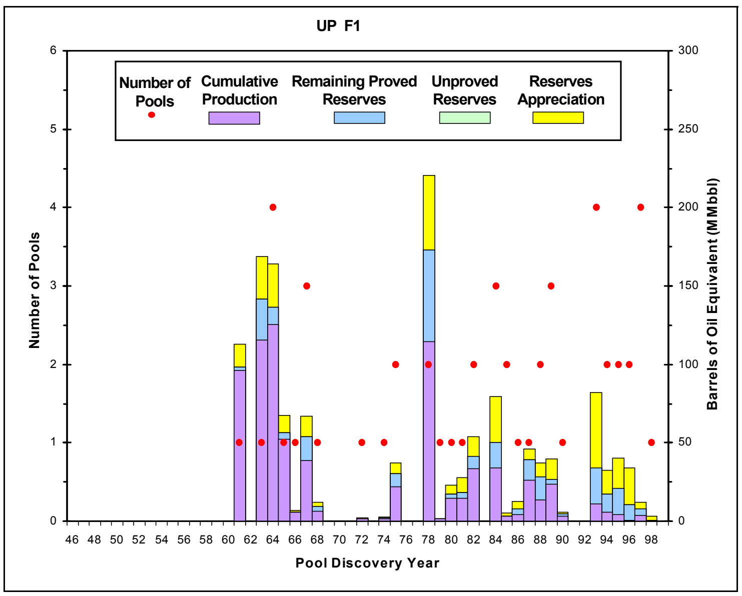


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UP F1 Play 51 Pools 206 Sands	Minimum	Mean	Maximum
Water depth (feet)	71	219	635
Subsea depth (feet)	6400	11994	16136
Number of sands per pool	1	4	23
Porosity	22%	28%	33%
Water saturation	16%	28%	55%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pliocene Fan 1 (UP F1) play occurs within the *Buliminella* 1 biozone and is defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern GOM shelf. The play extends from the Corpus Christi and Port Isabel Areas offshore Texas to the South Pass and northern Mississippi Canyon Areas near 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 P1) 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 is limited by the structural boundary of the Upper Pliocene Fan 2 (UP F2) play.

Miocene delta systems of Texas no longer provided significant clastic influx to the present-day Texas offshore area, and the ancestral Mississippi River Delta System became the dominant depocenter during UP time.

Play Characteristics

The UP F1 play is characterized by deep-sea fan systems deposited basinward of the UP shelf margin. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps that were deposited on the UP upper and lower slope in topographically low areas between salt structure highs and on the abyssal plain. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Nearly one-half of the fields

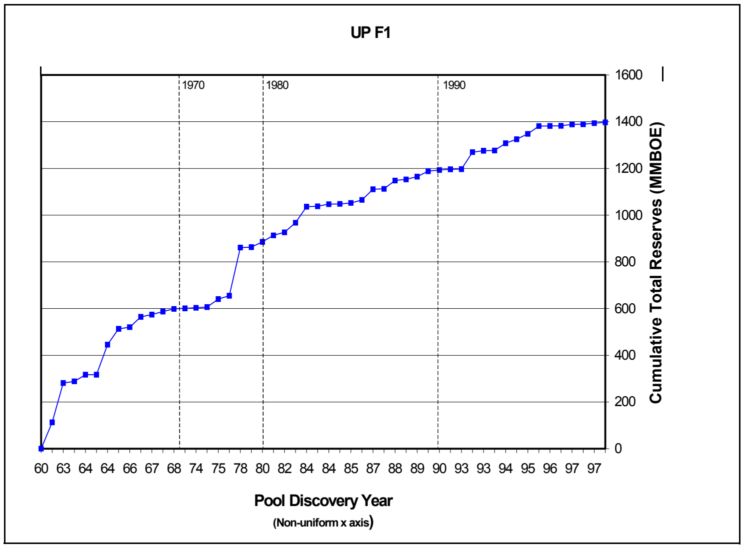


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UP F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	51	0.336	3.946	1.038
Cumulative production	--	0.257	2.928	0.778
Remaining proved	--	0.079	1.017	0.260
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.131	1.281	0.359
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.253	3.775	1.023
Mean	66	0.335	4.850	1.198
5th percentile	--	0.428	5.584	1.381
Total Endowment				
95th percentile	--	0.720	9.002	2.420
Mean	117	0.802	10.077	2.595
5th percentile	--	0.895	10.811	2.778

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

in the UP F1 play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other trapping structures are normal faults and growth fault anticlines. In addition, a few fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UP F1 mixed gas and oil play contains total reserves of 0.467 Bbo and 5.227 Tcfg (1.397 BBOE), of which 0.257 Bbo and 2.928 Tcfg (0.778 BBOE) have been produced. The play contains 206 producible sands in 51 pools, and all 51 pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Ship Shoal 208 field in 1961 (figure 2). Maximum yearly total reserves of 221 MMBOE were added in 1978 when two pools were discovered, including the largest pool in the play in the South Pass 89 field with 206 MMBOE in total reserves (figures 2 and 3). The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1998.

The 51 discovered pools contain 404 reservoirs, of which 196 are nonassociated gas, 164 are undersaturated oil, and 44 are saturated oil. Cumulative production has consisted of 67 percent gas and 33 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UP F1 play is 1.00. The play contains a mean total endowment of 0.802 Bbo and 10.077 Tcfg (2.595 BBOE) (table 2). Thirty percent of this BOE mean total

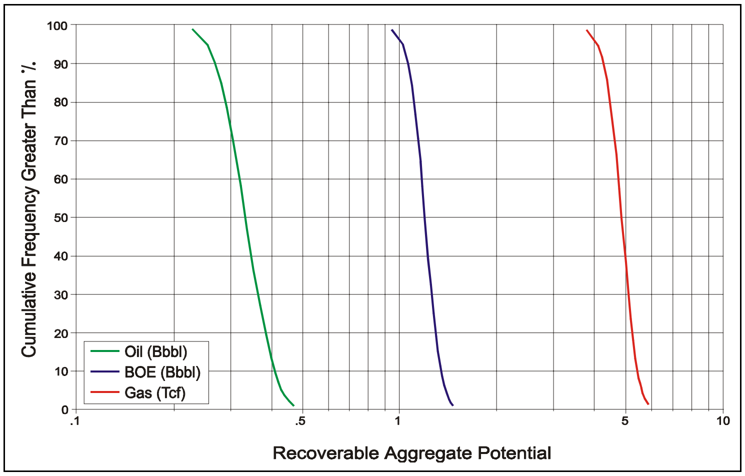


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

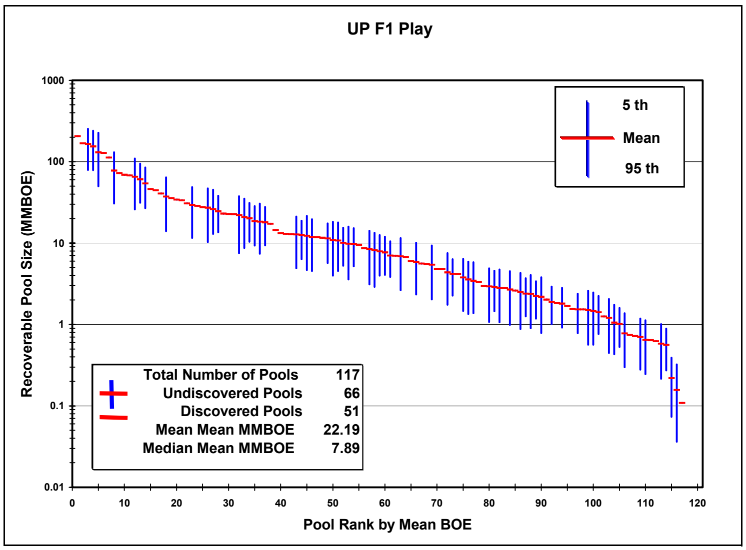


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.253 to 0.428 Bbo and 3.775 to 5.584 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.335 Bbo and 4.850 Tcfg (1.198 BBOE). These undiscovered resources might occur in as many as 66 pools. The largest undiscovered pool, with a mean size of 165 MMBOE, is forecast as the third largest pool in the play (figure 5). The forecast places the next four undiscovered pools in positions 4, 5, 8, and 12 on the pool rank plot. For all the undiscovered pools in the UP F1 play, the mean mean size is 18 MMBOE, which is substantially smaller than the 27 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 22 MMBOE.

The UP F1 play is the largest of 14 Gulf of Mexico fan 1 plays on the basis of BOE mean UCRR. BOE mean UCRR also contribute over 1 BBOE, or 46 percent, of the UP F1 play's BOE mean total endowment. Exploration potential continues to exist around salt in deep structural and stratigraphic traps as well as in structures located underneath salt overhangs and salt sheets. Three fields containing over 100 MMBOE are forecast as remaining to be discovered.

Upper Pliocene Fan 2 (UP F2) Play

Buliminella 1 biozone

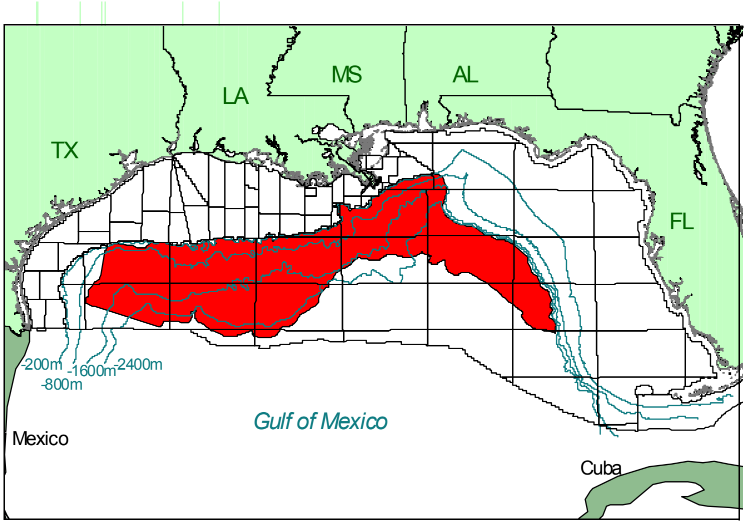


Figure 1. Play location.

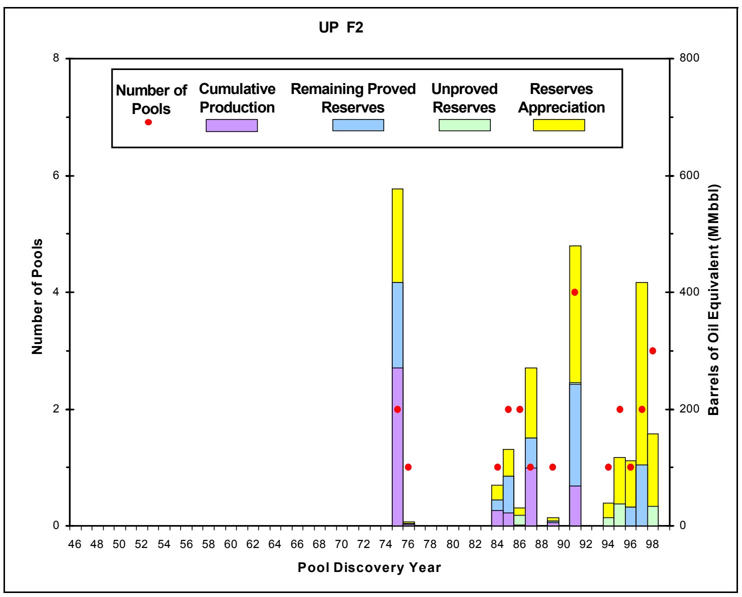


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UP F2 Play **23 Pools 75 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	663	2337	4851
Subsea depth (feet)	3700	12779	22572
Number of sands per pool	1	3	15
Porosity	27%	31%	36%
Water saturation	16%	24%	37%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Pliocene Fan 2 (UP F2) play is the second largest play in the Gulf of Mexico Region on the basis of both BOE mean total endowment and undiscovered conventionally recoverable resources (UCRR). The play occurs within the *Buliminella* 1 biozone and is defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The play extends from the East Breaks and Alaminos Canyon Areas offshore Texas to the southwestern Destin Dome and western Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas of offshore Florida (figure 1).

Updip, the UP F2 play is limited by the Upper Pliocene Fan 1 (UP F1) play. The UP F2 play does not extend farther to the west because of a lack of sediment influx at the edge of the UP depocenter. To the east, the play onlaps the Cretaceous carbonate slope. Downdip in the western and central Gulf of Mexico Regions, the UP F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/ High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component depositional facies include channel/levee com-

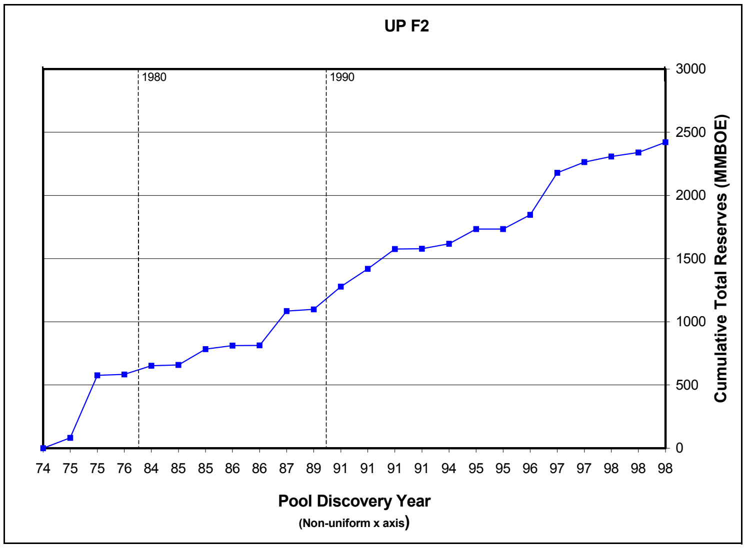


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UP F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	15	0.750	1.925	1.092
Cumulative production	–	0.321	0.971	0.494
Remaining proved	–	0.429	0.953	0.599
Unproved	8	0.081	0.132	0.104
Appreciation (P & U)	–	0.919	1.713	1.224
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	2.737	8.546	4.354
Mean	127	3.128	10.848	5.058
5th percentile	–	3.578	14.358	6.032
Total Endowment				
95th percentile	–	4.487	12.315	6.775
Mean	150	4.878	14.617	7.479
5th percentile	–	5.328	18.127	8.453

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

plexes, sheet-sand lobes, interlobes, lobe fringes, and slumps deposited on the UP upper and lower slope, in topographically low areas between salt structure highs and on the abyssal plain. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Over half of the fields in the UP F2 play are structurally associated with salt bodies with hydrocarbons trapped on salt flanks or in sediments draped over salt. Some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UP F2 mixed oil and gas play contains total reserves of 1.750 Bbo and 3.769 Tcfg (2.421 BBOE), of which 0.321 Bbo and 0.971 Tcfg (0.494 BBOE) have been produced. The play contains 75 producible sands in 23 pools, of which 15 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1975 in the Mississippi Canyon 148 and Mississippi Canyon 194 (Cognac) fields (figure 2). Maximum yearly total reserves of 577 MMBOE were also added in 1975, as was the largest pool in the play, Cognac, with an estimated 495 MMBOE in total reserves (figures 2 and 3). Eighty-six percent of the play's cumulative production and 45 percent of the play's total reserves were from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 23 discovered pools contain 118 reservoirs, of which 32 are nonassociated gas, 74 are undersaturated oil, and 12 are saturated

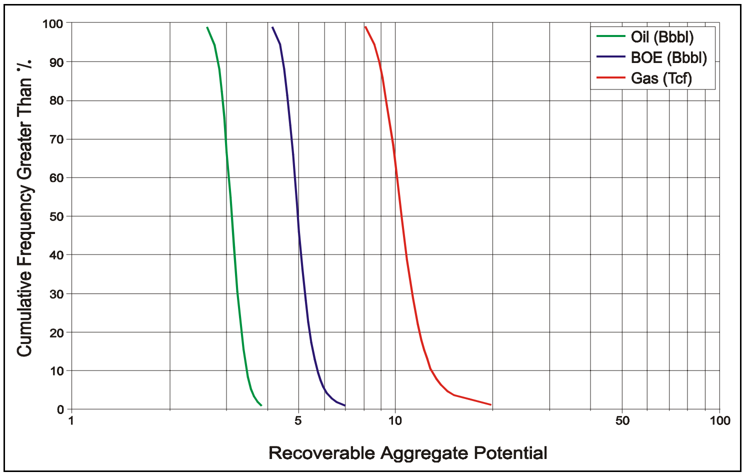


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

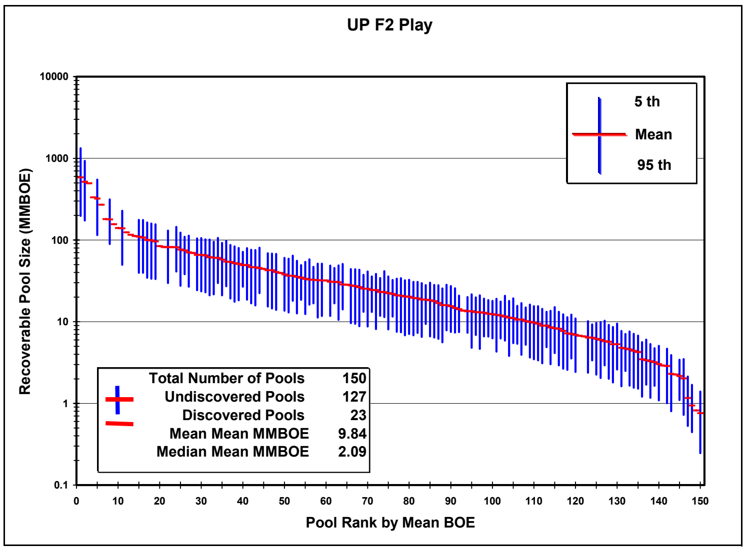


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

oil. Cumulative production has consisted of 65 percent oil and 35 percent gas.

Assessment Results

The marginal probability of hydrocarbons for the UP F2 play is 1.00. This play is the second largest in the Gulf of Mexico Region on the basis of a mean total endowment of 4.878 Bbo and 14.617 Tcfg (7.479 BBOE) (table 2). Seven percent of this BOE mean total endowment has been produced.

The UP F2 play is also the second largest play in the Gulf of Mexico Region on the basis of BOE mean UCRR. Assessment results indicate that UCRR have a range of 2.737 to 3.578 Bbo and 8.546 to 14.358 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 3.128 Bbo and 10.848 Tcfg (5.058 BBOE). Of the 13 fan 2 plays, the UP F2 play contains the largest BOE mean total endowment and the most UCRR. These undiscovered resources might occur in as many as 127 pools. The largest undiscovered pool, with a mean size of 585 MMBOE, is also forecast to be the largest pool in the play (figure 5). The forecast places the next four undiscovered pools in positions 2, 5, 8, and 11 on the pool rank plot. For all the undiscovered pools in the UP F2 play, the mean mean size is 40 MMBOE, which is smaller than the 105 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 50 MMBOE.

BOE mean UCRR contribute 68 percent to the play's BOE mean total endowment. The UP F2 play covers a vast area with relatively few well penetrations. With over 5 BBOE forecast to be discovered and eight undiscovered pools forecast to each contain over 100 MMBOE in total reserves, the likelihood of future significant discoveries is thought to be high. The UP section is very thick in the Garden Banks and Green Canyon Areas, and probably to the south of these areas as well. Exploration potential exists around salt stocks in deep structural and stratigraphic traps as well as in structures located below salt overhangs and sheets.

Lower Pliocene Aggradational (LP A1) Play

***Textularia* "X" biozone**

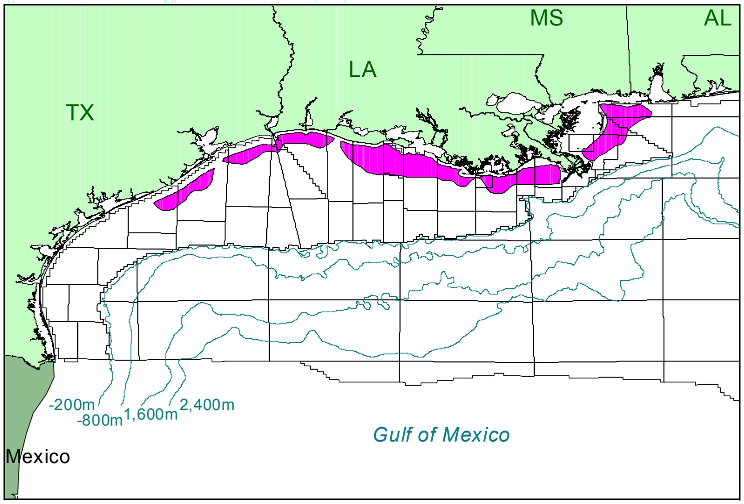


Figure 1. Play location.

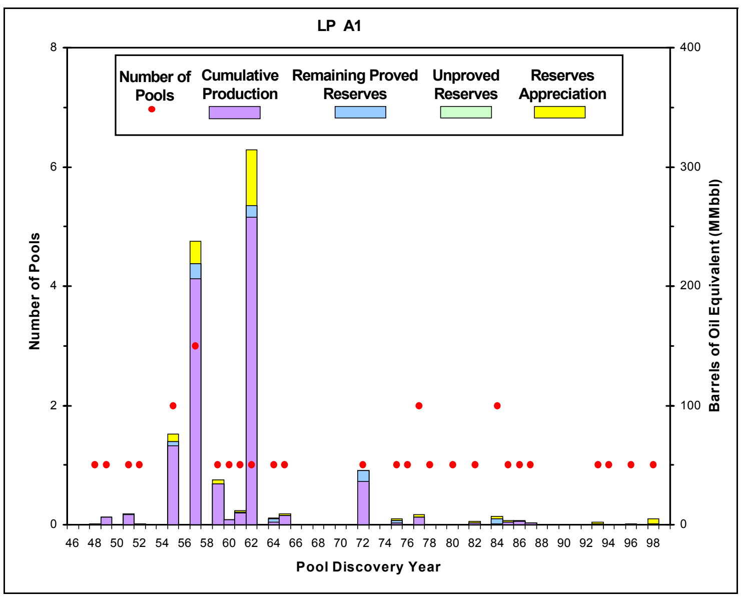


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LP A1 Play			
32 Pools 134 Sands	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	12	55	177
Subsea depth (feet)	2965	6644	10406
Number of sands per pool	1	4	21
Porosity	26%	31%	36%
Water saturation	16%	26%	42%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pliocene Aggradational (LP A1) play occurs within the *Textularia* "X" biozone. This play extends from the northeastern Brazos Area offshore Texas to the Mobile Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Texas and Louisiana. To the southwest and northeast, aggradational sand deposition ends at the edges of the LP depocenter. Downdip, the play grades into the sediments of the Lower Pliocene Progradational (LP P1) play.

The underlying Upper Upper Miocene Aggradational (UM3 A1) play is widespread in the offshore Texas area, but the lower Pliocene aggradational deposits have not been identified in offshore Texas west of the Brazos Area. Thus, UM3/LP sedimentation reflects the clockwise depocenter shift to the ancestral Mississippi River Delta System from the ancient Texas delta systems.

Play Characteristics

The LP A1 play is characterized by stacked, blocky, sand-dominated successions representing sediment buildup in fluvial channel/levee complexes, crevasse splays, and point bars; in deltaic distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches, and barrier islands; and in shallow marine shelf delta fringes and slumps. Additionally, retrogradational, reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of the LP A1 play.

Most of the fields in the play are structurally associated with anticlines, normal faults, salt diapirs, and

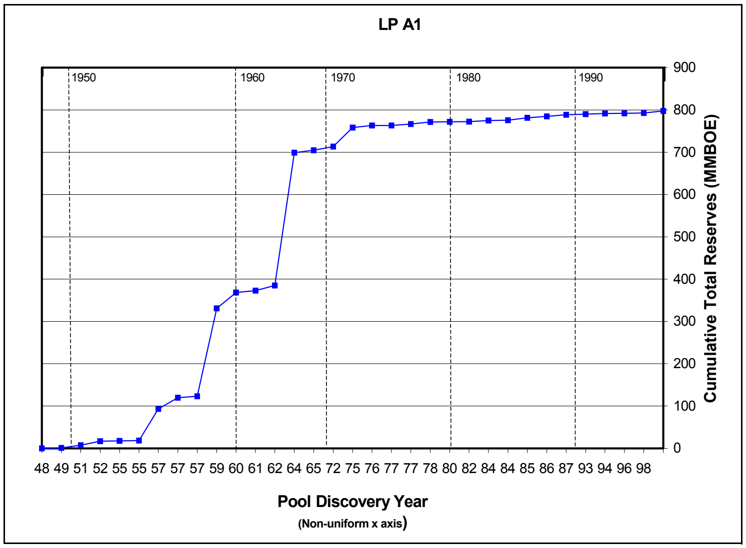


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LP A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	32	0.488	1.222	0.706
Cumulative production	--	0.461	1.110	0.658
Remaining proved	--	0.028	0.112	0.048
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.060	0.179	0.092
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.006	0.111	0.029
Mean	8	0.014	0.144	0.039
5th percentile	--	0.024	0.177	0.051
Total Endowment				
95th percentile	--	0.554	1.512	0.826
Mean	40	0.562	1.545	0.837
5th percentile	--	0.572	1.578	0.848

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

growth fault anticlines. Some fields also contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LP A1 play is predominantly an oil play, with total reserves of 0.548 Bbo and 1.401 Tcfg (0.797 BBOE), of which 0.461 Bbo and 1.110 Tcfg (0.658 BBOE) have been produced. The play contains 134 producible sands in 32 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves were discovered in 1948 in the Grand Isle 16 field (figure 2). Maximum yearly total reserves were added in 1962 with the discovery of the largest pool in the play, the West Delta 73 field with 314 MMBOE in total reserves (figures 2 and 3). Just over 90 percent of the cumulative production and total reserves for the play are from pools discovered prior to 1966. Almost all of the cumulative production occurred prior to 1990 and 99 percent of the total reserves were discovered before 1990, indicative of the play's maturity. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1998.

The 32 discovered pools contain 299 reservoirs, of which 100 are nonassociated gas, 157 are undersaturated oil, and 42 are saturated oil. Cumulative production has consisted of 70 percent oil and 30 percent gas.

Of the 12 aggradational plays in the Gulf of Mexico Cenozoic Province, the LP A1 play is the largest on the basis of BOE cumulative production and the second largest on the basis of BOE total reserves and BOE total endowment.

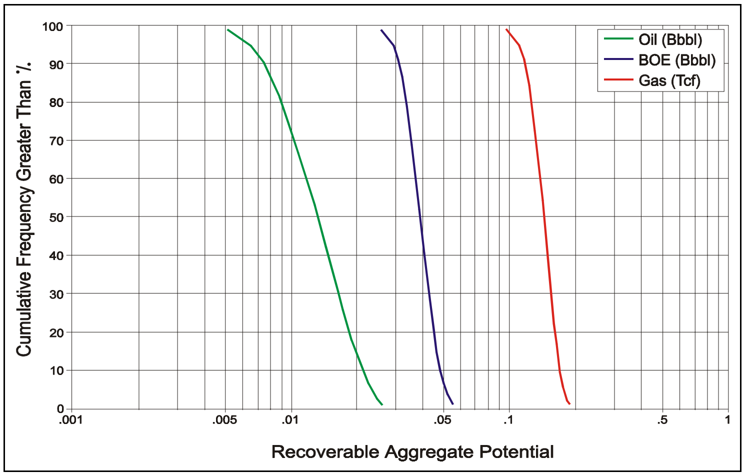


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

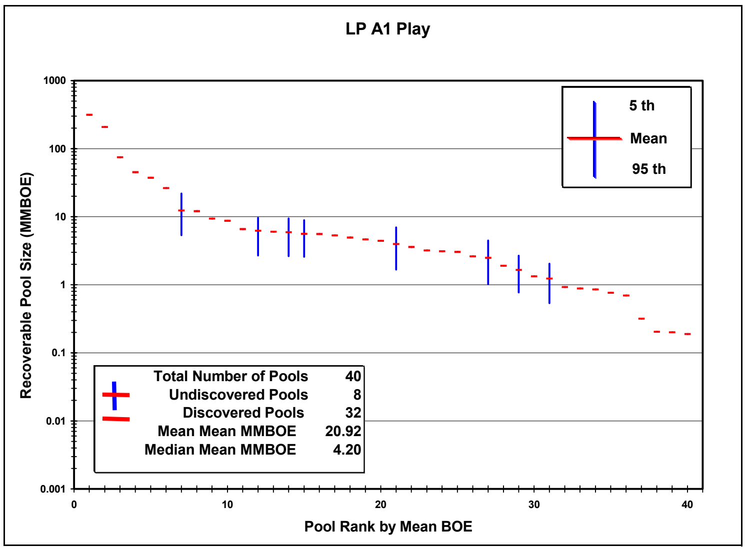


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Assessment Results

The marginal probability of hydrocarbons for the LP A1 play is 1.00. This play is the second largest aggradational play in the Gulf of Mexico Region on the basis of a mean total endowment of 0.562 Bbo and 1.545 Tcfg (0.837 BBOE) (table 2). Seventy-nine percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.006 to 0.024 Bbo and 0.111 to 0.177 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The mean UCRR are estimated at 0.014 Bbo and 0.144 Tcfg (0.039 BBOE). These undiscovered resources might occur in as many as eight pools. The largest undiscovered pool, with a mean size of 12 MMBOE, is forecast as the 7th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 12, 14, 15, and 21 on the pool rank plot. For all the undiscovered pools in the LP A1 play, the mean mean size is 5 MMBOE, which is substantially smaller than the 25 mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 21 MMBOE.

The LP A1 is a super-mature play with BOE mean UCRR contributing only 5 percent to the play's BOE mean total endowment.

Lower Pliocene Progradational (LP P1) Play

***Textularia* "X" biozone**

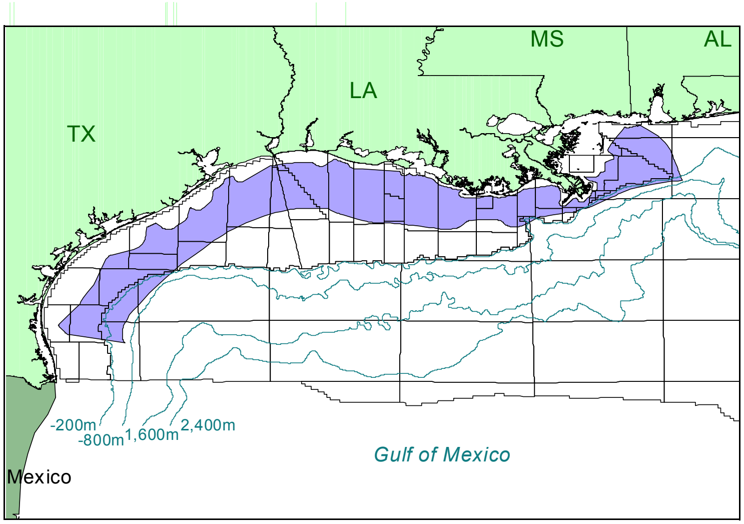


Figure 1. Play location.

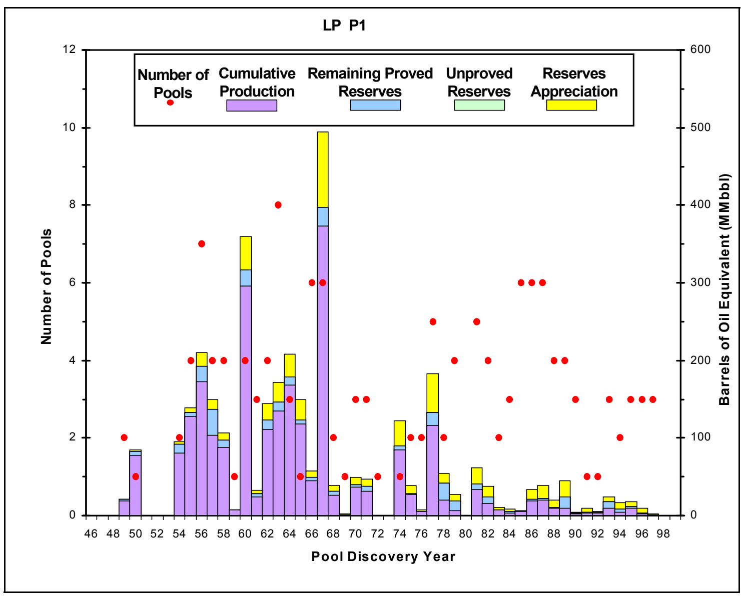


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LP P1 Play 145 Pools 752 Sands	Minimum	Mean	Maximum
Water depth (feet)	13	109	674
Subsea depth (feet)	1184	8953	15990
Number of sands per pool	1	5	36
Porosity	20%	29%	38%
Water saturation	16%	28%	61%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pliocene Progradational (LP P1) play is the fourth largest play in the Gulf of Mexico Region on the basis of cumulative production. The play occurs at the *Textularia* "X" biozone and extends from the North Padre Island and Port Isabel Areas offshore Texas to the Destin Dome Area of offshore Alabama (figure 1). Productive progradational deposits are found in a continuous band from the West Cameron Area to the eastern extent of the play, but occur very sporadically west of the West Cameron Area.

Except where the LP P1 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 A1) play. To the northeast and southwest, the LP P1 play is limited by a marked decrease in sediment influx at the edges of the LP depocenter. Downdip, the LP P1 play grades into slope shales and the deposits of the Lower Pliocene Fan 1 (LP F1) play.

Progradational deposits in offshore Texas areas southwest of the West Cameron Area 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, reflecting the depocenter shift from offshore Texas to the ancestral Mississippi River Delta System.

Play Characteristics

Sediments in the LP P1 play represent major regressive episodes of outbuilding of both the shelf and the slope. Additionally, retrogradational, reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they

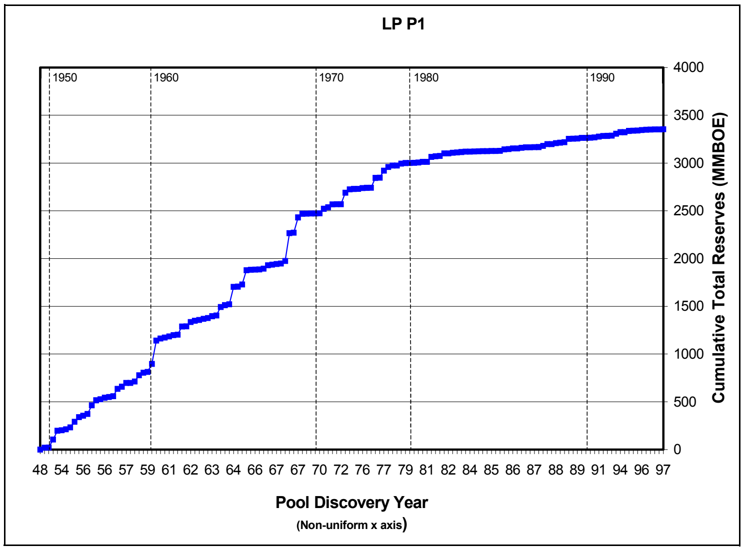


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LP P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	145	1.354	7.929	2.765
Cumulative production	–	1.233	6.880	2.457
Remaining proved	–	0.121	1.049	0.307
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	0.284	1.710	0.588
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.064	0.687	0.198
Mean	30	0.095	0.831	0.243
5th percentile	–	0.129	0.979	0.290
Total Endowment				
95th percentile	–	1.702	10.326	3.551
Mean	175	1.733	10.470	3.596
5th percentile	–	1.767	10.618	3.643

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

are included as part of the LP P1 play.

About one-third of the fields in this play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are associated with normal faults and growth fault anticlines. Some fields also contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LP P1 mixed oil and gas play contains total reserves of 1.638 Bbo and 9.639 Tcfg (3.353 BBOE), of which 1.233 Bbo and 6.880 Tcfg (2.457 BBOE) have been produced. The play contains 752 producible sands in 145 pools, and all 145 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves discovered in the play occurred in the Eugene Island 89 and Ship Shoal 28 fields in 1949 (figure 2). Maximum yearly total reserves of 495 MMBOE were added in 1967 when six pools were discovered, including the largest pool in the play, in the South Pass 61 field with 292 MMBOE in total reserves (figures 2 and 3). Though discoveries have averaged about three per year, reserves have declined significantly since the late 1960's. Ninety-seven percent of the play's total reserves and ninety-nine percent of the play's cumulative production have come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1997.

The 145 discovered pools contain 2,169 reservoirs, of which 928 are nonassociated gas, 1,069 are undersaturated oil, and 172 are saturated oil. Cumulative production

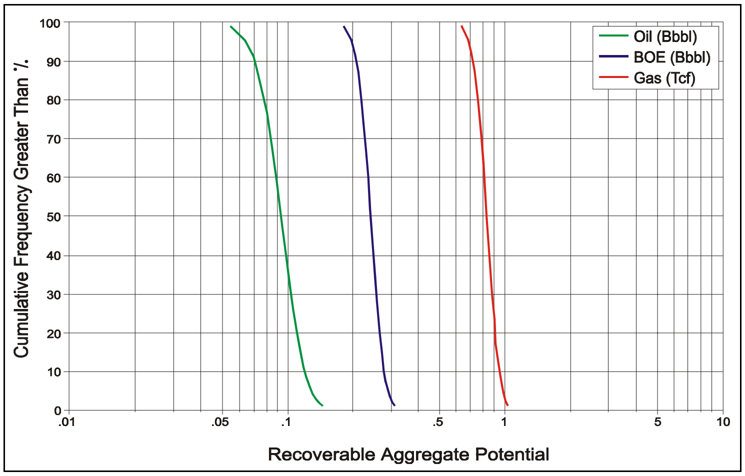


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

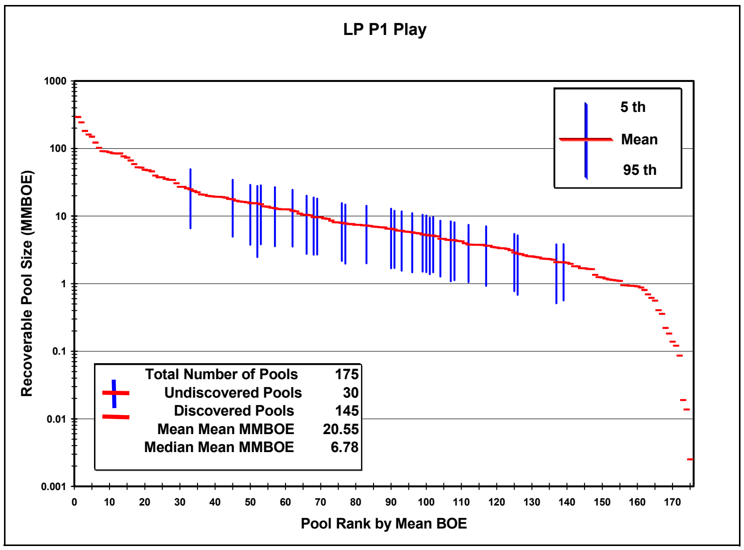


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

has consisted of 50 percent gas and 50 percent oil.

Of the 87 assessed Gulf of Mexico Region plays, the LP P1 play contains the fourth largest amount of BOE cumulative production. In fact, the play has produced the third largest amount of oil, at 11 percent of the total for the Region.

Assessment Results

The marginal probability of hydrocarbons for the LP P1 play is 1.00. This play has a mean total endowment of 1.733 Bbo and 10.470 Tcfg (3.596 BBOE) (table 2). Sixty-eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.064 to 0.129 Bbo and 0.687 to 0.979 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.095 Bbo and 0.831 Tcfg (0.243 BBOE). These undiscovered resources might occur in as many as 30 pools, the largest of which has a mean size of 25 MMBOE (figure 5). The five largest undiscovered pools occupy positions 33, 45, 50, 52, and 53 on the pool rank plot. For all the undiscovered pools in the LP P1 play, the mean mean size is 8 MMBOE, which is substantially smaller than the 23 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 21 MMBOE.

Of the 13 progradational plays in the Gulf of Mexico, the LP P1 play is projected to contain the second largest amount of mean undiscovered conventionally recoverable oil resources.

The LP P1 is a super-mature play with BOE mean UCRR contributing only 7 percent to the play's BOE mean total endowment. Limited exploration potential exists in deeper LP P1 sections around salt structures where the play may not be adequately tested.

Lower Pliocene Fan 1 (LP F1) Play

***Textularia* "X" biozone**

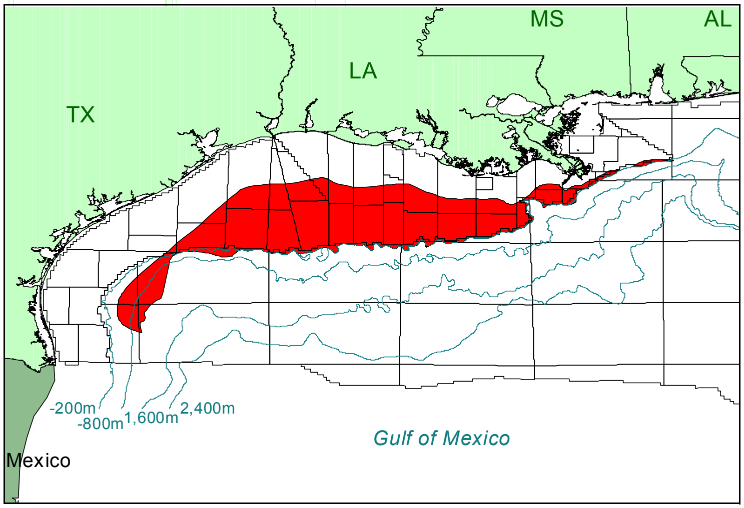


Figure 1. Play location.

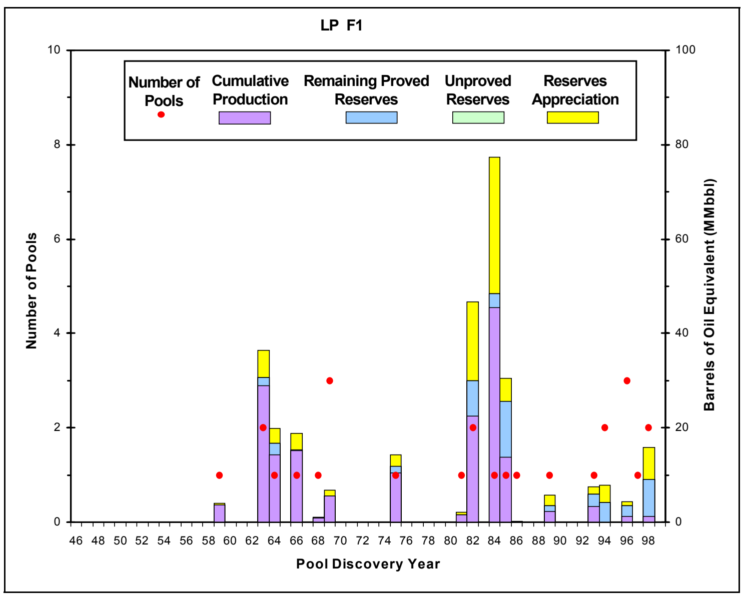


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LP F1 Play 26 Pools 82 Sands	Minimum	Mean	Maximum
Water depth (feet)	63	205	635
Subsea depth (feet)	9110	13429	17162
Number of sands per pool	1	3	9
Porosity	22%	26%	31%
Water saturation	23%	32%	68%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pliocene Fan 1 (LP F1) play occurs within the *Textularia* "X" biozone and is defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. This play extends from the Corpus Christi and Port Isabel Areas offshore Texas to the Viosca Knoll Area near 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 by the Lower Pliocene Progradational (LP P1) play. To the southwest, the play is limited by a marked decrease in sediment influx at the edge of the LP depocenter. Downdip, the play is limited by the structural boundary of the Lower Pliocene Fan 2 (LP F2) play.

The offshore Texas area no longer received significant amounts of sand during LP time compared with UM3 time, reflecting the depocenter shift to the ancestral Mississippi River Delta System.

Play Characteristics

The LP F1 play is characterized by deepwater turbidites deposited basinward of the LP shelf margin on the LP upper and lower slope, in topographically low areas between salt structure highs and on the abyssal plain. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Most of the fields in LP F1 are structurally associated with salt diapirs and normal faults. A few fields

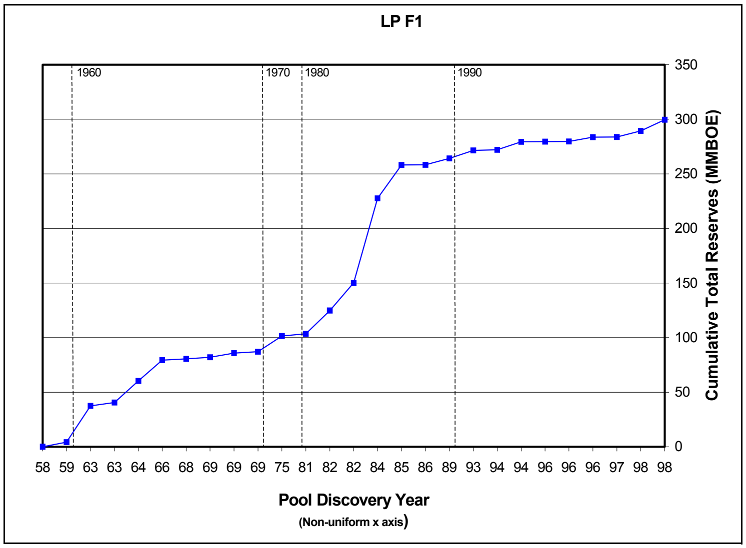


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LP F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	26	0.051	0.928	0.217
Cumulative production	–	0.043	0.719	0.170
Remaining proved	–	0.009	0.209	0.046
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	0.019	0.358	0.083
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.034	0.606	0.148
Mean	31	0.052	0.850	0.203
5th percentile	–	0.075	1.114	0.266
Total Endowment				
95th percentile	–	0.105	1.892	0.448
Mean	57	0.122	2.136	0.503
5th percentile	–	0.146	2.400	0.566

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LP F1 mixed oil and gas play contains total reserves of 0.071 Bbo and 1.286 Tcfg (0.300 BBOE), of which 0.043 Bbo and 0.719 Tcfg (0.170 BBOE) have been produced. The play contains 82 producible sands in 26 pools, and all 26 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). 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. Maximum yearly total reserves of 77 MMBOE were added in 1984 when the largest pool in the play was discovered in the South Pass 83 field (figures 2 and 3). This field alone accounts for 26 percent of the play's total reserves. Over 96 percent of the play's cumulative production and 88 percent of its total reserves have come from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, occurred in 1998.

The 26 discovered pools contain 132 reservoirs, of which 80 are nonassociated gas, 50 are undersaturated oil, and 2 are saturated oil. Cumulative production has consisted of 75 percent gas and 25 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the LP F1 play is 1.00. The play contains a mean total endowment of 0.122 Bbo and 2.136 Tcfg (0.503 BBOE) (table 2). Thirty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate

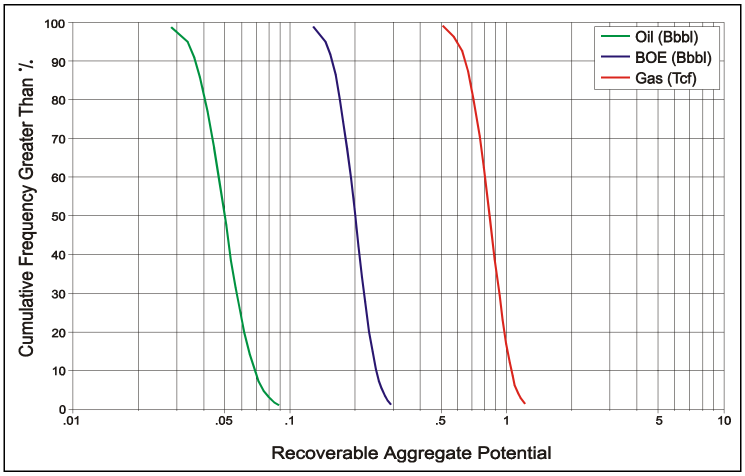


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

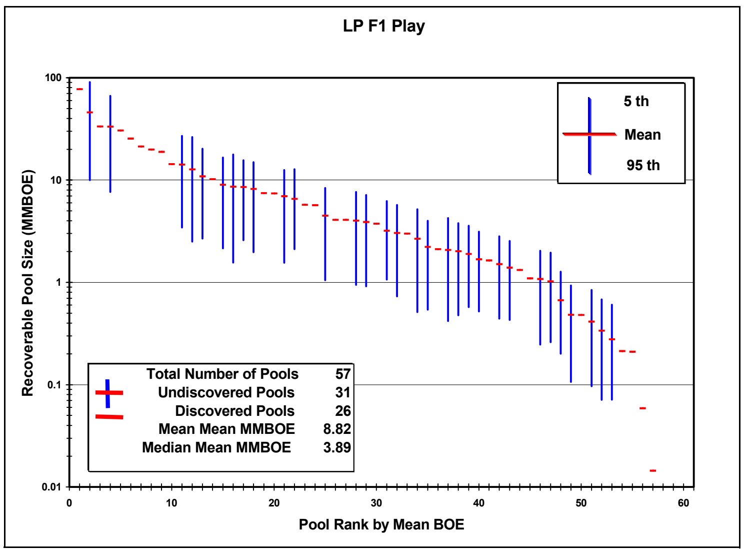


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

that undiscovered conventionally recoverable resources (UCRR) have a range of 0.034 to 0.075 Bbo and 0.606 to 1.114 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.052 Bbo and 0.850 Tcfg (0.203 BBOE). These undiscovered resources might occur in as many as 31 pools. The largest undiscovered pool, with a mean size of 46 MMBOE, is forecast as the second largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 4, 11, 12, and 13 on the pool rank plot. For all the undiscovered pools in the LP F1 play, the mean mean size is 7 MMBOE, which is smaller than the 11 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 9 MMBOE.

The LP F1 is a relatively well-explored play; however, the play's area contains allochthonous salt sheets with LP potential both above and below salt. BOE mean UCRR are expected to contribute 40 percent to the play's BOE mean total endowment.

Lower Pliocene Fan 2 (LP F2) Play

Textularia "X" biozone

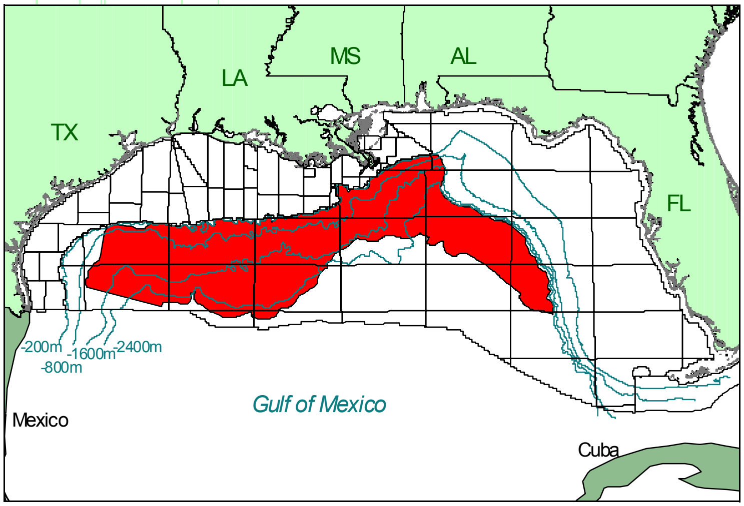


Figure 1. Play location.

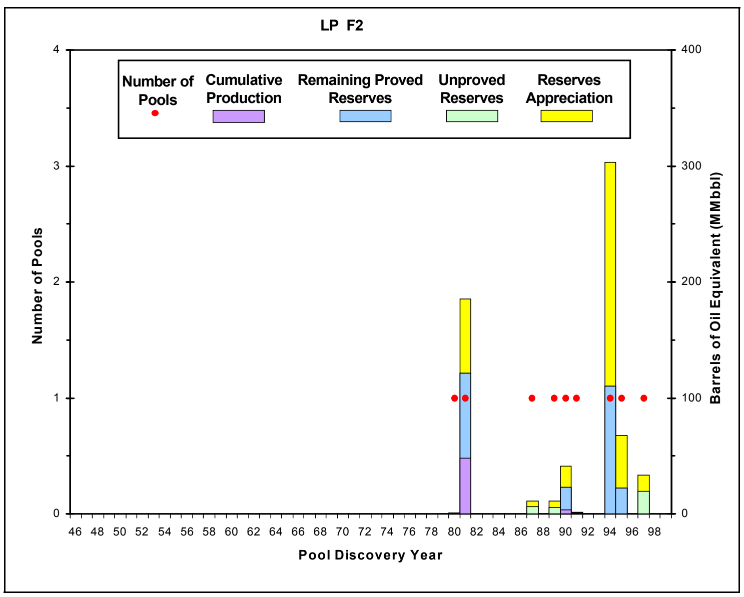


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LP F2 Play 9 Pools 18 Sands	Minimum	Mean	Maximum
Water depth (feet)	1023	3438	7500
Subsea depth (feet)	6110	12062	16231
Number of sands per pool	1	2	5
Porosity	27%	30%	35%
Water saturation	17%	29%	46%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Pliocene Fan 2 (LP F2) play occurs within the *Textularia* "X" biozone. The play is also defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. This play extends from the East Breaks and Alaminos Canyon Areas to the southwestern Destin Dome and western Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas of offshore Florida (figure 1).

Updip, the play is bounded by the Lower Pliocene Fan 1 (LP F1) play. To the west and northeast, the play is limited by a marked decrease in sediment influx at the edge of the LP depocenter, while to the east, the play onlaps the Cretaceous carbonate slope. Downdip, the LPL F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf of Mexico Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps deposited on the LP upper and lower slope, in topographically low areas between salt structure highs and on the abyssal plain. These deep-sea fan sys-

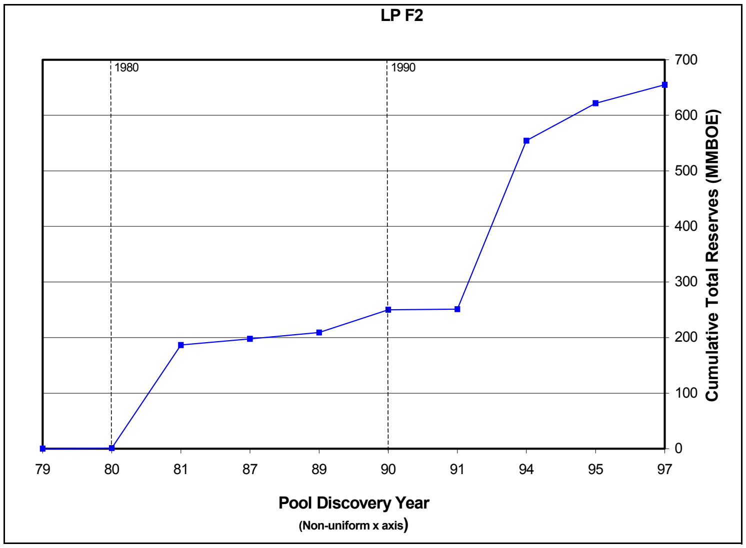


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LP F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	6	0.214	0.359	0.278
Cumulative production	–	0.042	0.055	0.052
Remaining proved	–	0.172	0.304	0.226
Unproved	3	0.023	0.047	0.031
Appreciation (P & U)	–	0.257	0.499	0.346
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.787	3.081	1.406
Mean	51	0.992	4.820	1.850
5th percentile	–	1.228	9.585	2.721
Total Endowment				
95th percentile	–	1.281	3.987	2.061
Mean	60	1.486	5.726	2.505
5th percentile	–	1.722	10.491	3.376

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

tems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

The majority of the fields in the LP F2 play are structurally associated with salt bodies with hydrocarbons trapped on salt flanks or in sediments draped over salt. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LP F2 is predominately an oil play containing total reserves of 0.494 Bbo and 0.906 Tcfg (0.655 BBOE), of which 0.042 Bbo and 0.055 Tcfg (0.052 BBOE) have been produced. The play contains 18 producible sands in 9 pools, of which 6 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1980 in the Mississippi Canyon 194 field (Cognac) (figure 2). Maximum yearly total reserves of 303 MMBOE were added in 1994 when the largest pool in the play was discovered in the Mississippi Canyon 935 field (Europa). Europa contains an estimated 303 MMBOE in total reserves (figures 2 and 3). Just under 94 percent of the play's cumulative production and 32 percent of its total reserves have come from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, occurred in 1997.

The nine discovered pools contain 24 reservoirs, of which 3 are nonassociated gas, 18 are undersaturated oil, and 3 are saturated oil. Cumulative production has consisted of 81 percent oil and 19 percent gas.

Assessment Results

The marginal probability of hydrocarbons for the LP F2 play is 1.00. The play contains a mean total endowment of 1.486 Bbo and 5.726

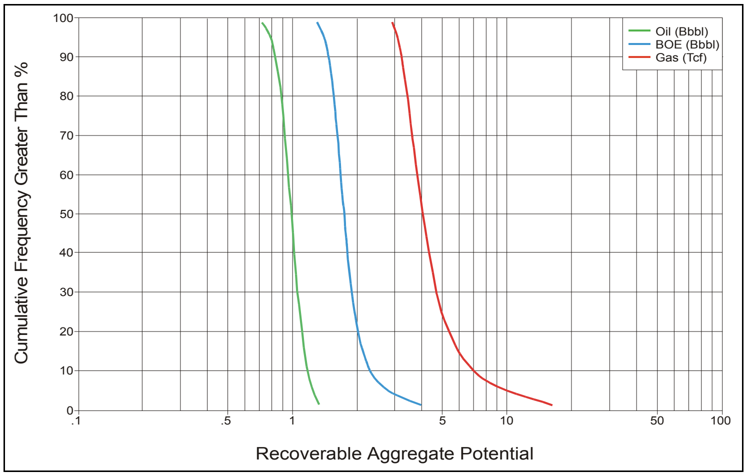


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

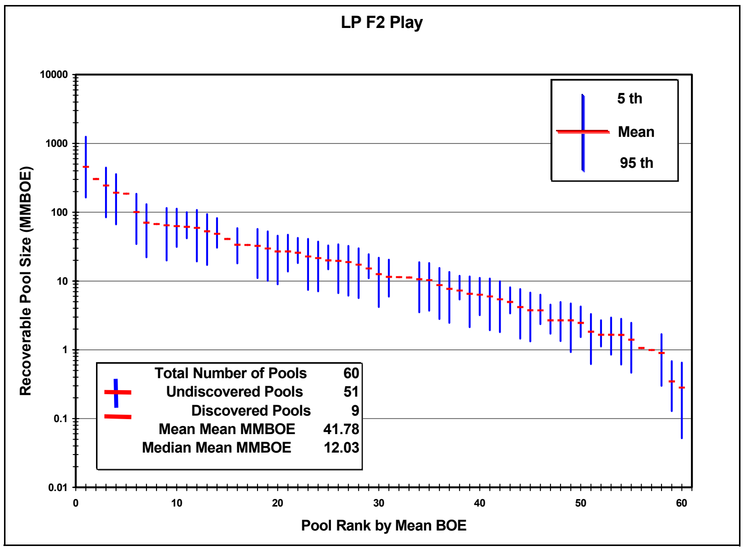


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Tcfg (0.2.505 BBOE) (table 2). Only 2 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.787 to 1.228 Bbo and 3.081 to 9.585 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.992 Bbo and 4.820 Tcfg (1.850 BBOE). These undiscovered resources might occur in as many as 51 pools. The largest undiscovered pool, with a mean size of 456 MMBOE, is also forecast as the largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 3, 4, 6, and 7 on the pool rank plot. For all the undiscovered pools in the LP F2 play, the mean mean size is 36 MMBOE, which is smaller than the 73 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 42 MMBOE.

The LP F2 is an immature play forecast to have 1.850 BBOE in mean UCRR, contributing 74 percent to the play's BOE mean total endowment. Future discoveries are expected to be made in structural and stratigraphic closures around salt, as well as below salt in a variety of structural and stratigraphic traps.

Upper Upper Miocene Retrogradational (UM3 R1) Play

Cristellaria "K" through *Robulus* "E" biozones

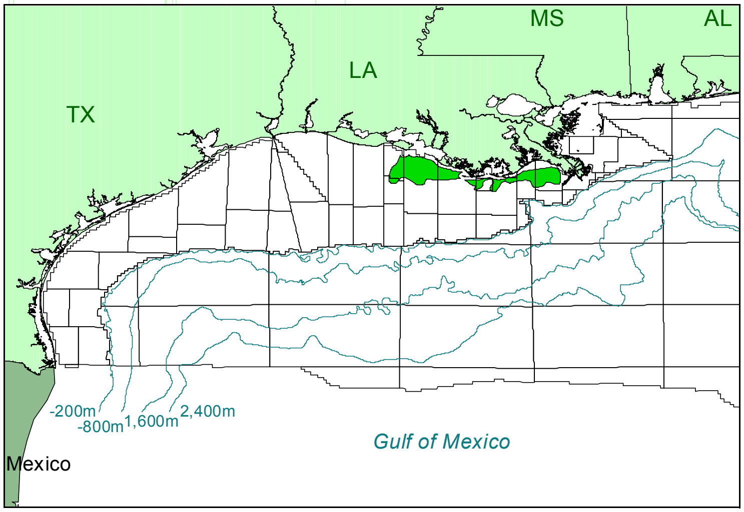


Figure 1. Play location.

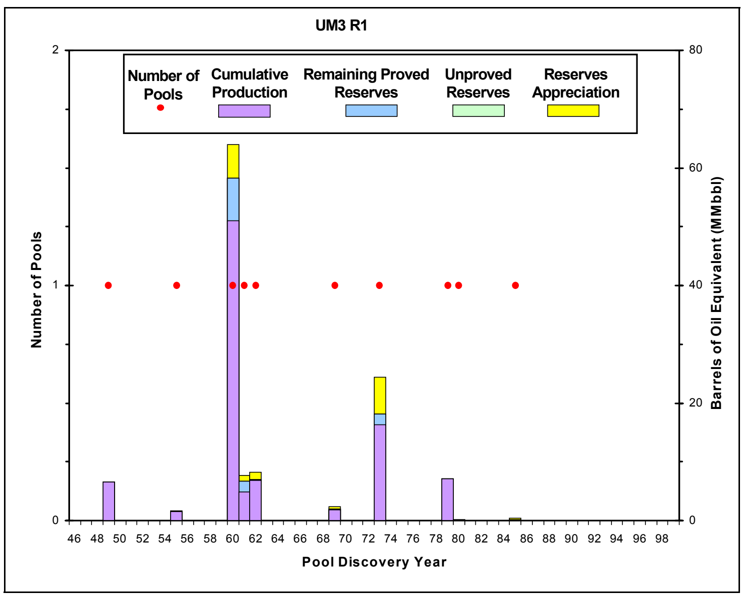


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM3 R1 Play **10 Pools 18 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	13	59	139
Subsea depth (feet)	7200	9607	11152
Number of sands per pool	1	2	3
Porosity	25%	28%	33%
Water saturation	18%	30%	42%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Upper Miocene Retrogradational (UM3 R1) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. This play extends from the South Marsh Island Area to the West Delta Area offshore Louisiana (figure 1).

Updip, the play continues onshore. To the east, west, and downdip, the play grades into either deposits of the Upper Upper Miocene Aggradational (UM3 A1) play or the Upper Upper Miocene Progradational (UM3 P1) play.

Clastic influx in the offshore Texas area was waning during UM3 time, and thus the UM3 R1 play is sand-poor toward the west. Because UM3 retrogradational sands in offshore Texas are poorly developed and discontinuous, they are not considered for play analysis.

Play Characteristics

Retrogradational sediments of the play are characterized by the reworking of UM3 R1 shelf sands during relative sea level rises. These retrogradational sands become progressively thinner and finer vertically and exhibit a back-stepping log signature, terminating in the *Robulus* "E" flooding surface.

Half of the fields in this play are structurally associated with salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are structurally associated with growth fault anticlines and simple anticlines. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

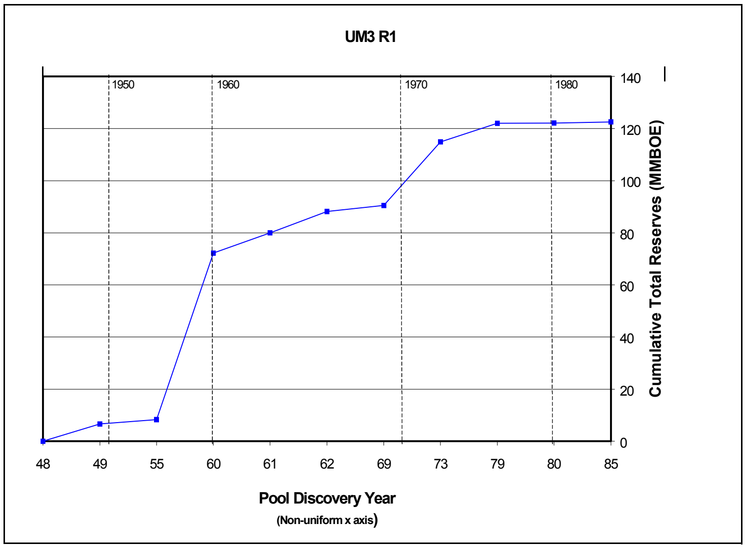


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM3 R1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	10	0.051	0.319	0.108
Cumulative production	--	0.045	0.286	0.096
Remaining proved	--	0.005	0.033	0.011
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.006	0.049	0.015
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.001	0.012	0.003
Mean	3	0.002	0.021	0.006
5th percentile	--	0.004	0.031	0.008
Total Endowment				
95th percentile	--	0.058	0.379	0.126
Mean	13	0.059	0.388	0.129
5th percentile	--	0.061	0.398	0.131

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Discoveries

The UM3 R1 mixed gas and oil play contains total reserves of 0.057 Bbo and 0.367 Tcfg (0.123 BBOE), of which 0.045 Bbo and 0.286 Tcfg (0.096 BBOE) have been produced. The play contains 18 producible sands in 10 pools (table 1). The first reserves were added in 1949. Maximum yearly total reserves were added in 1960, when the largest discovered pool in the play was found in the Grand Isle 43 field with 64 MMBOE in total reserves (figure 2). The most recent discovery occurred in 1985.

The 10 discovered pools contain 58 reservoirs, of which 25 are nonassociated gas, 22 are undersaturated oil, and 11 are saturated oil. Cumulative production has consisted of 53 percent gas and 47 percent oil.

Assessment Results

Because of limited data for the UM3 R1 play, the Upper Lower Miocene Retrogradational (LM4 R1) play was used as an analog to forecast pool sizes in the UM3 R1 play. The analog play was selected 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 has a mean total endowment of 0.059 Bbo and 0.388 Tcfg (0.129 BBOE) (table 2). Seventy-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.001 to 0.004 Bbo and 0.012 to 0.031 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR are 0.002 Bbo and 0.021 Tcfg (0.006 BBOE). These undiscovered resources might occur in as many as three pools. The largest undiscovered pool, with a mean size of 3 MMBOE, is forecast as the seventh largest pool in the play (figure 4). The other two undiscovered pools occupy positions 8 and 11 on

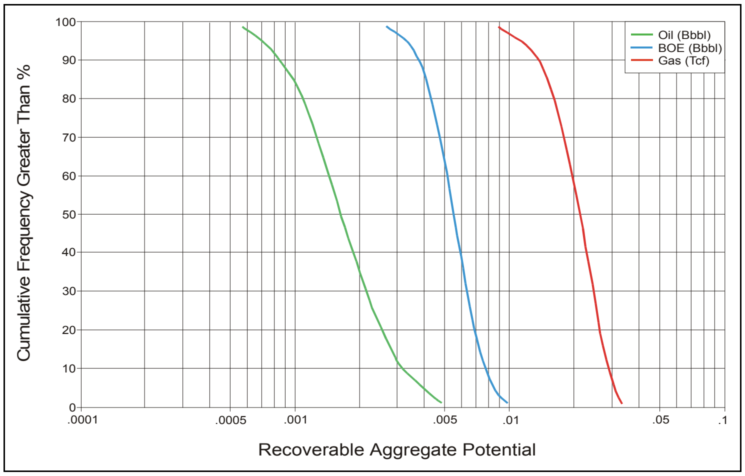


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

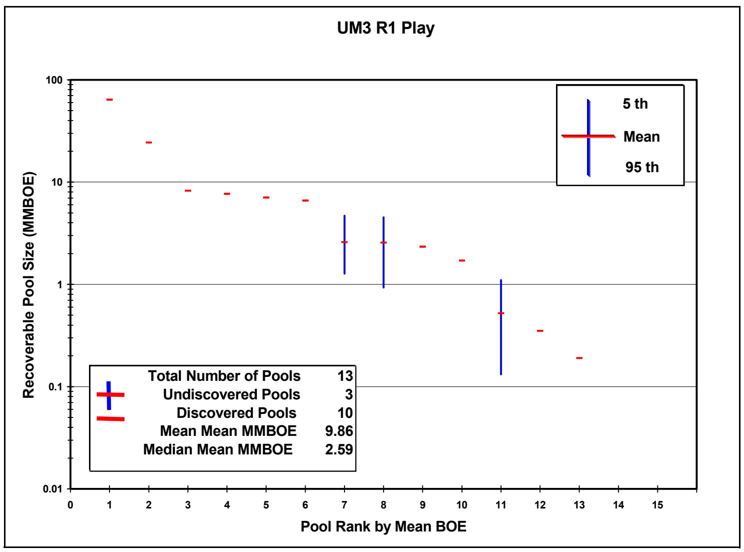


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

the pool rank plot. For all the three of the undiscovered pools in the UM3 R1 play, the mean mean size is 2 MMBOE, which is less than the 12 MMBOE mean size of the discovered pools. The mean mean size of all pools, including both discovered and discovered, is 10 MMBOE.

BOE mean UCRR contribute only 5 percent to the play's BOE mean total endowment. No pools have been discovered in the play since 1985.

Upper Upper Miocene Aggradational (UM3 A1) Play

***Cristellaria* "K" through *Robulus* "E" biozones**

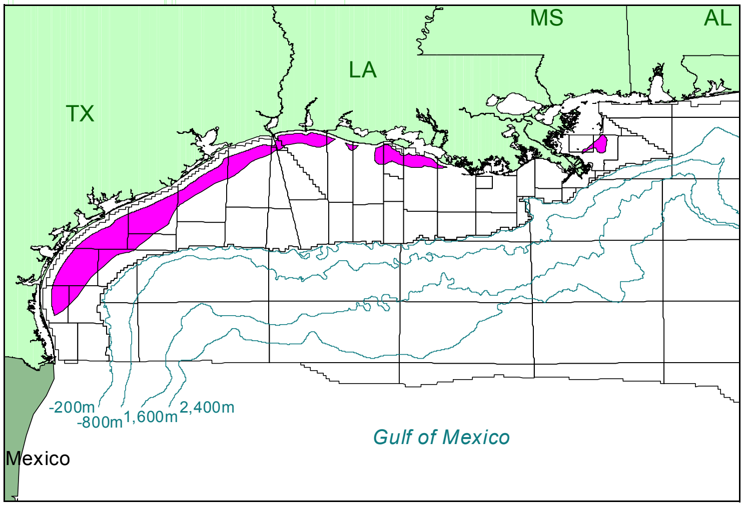


Figure 1. Play location.

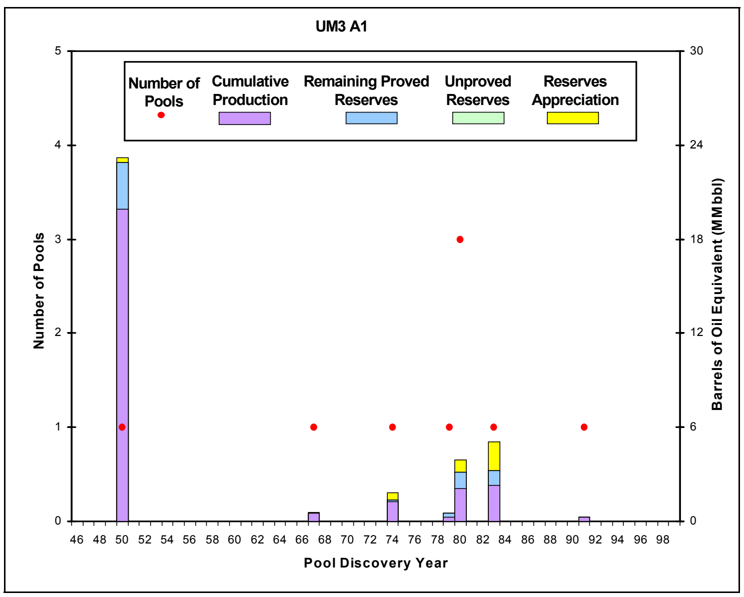


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM3 A1 Play 9 Pools 21 Sands	Minimum	Mean	Maximum
Water depth (feet)	11	29	71
Subsea depth (feet)	1375	5910	9624
Number of sands per pool	1	2	8
Porosity	31%	33%	35%
Water saturation	16%	20%	32%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Upper Miocene Aggradational (UM3 A1) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. This play extends in a discontinuous band from the North Padre Island Area offshore Texas to the Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Texas and Louisiana. To the southwest, the play continues into onshore Texas, while to the northeast the play is limited by deposits of the Upper Upper Miocene Aggradational/Progradational (UM3 AP1) play. Downdip, the play grades into the deposits of the Upper Upper Miocene Progradational (UM3 P1) play.

In offshore Texas, aggradational sequences of the UM3 chronozone and the underlying lower upper Miocene (UM1) chronozones occupy similar geographical areas, indicating stable shelf sedimentation. However, in the Louisiana offshore, the downdip extent of the UM3 aggradational sequence is located much farther offshore than the downdip extent of the underlying UM1 aggradational sequence. Therefore, UM3 aggradational sediments overlie the UM1 progradational sediments.

Play Characteristics

The Louisiana offshore area had a higher clastic influx than did the Texas offshore area during UM3 time. Consequently, UM3 sands in offshore Louisiana tend to be thick and well developed. These sands were deposited in various fluvial-deltaic to shallow marine depositional environments, including point bars, distributary channel/levee complexes, crevasse splays, distributary mouth bars, beaches, barrier islands, and offshore marine bars. In contrast,

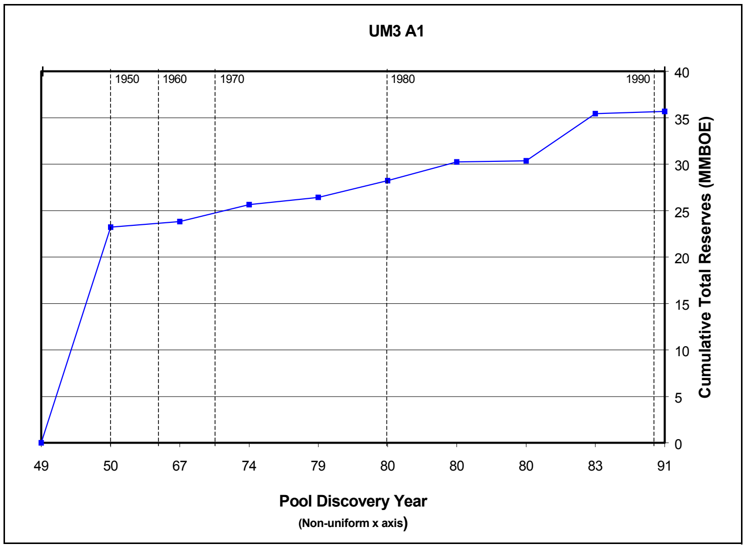


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM3 A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	9	0.019	0.074	0.032
Cumulative production	--	0.016	0.057	0.027
Remaining proved	--	0.002	0.017	0.005
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.019	0.004
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.007	0.001
Mean	3	<0.001	0.018	0.003
5th percentile	--	<0.001	0.030	0.006
Total Endowment				
95th percentile	--	0.019	0.099	0.037
Mean	12	0.019	0.110	0.039
5th percentile	--	0.019	0.122	0.041

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

the offshore Texas area had a lower influx of clastics during UM3 time, resulting in fewer, thinner sands. These sands were deposited behind barrier islands in distributary crevasse splays and storm-generated washover fans.

Most of the fields in UM3 A1 are structurally associated with normal faults and growth fault anticlines. The remaining fields are associated with simple anticlines or hydrocarbon accumulations trapped by permeability barriers and updip pinchouts or facies changes. Seals are provided by lateral shale-outs and overlying shelf shales.

Discoveries

The UM3 A1 play is a mixed oil and gas play, with total reserves of 0.019 Bbo and 0.092 Tcfg (0.036 BBOE), of which 0.016 Bbo and 0.057 Tcfg (0.027 BBOE) have been produced. The play contains 21 producible sands in nine pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1950 in the Eugene Island 32 field. This field also added the maximum yearly total reserves in the play of 23 MMBOE (figure 2). A hiatus in pool discoveries occurred between 1950 and 1967, but then seven out of the nine pools were discovered between 1967 and 1983 (figures 2 and 3). Ninety-nine percent of the play's cumulative production and total reserves were discovered before 1990, indicative of the maturity of the play. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1991.

The nine discovered pools contain 24 reservoirs, of which 13 are nonassociated gas, 7 are undersaturated oil, and 4 are saturated oil. Cumulative production has consisted of 62 percent oil and 38 percent gas.

Assessment Results

The marginal probability of hydrocarbons for the UM3 A1 play is 1.00. The play has a mean total

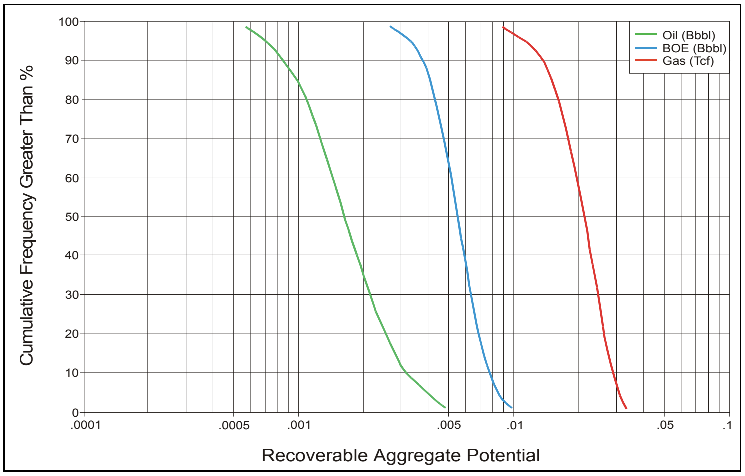


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

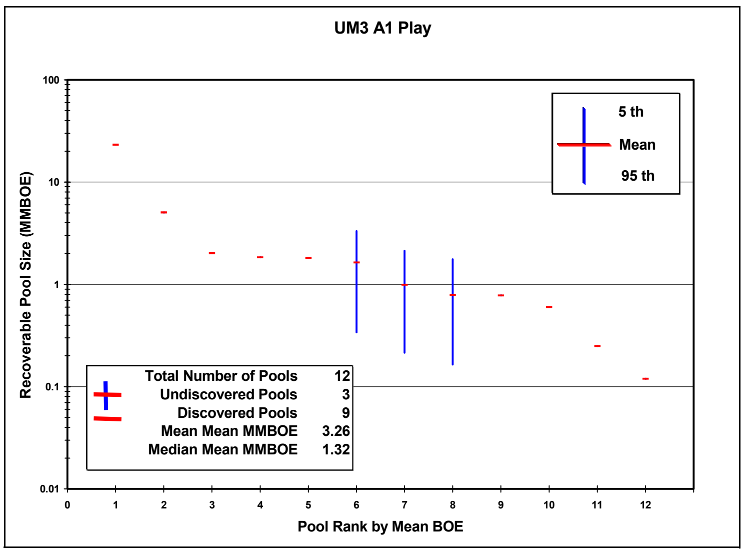


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment of 0.019 Bbo and 0.110 Tcfg (0.039 BBOE) (table 2). Sixty-nine percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable oil resources are insignificant (<0.001 Bbo) and that undiscovered conventionally recoverable gas resources have a range of 0.007 to 0.030 Tcf at the 95th and 5th percentiles, respectively (figure 4). The forecast amount of mean undiscovered conventionally recoverable gas resources is 0.018 Tcf (0.003 BBOE). These undiscovered resources might occur in as many as three pools. The largest undiscovered pool, with a mean size of 2 MMBOE, is forecast as the 6th largest pool in the play (figure 5). The forecast places the remaining two undiscovered pools in positions 7 and 8 on the pool rank plot. The three undiscovered pools have a mean mean size of 1 MMBOE, which is significantly smaller than the 4 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 3 MMBOE.

The UM3 A1 is a supermature play with BOE mean undiscovered conventionally recoverable resources forecast to contribute 8 percent to the play's BOE mean total endowment.

Upper Upper Miocene Aggradational/Progradational (UM3 AP1) Play *Cristellaria* "K" through *Robulus* "E" biozones

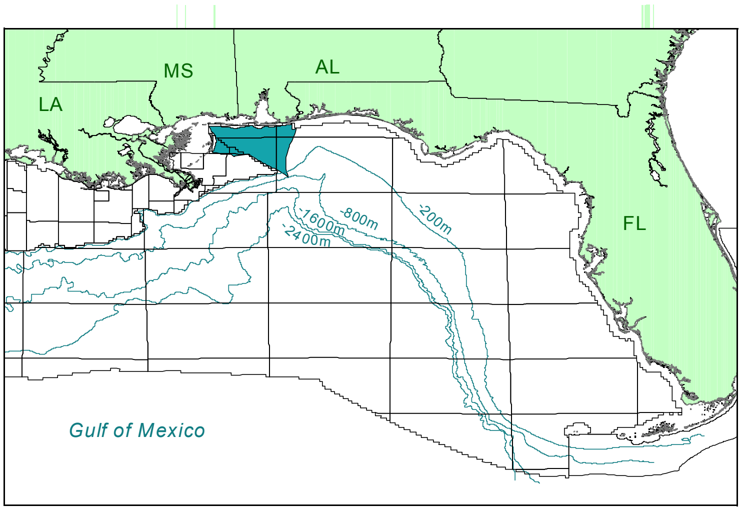


Figure 1. Play location.

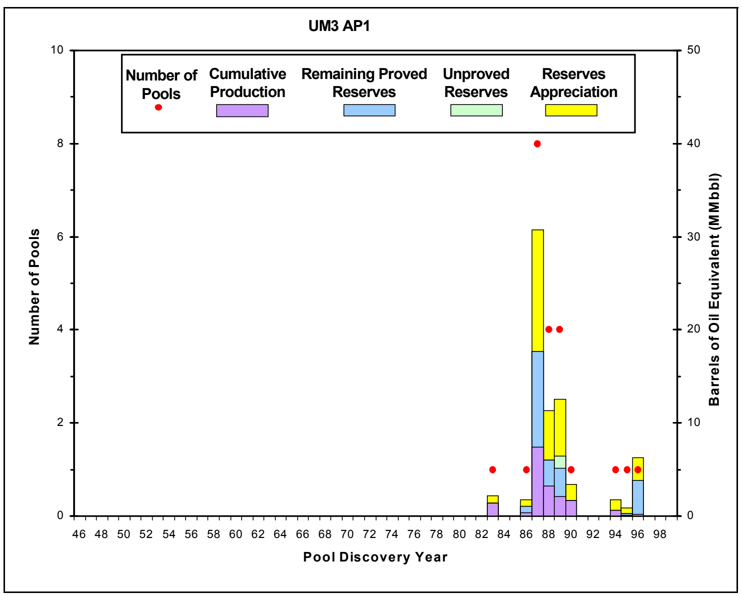


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM3 AP1 Play 22 Pools 31 Sands	Minimum	Mean	Maximum
Water depth (feet)	40	92	130
Subsea depth (feet)	1370	2544	3850
Number of sands per pool	1	1	5
Porosity	23%	34%	39%
Water saturation	16%	26%	48%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Upper Miocene Aggradational/Progradational (UM3 AP1) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. The play is also defined by minimal structural deformation and gas accumulations associated with seismic hydrocarbon indicators (bright spots). The play overlies the Cretaceous carbonate shelf in the Mobile, western Pensacola, northern Chandeleur, northern Viosca Knoll, and western Destin Dome Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Mississippi and Alabama, while downdip, the play downlaps the Cretaceous carbonate shelf.

The UM3 AP1 play is one of three plays within the combined aggradational and progradational (AP) "Shallow Miocene Bright Spot Trend." The other two plays are the Lower Upper Miocene Aggradational/Progradational (UM1 AP1) play and the Upper Middle Miocene Aggradational/Progradational (MM9 AP1) play. Of the three aggradational/progradational plays in the Gulf of Mexico Region, the UM3 AP1 is the largest on the basis of undiscovered conventionally recoverable resources (UCRR).

Play Characteristics

Two different depositional styles are found in the play area. The first depositional style resulted from deposition in a constructional deltaic system with a higher clastic influx. These deposits are found in northern Viosca Knoll, Chandeleur, and part of the Mobile Areas. This constructional deltaic system prograded out onto the Lower Cretaceous carbonate shelf. The sequence is characterized by fluvial point bars and distributary mouth bars with subordinate marine

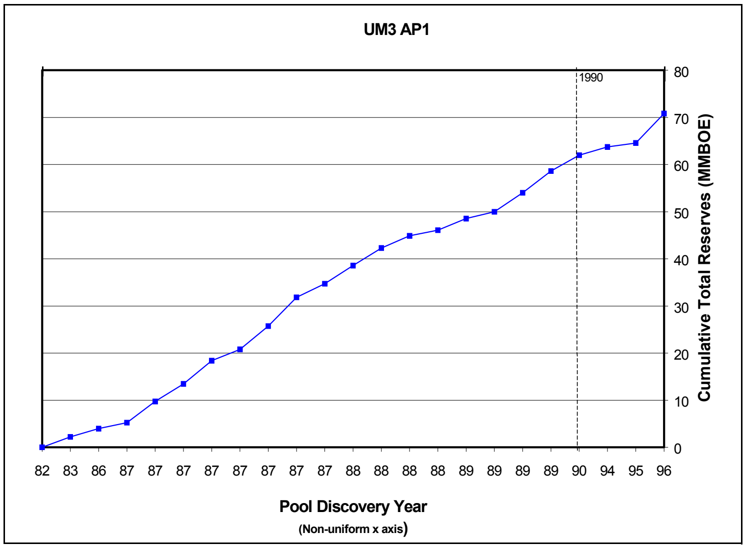


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM3 AP1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	21	<0.001	0.211	0.038
Cumulative production	--	<0.001	0.095	0.017
Remaining proved	--	<0.001	0.116	0.021
Unproved	1	<0.001	0.007	0.001
Appreciation (P & U)	--	<0.001	0.179	0.032
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.199	0.035
Mean	19	<0.001	0.236	0.042
5th percentile	--	<0.001	0.276	0.049
Total Endowment				
95th percentile	--	<0.001	0.597	0.106
Mean	41	<0.001	0.634	0.113
5th percentile	--	<0.001	0.674	0.120

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

bar sands deposited within inner to middle neritic depths of the shelf. This sequence contains less shale and more sand than in the onshore equivalent strata.

The second depositional style, found in onshore Alabama and part of the offshore Mobile Area, resulted from deposition in a sand-poor, destructional deltaic system characterized by marine bars. This later depositional sequence contains mostly shale with subordinate amounts of bar sands (Mink et. al., 1988).

Stratigraphic traps dominate the play. Faulting and local uplifts are rare and have a limited role in the accumulation of hydrocarbons. The Cretaceous carbonate shelf created a stable platform for sediment deposition. Consequently, the Miocene deposits of the three AP plays appear minimally affected by salt movement and faulting. The stratigraphic traps are influenced by a combination of pinchout and subtle structural flexure over anticlinal noses (Mink et. al., 1988). Seals are provided by lateral shale-outs and overlying shelf shales.

Discoveries

The UM3 AP1 gas play contains total reserves of <0.001 Bbo and 0.398 Tcfg (0.071 BBOE), of which <0.001 Bbo and 0.095 Tcfg (0.017 BBOE) have been produced. The play contains 31 producible sands in 22 pools, and 21 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1983 in the Chandeleur 14 field (figure 2). Maximum yearly total reserves of 31 MMBOE were added in 1987 when 8 pools were discovered. The largest pool in the play was discovered in 1996 in the Chandeleur 21 field with 6 MMBOE in total reserves (figures 2 and 3). Eighty-five percent of the play's cumulative production and 83 percent of the play's total reserves have come from pools discovered prior to 1990. The most recent dis-

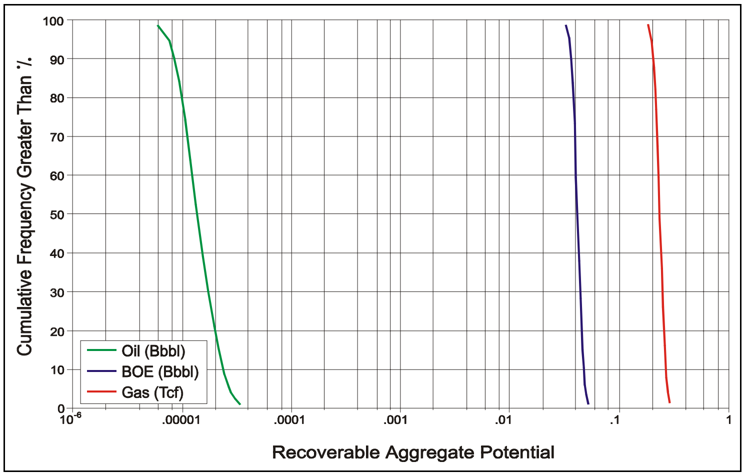


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

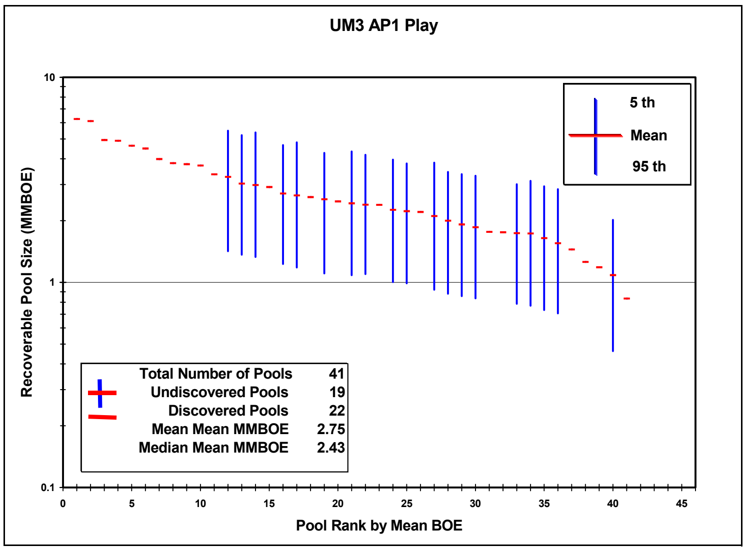


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

covery, prior to this study's cutoff date of January 1, 1999, was in 1996.

The 22 discovered pools contain 33 reservoirs, all of which are nonassociated gas. Gas in the play is biogenically derived (Mink et al., 1988).

Assessment Results

The marginal probability of hydrocarbons for the UM3 AP1 play is 1.00. The play has a mean total endowment of less than 0.001 Bbo and 0.634 Tcfg (0.113 BBOE) (table 2). Fifteen percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable oil resources are insignificant (<0.001 Bbo) and that undiscovered conventionally recoverable gas resources have a range of 0.199 to 0.276 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean undiscovered conventionally recoverable gas resources are 0.236 Tcfg (0.042 BBOE). These undiscovered resources might occur in as many as 19 pools. The largest undiscovered pool, with a mean size of 3 MMBOE, is forecast as the 12th largest pool in the play (figure 5). The forecast places the remaining four undiscovered pools in positions 13, 14, 16 and 17 on the pool rank plot. For all the undiscovered pools in the UM3 AP1 play, the mean mean size is 2 MMBOE, which is smaller than the 3 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 3 MMBOE.

UCRR contribute 37 percent to the play's BOE mean total endowment. Future discoveries are dependent on the economics of drilling and developing remaining bright-spot-defined reservoirs.

Reference

Mink, R.M., Mancini, E.A., Bearden, B.L., and C. C. Smith. 1988. Middle and upper Miocene natural gas sands in onshore and offshore Alabama: Gulf Coast Association of Geological Societies Transactions, vol. 36, p. 1-6.

Upper Upper Miocene Progradational (UM3 P1) Play

***Cristellaria* "K" through *Robulus* "E" biozones**

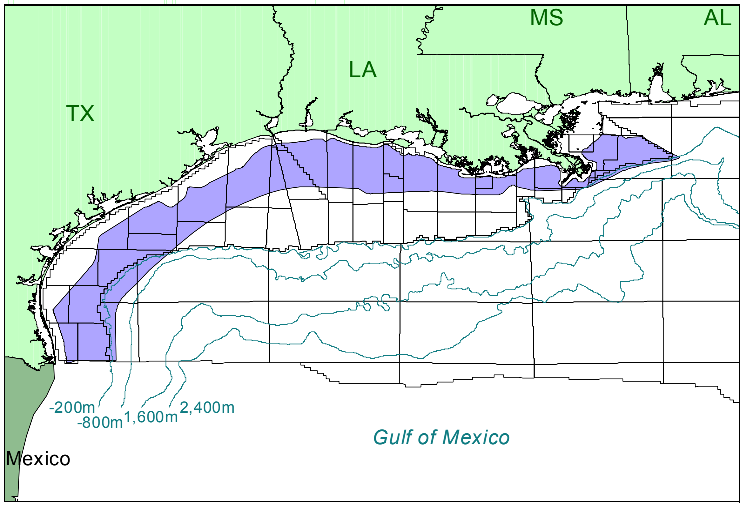


Figure 1. Play location.

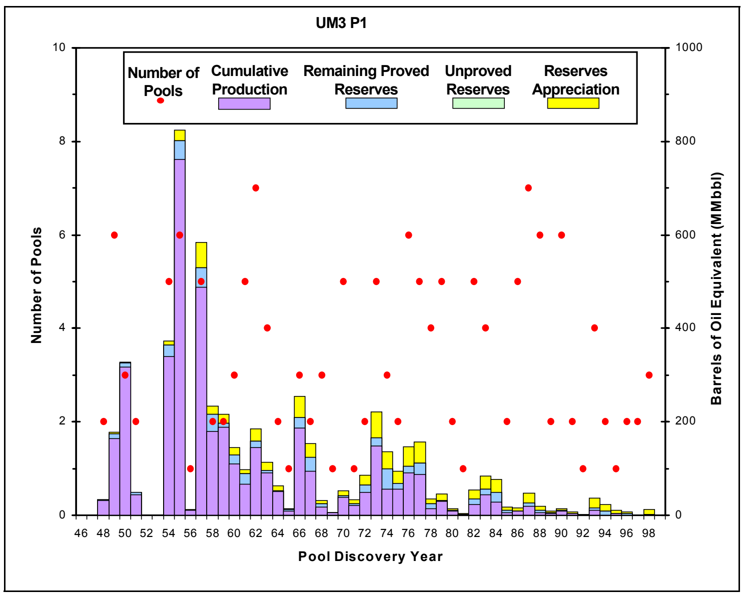


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM3 P1 Play 174 Pools 1067 Sands	Minimum	Mean	Maximum
Water depth (feet)	9	73	339
Subsea depth (feet)	1725	8505	16846
Number of sands per pool	1	6	44
Porosity	19%	29%	37%
Water saturation	16%	28%	55%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The Upper Upper Miocene Progradational (UM3 P1) play is the second largest play in the Gulf of Mexico Region on the basis of BOE total reserves and BOE cumulative production. The play has also produced the most oil of any play in the Gulf of Mexico Region. The UM3 P1 play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones 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 deposits of the Upper Upper Miocene Aggradational (UM3 A1) play, while in Louisiana, the UM3 P1 play continues onshore. The play continues to the southwest into Texas State and Mexican national waters. To the northeast, the play is limited by the deposits of the Upper Upper Miocene Aggradational/Progradational (UM3 AP1) play overlying the Cretaceous carbonate shelf. Downdip and to the east, the UM3 P1 play grades into the deposits of the Upper Upper Miocene Fan 1 (UM3 F1) play.

Play Characteristics

The 29 reservoir sands offshore Texas were deposited mostly in distal portions of prograding delta lobes or offshore bars. Many of these sands are thin and poorly developed because of a low influx of clastics into the offshore Texas area during UM3 time. Consequently, many UM3 progradational sands in the Texas offshore have not been prolific reservoirs. In fact, in the South Padre Island and Mustang Island Areas, the progradational facies is present but not productive.

The 1,038 reservoir sands of the offshore Louisiana area were deposited in delta fringes, channel/

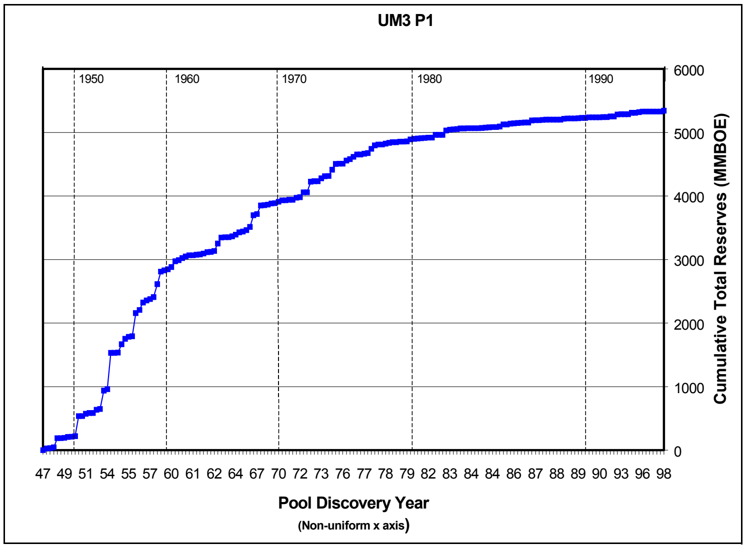


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM3 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	172	2.421	12.207	4.593
Cumulative production	--	2.183	10.525	4.056
Remaining proved	--	0.238	1.682	0.537
Unproved	2	<0.001	0.002	<0.001
Appreciation (P & U)	--	0.299	2.517	0.747
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.054	0.734	0.195
Mean	35	0.079	0.885	0.236
5th percentile	--	0.107	1.046	0.281
Total Endowment				
95th percentile	--	2.774	15.460	5.536
Mean	209	2.799	15.611	5.577
5th percentile	--	2.827	15.772	5.622

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

levee complexes, and distributary mouth bars. Because the central offshore Louisiana area was the locus of the main UM3 deltaic depocenter, these sands are thick and well developed. The thickest sand-dominated intervals probably represent stacked facies of multiple episodes of delta-lobe switching and progradation.

The majority of the fields in this play are structurally associated with normal faults and salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are structurally associated with growth fault anticlines, while some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UM3 P1 mixed oil and gas play contains total reserves of 2.720 Bbo and 14.726 Tcfg (5.341 BBOE), of which 2.183 Bbo and 10.525 Tcfg (4.056 BBOE) have been produced. The play contains 1,067 producible sands in 174 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Ship Shoal 72 field in 1948 (figure 2). Since then pool discoveries have averaged three to four per year. The maximum yearly total reserves of 824 MMBOE were added in 1955 when six pools were discovered, including the largest pool in the play, the Bay Marchand 2 field with 572 MMBOE in total reserves (figures 2 and 3). Ninety-nine percent of the play's cumulative production and ninety-seven percent of the play's total reserves are in pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 174 discovered pools contain 2,766 reservoirs, of which

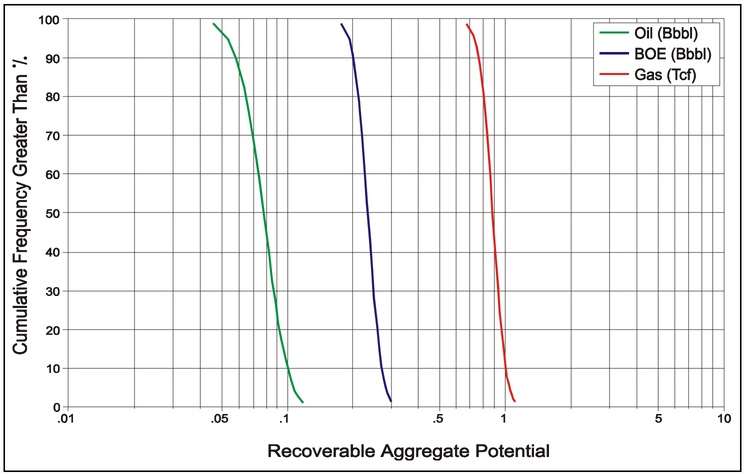


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

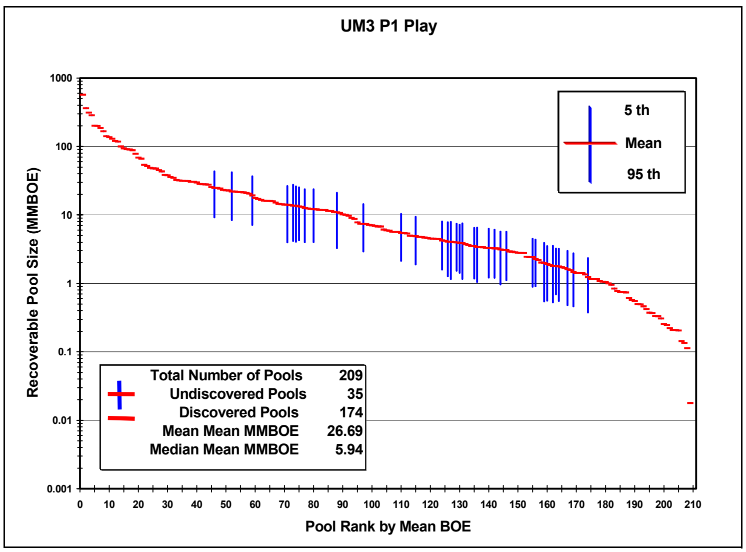


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

1,194 are nonassociated gas, 1,289 are undersaturated oil, and 283 are saturated oil. Cumulative production has consisted of 54 percent oil and 46 percent gas.

The Upper Upper Miocene Progradational (UM3 P1) play is the second largest play in the Gulf of Mexico Region on the basis of BOE total reserves (8 percent of BOE total reserves in the Region) and BOE cumulative production (12 percent of the total in the Region). It has also produced the most oil of any play in the Gulf of Mexico Region (20 percent of oil production). The UM3 P1 play is the second largest progradational play in the Gulf of Mexico Region in total endowment, total reserves, and cumulative production.

Assessment Results

The marginal probability of hydrocarbons for the UM3 P1 play is 1.00. This play is the third largest in the Gulf of Mexico on the basis of a mean total endowment of 2.799 Bbo and 15.611 Tcfg (5.577 BBOE) (table 2). Seventy-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.054 to 0.107 Bbo and 0.734 to 1.046 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.079 Bbo and 0.885 Tcfg (0.236 BBOE). These undiscovered resources might occur in as many as 35 pools. The largest undiscovered pool, with a mean size of 25 MMBOE, is forecast as the 46th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 52, 59, 71, and 73 on the pool rank plot. For all the undiscovered pools in the UM3 P1 play, the mean mean size is 7 MMBOE, which is significantly smaller than the 31 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 27 MMBOE.

The UM3 P1 is a supermature play with UCRR contributing only 4 percent to the UM3 P1 play's total endowment. In the Texas offshore, limited potential may lie downdip of the discovered fields where wells have not penetrated deeply enough to reach the UM3 P1 play.

Upper Upper Miocene Fan 1 (UM3 F1) Play

***Cristellaria* "K" through *Robulus* "E" biozones**

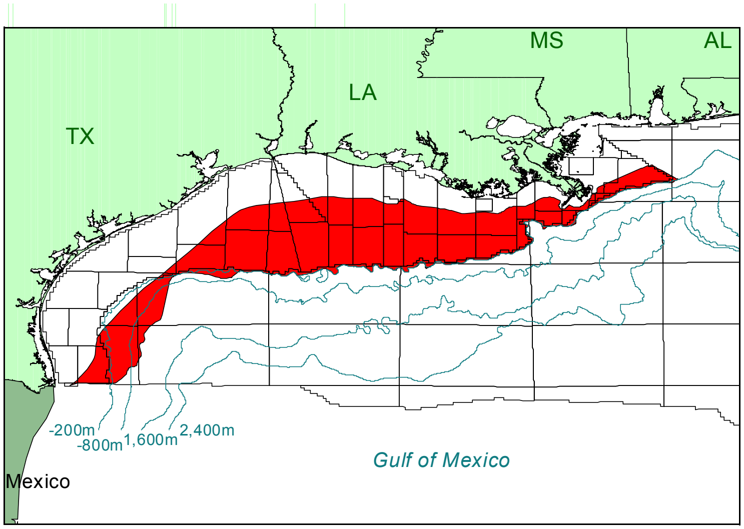


Figure 1. Play location.

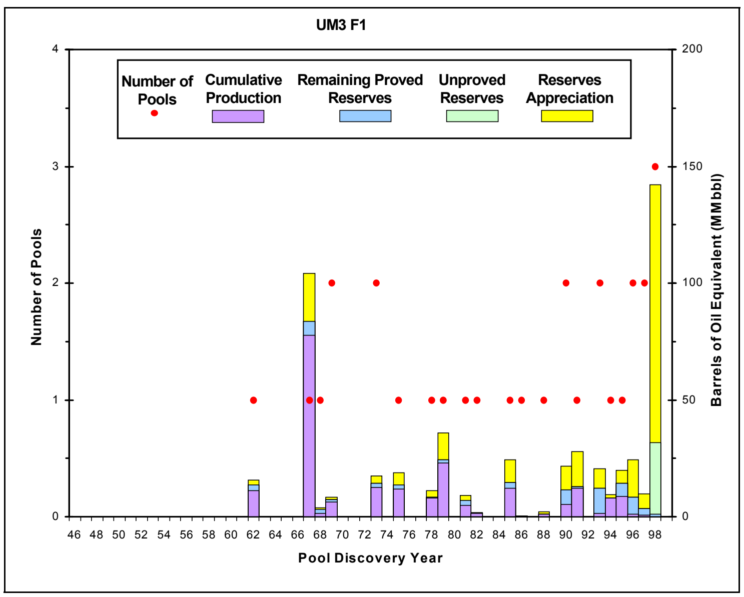


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM3 F1 Play 29 Pools 82 Sands	Minimum	Mean	Maximum
Water depth (feet)	57	164	428
Subsea depth (feet)	6200	13339	17697
Number of sands per pool	1	3	17
Porosity	17%	25%	35%
Water saturation	16%	29%	55%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Upper Miocene Fan 1 (UM3 F1) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Main Pass Area 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 P1) play. To the northeast, the UM3 F1 play is bounded by deposits of the Upper Upper Miocene Aggradational/ Progradational (UM3 A/P1) play overlying the Cretaceous carbonate shelf. To the southwest, the play extends into Mexican national waters. Downdip, the UM3 F1 play is limited by the structural boundary of the Upper Upper Miocene Fan 2 (UM3 F2) play.

Play Characteristics

The UM3 F1 play is characterized by deepwater turbidites deposited basinward of the *Robulus* "E" biozone shelf margin on the Upper Upper Miocene upper and lower slopes, in topographically low areas between salt structure highs and on the abyssal plain. Component depositional facies include channel/ levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Many of the fields in the UM3 F1 play are structurally associated

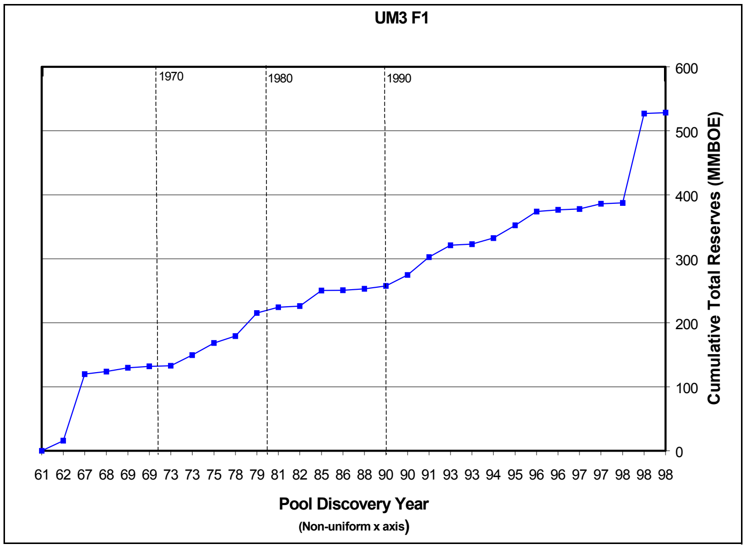


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM3 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	27	0.110	0.867	0.264
Cumulative production	--	0.089	0.674	0.209
Remaining proved	--	0.021	0.193	0.055
Unproved	2	0.007	0.135	0.031
Appreciation (P & U)	--	0.064	0.950	0.233
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.130	2.054	0.514
Mean	55	0.229	3.038	0.769
5th percentile	--	0.415	4.602	1.206
Total Endowment				
95th percentile	--	0.311	4.006	1.042
Mean	84	0.410	4.990	1.298
5th percentile	--	0.596	6.554	1.734

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

with normal faults and salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Less common trapping structures include growth fault anticlines. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UM3 F1 mixed gas and oil play contains total reserves of 0.181 Bbo and 1.952 Tcfg (0.528 BBOE), of which 0.089 Bbo and 0.674 Tcfg (0.209 BBOE) have been produced. The play contains 82 producible sands in 29 pools, of which 27 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, pools, and sands). The first reserves in the play were discovered in the South Marsh Island 23 field in 1962 (figure 2). Maximum yearly total reserves of 142 MMBOE were added in 1998 when three pools were discovered, including the largest pool in the play in the Grand Isle 116 field (Hickory) with 140 MMBOE in total reserves (figures 2 and 3). Eighty-two percent of the play's cumulative production and forty-eight percent of the play's total reserves have come from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 29 discovered pools contain 191 reservoirs, of which 81 are nonassociated gas, 98 are undersaturated oil, and 12 are saturated oil. Cumulative production has consisted of 57 percent gas and 43 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UM3 F1 play is 1.00. The play has a mean total endowment of 0.410 Bbo and 4.990 Tcfg (1.298 BBOE) (table 2). Sixteen percent of this BOE mean total

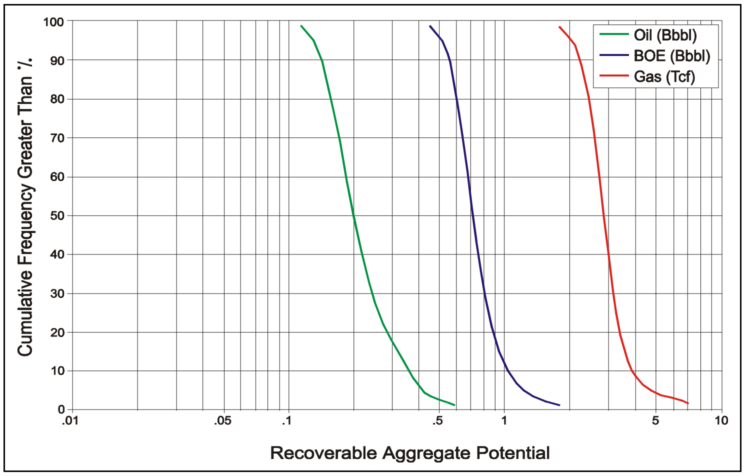


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

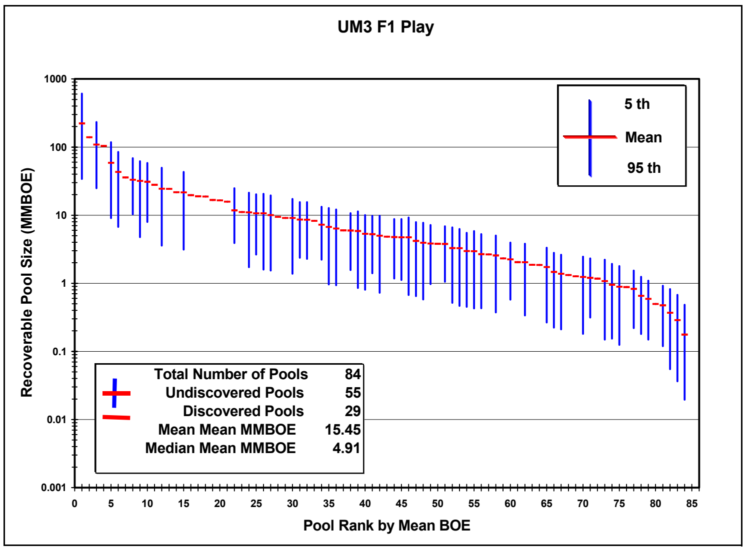


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCCR) have a range of 0.130 to 0.415 Bbo and 2.054 to 4.602 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are forecast at 0.229 Bbo and 3.038 Tcfg (0.769 BBOE). These undiscovered resources might occur in as many as 55 pools. The largest undiscovered pool, with a mean size of 223 MMBOE, is also forecast as the largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 3, 5, 6, and 8 on the pool rank plot. For all the undiscovered pools in the UM3 F1 play, the mean mean size is 14 MMBOE, which is smaller than the 18 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 15 MMBOE.

BOE mean UCRR contribute 59 percent to the play's BOE mean total endowment. The UM3 F1 play includes areas covered by allochthonous salt sheets with exploration potential lying below and around these salt sheets, as well as in structural and stratigraphic traps around salt diapirs.

Upper Upper Miocene Fan 2 (UM3 F2) Play

Cristellaria "K" through *Robulus* "E" biozones

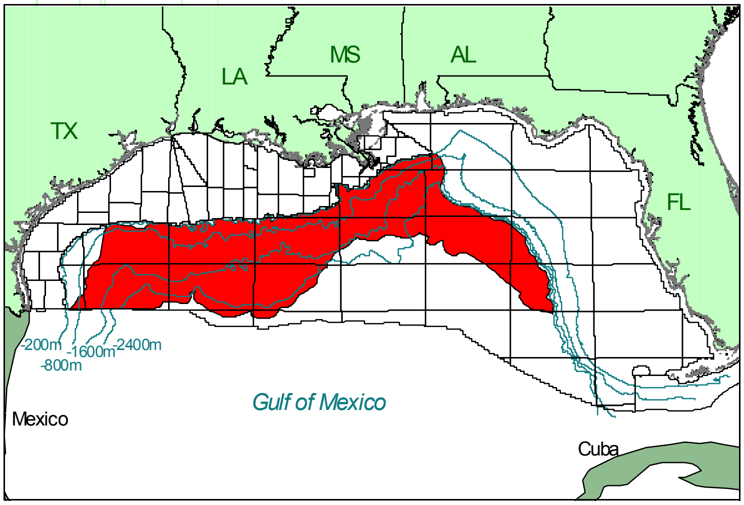


Figure 1. Play location.

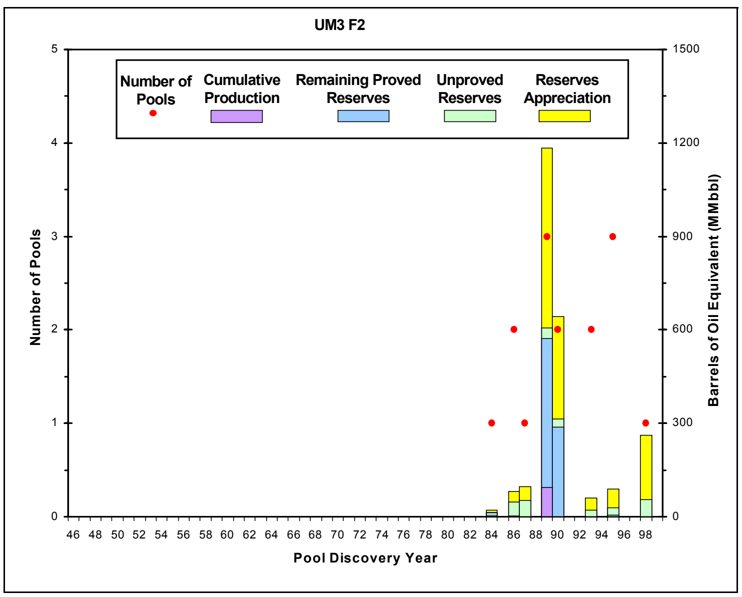


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM3 F2 Play 15 Pools 49 Sands	Minimum	Mean	Maximum
Water depth (feet)	851	3679	6845
Subsea depth (feet)	7709	12591	17179
Number of sands per pool	1	3	10
Porosity	22%	30%	36%
Water saturation	16%	30%	50%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Upper Miocene Fan 2 (UM3 F2) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. The play is also defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico slope. The play extends from the southern Port Isabel, East Breaks, and Alaminos Areas to the southwestern Destin Dome and western Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the play is bounded by the Upper Upper Miocene Fan 1 (UM3 F1) play. To the east, the play onlaps the Cretaceous carbonate slope. Downdip, the UM3 F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt Plays. Downdip in the eastern Gulf of Mexico Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component depositional facies of the UM3 F2 play include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps deposited on the Upper Upper Miocene upper and lower slopes, in topographically low areas between salt structure highs and on the abyssal plain. These deep-sea fan systems are often overlain by

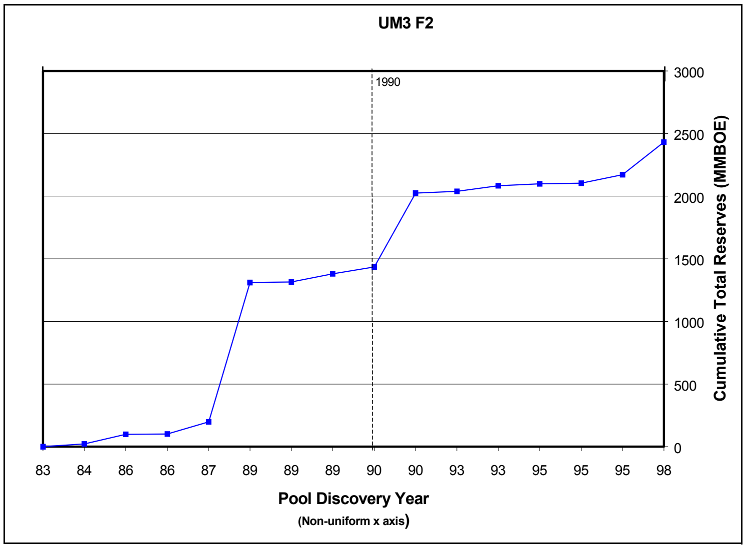


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM3 F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	6	0.692	1.052	0.880
Cumulative production	--	0.081	0.091	0.097
Remaining proved	--	0.612	0.961	0.783
Unproved	9	0.152	0.599	0.258
Appreciation (P & U)	--	0.957	1.894	1.294
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.777	6.630	2.034
Mean	70	1.041	7.660	2.404
5th percentile	--	1.364	8.811	2.847
Total Endowment				
95th percentile	--	2.578	10.176	4.466
Mean	85	2.842	11.206	4.836
5th percentile	--	3.165	12.357	5.279

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

The majority of the fields in the UM3 F2 play are structurally associated with salt bodies with hydrocarbons trapped on salt flanks or in sediments draped over salt. Some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UM3 F2 is predominately an oil play containing total reserves of 1.801 Bbo and 3.546 Tcfg (2.432 BBOE), of which 0.081 Bbo and 0.091 Tcfg (0.097 BBOE) have been produced. The play contains 49 producible sands in 15 pools, of which 6 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, pools, and sands). The first reserves in the play were discovered in 1984 in the Viosca Knoll 783 field (Tahoe) (figure 2). Maximum yearly total reserves of 1,183 MMBOE were added in 1989 when three pools were discovered, including the largest pool in the play in the Mississippi Canyon 807 field (Mars) with 1,113 MMBOE in total reserves (figures 2 and 3). All of the play's cumulative production and 57 percent of the play's total reserves have come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1998.

The15 discovered pools contain 53 reservoirs, of which 15 are nonassociated gas, 36 are undersaturated oil, and 2 are saturated oil. Cumulative production has consisted of 83 percent oil and 17 percent gas.

Assessment Results

The marginal probability of

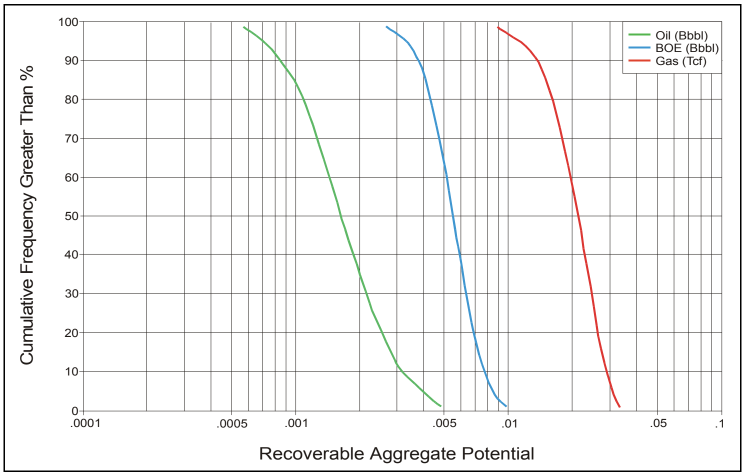


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

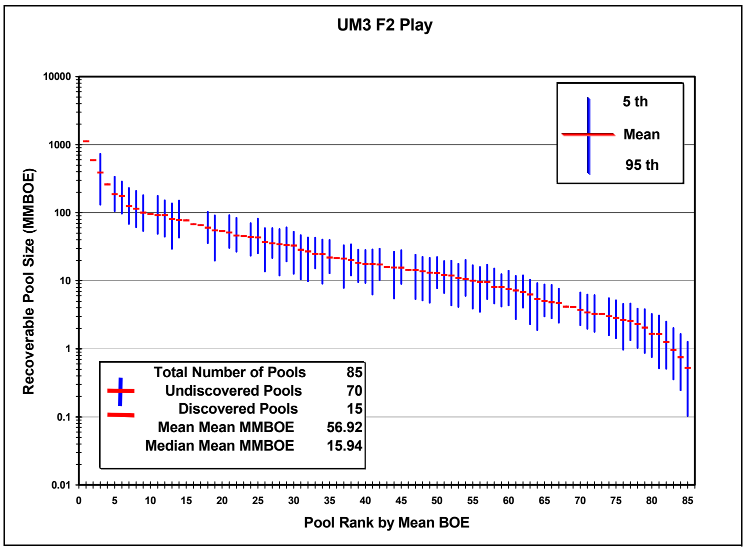


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

hydrocarbons for the UM3 F2 play is 1.00. The play has a mean total endowment of 2.842 Bbo and 11.206 Tcfg (4.836 BBOE) (table 2). Only 2 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCCR) have a range of 0.777 to 1.364 Bbo and 6.630 to 8.811 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 1.041 Bbo and 7.660 Tcfg (2.404 BBOE). These undiscovered resources might occur in as many as 70 pools. The largest undiscovered pool, with a mean size of 388 MMBOE, is forecast as the third largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 5, 6, 7, and 8 on the pool rank plot. For all the undiscovered pools in the UM3 F2 play, the mean mean size is 34 MMBOE, which is smaller than the 162 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 57 MMBOE.

BOE mean UCRR contribute 50 percent to the play's BOE mean total endowment. The UM3 F2 play contains large areas covered by allochthonous salt sheets under which several discoveries have already been made. Exploration potential lies below and around these salt sheets, as well as in structural and stratigraphic traps around salt bodies. Six fields with over 100 MMBOE are forecast as remaining to be discovered. Thus far, discoveries have been located mainly in the Mississippi Canyon and Viosca Knoll Areas.

Lower Upper Miocene Aggradational (UM1 A1) Play

Discorbis 12 biozone

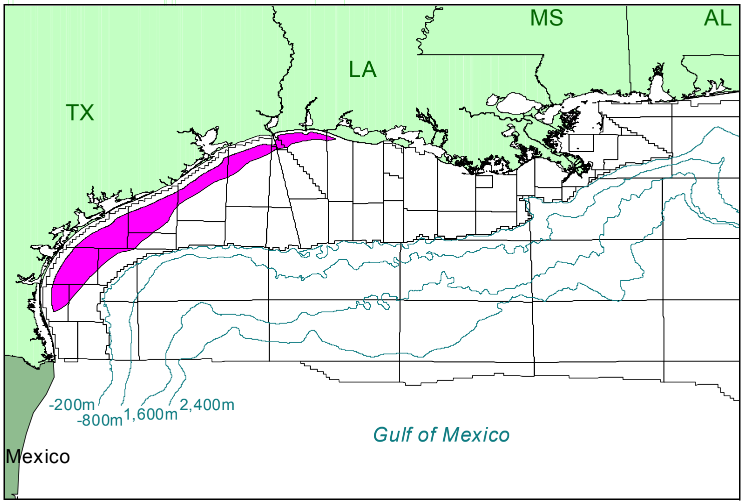


Figure 1. Play location.

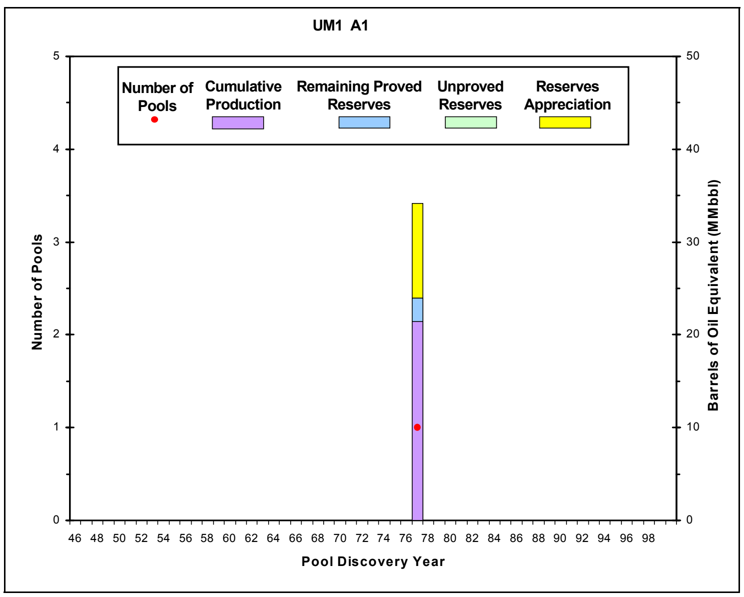


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM1 A1 Play 1 Pool 3 Sands	Minimum	Mean	Maximum
Water depth (feet)	71	71	71
Subsea depth (feet)	1917	1917	1917
Number of sands per pool	3	3	3
Porosity	32%	32%	32%
Water saturation	16%	16%	16%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

Economic hydrocarbons have been found in only the Matagorda Island 665 pool in the Lower Upper Miocene Aggradational (UM1 A1) play. The play occurs within the *Discorbis* 12 biozone and 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 to the west and east, the play continues onshore into Texas and Louisiana. Downdip, the play grades into the sediments of the Lower Upper Miocene Progradational (UM1 P1) play.

Play Characteristics

Thin, storm-generated washover fans that were deposited in lagoons located behind barrier islands comprise the UM1 A1 play. Thick lagoon shales provide the seals for hydrocarbons in the four sands in the play. Non-productive retrogradational sands with a thinning and backstepping log signature locally cap the play. Because these sands are poorly developed and discontinuous, they are included as part of the UM1 A1 play.

The structural style of the Matagorda Island 665 field is a faulted anticline. Traps are formed by the juxtaposition of sands and shales along the faults.

Discoveries

The UM1 A1 gas play contains total reserves of <0.001 Bbo and 0.192 Tcfg (0.034 BBOE), of which 0.121 Tcfg (0.021 BBOE) have been produced. The Matagorda 665 UM1 A1 pool was discovered in 1977 (figures 2 and 3) and contains three producible sands/reservoirs (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and

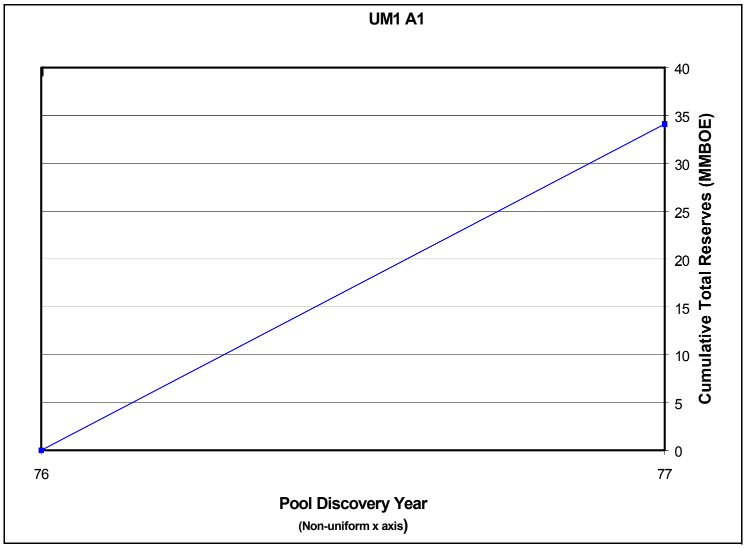


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM1 A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	1	<0.001	0.135	0.024
Cumulative production	–	<0.001	0.121	0.021
Remaining proved	–	<0.001	0.014	0.002
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	<0.001	0.057	0.010
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	<0.001	<0.001	<0.001
Mean	1	<0.001	0.025	0.005
5th percentile	–	<0.001	0.121	0.022
Total Endowment				
95th percentile	–	<0.001	0.192	0.034
Mean	2	<0.001	0.217	0.039
5th percentile	–	<0.001	0.313	0.056

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

pools). All of the reservoirs are non-associated gas.

Assessment Results

Because of limited data for the UM1 A1 play, the Upper Lower Miocene Aggradational (LM4 A1) play was used as an analog to forecast pool sizes in the UM1 A1 play. The LM4 A play was selected as an analog because of similarities to the UM1 A1 play in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the UM1 A1 play is 1.00. The play ranks as one of the smallest of all 87 assessed Gulf of Mexico Region plays on the basis of a mean total endowment of <0.001 Bbo and 0.217 Tcfg (0.039 BBOE) (table 2). Fifty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable gas resources have a range of <0.001 to 0.121 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The estimated amount of mean undiscovered conventionally recoverable gas reserves is 0.025 Tcfg (0.005 BBOE). These undiscovered resources might occur in just one additional pool. The undiscovered pool has a mean size of 5 MMBOE (figure 5). The mean mean size of both the discovered and undiscovered pools is 19 MMBOE.

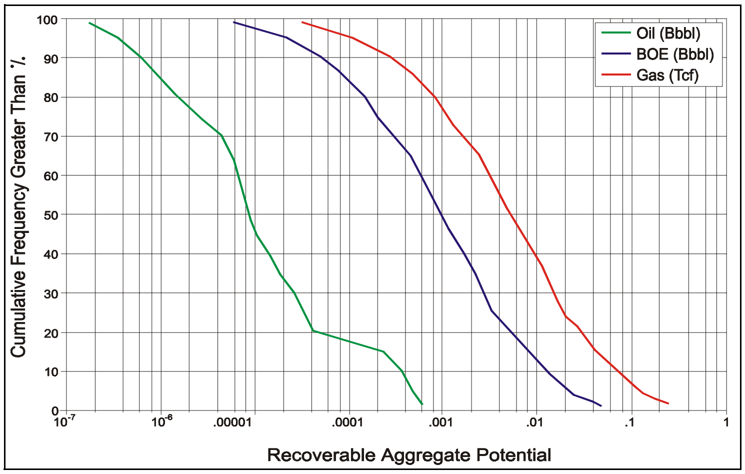


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

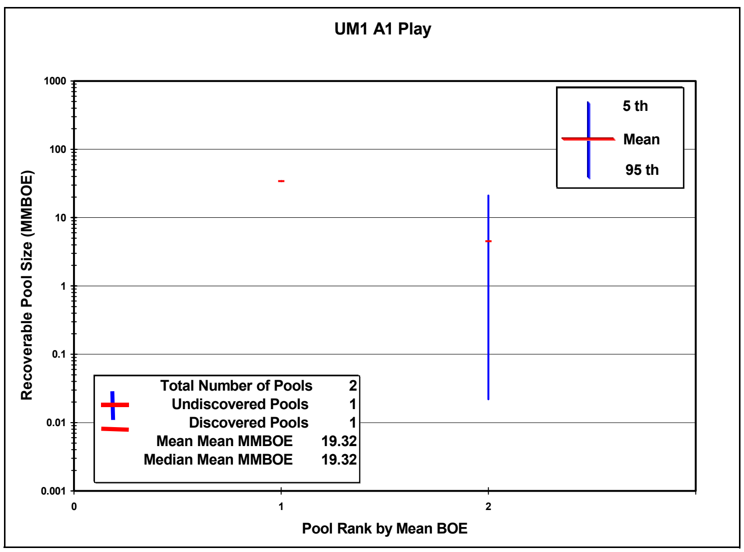


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Lower Upper Miocene Aggradational/Progradational (UM1 AP1) Play *Discorbis* 12 biozone

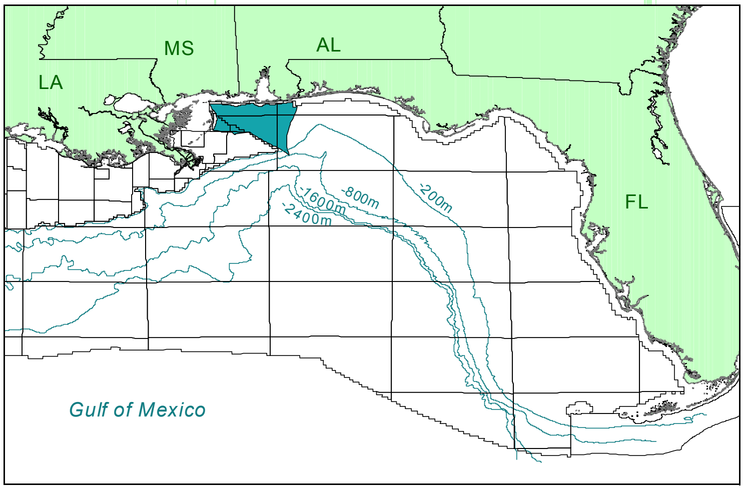


Figure 1. Play location.

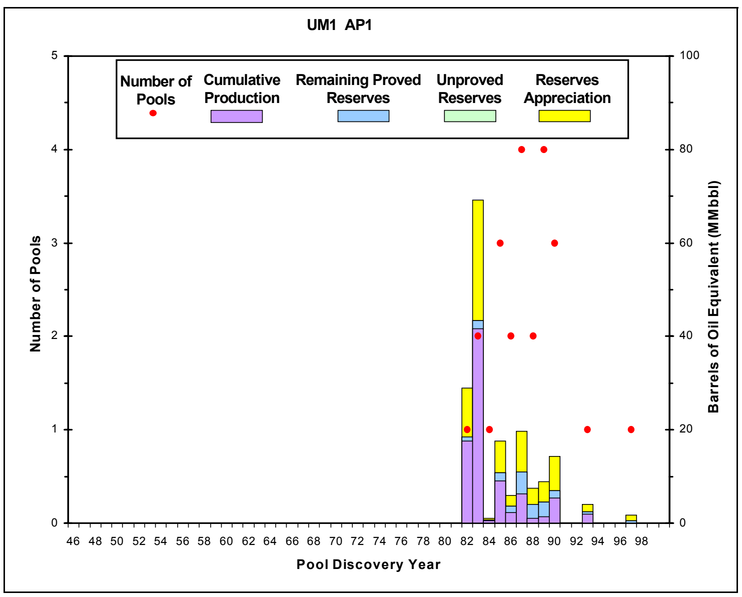


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM1 AP1 Play 24 Pools 30 Sands	Minimum	Mean	Maximum
Water depth (feet)	42	73	121
Subsea depth (feet)	1500	2910	4957
Number of sands per pool	1	1	4
Porosity	26%	34%	38%
Water saturation	16%	28%	75%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Upper Miocene Aggradational/Progradational (UM1 AP1) play occurs within the *Discorbis* 12 biozone. The play is also defined by minimal structural deformation and gas accumulations associated with seismic hydrocarbon indicators (bright spots). The play overlies the Cretaceous carbonate shelf in the Mobile, western Pensacola, northern Chandeleur, northern Viosca Knoll, and western 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 grades into shale.

The UM1 AP1 play is one of three plays within the combined aggradational and progradational (AP) "Shallow Miocene Bright Spot Trend." The other two plays are the Upper Middle Miocene Aggradational/Progradational (MM9 AP1) play and the Upper Upper Miocene Aggradational/Progradational (UM3 AP1) play. The UM1 AP1 play is the largest of the three AP plays on the basis of total endowment, total reserves, and cumulative production.

Play Characteristics

Two different depositional styles are found in the play area. The first depositional style resulted from deposition in a constructional deltaic system with a higher clastic influx. These deposits are found in northern Viosca Knoll, Chandeleur, and part of Mobile Areas. This constructional delta system prograded out onto the Lower Cretaceous carbonate shelf. The sequence is characterized by fluvial point bars and distributary mouth bars with subordinate marine bar sands deposited within inner to middle neritic depths of the shelf. This

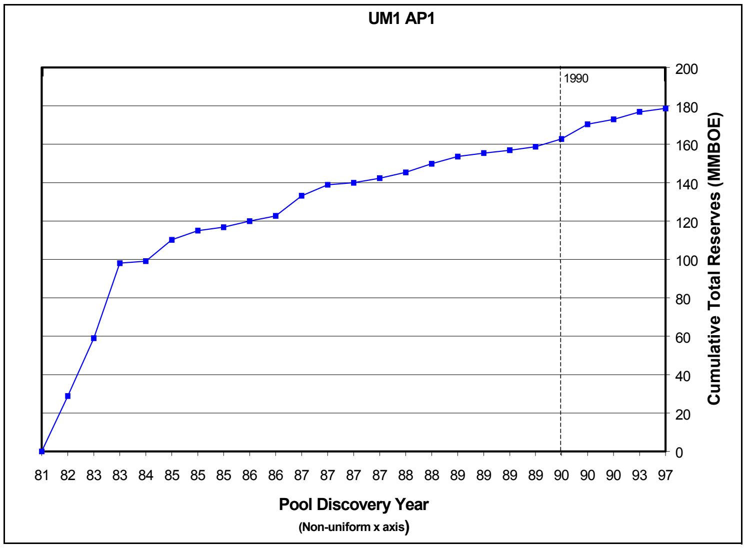


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM1 AP1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	24	<0.001	0.597	0.106
Cumulative production	–	<0.001	0.491	0.087
Remaining proved	–	<0.001	0.106	0.019
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	<0.001	0.407	0.072
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	<0.001	0.131	0.023
Mean	14	<0.001	0.166	0.030
5th percentile	–	<0.001	0.208	0.037
Total Endowment				
95th percentile	–	<0.001	1.135	0.202
Mean	38	<0.001	1.170	0.209
5th percentile	–	<0.001	1.212	0.216

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

sequence contains more sand and less shale than in onshore equivalent strata.

The second depositional style, found in onshore Alabama and part of the offshore Mobile Area, resulted from deposition in a sand-poor, destructional deltaic system characterized by marine bars. This later depositional sequence contains mostly shale with subordinate amounts of bar sands (Mink et al., 1988).

Stratigraphic traps dominate the play. The Cretaceous carbonate shelf created a stable platform for sediment deposition. Consequently, Miocene deposits of the three AP plays appear minimally affected by salt movement and faulting. The stratigraphic traps are influenced by a combination of pinchout and subtle structural flexure over anticlinal noses (Mink et. al., 1988). Seals are provided by lateral shale-outs and overlying shelf shales.

Discoveries

The UM1 AP1 gas play contains total reserves of <0.001 Bbo and 1.004 Tcfg (0.179 BBOE), of which 0.491 Tcfg (0.087 BBOE) have been produced. The play contains 30 producible sands in 24 pools, and all 24 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Chandeleur 25 field in 1982 (figure 2). The maximum yearly total reserves of 69 MMBOE were added in 1983 when two pools were discovered, including the largest pool in the play, the Chandeleur 29 field with 39 MMBOE in total reserves (figures 2 and 3). The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1997.

The 24 discovered pools contain 34 reservoirs, all of which are nonassociated gas.

Assessment Results

The marginal probability of

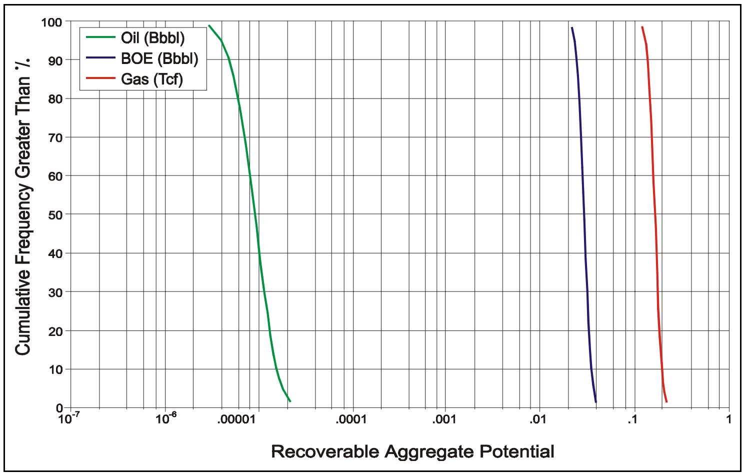


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

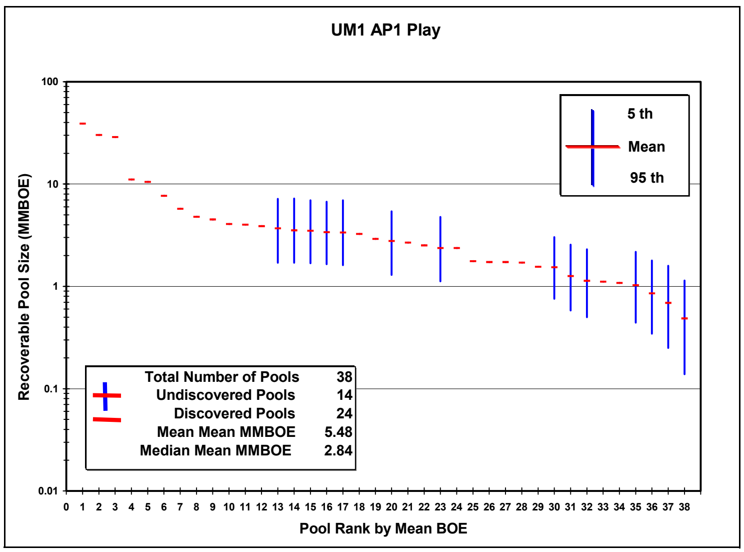


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

hydrocarbons for the UM1 AP1 play is 1.00. The play contains a mean total endowment of <0.001 Bbo and 1.170 Tcfg (0.209 BBOE) (table 2). Forty-two percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable oil resources are insignificant (<0.001 Bbbl) and that undiscovered conventionally recoverable gas resources have a range of 0.131 to 0.208 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The forecast amount of mean undiscovered gas is 0.166 Tcfg (0.030 BBOE). These undiscovered conventionally recoverable resources (UCRR) might occur in as many as 14 pools. The largest undiscovered pool, with a mean size of 4 MMBOE, is forecast as the 13th largest pool in the play (figure 5). The next four undiscovered pools occupy positions 14, 15, 16, and 17 on the pool rank plot. For all the undiscovered pools in the UM1 AP1 play, the mean mean size is 2 MMBOE, which is smaller than the 7 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5 MMBOE.

BOE mean UCRR contribute only 14 percent to the play's BOE mean total endowment. Future discoveries are dependent on the economics of developing remaining small bright-spot-defined gas reservoirs.

Reference

Mink, R.M., E.A. Mancini, B.L., Bearden, and C. C. Smith. 1988. Middle and upper Miocene natural gas sands in onshore and offshore Alabama: Gulf Coast Association of Geological Societies Transactions, vol. 36, p. 1-6.

Lower Upper Miocene Progradational (UM1 P1) Play

***Discorbis* 12 biozone**

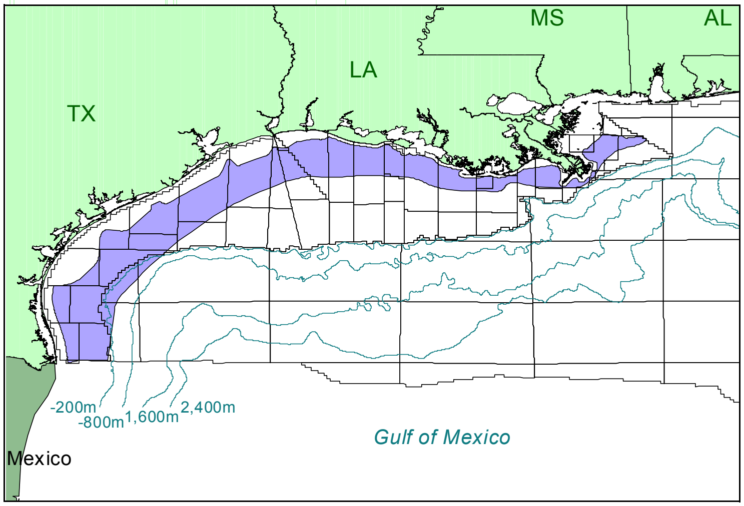


Figure 1. Play location.

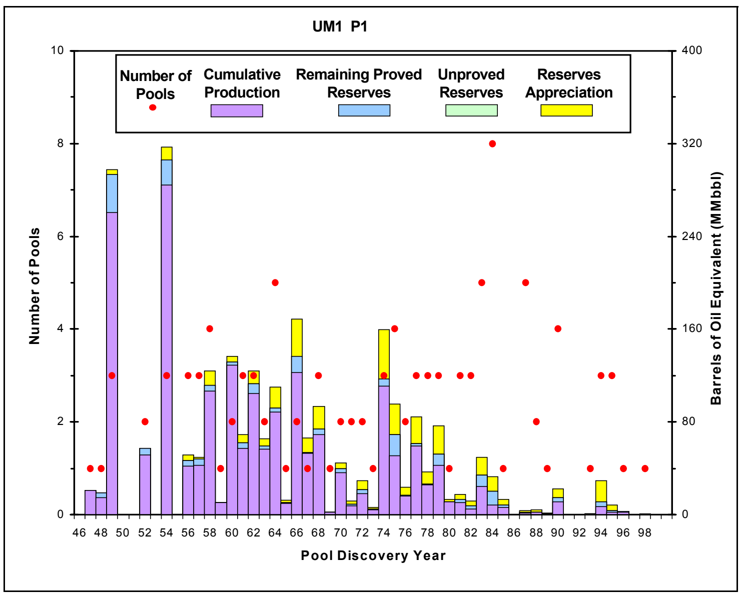


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM1 P1 Play 111 Pools 492 Sands	Minimum	Mean	Maximum
Water depth (feet)	9	63	380
Subsea depth (feet)	3778	9787	17260
Number of sands per pool	1	4	37
Porosity	15%	27%	33%
Water saturation	16%	30%	57%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Upper Miocene Progradational (UM1 P1) play occurs within the *Discorbis* 12 biozone. The play 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 A1) play. Updip in Louisiana, the UM1 P1 play continues onshore. To the northeast, the play is limited by the deposits of the Lower Upper Miocene Aggradational/Progradational (UM1 AP1) play overlying the Cretaceous carbonate shelf. The UM1 P1 play continues to the southwest into Texas State and Mexican national waters. Downdip, the play grades into the deposits of the Lower Upper Miocene Fan 1 (UM1 F1) play.

Play Characteristics

The 29 reservoir sands of the offshore Texas area were deposited in the distal portion of prograding delta lobes or in offshore bars. Most of these sands have a coarsening-upward log character, but some retrogradational fining-upward sands are also present in the overall prograding section. Many of these sands are thin and poorly developed because of a low influx of clastics into the offshore Texas area during UM1 time. Consequently, many UM1 progradational reservoirs in the Texas offshore have not been prolific. In the South Padre Island and High Island Areas, the progradational facies is present but not productive.

The 463 reservoir sands of the offshore Louisiana area were deposited in more proximal portions of prograding lobes. From the West Cameron through Vermilion Areas, UM1 P1 deposits are characterized

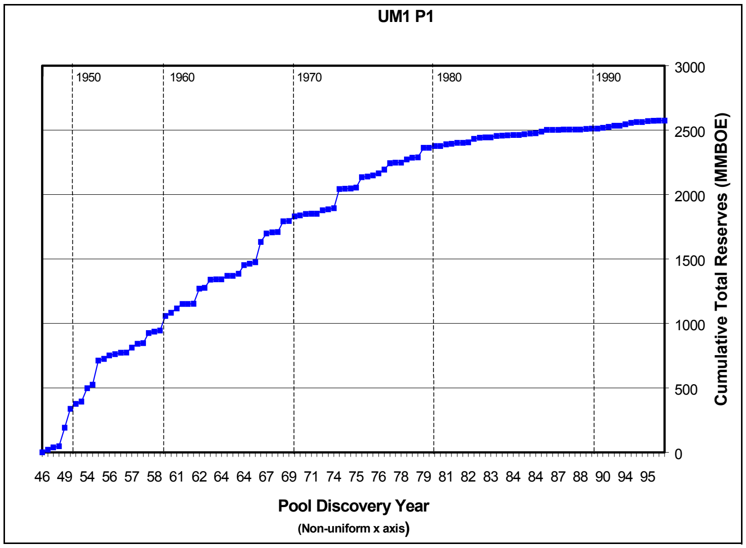


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM1 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	110	0.566	9.167	2.198
Cumulative production	–	0.512	8.304	1.989
Remaining proved	–	0.055	0.862	0.208
Unproved	1	0.001	0.001	0.001
Appreciation (P & U)	–	0.083	1.651	0.377
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.036	0.627	0.155
Mean	26	0.055	0.755	0.190
5th percentile	–	0.081	0.886	0.229
Total Endowment				
95th percentile	–	0.686	11.445	2.730
Mean	137	0.705	11.573	2.765
5th percentile	–	0.731	11.704	2.804

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

by predominately thin, coarsening-upward sands separated by thick, clean shales. The central offshore Louisiana area was the locus of the main UM1 deltaic depocenter resulting in abundant, well-developed, thick sands. East of the Mississippi River Delta, UM1 P1 sediments are mostly shale with a few well-developed sands. Retrogradational, reworked sands with a thinning and backstepping log signature locally cap the play. Because these retrogradational sands are poorly developed and discontinuous, they are included as part of UM1 P1 play.

The majority of the fields in this play are structurally associated with normal faults and salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Other fields are associated with growth fault anticlines, while some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts, or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UM1 P1 play is predominantly a gas play, with total reserves of 0.650 Bbo and 10.818 Tcfg (2.575 BBOE), of which 0.512 Bbo and 8.304 Tcfg (1.989 BBOE) have been produced. The play contains 492 producible sands in 111 pools, and 110 of these pools contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Vermilion 71 field in 1947 (figure 2). Maximum yearly total reserves of 317 MMBOE were added in 1954, when three pools were discovered, including the largest pool in the play, West Delta 30 field, with 186 MMBOE in total reserves (figures 2 and 3). Ninety-nine percent of the play's cumulative production and 97 percent of the play's total reserves

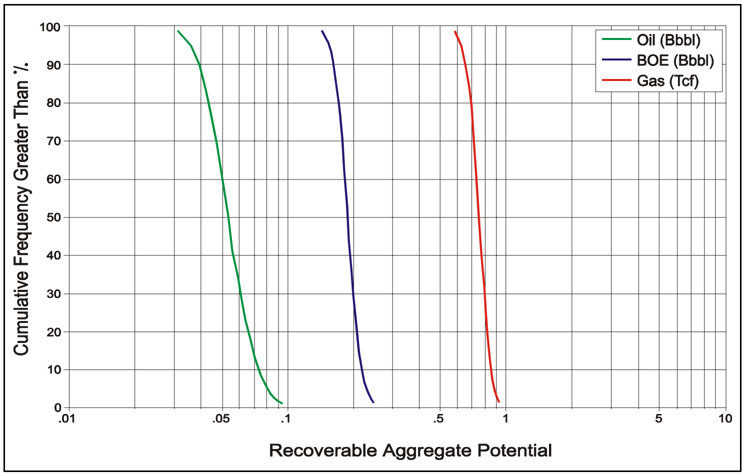


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

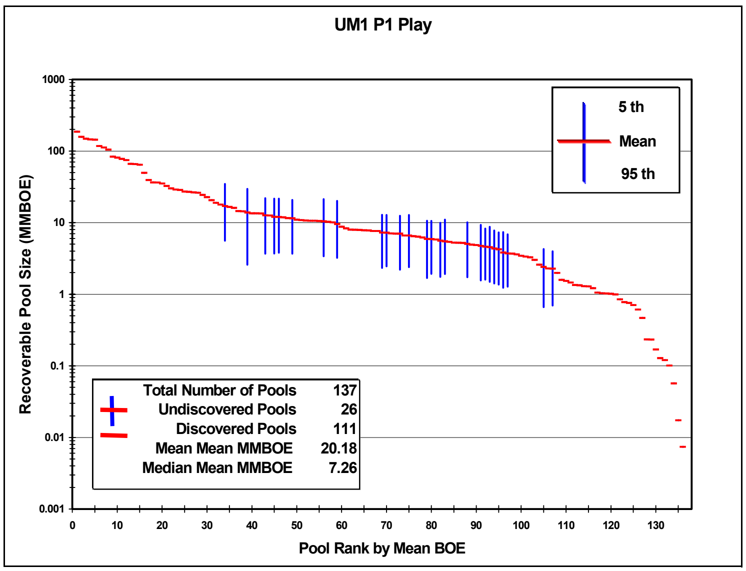


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

have come from pools discovered prior to 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1998.

The 111 discovered pools contain 965 reservoirs, of which 636 are nonassociated gas, 257 are undersaturated oil, and 72 are saturated oil. Cumulative production has consisted of 74 percent gas and 26 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UM1 P1 play is 1.00. The play has a mean total endowment of 0.705 Bbo and 11.573 Tcfg (2.765 BBOE) (table 2). Seventy-two percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.036 to 0.081 Bbo and 0.627 to 0.886 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.055 Bbo and 0.755 Tcfg (0.190 BBOE). These undiscovered resources might occur in as many as 26 pools. The largest undiscovered pool, with a mean size of 17 MMBOE, is forecast as the 34th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 39, 43, 45, and 46 on the pool rank plot. For all the undiscovered pools in the UM1 P1 play, the mean mean size is 7 MMBOE, which is substantially smaller than the 23 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 20 MMBOE.

The UM1 P1 is a supermature play with BOE mean UCRR contributing only 7 percent to the play's BOE mean total endowment.

Lower Upper Miocene Fan 1 (UM1 F1) Play

Discorbis 12 biozone

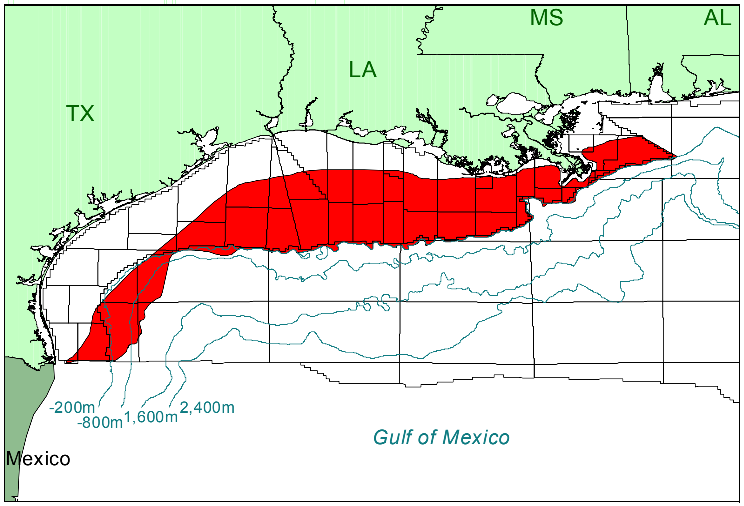


Figure 1. Play location.

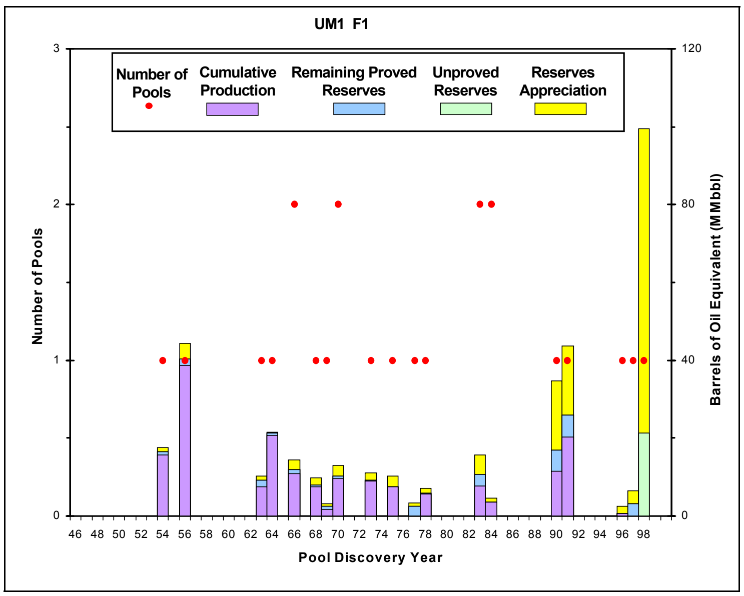


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM1 F1 Play 23 Pools 77 Sands	Minimum	Mean	Maximum
Water depth (feet)	29	152	348
Subsea depth (feet)	6400	12777	19398
Number of sands per pool	1	3	8
Porosity	14%	25%	33%
Water saturation	16%	32%	49%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Upper Miocene Fan 1 (UM1 F1) play occurs within the *Discorbis* 12 biozone. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Main Pass Area 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 sediments of the Lower Upper Miocene Progradational (UM1 P1) play. To the northeast, the UM1 F1 play is bounded by the Cretaceous carbonate shelf, while to the southwest, the play extends into Mexican national waters. Downdip, the play is bounded by the structural boundary of the Lower Upper Miocene Fan 2 (UM1 F2) play.

The UM1 is the oldest chronozone in which the shelf/slope break is located predominately in the present-day Federal offshore.

Play Characteristics

The UM1 F1 play is characterized by deepwater turbidites deposited basinward of the UM1 shelf margin on the UM1 upper and lower slope, in topographically low areas between salt structure highs, and on the abyssal plain. Component facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps. These deep-sea fan systems are often overlain by thick shale intervals representative of sand bypass on the shelf, or sand-poor zones on the slope.

Many of the fields in the UM1 F1 play are structurally associated with growth fault anticlines and salt

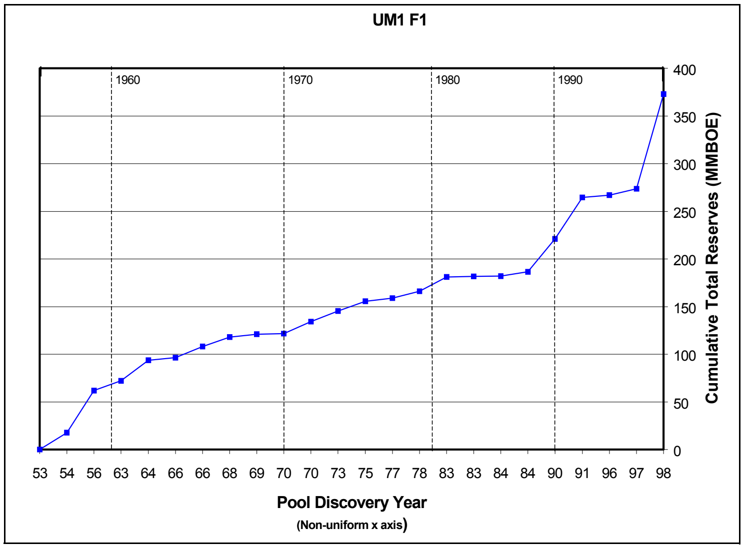


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM1 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	22	0.046	0.899	0.206
Cumulative production	–	0.042	0.763	0.178
Remaining proved	–	0.003	0.136	0.028
Unproved	1	0.005	0.093	0.021
Appreciation (P & U)	–	0.027	0.669	0.146
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.178	1.769	0.516
Mean	62	0.277	2.593	0.739
5th percentile	–	0.425	4.181	1.104
Total Endowment				
95th percentile	–	0.255	3.430	0.889
Mean	85	0.354	4.254	1.112
5th percentile	–	0.502	5.842	1.477

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Some fields contain hydrocarbon accumulations trapped by permeability barriers, updip pinchouts or facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UM1 F1 play is a mixed oil and gas play, with total reserves of 0.077 Bbo and 1.661 Tcfg (0.373 BBOE), of which 0.042 Bbo and 0.763 Tcfg (0.178 BBOE) have been produced. The play contains 77 producible sands in 23 pools of which 22 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the West Delta 58 field in 1954 (figure 2). The maximum yearly total reserves of 100 MMBOE were added in 1998 when the largest pool in the play in the play was discovered in the Grand Isle 116 field (Hickory) (figures 2 and 3). Eighty-two percent of the play's cumulative production and 50 percent of the play's total reserves are from pools discovered before 1990.

The 23 discovered pools contain 135 reservoirs, of which 89 are nonassociated gas, 40 are undersaturated oil, and 6 are saturated oil. Cumulative production has consisted of 76 percent gas and 24 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UM1 F1 play is 1.00. The play has a mean total endowment of 0.354 Bbo and 4.254 Tcfg (1.112 BBOE) (table 2). Sixteen percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) range from 0.178 to 0.425 Bbo and 1.769 to 4.181 Tcfg at the 95th and 5th per-

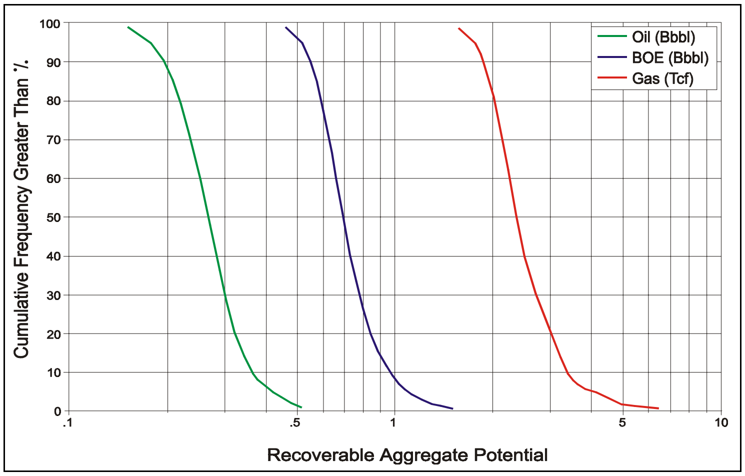


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

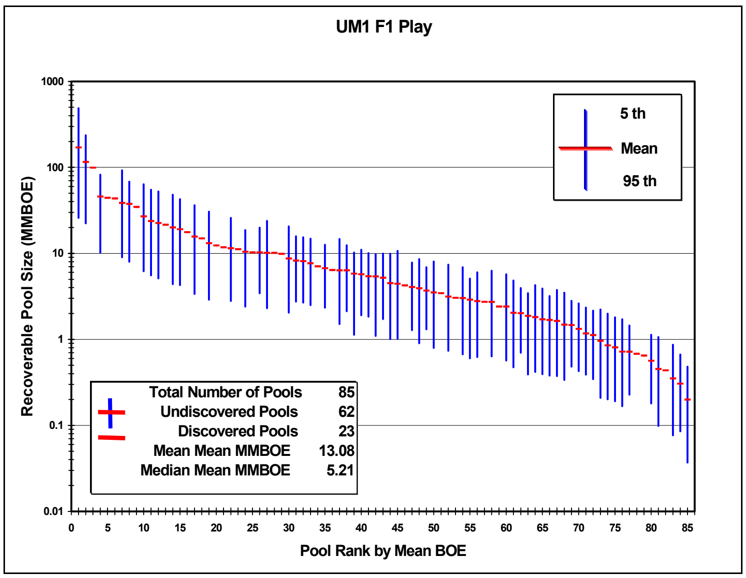


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

centiles, respectively (figure 4). Mean UCRR are estimated at 0.277 Bbo and 2.593 Tcfg (0.739 BBOE). These undiscovered resources might occur in as many as 62 pools. The largest undiscovered pool, with a mean size of 171 MMBOE, is also forecast as the largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 2, 4, 7, and 8 on the pool rank plot. For all the undiscovered pools in the UM1 F1 play, the mean mean size is 12 MMBOE, which is smaller than the 16 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 13 MMBOE.

UCRR contribute 66 percent to the play's BOE mean total endowment. The UM1 F1 play encloses large areas containing allochthonous salt sheets, and thus has the potential for additional subsalt discoveries.

Lower Upper Miocene Fan 2 (UM1 F2) Play

Discorbis 12 biozone

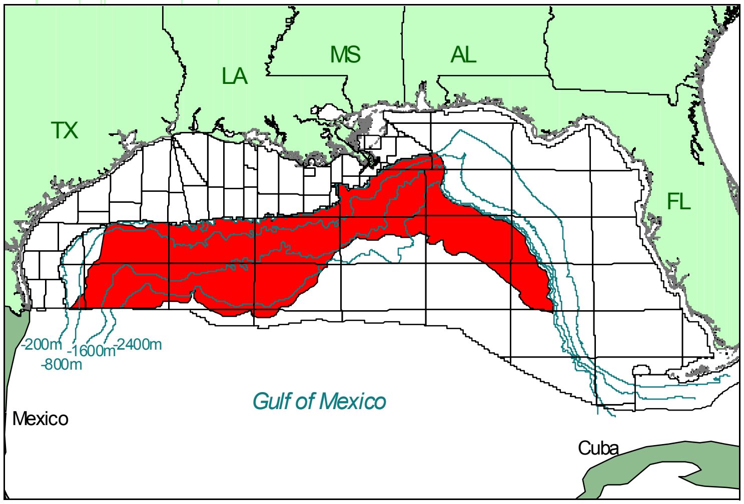


Figure 1. Play location.

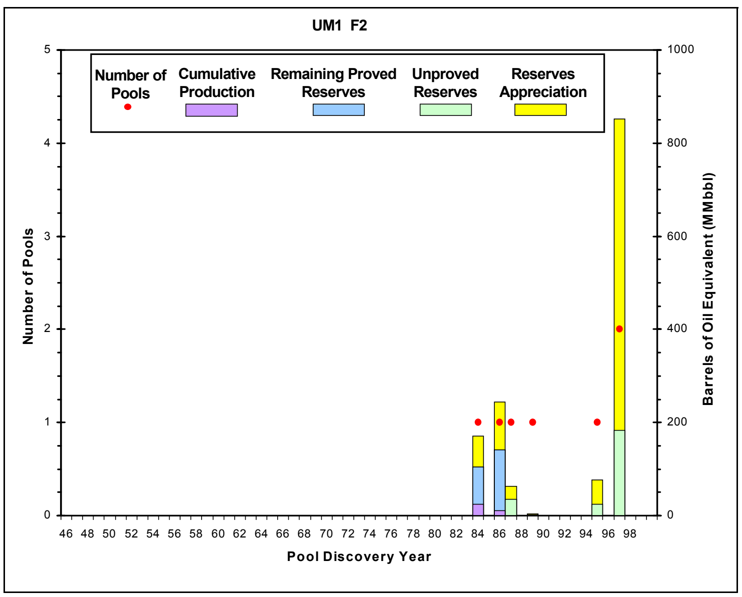


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UM1 F2 Play 7 Pools 12 Sands	Minimum	Mean	Maximum
Water depth (feet)	1492	4956	7500
Subsea depth (feet)	9896	16050	20170
Number of sands per pool	1	2	3
Porosity	24%	29%	33%
Water saturation	16%	27%	40%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Upper Miocene Fan 2 (UM1 F2) play occurs within the *Discorbis* 12 biozone. The play is also defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The play extends from the southern Port Isabel, East Breaks, and Alaminos Canyon Areas offshore Texas to the southwestern Destin Dome and western DeSoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the play is bounded by the Lower Upper Miocene Fan 1 (UM1 F1) play. To the east, the UM1 F2 play onlaps the Cretaceous slope of offshore Florida. Downdip in the western and central Gulf of Mexico Regions, the UPL F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf of Mexico Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps deposited on the upper Miocene upper and lower slope, in topographically low areas between salt structure highs and on the abyssal plain. These deep-sea fan systems are often over-

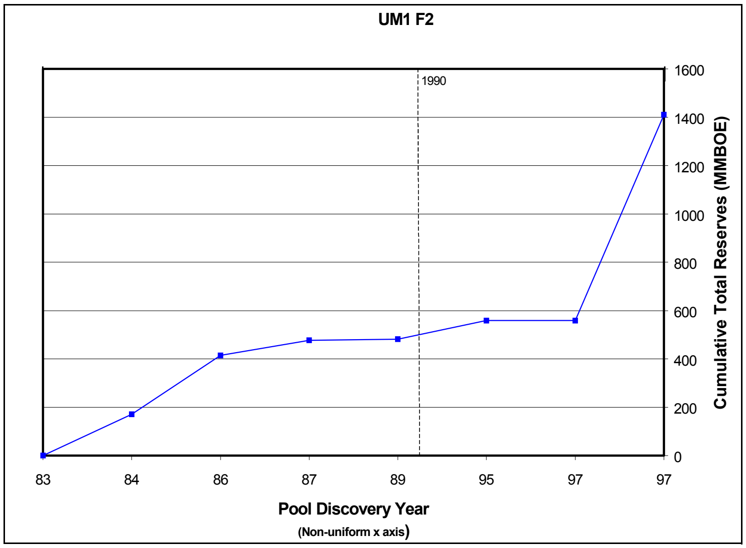


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UM1 F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2	0.021	1.257	0.244
Cumulative production	–	0.004	0.174	0.034
Remaining proved	–	0.017	1.083	0.210
Unproved	5	0.188	0.318	0.245
Appreciation (P & U)	–	0.598	1.813	0.921
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.773	8.446	.2.323
Mean	75	0.938	9.154	2.567
5th percentile	–	1.112	10.011	2.830
Total Endowment				
95th percentile	–	1.580	11.835	3.733
Mean	82	1.745	12.543	3.977
5th percentile	–	1.919	13.400	4.240

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

lain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

The majority of the fields in the UM1 F2 play are structurally associated with anticlines and normal faults, while other fields contain hydrocarbons trapped on the flanks of salt bodies. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The UM1 F2 play is a mixed oil and gas play, with total reserves of 0.807 Bbo and 3.389 Tcfg (1.410 BBOE), of which 0.004 Bbo and 0.174 Tcfg (0.034 BBOE) have been produced. The play contains 12 producible sands in seven pools, of which two contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1984 in the Viosca Knoll 783 field (Tahoe) (figure 2). Maximum yearly total reserves of 852 MMBOE were added in 1997 when two pools were discovered, including the largest pool in the play in the Mississippi Canyon 899 field (Flathead) with 852 MMBOE in total reserves (figures 2 and 3). All of the play's cumulative production and 34 percent of the play's total reserves have been from pools discovered before 1990.

The seven discovered pools contain 15 reservoirs, of which 6 are nonassociated gas, 7 are undersaturated oil, and 2 are saturated oil. Cumulative production has consisted of 90 percent gas and 10 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the UM1 F2 play is 1.00. The play has a mean total endowment of 1.745 Bbo and 12.543 Tcfg (3.977 BBOE) (table 2). Less than 1 percent of this BOE mean total

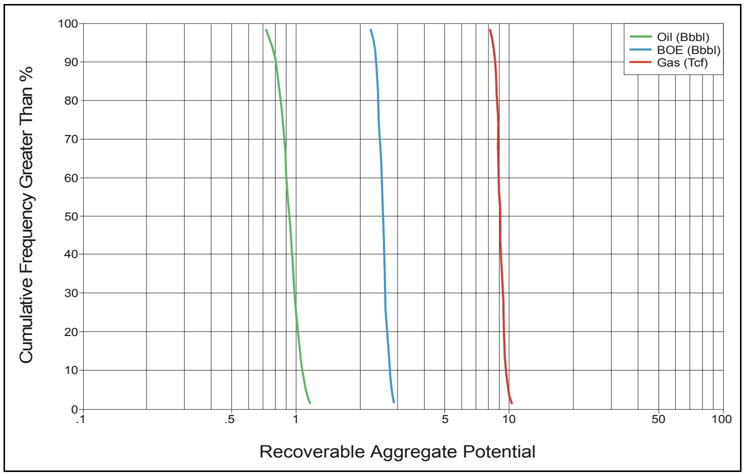


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

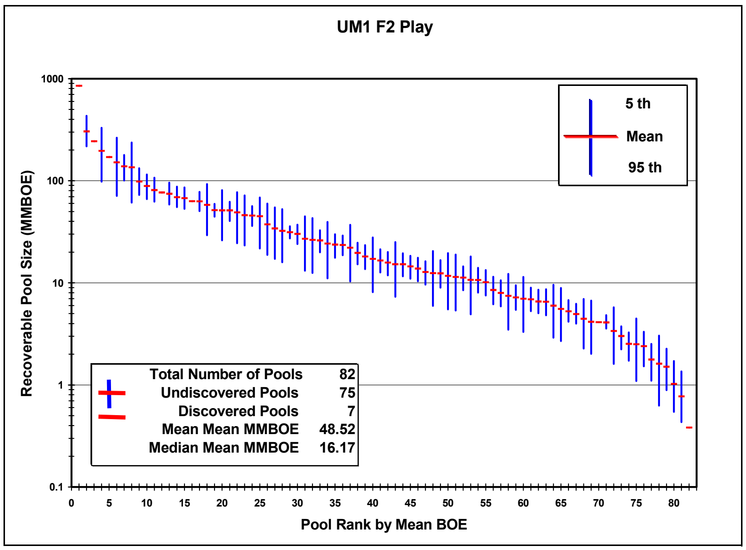


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) range from 0.773 to 1.112 Bbo and 8.446 to 10.011 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.938 Bbo and 9.154 Tcfg (2.567 BBOE). These undiscovered resources might occur in as many as 75 pools. The largest undiscovered pool, with a mean size of 305 MMBOE, is forecast as the second largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 4, 6, 7, and 8 on the pool rank plot. For all the undiscovered pools in the UM1 F2 play, the mean mean size is 34 MMBOE, which is smaller than the 201 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 49 MMBOE.

The UM1 F2 play is forecast to contain 2.6 BBOE in mean UCRR, contributing 65 percent to the play's BOE mean total endowment. Five additional pools containing more than 100 MMBOE in total reserves are expected to be discovered. Exploration potential exists in structural and stratigraphic traps near and against salt.

Upper Middle Miocene Aggradational (MM9 A1) Play

***Textularia* "W" and *Bigenerina* 2 biozones**

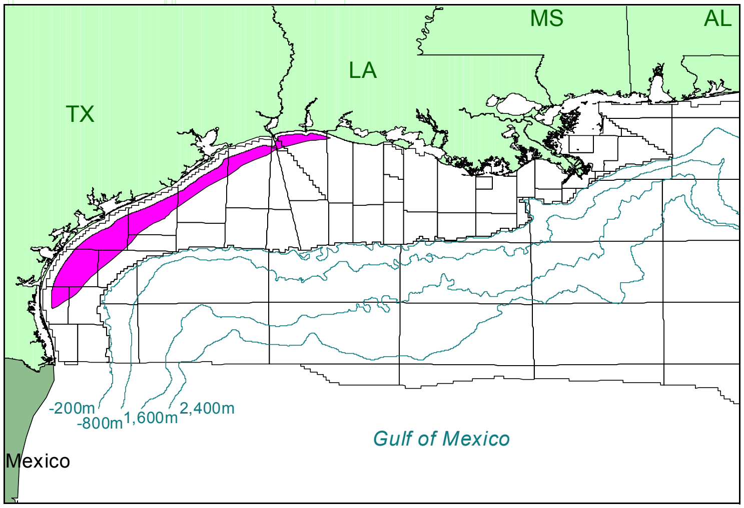


Figure 1. Play location.

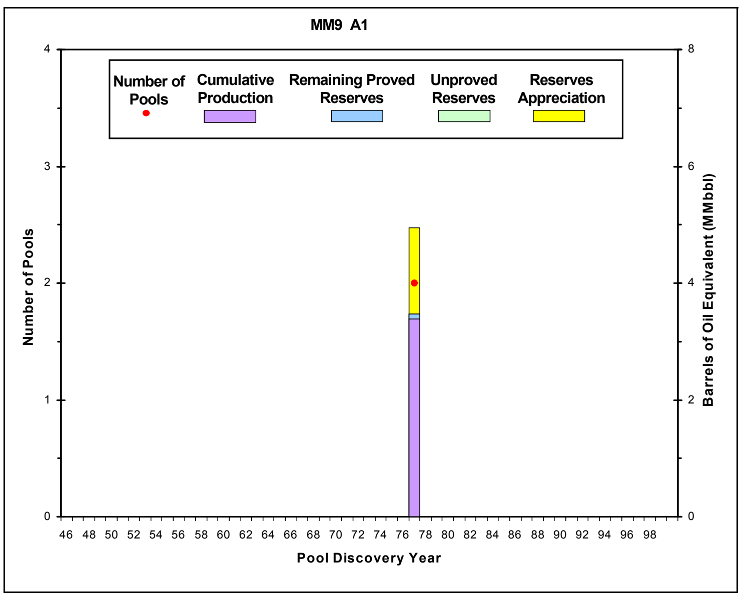


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM9 A1 Play 2 Pools 7 Sands	Minimum	Mean	Maximum
Water depth (feet)	71	132	192
Subsea depth (feet)	2129	2898	3666
Number of sands per pool	3	4	4
Porosity	29%	29%	29%
Water saturation	25%	27%	28%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

Economic hydrocarbons have been found in only two pools in the Upper Middle Miocene Aggradational (MM9 A1) play. The play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones, and extends from the North Padre Island Area offshore Texas to the northern East Cameron Area offshore Louisiana (figure 1).

Updip and along strike, the play continues onshore into Texas and Louisiana. Downdip, the play either grades into deposits of the Upper Middle Miocene Progradational (MM9 P1) play or is limited by the Upper Middle Miocene Structural Corsair (MM9 S1) Play.

Play Characteristics

The MM9 A1 play is characterized by delta plain and shallow-marine shelf sands that were deposited in channel/levee complexes, barrier bars, and distributary mouth bars. Retrogradational sands locally cap the MM9 A1 play, but because they are so discontinuous, they are included as part of the MM9 A1 play.

The major structural feature in the play is faulted anticlines. 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

The MM9 A1 gas play contains total reserves of <0.001 Bbo and 0.028 Tcfg (0.005 BBOE), of which <0.001 Bbo and 0.019 Tcfg (0.003 BBOE) have been produced. The play contains seven producible sands in two pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). These two pools are in the Matagorda Island 665 and 7A fields and

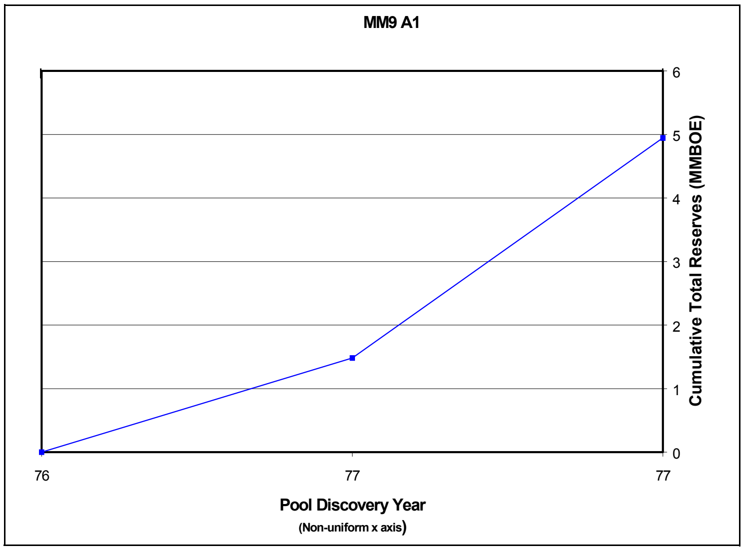


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM9 A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2	<0.001	0.020	0.003
Cumulative production	--	<0.001	0.019	0.003
Remaining proved	--	<0.001	<0.001	<0.001
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.008	0.001
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.003	0.001
Mean	3	<0.001	0.011	0.002
5th percentile	--	0.001	0.021	0.005
Total Endowment				
95th percentile	--	<0.001	0.031	0.006
Mean	5	<0.001	0.038	0.007
5th percentile	--	0.001	0.049	0.010

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

contain 0.003 and 0.001 BBOE, respectively (figures 2 and 3). Both pools were discovered in 1977.

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

Assessment Results

Because of limited data for the MM9 A1 play, the Middle Middle Miocene Aggradational (MM4 A1) play was used as an analog to forecast pool sizes in the MM9 A1 play. The MM4 A1 play was selected because of similarities to the MM9 A1 play in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the MM9 A1 play is 1.00. The play has a mean total endowment of <0.001 Bbo and 0.038 Tcfg (0.007 BBOE) (table 2). Forty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable oil resources are insignificant (<0.001 Bbbl) and that undiscovered conventionally recoverable gas resources have a range of 0.003 to 0.021 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The estimated amount of mean undiscovered gas is 0.011 Tcfg (0.002 BBOE). These undiscovered resources might occur in as many as three pools. The largest undiscovered pool, with a mean size of 1 MMBOE, is forecast as the third largest pool in the play (figure 5). The forecast places the two other undiscovered pools in positions 4 and 5 on the pool rank plot. For the three undiscovered pools in the MM9 A1 play, the mean mean size is 1 MMBOE compared with the 2 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 1 MMBOE.

Undiscovered conventionally recoverable gas resources are expected to contribute 29 percent to the play's BOE mean total endowment. However, the BOE mean total endowment forecast for the MM9 A1

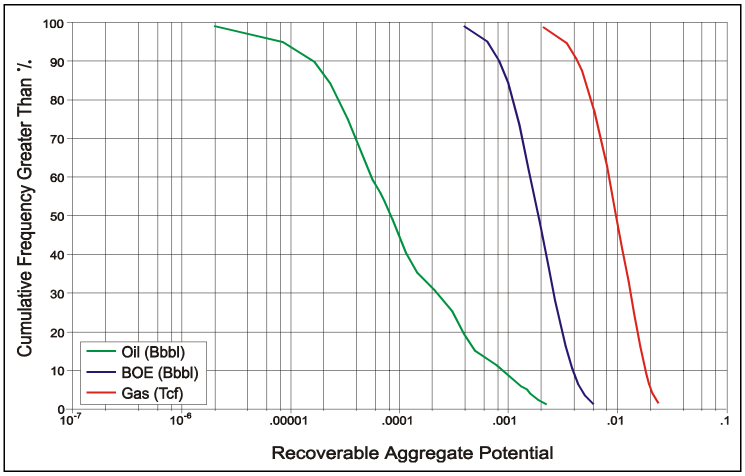


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

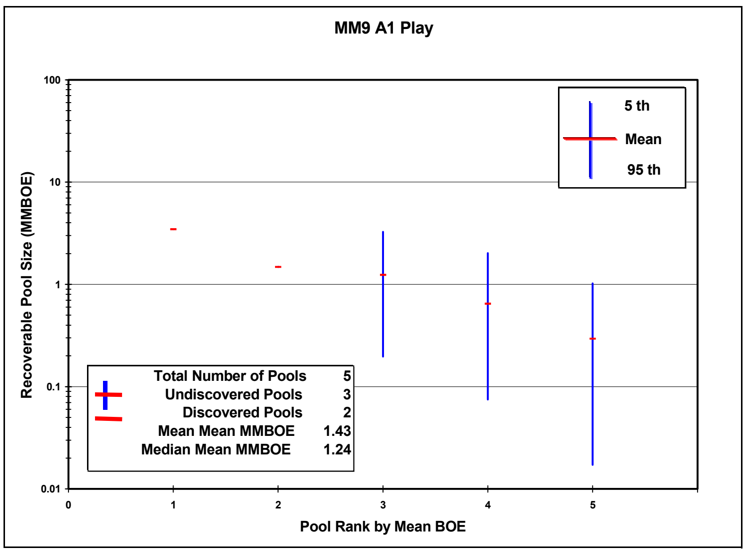


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

play is small, limiting exploration potential in the play.

Upper Middle Miocene Aggradational/Progradational (MM9 AP1) Play *Textularia* "W" and *Bigenerina* 2 biozones

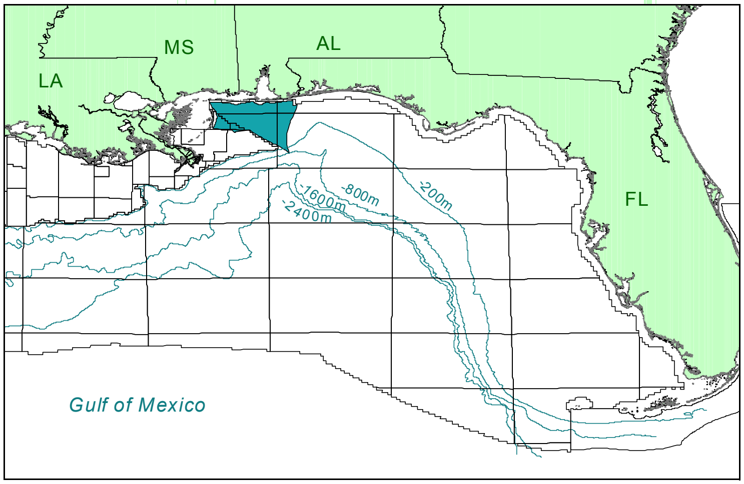


Figure 1. Play location.

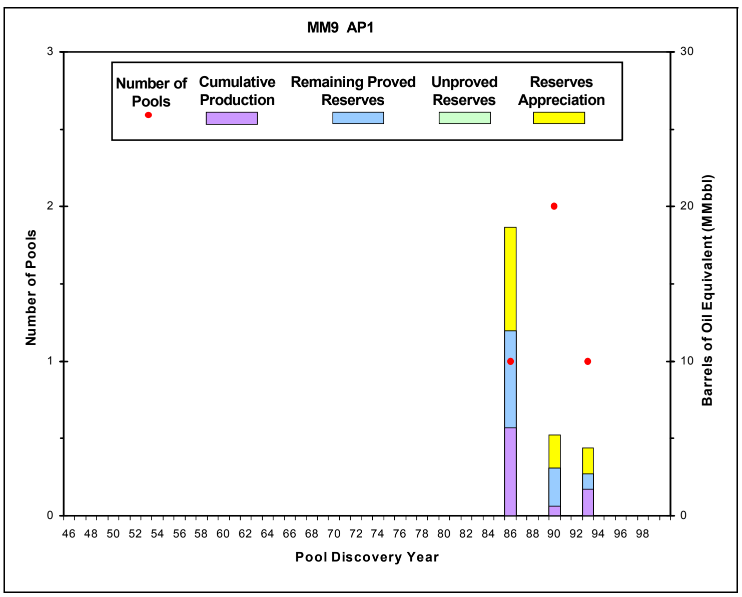


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM9 AP1 Play 4 Pools 5 Sands	Minimum	Mean	Maximum
Water depth (feet)	47	74	121
Subsea depth (feet)	2500	3359	4150
Number of sands per pool	1	1	2
Porosity	32%	36%	38%
Water saturation	28%	35%	46%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Middle Miocene Aggradational/Progradational (MM9 AP1) play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones. The play is also defined by minimal structural deformation and gas accumulations associated with seismic hydrocarbon indicators (bright spots). This play overlies the Cretaceous carbonate shelf in the Mobile, western Pensacola, northern Chandeleur, northern Viosca Knoll, and western Destin Dome Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Mississippi and Alabama while downdip, the play grades into shale.

The MM9 AP1 play is one of three plays within the combined aggradational and progradational (AP) "Shallow Miocene Bright Spot Trend." The other two plays are the Lower Upper Miocene Aggradational/ Progradational (UM1 AP1) play and the Upper Upper Miocene Aggradational/Progradational (UM3 AP1) play. The MM9 AP1 play contains the oldest productive sediments that overlie the Cretaceous carbonate shelf. The underlying middle middle Miocene (MM7) chronozone includes sediments of a similar depositional setting and geographic extent as the MM9 AP1 play. However, the MM7 chronozone in this area is extremely thin and sand poor and, therefore, is not considered prospective.

Play Characteristics

The MM9 AP1 play is comprised of wasteland, incised-valley fill deposits that are usually not stacked like the AP deposits in the overlying UM1 and UM3 chronozones. Additionally, the AP section in the MM9 chronozone is relatively thinner and less sandy than the overlying AP sec-

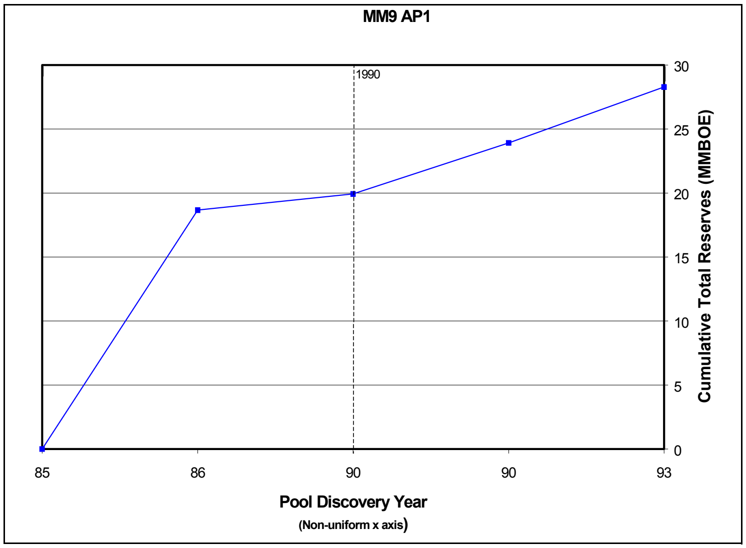


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM9 AP1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	4	<0.001	0.100	0.018
Cumulative production	–	<0.001	0.045	0.008
Remaining proved	–	<0.001	0.055	0.010
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	<0.001	0.059	0.010
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	<0.001	0.042	0.008
Mean	4	<0.001	0.061	0.011
5th percentile	–	<0.001	0.083	0.015
Total Endowment				
95th percentile	–	<0.001	0.201	0.036
Mean	8	<0.001	0.220	0.039
5th percentile	–	<0.001	0.242	0.043

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

tions, and does not extend as far downdip.

The Cretaceous carbonate shelf created a stable platform for sediment deposition. Consequently, Miocene deposits of the three AP plays appear minimally affected by salt movement and faulting, and stratigraphic traps dominate the play. The stratigraphic traps are influenced by a combination of pinchout and subtle structural flexure over anticlinal noses (Mink *et al.,* 1988). Lateral shale-outs and overlying shelf shales create seals in the play. These thick, enclosing shales are known to be an immature source rock, and the gas is proven to have originated biogenically (Mink *et al.,* 1988).

Discoveries

The MM9 AP1 gas play contains total reserves of <0.001 Bbo and 0.159 Tcfg (0.028 BBOE), of which 0.045 Tcfg (0.008 BBOE) have been produced. The play contains five producible sands in four pools (table 1). Maximum yearly total reserves were discovered in 1986 in the first and largest pool in the play in the Viosca Knoll 204 field with 19 MMBOE in total reserves (figures 2 and 3). The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1993.

The four discovered pools contain seven reservoirs, all of which are nonassociated gas.

Assessment Results

Because of limited data, the Upper Upper Miocene Aggradational/Progradational (UM3 AP1) play was used as an analog for the MM9 AP1 play. The UM3 AP1 play was selected because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the MM9 AP1 play is 1.00. The play has a mean total endowment of <0.001 Bbo and 0.220 Tcfg (0.039 BBOE) (table 2). Twenty-one percent of this BOE mean total

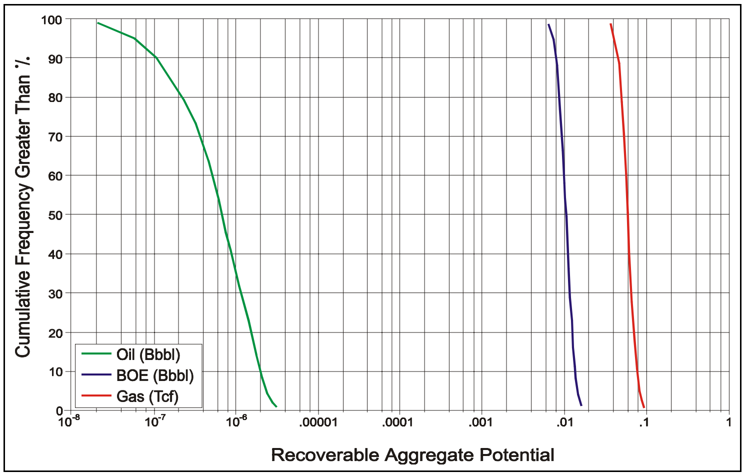


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

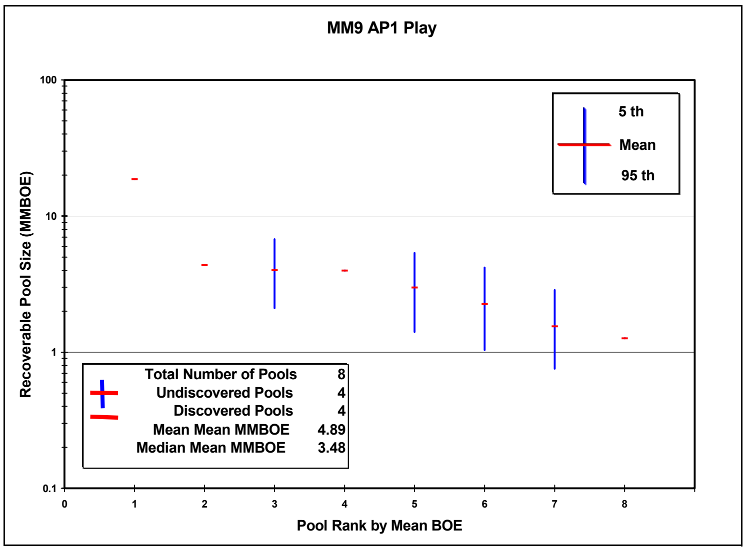


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable oil resources are negligible (<0.001 Bbbl) and that undiscovered conventionally recoverable gas resources have a range of 0.042 to 0.083 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The forecast amount of mean undiscovered gas is 0.061 Tcfg (0.011 BBOE). These undiscovered resources might occur in as many as four pools. The largest undiscovered pool, with a mean size of 4 MMBOE, is forecast as the third largest pool in the play (figure 5). The forecast places the remaining three undiscovered pools in positions 5, 6, and 7 on the pool rank plot. For all four of the undiscovered pools in the MM9 AP1 play, the mean mean size is 3 MMBOE, which is smaller than the 7 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5 MMBOE.

BOE mean undiscovered conventionally recoverable resources contribute 28 percent to the play's BOE mean total endowment. Future discoveries are dependent on the economics of developing small, bright-spot-defined gas reservoirs.

Reference

Mink, R. M., E. A. Mancini, B. L. Bearden, and C. C. Smith. 1988. Middle and upper Miocene natural gas sands in onshore and offshore Alabama: Gulf Coast Association of Geological Societies Transactions, vol. 36 p. 1-6.

Upper Middle Miocene Progradational (MM9 P1) Play

***Textularia* "W" and *Bigenerina* 2 biozones**

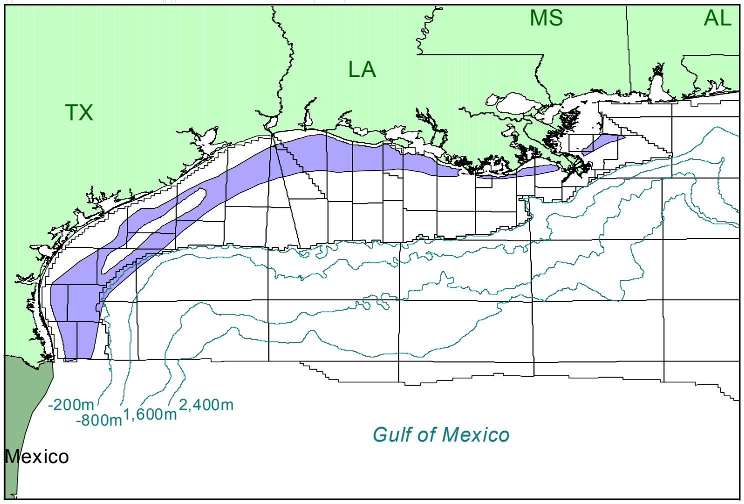


Figure 1. Play location.

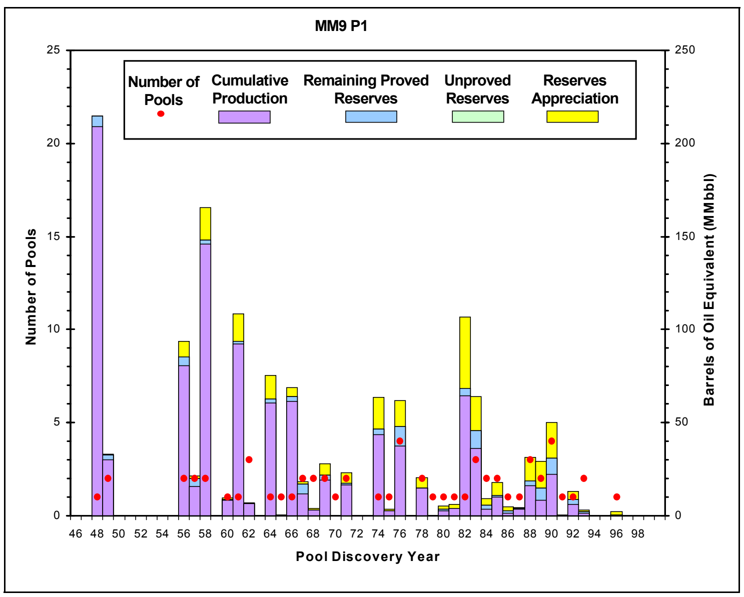


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM9 P1 Play **61 Pools 164 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	11	52	274
Subsea depth (feet)	3802	8845	16067
Number of sands per pool	1	3	8
Porosity	22%	28%	32%
Water saturation	16%	29%	65%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Middle Miocene Progradational (MM9 P1) play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones. This play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip in offshore Texas, the MM9 P1 play grades into the deposits of the Upper Middle Miocene Aggradational (MM9 A1) play, while updip in Louisiana, the MM9 P1 play extends onshore. To the northeast, the MM9 P1 play is limited by the deposits of the Upper Middle Miocene Aggradational/Progradational (MM9 AP1) play overlying the Cretaceous carbonate shelf. To the southwest, the MM9 P1 play continues onshore into Texas and into Mexican national waters. Downdip, the play grades into the deposits of the Upper Middle Miocene Fan 1 (MM9 F1) play. In parts of the Mustang Island, Matagorda Island, Brazos, and Galveston Areas, the MM9 P1 play is limited by the Upper Middle Miocene Structural Corsair (MM9 S1) play.

Play Characteristics

Sediments in the MM9 P1 play represent major regressive episodes of outbuilding of both the shelf and slope. Additionally, retrogradational reworked sands associated with the *Bigenerina* 2 transgression locally cap the play. Because these sands are poorly developed and discontinuous, they are included as part of the MM9 P1 play.

In offshore Texas, sand deposition on the shelf was insufficient to develop an extensive prograding facies. In addition, the active regional Corsair Fault System of offshore Texas captured much of the sand that was available. MM9 P1 sands of

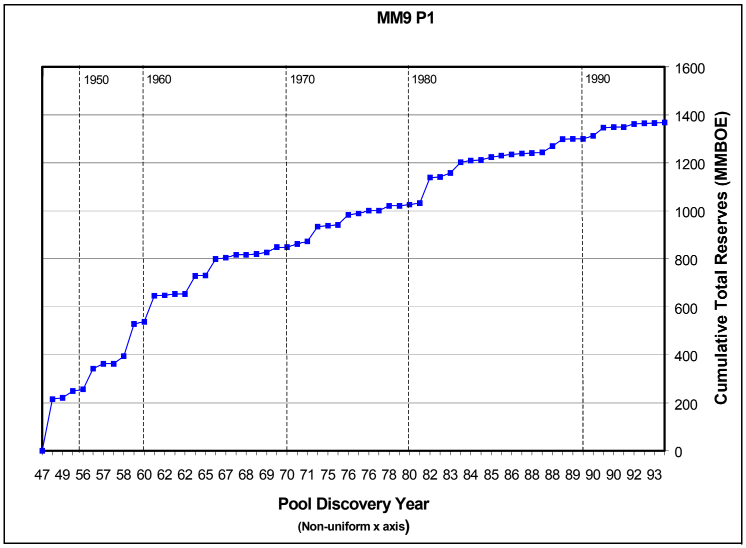


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM9 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	61	0.105	5.749	1.128
Cumulative production	--	0.096	5.300	1.040
Remaining proved	--	0.009	0.449	0.089
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.037	1.138	0.239
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.012	0.863	0.174
Mean	29	0.028	1.078	0.220
5th percentile	--	0.056	1.296	0.270
Total Endowment				
95th percentile	--	0.154	7.750	1.542
Mean	90	0.170	7.965	1.588
5th percentile	--	0.198	8.183	1.638

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

the Texas offshore were deposited in marine bars and in crevasse splays that are characterized by isolated spiky, prominent-to-subdued log patterns.

In contrast to the offshore Texas shelf area, the offshore Louisiana shelf area received greater sand input during MM9 time. MM9 P1 sands of the Louisiana offshore were deposited in delta fringes, channel/levee complexes, and distributary mouth bars. The thickest sand-dominated intervals probably represent stacked facies of multiple episodes of delta-lobe switching and progradation.

The majority of the fields in this play are structurally associated with normal faults. Other less common structures are growth fault anticlines and shallow salt diapirs. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MM9 P1 play is predominantly a gas play, with total reserves of 0.142 Bbo and 6.887 Tcfg (1.368 BBOE), of which 0.096 Bbo and 5.300 Tcfg (1.040 BBOE) have been produced. The play contains 164 producible sands in 61 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first and largest pool in the play was discovered in 1948 in the Vermilion 39 field, which contains 215 MMBOE in total reserves (figures 2 and 3). Discoveries have occurred at a steady rate throughout the play's exploration history. Over 70 percent of the play's cumulative production has been from pools discovered prior to 1971, while 97 percent of the play's cumulative production and 95 percent of the play's total reserves have been from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1996.

The 61 discovered pools contain 330 reservoirs, of which 304

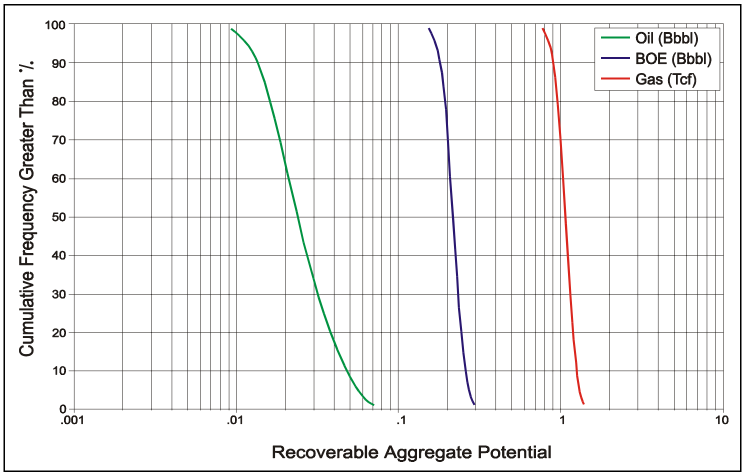


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

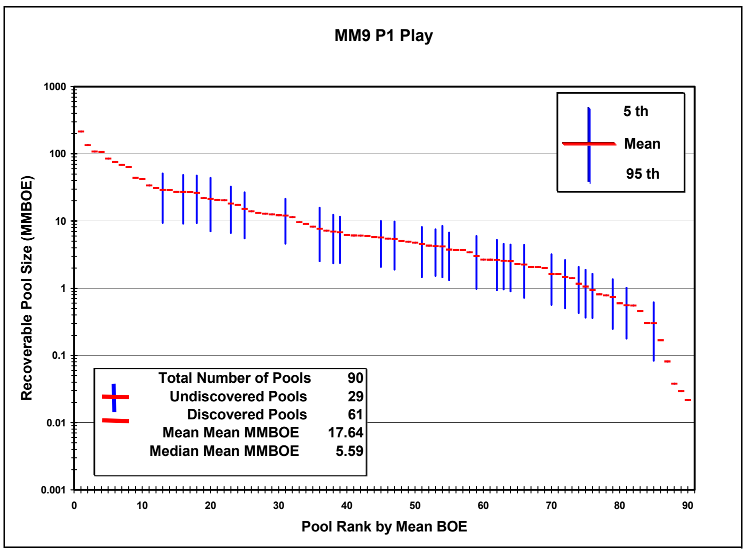


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

are nonassociated gas, 17 are undersaturated oil, and 9 are saturated oil. Cumulative production has consisted of 91 percent gas and 9 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM9 P1 play is 1.00. The play contains a mean total endowment of 0.170 Bbo and 7.965 Tcfg (1.588 BBOE) (table 2). Sixty-five percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.012 to 0.056 Bbo and 0.863 to 1.296 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.028 Bbo and 1.078 Tcfg (0.220 BBOE). These undiscovered resources might occur in as many as 29 pools. The largest undiscovered pool, with a mean size of 29 MMBOE, is forecast as the 13th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 16, 18, 20, and 23 on the pool rank plot. For all the undiscovered pools in the MM9 P1 play, the mean mean size is 7 MMBOE, which is smaller than the 22 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 18 MMBOE.

The MM9 P1 is a mature play with mean UCRR contributing 14 percent to the play's BOE mean total endowment. Exploration potential in this play exists in small, subtle structures and downdip from existing fields on the upper slope where the MM9 P section may not be adequately tested.

Upper Middle Miocene Structural Corsair (MM9 S1) Play *Textularia* "W" and *Bigenerina* 2 biozones

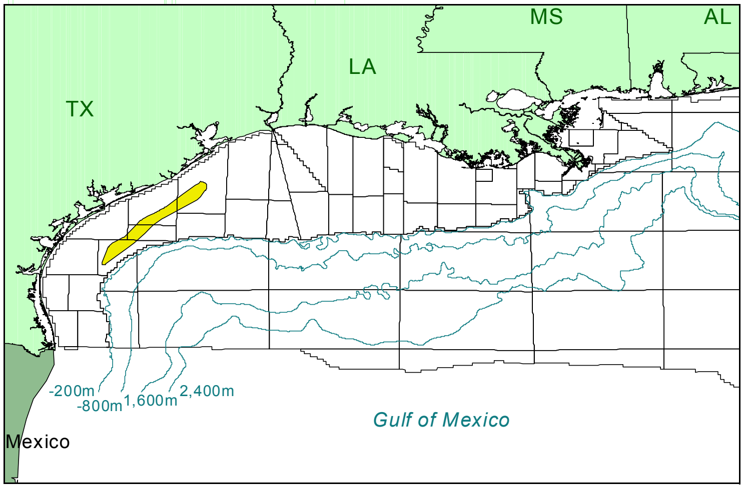


Figure 1. Play location.

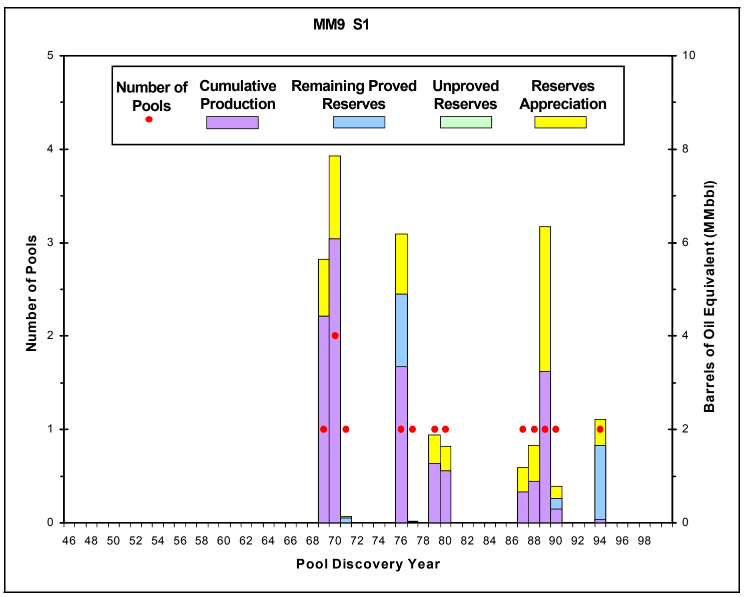


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM9 S1 Play 13 Pools 41 Sands	Minimum	Mean	Maximum
Water depth (feet)	80	120	202
Subsea depth (feet)	5847	7021	8824
Number of sands per pool	1	3	11
Porosity	21%	27%	29%
Water saturation	21%	35%	51%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Middle Miocene Structural Corsair (MM9 S1) 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. The play 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 sediments of the Upper Middle Miocene Progradational (MM9 P1) play that are not associated with the Corsair Fault System.

The MM9 S1 is the youngest play included in the structurally controlled plays of the Corsair Fault System. The MM9 S1 play contains only relatively shallow-water sands in contrast to the underlying Middle Middle Miocene Structural Corsair (MM7 S1) play that contains both shallow-water and deep-sea fan sands.

Play Characteristics

The MM9 S1 play consists of stacked sequences of MM9 retrogradational, aggradational, and progradational sands that accumulated on the downthrown side of the Corsair Fault System. Movement on the Corsair Fault occurred in response to rapid influx of progradational and aggradational sands during periods of sea level lowstand, resulting in a greatly expanded MM9 section. Reworking of progradational and aggradational sands during marine transgressions produced the retrogradational facies that locally occur within and at the top of the section. Because sand accumulation was so

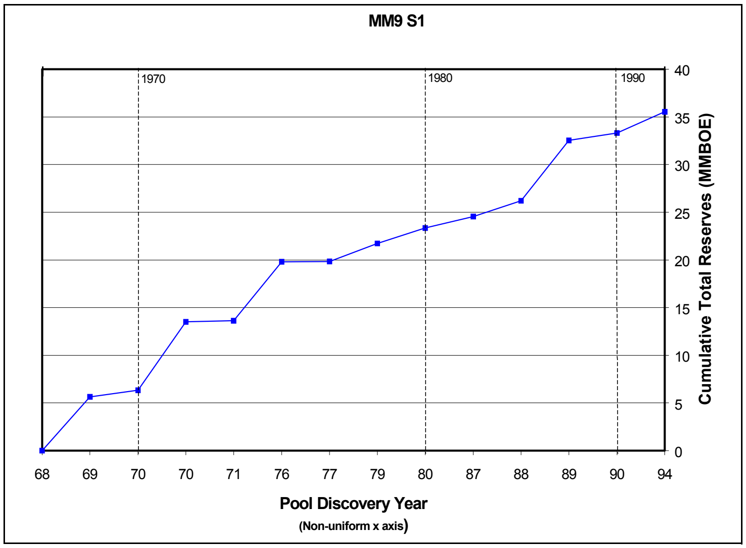


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM9 S1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	13	0.001	0.134	0.025
Cumulative production	--	0.001	0.114	0.021
Remaining proved	--	<0.001	0.019	0.003
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.058	0.011
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.010	0.002
Mean	5	<0.001	0.018	0.003
5th percentile	--	<0.001	0.030	0.006
Total Endowment				
95th percentile	--	0.002	0.201	0.038
Mean	18	0.002	0.209	0.039
5th percentile	--	0.002	0.221	0.042

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

influenced by movement along the fault, the play is considered to be structurally controlled rather than depositionally controlled, thus providing the “S” designation.

The Corsair Fault is only one of a series of growth fault systems that formed in offshore Texas during the late Oligocene through late Miocene, but it is the most significant and well known because of the numerous hydrocarbon accumulations associated with it.

Two structural styles are identifiable along the Corsair Fault System. In the Galveston Area, the main Corsair Fault has broken into a series of secondary relief or en echelon faults with traps formed on their upthrown sides. In the Mustang Island and Brazos Areas, large rollover anticlinal structures broken by antithetic faults have formed on the downthrown side of the main Corsair Fault. Though the Corsair Fault is classified as a primary salt-withdrawal fault system with detachments into salt, its hanging walls overlie shale ridges (Bradshaw and Watkins, 1994). The Corsair Fault exhibits up to a tenfold expansion of the middle Miocene section, the largest expansion of any of the offshore Texas growth faults.

Discoveries

The MM9 S1 gas play contains total reserves of 0.002 Bbo and 0.191 Tcfg (0.036 BBOE), of which 0.001 Bbo and 0.114 Tcfg (0.021 BBOE) have been produced. The play contains 41 producible sands in 13 pools, of which all 13 contain proved reserves (table 1). The first discovery in the play was in 1969 in the Galveston 360 field. Maximum yearly total reserves of 8 MMBOE were added from two pools discovered in 1970 (figure 2), including the largest pool in the play (7 MMBOE) in the Brazos 1A field (figures 2 and 3). Ninety-eight percent of the play’s cumulative production and 92 percent of the play’s total reserves come from pools discovered before 1990, reflecting the maturity of the play. The

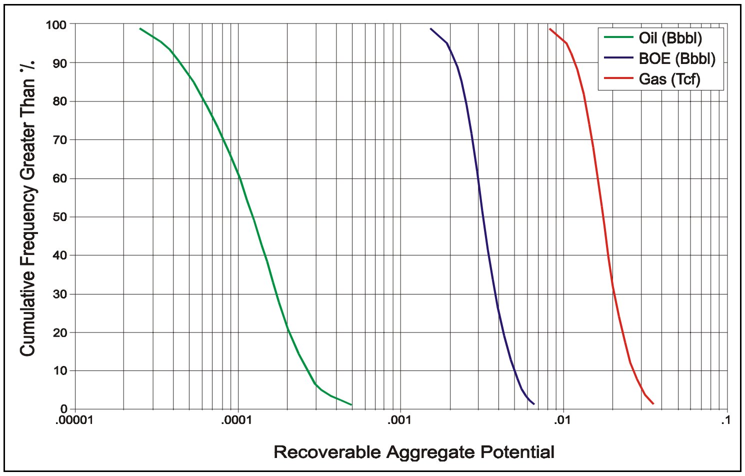


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

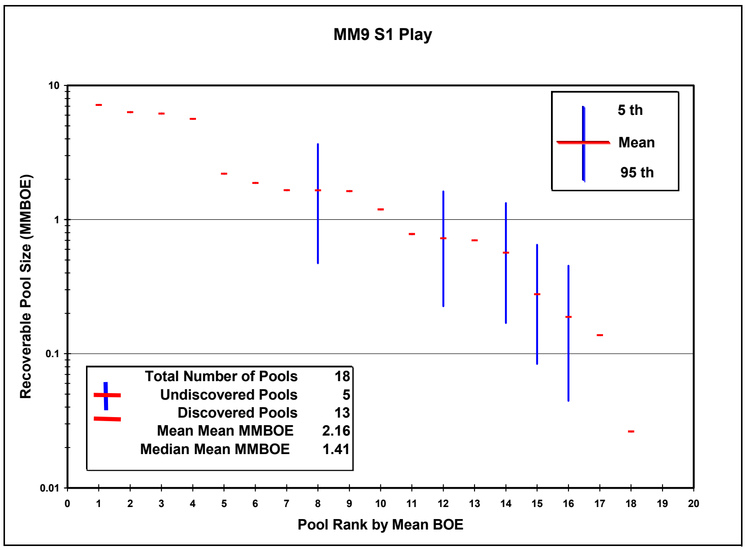


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1994.

The 13 discovered pools contain 51 reservoirs, all of which are nonassociated gas. Cumulative production has consisted of 95 percent gas and 5 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM9 S1 play is 1.00. The play has a mean total endowment of 0.002 Bbo and 0.209 Tcfg (0.039 BBOE) (table 2). Fifty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable oil resources are <0.001 Bbbl and that undiscovered conventionally recoverable gas resources have a range of 0.010 to 0.030 Tcf at the 95th and 5th percentiles, respectively (figure 4). The estimated amount of mean undiscovered conventionally recoverable gas resources is 0.018 Tcfg (0.003 BBOE). These undiscovered resources might occur in as many as five pools. The largest undiscovered pool, with a mean size of 2 MMBOE, is modeled as the eighth largest pool in the play. The four remaining undiscovered pools occupy positions 12, 14, 15 and 16 on the pool rank plot (figure 5). For the five undiscovered pools in the MM9 S1 play, the mean mean size is 1 MMBOE compared to the 3 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 2 MMBOE.

The MM9 S is an extensively explored play with undiscovered conventionally recoverable resources contributing only 8 percent to the play's BOE mean total endowment.

Reference

Bradshaw, Barry E. and Joel S. Watkins. 1994. Growth-fault evolution in offshore Texas: Gulf Coast Association of Geological

Societies Transactions, vol.
44, p. 103-110.

Upper Middle Miocene Fan 1 (MM9 F1) Play

Textularia "W" and *Bigenerina* 2 biozones

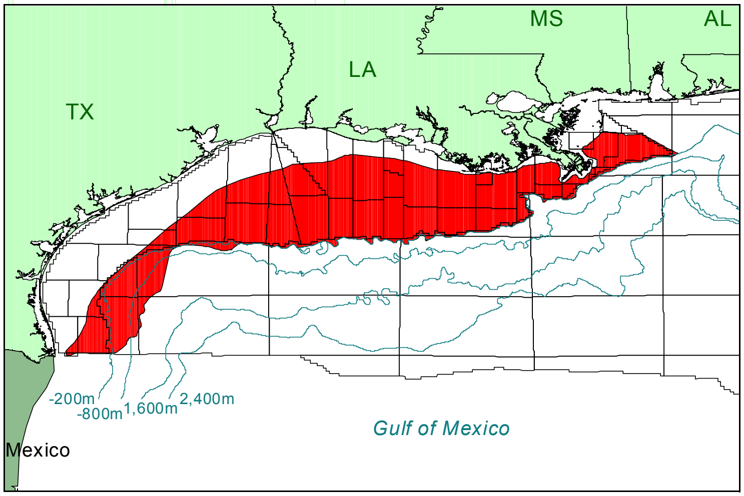


Figure 1. Play location.

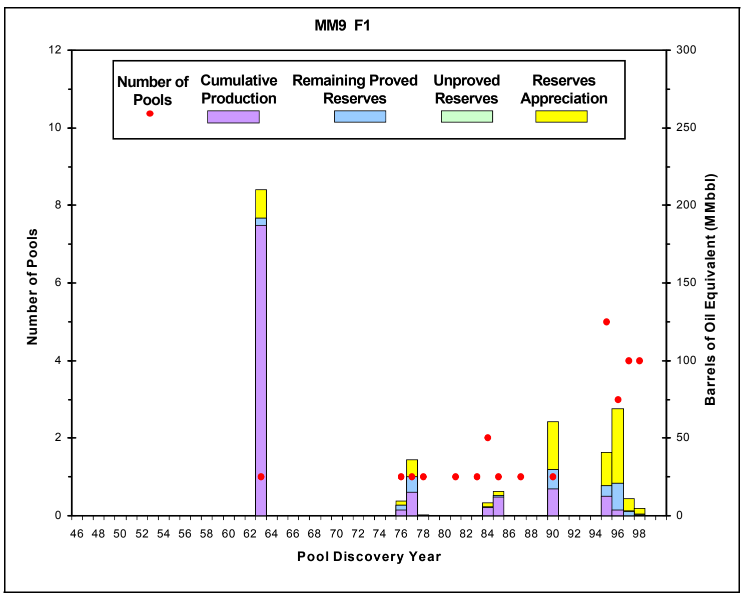


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM9 F1 Play 27 Pools 63 Sands	Minimum	Mean	Maximum
Water depth (feet)	15	154	399
Subsea depth (feet)	7950	11016	18350
Number of sands per pool	1	2	11
Porosity	19%	26%	30%
Water saturation	20%	37%	54%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Middle Miocene Fan 1 (MM9 F1) play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The MM9 F1 play extends from the South Padre Island and Port Isabel Areas offshore Texas to Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip, the MM9 F1 play is bounded by the shelf/slope break associated with the *Textularia "W"* biozone and grades into the deposits of the Upper Middle Miocene Progradational (MM9 P1) play. To the northeast, the MM9 F1 play's boundary is the Upper Middle Miocene Aggradational/Progradational (MM9 AP1) play overlying the Cretaceous carbonate shelf. To the southwest, the play extends into Mexican national waters. Downdip, the MM9 F1 play is limited by the Upper Middle Miocene Fan 2 (MM9 F2) play.

Play Characteristics

The MM9 F1 play is characterized by deepwater turbidites deposited basinward of the MM9 shelf margin. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps deposited on the upper and lower slope, in topographically low areas between salt structure highs, and on the abyssal plain. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Many of the fields in the MM9 F1 play are associated with permeability barriers, updip pinchouts or facies changes, and salt diapirs with

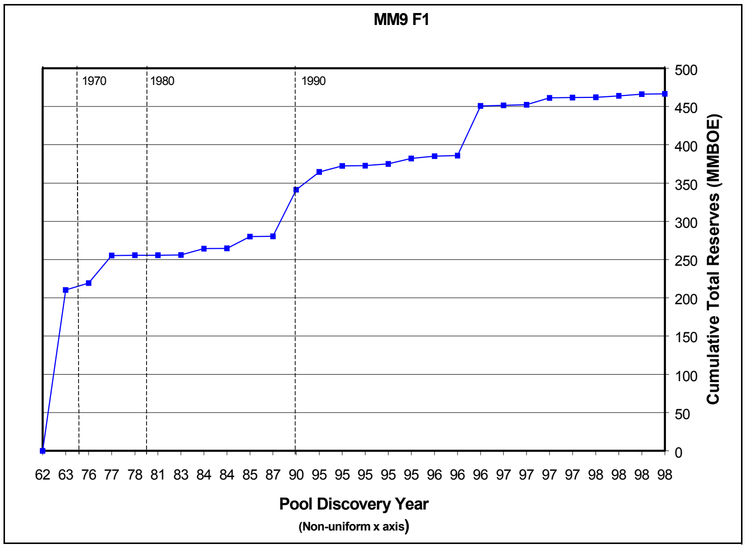


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM9 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	23	0.161	0.873	0.317
Cumulative production	--	0.148	0.620	0.258
Remaining proved	--	0.013	0.253	0.058
Unproved	4	<0.001	0.003	0.001
Appreciation (P & U)	--	0.043	0.597	0.149
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.057	1.920	0.418
Mean	53	0.092	2.611	0.556
5th percentile	--	0.135	3.360	0.708
Total Endowment				
95th percentile	--	0.262	3.392	0.885
Mean	80	0.297	4.083	1.023
5th percentile	--	0.340	4.832	1.175

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Less common trapping structures include normal faults and growth fault anticlines. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MM9 F1 mixed oil and gas play contains total reserves of 0.205 Bbo and 1.472 Tcfg (0.467 BBOE), of which 0.148 Bbo and 0.620 Tcfg (0.258 BBOE) have been produced. The play contains 63 producible sands in 27 pools of which 23 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Main Pass 41 field in 1963 (figure 2). This field contains the largest pool in the play by far with 210 MMBOE in total reserves, which also accounts for the play's maximum yearly total reserves. Sixty percent of the play's total reserves and 87 percent of the play's cumulative production have come from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 27 discovered pools contain 103 reservoirs, of which 71 are nonassociated gas, 26 are undersaturated oil, and 6 are saturated oil. Cumulative production has consisted of 57 percent oil and 43 percent gas.

Assessment Results

The marginal probability of hydrocarbons for the MM9 F1 play is 1.00. The play has a mean total endowment of 0.297 Bbo and 4.083 Tcfg (1.023 BBOE) (table 2). Twenty-five percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.057 to 0.135 Bbo and

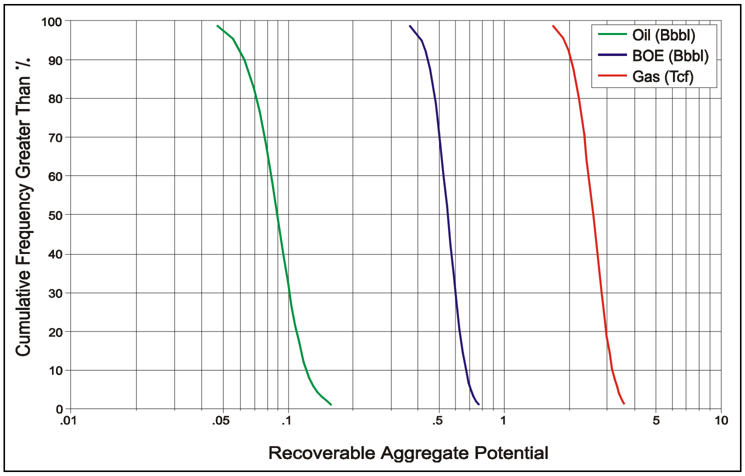


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

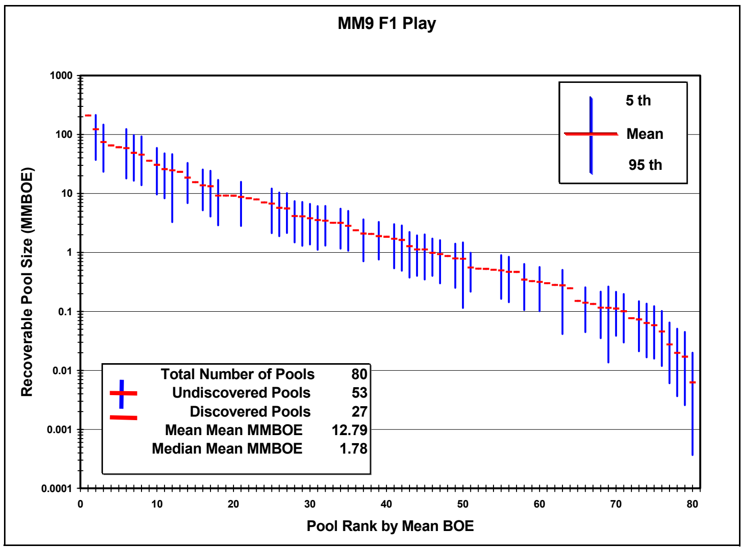


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

1.920 to 3.360 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.092 Bbo and 2.611 Tcfg (0.556 BBOE). These undiscovered resources might occur in as many as 53 pools. The largest undiscovered pool, with a mean size of 123 MMBOE, is forecast as the second largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 3, 6, 7, and 8 on the pool rank plot. For all the undiscovered pools in the MM9 F1 play, the mean mean size is 11 MMBOE, which is smaller than the 17 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 13 MMBOE.

The MM9 F1 is a relatively well explored play and BOE mean UCRR contribute over half of the play's BOE mean total endowment. Discoveries will continue to be made in structural and stratigraphic traps located around salt bodies and below salt sheets.

Upper Middle Miocene Fan 2 (MM9 F2) Play

***Textularia* "W" and *Bigenerina* 2 biozones**

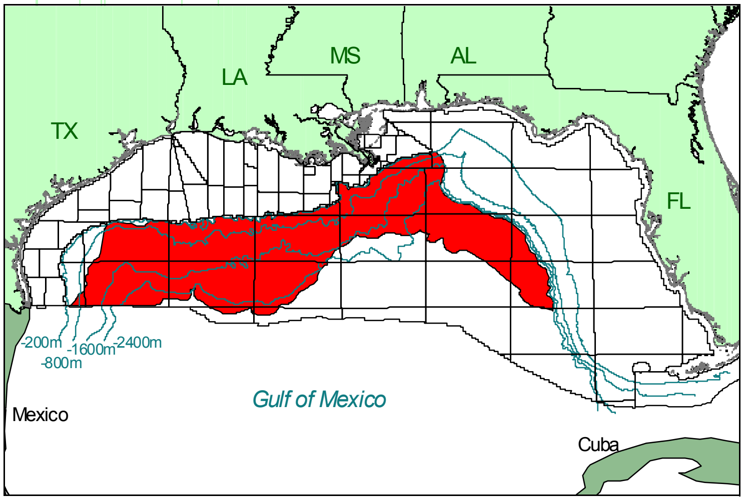


Figure 1. Play location.

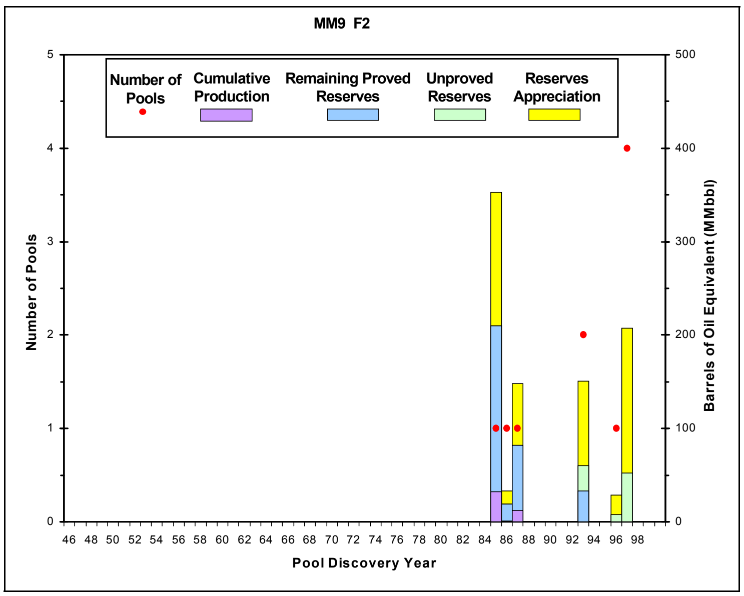


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM9 F2 Play 10 Pools 27 Sands	Minimum	Mean	Maximum
Water depth (feet)	689	2745	6590
Subsea depth (feet)	10056	11979	16312
Number of sands per pool	1	3	6
Porosity	21%	26%	29%
Water saturation	19%	27%	47%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Middle Miocene Fan 2 (MM9 F2) play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones. The play is also defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The MM9 F2 play extends from the Port Isabel, East Breaks, and Alaminos Canyon Areas to the southwestern Destin Dome and southwestern Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the MM9 F2 play is bounded by the Upper Middle Miocene Fan 1 (MM9 F1) play. To the east, the play onlaps the Cretaceous carbonate slope, while to the southwest, the play extends into Mexican national waters. Downdip in the western and central Gulf of Mexico Regions, the MM9 F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain or (2) the downdip limit of the Perdido Fold Belt or Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps deposited on the upper and lower slope, in topographically low areas between salt structure highs, and on the abys-

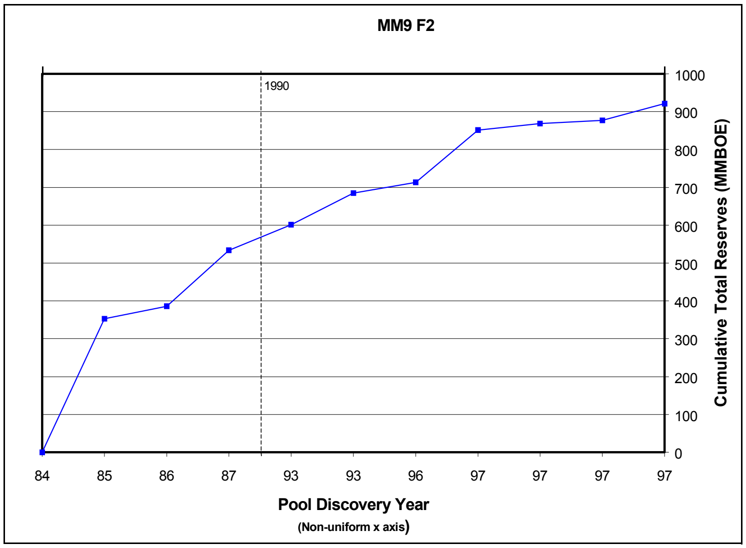


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM9 F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	4	0.147	1.108	0.344
Cumulative production	--	0.028	0.095	0.045
Remaining proved	--	0.119	1.013	0.300
Unproved	6	0.027	0.340	0.087
Appreciation (P & U)	--	0.167	1.813	0.489
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	1.575	9.707	3.424
Mean	80	1.838	12.334	4.033
5th percentile	--	2.153	17.219	5.008
Total Endowment				
95th percentile	--	1.916	12.969	4.345
Mean	90	2.179	15.596	4.954
5th percentile	--	2.494	20.481	5.929

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

sal plain. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Hydrocarbon accumulations in the play are stratigraphically trapped around salt bodies by permeability barriers, updip pinchouts or updip facies changes, or structurally, in simple anticlines. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MM9 F2 mixed oil and gas play contains total reserves of 0.341 Bbo and 3.262 Tcfg (0.921 BBOE), of which 0.028 Bbo and 0.095 Tcfg (0.045 BBOE) have been produced. The play contains 27 producible sands in 10 pools, four of which contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Viosca Knoll 956 (Ram-Powell) field in 1985 (figure 2). Ram-Powell also contains the largest pool in the play with 353 MMBOE in total reserves, which also accounts for the maximum yearly total reserves discovered in the play (figures 2 and 3). All of the play's cumulative production and 58 percent of the play's total reserves have come from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1997.

The 10 discovered pools contain 34 reservoirs, of which 16 are nonassociated gas, 13 are undersaturated oil, and 5 are saturated oil. Cumulative production has consisted of 62 percent oil and 38 percent gas.

Assessment Results

The marginal probability of hydrocarbons for the MM9 F2 play is 1.00. The play has a mean total endowment of 2.179 Bbo and 15.596

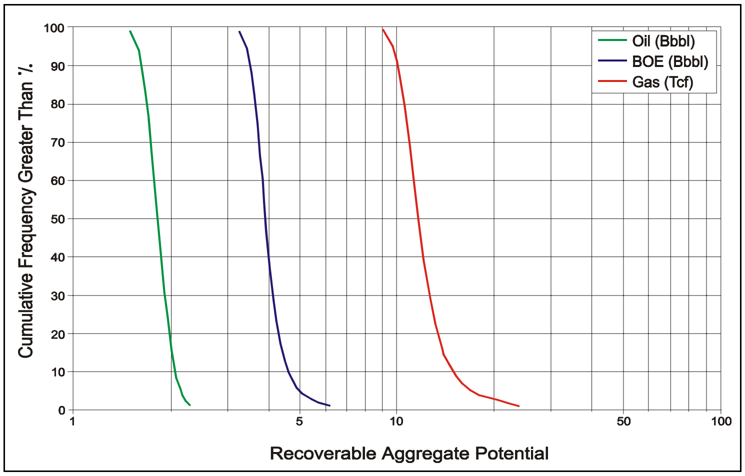


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

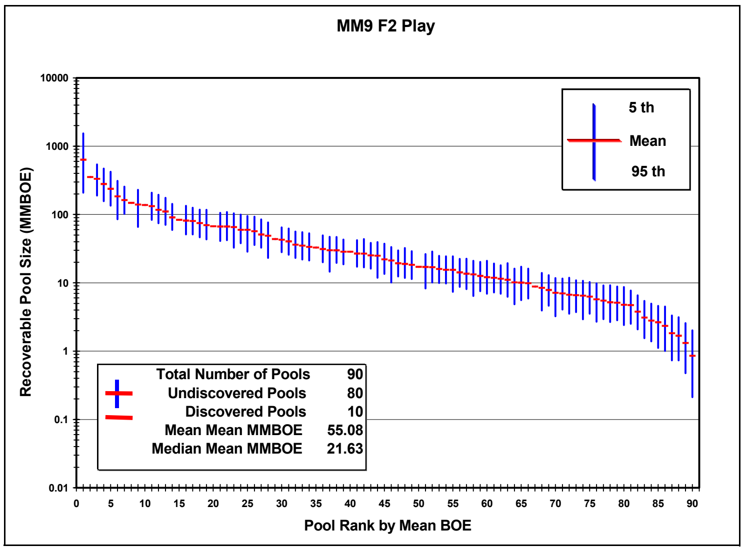


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Tcfg (4.954 BBOE) (table 2). Only 1 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 1.575 to 2.153 Bbo and 9.707 to 17.219 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 1.838 Bbo and 12.334 Tcfg (4.033 BBOE). These undiscovered resources might occur in as many as 80 pools. The largest undiscovered pool, with a mean size of 635 MMBOE, is also the largest pool in the play (figure 5). The forecast places 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 MM9 F2 play, the mean mean size is 50 MMBOE, which is smaller than the 92 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 55 MMBOE.

The MM9 F2 is an immature play with BOE mean UCRR contributing 81 percent to the play's BOE mean total endowment. Only 10 discoveries have been made as of this report's cutoff date and large areas within the play's boundaries remain untested. Ten fields of over 100 MMBOE in total reserves, including four fields of over 200 MMBOE, are forecast as remaining to be discovered. Exploration potential exists in structural and stratigraphic traps near, against, and below salt, as well as in salt withdrawal anticlines (turtle structures).

Middle Middle Miocene Retrogradational (MM7 R1) Play *Cibicides opima* through *Bigenerina humblei* biozones

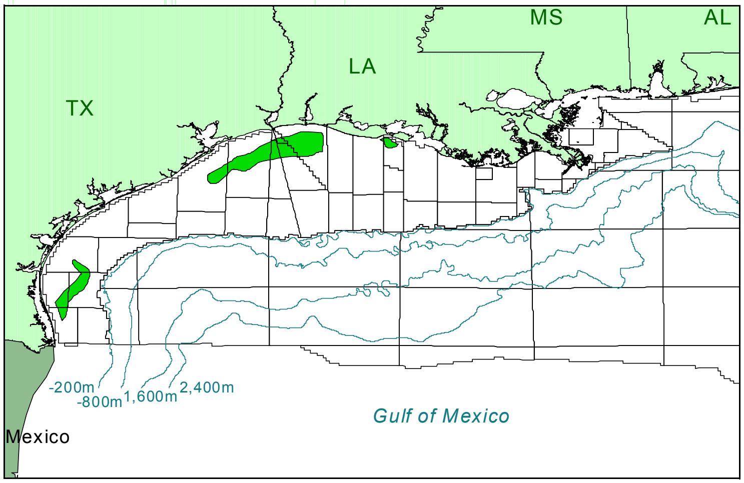


Figure 1. Play location.

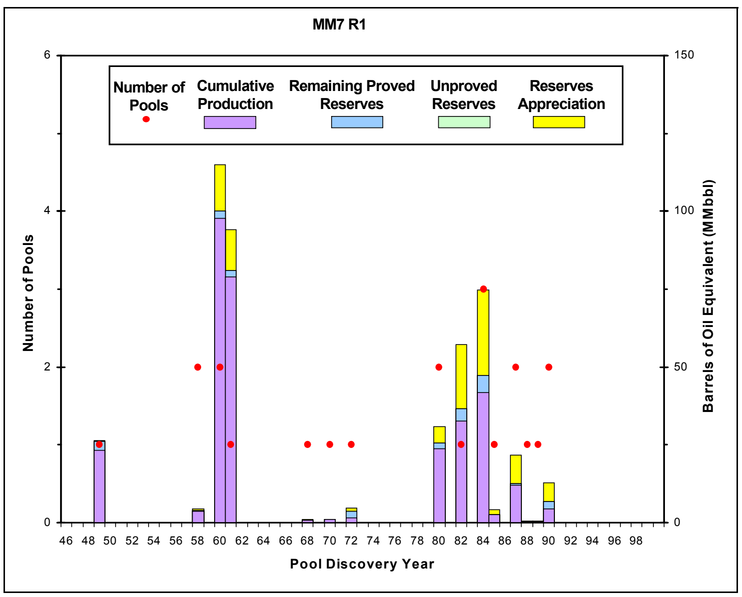


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM7 R1 Play 22 Pools 68 Sands	Minimum	Mean	Maximum
Water depth (feet)	11	60	221
Subsea depth (feet)	3958	8140	10133
Number of sands per pool	1	3	8
Porosity	23%	27%	32%
Water saturation	17%	30%	47%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Middle Miocene Retrogradational (MM7 R1) play occurs within the *Cibicides opima, 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). The MM7 R1 play is the largest of four retrogradational plays in the Gulf of Mexico Region.

Play Characteristics

Retrogradational sediments are characterized by the reworking of shelf sands during relative sea level rises. Thick shale sequences typically overlie retrogradational sands as a result of sea level rises. MM7 retrogradational sands are typically thin and exhibit an upward-fining, backstepping log signature. Retrogradational sequences in the MM7 play vary from about 100 to 800 feet in thickness.

Productive MM7 R1 sequences are mainly associated with the *Bigenerina humblei* marine transgression that resulted in the flooding surface capping 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 within the section and is productive. The lowest-most *Cibicides opima* retrogradatonal sequence is not productive.

Most of the fields in the MM7 R1 play are structurally associated with normal faults and simple anticlines. Other less common structures include growth fault anticlines. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-

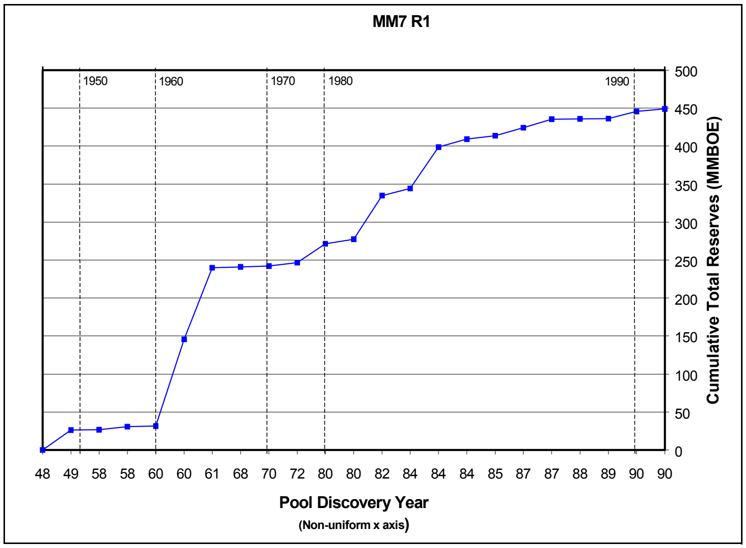


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM7 R1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	22	0.023	1.831	0.348
Cumulative production	--	0.019	1.716	0.324
Remaining proved	--	0.004	0.115	0.024
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.008	0.522	0.101
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.001	0.080	0.015
Mean	7	0.002	0.115	0.022
5th percentile	--	0.004	0.154	0.030
Total Endowment				
95th percentile	--	0.031	2.433	0.464
Mean	29	0.032	2.468	0.471
5th percentile	--	0.034	2.507	0.479

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

outs, overlying shales).

Discoveries

The MM7 R1 gas play contains total reserves of 0.030 Bbo and 2.353 Tcfg (0.449 BBOE), of which 0.019 Bbo and 1.716 Tcfg (0.324 BBOE) have been produced. The play contains 68 producible sands in 22 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the West Cameron 149 field in 1949 (figure 2). Maximum yearly total reserves of 115 MMBOE were added in 1960 when two pools were discovered. The largest pool in the play is in the Galveston 288 field, which was also discovered in 1960. The pool contains 114 MMBOE in total reserves. Ninety-nine percent of the play's cumulative production and 97 percent of the play's total reserves have come from pools discovered before 1990, reflecting the play's maturity. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1990.

The 22 discovered pools contain 148 reservoirs, of which 139 are nonassociated gas, 5 are undersaturated oil, and 4 are saturated oil. Cumulative production has consisted of 94 percent gas and 6 percent oil.

Of the four retrogradational plays in the Gulf of Mexico Region, the MM7 R1 play is the largest in terms of BOE total endowment and BOE total reserves.

Assessment Results

The marginal probability of hydrocarbons for the MM7 R1 play is 1.00. The play has a mean total endowment of 0.032 Bbo and 2.468 Tcfg (0.471 BBOE) (table 2). Sixty-nine percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.001 to 0.004 Bbo and 0.080 to 0.154 Tcfg at the 95th and 5th percentiles, respectively (figure

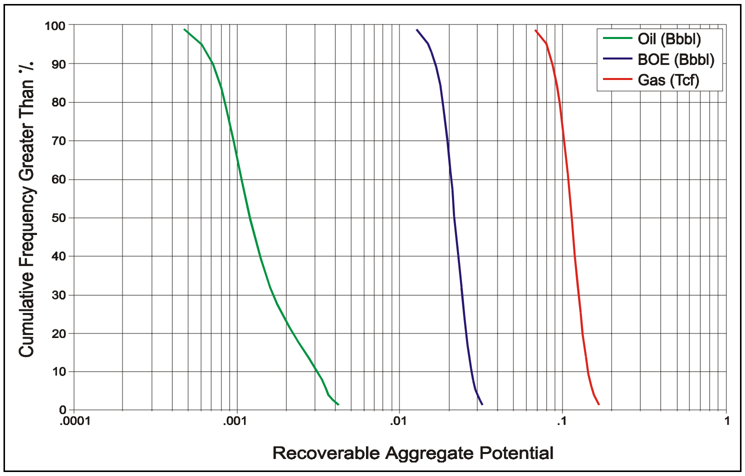


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

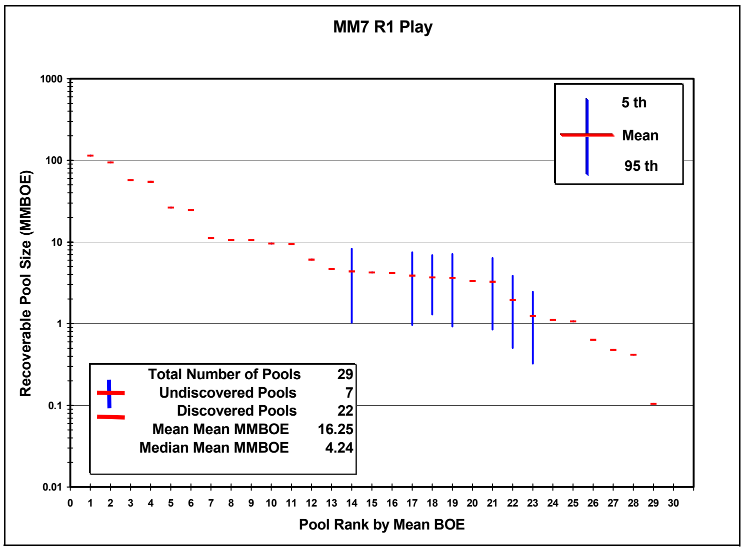


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

3). Mean UCRR are estimated at 0.002 Bbo and 0.115 Tcfg (0.022 BBOE). These undiscovered resources might occur in as many as seven pools. The largest undiscovered pool, with a mean size of 4 MMBOE, is forecast as the 14th largest pool in the play (figure 4). The next four largest undiscovered pools occupy positions 17, 18, 19, and 21 on the pool rank plot. For all the undiscovered pools in the MM7 R1 play, the mean mean size is 3 MMBOE compared with the 20 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 16 MMBOE.

The MM7 R1 is a supermature play with BOE mean UCRR contributing only 5 percent to the play's BOE mean total endowment.

Middle Middle Miocene Aggradational (MM7 A1) Play

Cibicides opima **through** ***Bigenerina humblei*** **biozones**

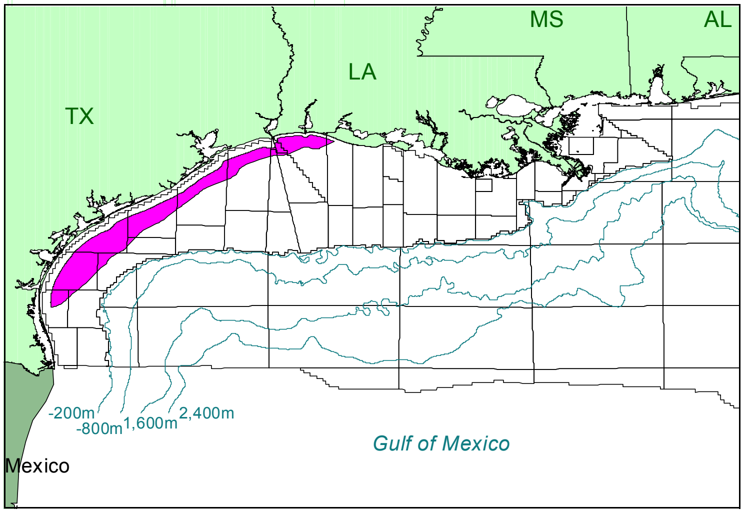


Figure 1. Play location.

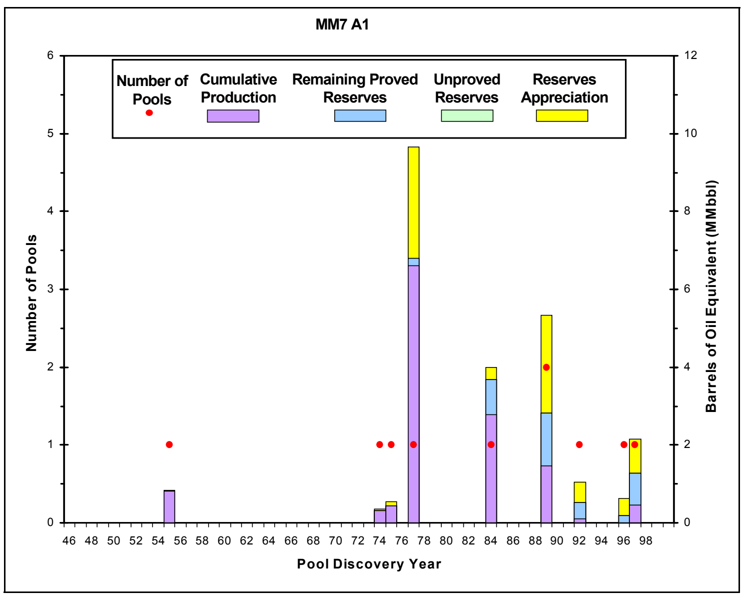


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM7 A1 Play **10 Pools 22 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	32	60	88
Subsea depth (feet)	3092	5350	7369
Number of sands per pool	1	2	6
Porosity	27%	32%	36%
Water saturation	17%	23%	34%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Middle Miocene Aggradational (MM7 A1) 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 East Cameron Area offshore Louisiana (figure 1).

Updip, the play continues onshore into Texas and Louisiana. To the east, west and downdip, the play grades into the sediments of the Middle Middle Miocene Progradational (MM7 P1) play and the Middle Middle Miocene Retrogradational (MM7 R1) play.

Play Characteristics

The MM7 A1 play is characterized by stacked, sand-dominated successions representing sediment buildup in fluvial channel/levee complexes, crevasse splays, and point bars; in deltaic distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches, and barrier islands; and in shallow marine shelf delta fringes and slumps. These sands are often coarse grained and exhibit a blocky log signature that may show an upward-fining character at the top.

In the productive areas, the MM7 A1 play often comprises a significant portion of the MM7 section in terms of not only net sand development but also total MM7 section thickness. Across the Texas offshore, the MM7 aggradational interval varies from approximately 50 feet to more than 4,600 feet in thickness, with net sand thicknesses of as much as 1,400 feet. In the more limited offshore Louisiana area, the interval varies from approximately 400 to more than 1,800 feet in thickness, with net sand thicknesses of as much as 600 feet.

Most fields in MM7 A1 are structurally associated with simple

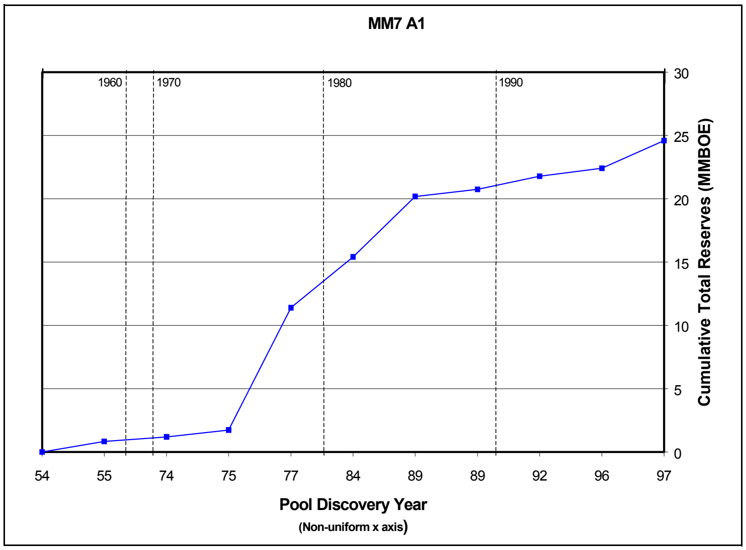


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM7 A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	10	0.001	0.092	0.017
Cumulative production	--	<0.001	0.070	0.013
Remaining proved	--	<0.001	0.021	0.004
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.043	0.008
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.042	0.008
Mean	10	0.002	0.072	0.015
5th percentile	--	0.006	0.113	0.024
Total Endowment				
95th percentile	--	0.001	0.176	0.033
Mean	20	0.003	0.206	0.040
5th percentile	--	0.007	0.247	0.049

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

anticlines and normal faults or, less commonly, with growth fault anticlines. 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

The MM7 A1 gas play contains total reserves of 0.001 Bbo and 0.134 Tcfg (0.025 BBOE), of which <0.001 Bbo and 0.070 Tcfg (0.013 BBOE) have been produced. The play contains 22 producible sands in 10 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). 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. Both the maximum yearly total reserves and the largest pool in the play were accounted for in 1977 with the discovery of the Matagorda Island 665 field (10 MMBOE; figures 2 and 3). Ninety-six percent of the play's cumulative production and 84 percent of the play's total reserves have come from pools discovered before 1990. The most recent pool discovery, prior to this study's cutoff date of January 1, 1999, was in 1997.

The ten discovered pools contain 25 reservoirs, of which 22 are nonassociated gas, 2 are undersaturated oil, and 1 is saturated oil. Cumulative production has consisted of 96 percent gas and 4 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM7 A1 play is 1.00. The play has a mean total endowment of 0.003 Bbo and 0.206 Tcfg (0.040 BBOE) (table 2). Thirty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of <0.001 to 0.006 Bbo and 0.042 to 0.113 Tcfg at the 95th and

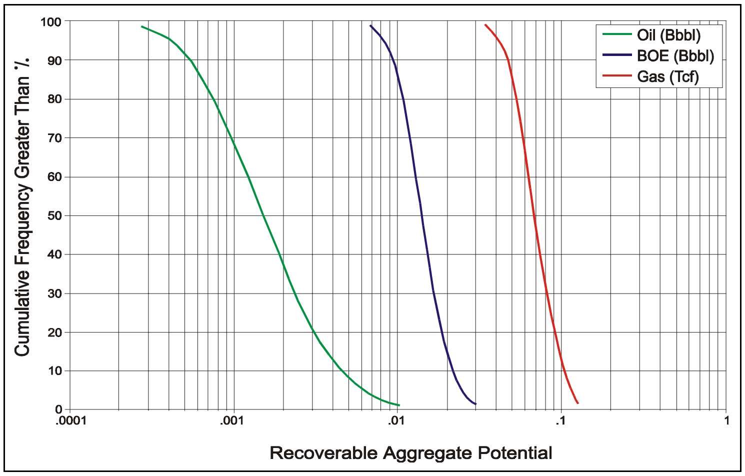


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

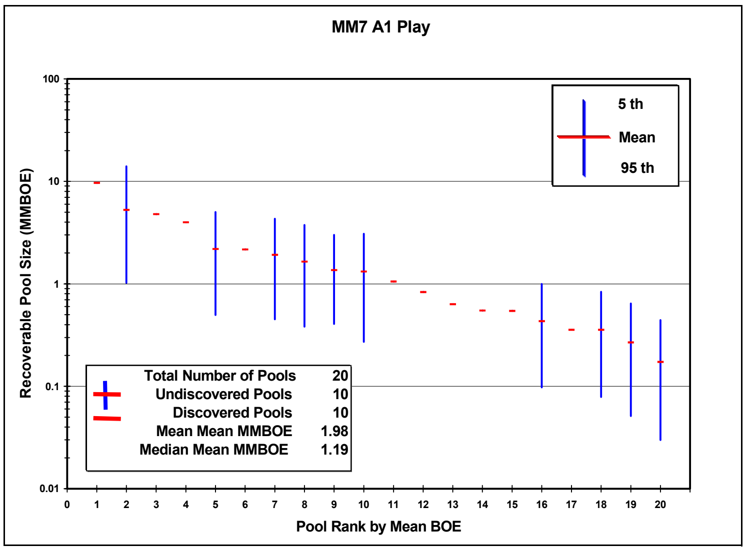


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.002 Bbo and 0.0.072 Tcfg (0.015 BBOE). These undiscovered resources might occur in as many as 10 pools. The largest undiscovered pool, with a mean size of 5 MMBOE, is forecast as the second largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 5, 7, 8, and 9 on the pool rank plot. For all the undiscovered pools in the MM7 A1 play, the mean mean size is 1 MMBOE, which is smaller than the 2 MMBOE mean size of the discovered pools.

BOE mean UCRR contribute 38 percent to the play's BOE mean total endowment. Discoveries will continue to be made in and around existing fields by drilling small, subtle structures as economics warrant.

Middle Middle Miocene Progradational (MM7 P1) Play

Cibicides opima through *Bigenerina humblei* biozones

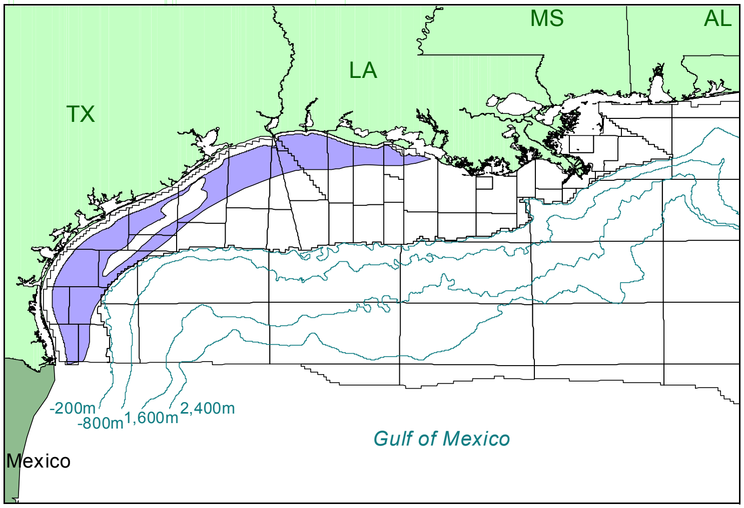


Figure 1. Play location.

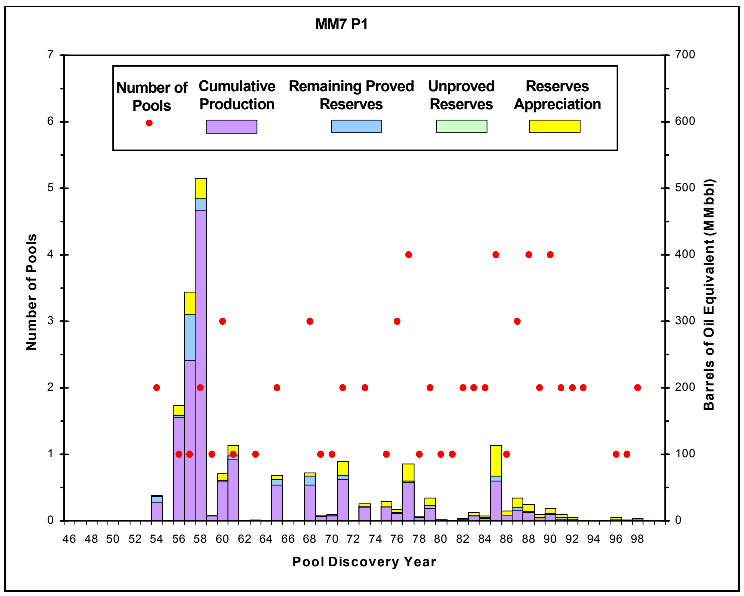


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM7 P1 Play 70 Pools 221 Sands	Minimum	Mean	Maximum
Water depth (feet)	11	70	274
Subsea depth (feet)	3514	8566	14548
Number of sands per pool	1	3	11
Porosity	17%	27%	35%
Water saturation	16%	28%	48%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Middle Miocene Progradational (MM7 P1) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. The play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Eugene Island Area offshore Louisiana (figure 1).

Updip and to the northeast, the MM7 P1 play continues onshore into Texas and Louisiana. To the southwest, the play continues into Mexican national waters. Downdip, the play grades into the deposits of the Middle Middle Miocene Fan 1 (MM7 F1) play. In parts of the Mustang Island, Matagorda Island, Brazos, and Galveston Areas offshore Texas, the MM7 P1 play encloses the Middle Middle Miocene Structural Corsair (MM7 S1) play and the Middle Middle Miocene Structural Seagull (MM7 S2) play.

Play Characteristics

Sediments in the MM7 P1 play represent major regressive episodes of outbuilding of both the shelf and slope. The MM7 progradational section varies from approximately 50 feet to more than 6,000 feet in thickness, with net sand thicknesses of as much as 600 feet. The play is punctuated by well developed flooding surfaces associated with the *Cristellaria* "I" and *Bigenerina humblei* biozones. Depositional environments represented in the play include delta fringes, offshore marine bars, channel/levee complexes, and distributary mouth bars. In the western part of the play, the sandy progradational section is underlain by a thick shale section. In the eastern part of the play, the MM7 P1 play is overlain by a retrogradational section, while in other areas the play is overlain by a well developed aggradational sec-

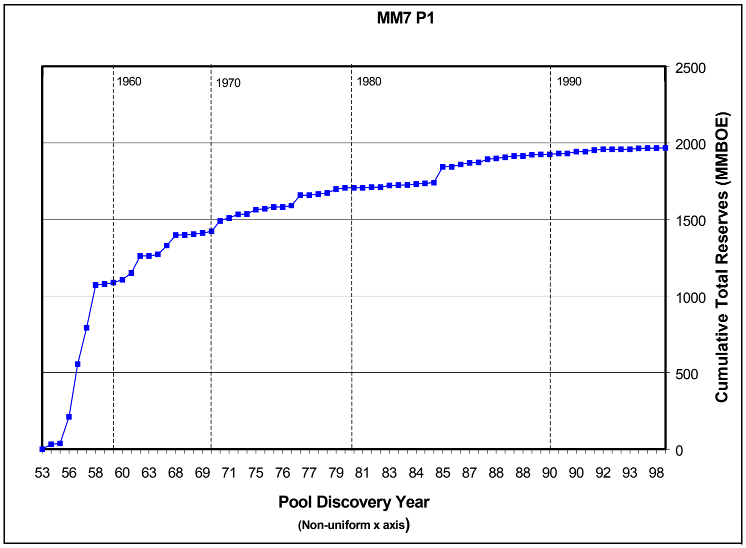


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM7 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	69	0.143	8.520	1.659
Cumulative production	--	0.129	7.681	1.496
Remaining proved	--	0.014	0.839	0.163
Unproved	1	<0.001	0.003	0.001
Appreciation (P & U)	--	0.035	1.535	0.309
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.009	0.716	0.140
Mean	40	0.016	0.871	0.171
5th percentile	--	0.028	1.030	0.203
Total Endowment				
95th percentile	--	0.187	10.774	2.108
Mean	110	0.194	10.929	2.139
5th percentile	--	0.206	11.088	2.171

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

tion.

Most of the fields in the MM7 P1 play are structurally associated with normal faults and simple anticlines. The remaining fields are associated with growth fault anticlines and shale diapir-like bodies, with traps on the flanks of the shale or in sediment drape over the shale. 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

The MM7 P1 gas play contains total reserves of 0.178 Bbo and 10.058 Tcfg (1.968 BBOE), of which 0.129 Bbo and 7.681 Tcfg (1.496 BBOE) have been produced. The play contains 221 producible sands in 70 pools of which 69 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the West Cameron 110 field in 1954 (figure 2). The largest pool in the play, with 344 MMBOE in total reserves, was discovered in 1957 in the East Cameron 64 field (figures 2 and 3). Maximum yearly total reserves of 514 MMBOE were added in 1958 with the discovery of two pools. Almost 75 percent of the play's cumulative production has come from pools discovered prior to 1968, reflecting the large sizes of early discoveries. Ninety-nine percent of the play's cumulative production and 98 percent of the play's total reserves have come from pools discovered before 1990, reflecting the maturity of the play. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were made in 1998.

The 70 discovered pools contain 456 reservoirs, of which 420 are nonassociated gas, 18 are undersaturated oil, and 18 are saturated oil. Cumulative production has consisted of 91 percent gas and 9 percent oil.

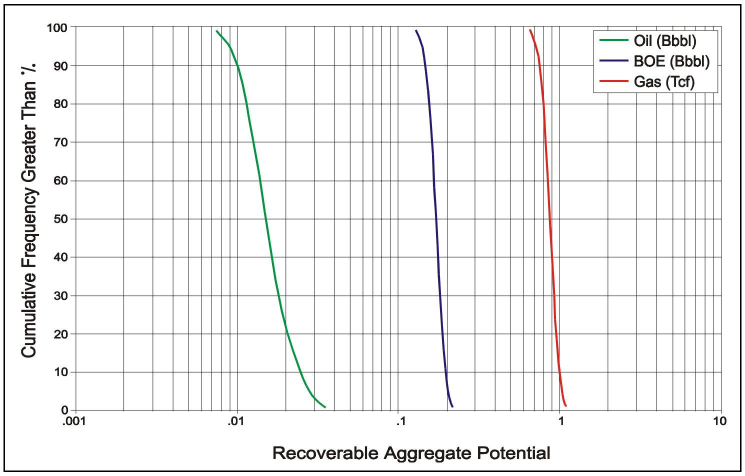


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

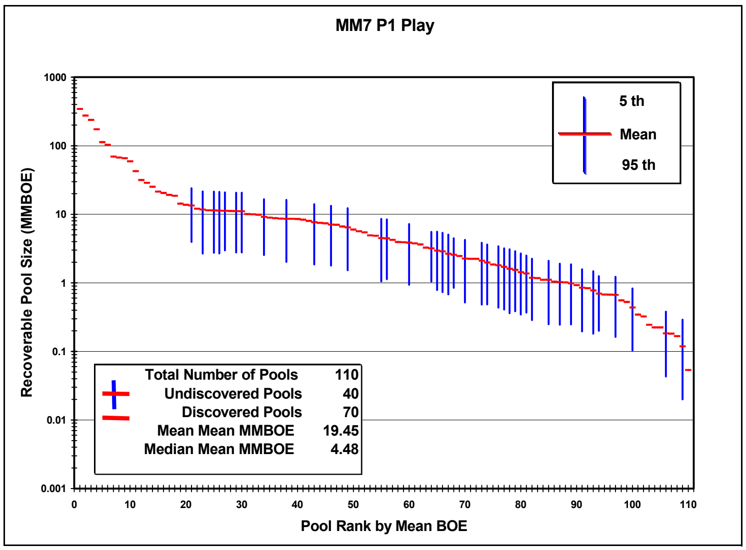


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Assessment Results

The marginal probability of hydrocarbons for the MM7 P1 play is 1.00. The play contains a mean total endowment of 0.194 Bbo and 10.929 Tcfg (2.139 BBOE) (table 2). Seventy percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.009 to 0.028 Bbo and 0.716 to 1.030 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.016 Bbo and 0.871 Tcfg (0.171 BBOE). These undiscovered resources might occur in as many as 40 pools. The largest undiscovered pool, with a mean size of 13 MMBOE, is forecast as the 21st largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 23, 25, 26, and 27 on the pool rank plot. For all the undiscovered pools in the MM7 P1 play, the mean mean size is 4 MMBOE compared with 28 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 19 MMBOE.

The MM7 P1 is a supermature play with BOE mean UCRR contributing only 8 percent to the play's BOE mean total endowment.

Middle Middle Miocene Structural Corsair (MM7 S1) Play *Cibicides opima through Bigenerina humblei* biozones

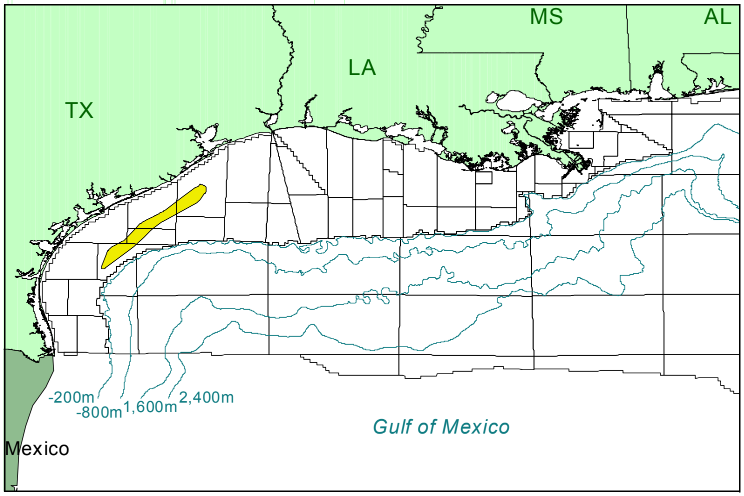


Figure 1. Play location.

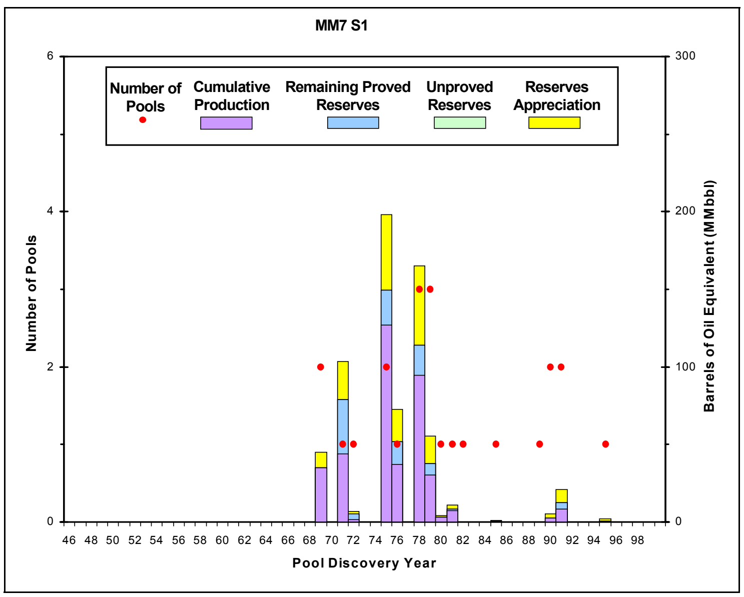


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM7 S1 Play 23 Pools 120 Sands	Minimum	Mean	Maximum
Water depth (feet)	82	143	305
Subsea depth (feet)	5904	9825	16460
Number of sands per pool	1	5	15
Porosity	17%	26%	33%
Water saturation	16%	31%	44%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Middle Miocene Structural Corsair (MM7 S1) 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 by significant expansion of the MM7 section across the Corsair faults. The play extends in a narrow zone in offshore Texas from the Mustang Island East Addition Area northeastward to the central Galveston Area (figure 1). The MM7 S1 play is the largest of the three structurally defined plays (MM7 S1, MM9 S1, and MM7 S2).

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 sections of the Middle Middle Miocene Progradational (MM7 P1) and Middle Middle Miocene Fan 1 (MM7 F1) plays.

The MM7 S1 play is the deeper of two regional Corsair Fault System plays. The younger play is the Upper Middle Miocene (MM9 S1) play. Both plays are very similar in geographical and structural control; however, the MM7 S1 play is much more expanded across the Corsair Fault System, being up to 11,000 feet thick in comparison with a maximum thickness of only 3,800 feet for the MM9 S1 play. The MM7 S1 play also contains about 20 times the total endowment of the MM9 S1 play.

Play Characteristics

The MM7 S1 play consists of stacked sequences of MM7 retrogradational, aggradational, progradational, and deep-sea fan sands that accumulated on the downthrown side of the Corsair Fault System. Movement on the Corsair Fault occurred in

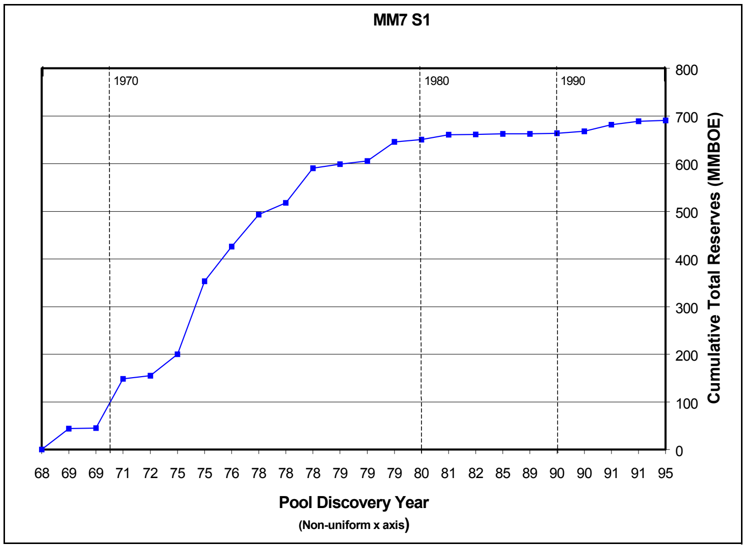


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM7 S1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	23	0.009	2.760	0.500
Cumulative production	--	0.006	2.171	0.393
Remaining proved	--	0.003	0.589	0.107
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.004	1.050	0.190
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.001	0.326	0.059
Mean	14	0.001	0.449	0.081
5th percentile	--	0.002	0.587	0.106
Total Endowment				
95th percentile	--	0.014	4.136	0.750
Mean	37	0.014	4.259	0.772
5th percentile	--	0.015	4.397	0.797

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

response to rapid influx of progradational and aggradational sands during periods of sea level lowstand, resulting in a greatly expanded MM7 S1 section. Reworking of progradational and aggradational sands during marine transgressions produced the retrogradational facies that locally occur within and at top of the section. Because sand accumulation was so influenced by movement along the fault system, the play is considered to be structurally controlled rather than depositionally controlled.

The Corsair Fault is only one of a series of growth fault systems that formed during the late Oligocene through the late Miocene in offshore Texas, but it is the most significant and well known because of the numerous hydrocarbon accumulations associated with it. Two structural styles are identifiable along the Corsair Fault System. In the Galveston Area, the main Corsair Fault has broken into a series of secondary relief or en echelon faults with traps formed on their upthrown sides. In the Mustang Island and Brazos Areas, large rollover anticlinal structures broken by antithetic faults developed on the downthrown side of the main Corsair Fault. Though the Corsair Fault is classified as a primary salt-withdrawal fault system with detachments into salt, its hanging walls overlie shale ridges (Bradshaw and Watkins, 1994). Hydrocarbon seals are provided by the juxtaposition of reservoir sands with shale, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales). The MM7 expanded section is overpressured in the Mustang Island and Brazos Areas.

Discoveries

The MM7 S1 gas play contains total reserves of 0.013 Bbo and 3.810 Tcfg (0.691 BBOE), of which 0.006 Bbo and 2.171 Tcfg (0.393 BBOE) have been produced. The play contains 120 producible sands in 23 pools, of which all 23 contain proved reserves (table 1; refer to the

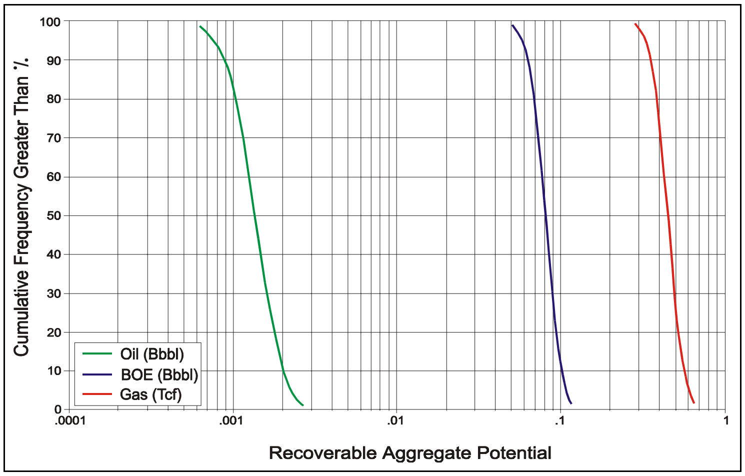


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

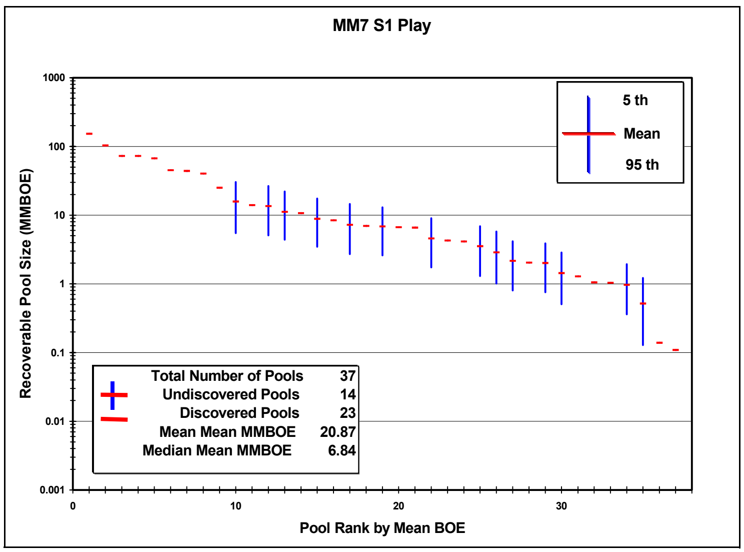


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Brazos 76A and Brazos 541 fields in 1969 (figure 2). Maximum yearly total reserves of 198 MMBOE were found in 1975 with the discovery of two pools, including the largest pool in the play (153 MMBOE) in the Brazos 133A field (figures 2 and 3). Discoveries peaked during the 1970's, during which 85 percent of the total reserves and over 80 percent of cumulative production were discovered. Ninety-seven percent of the play's cumulative production and 96 percent of the play's total reserves have come from pools discovered before 1990, reflecting the play's maturity. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1995.

The 23 discovered pools contain 216 reservoirs, all of which are nonassociated gas. The MM7 S1 play contains 95 percent of the combined total reserves in the MM7 S1 and MM9 S1 plays.

Assessment Results

The marginal probability of hydrocarbons for the MM7 S1 play is 1.00. The play contains a mean total endowment of 0.014 Bbo and 4.259 Tcfg (0.772 BBOE) (table 2). Fifty-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.001 to 0.002 Bbo and 0.326 to 0.587 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.001 Bbo and 0.449 Tcfg (0.081 BBOE). These undiscovered resources might occur in as many as 14 pools. The largest undiscovered pool, with a mean size of 16 MMBOE, is forecast as the tenth largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 12, 13, 15, and 17 on the pool rank plot. For all the undiscovered pools in the MM7 S1 play, the mean mean size is 6

MMBOE, which is smaller than the 30 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 21 MMBOE.

The MM7 S1 is a mature play with a limited geographic extent. BOE mean UCRR contribute only 10 percent to the play's BOE mean total endowment.

Reference

Bradshaw, Barry E. and Joel S. Watkins. 1994. Growth-fault evolution in offshore Texas: Gulf Coast Association of Geological Societies Transactions, vol. 44, p.103-110.

Middle Middle Miocene Structural Seagull (MM7 S2) Play *Cibicides opima* through *Bigenerina humblei* biozones

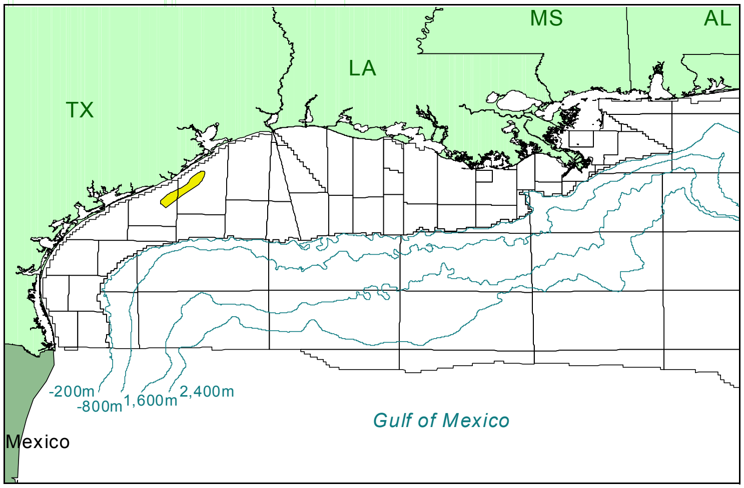


Figure 1. Play location.

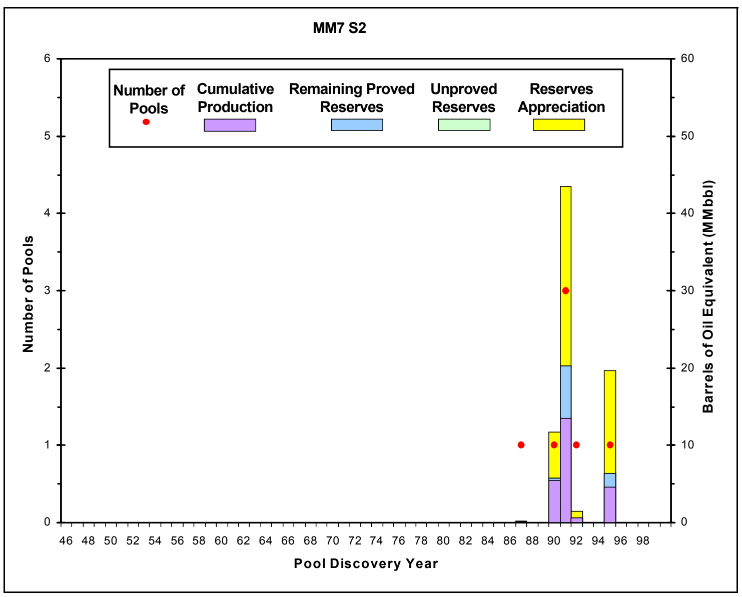


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM7 S2 Play 7 Pools 10 Sands	Minimum	Mean	Maximum
Water depth (feet)	64	79	92
Subsea depth (feet)	5441	6895	7983
Number of sands per pool	1	1	2
Porosity	26%	28%	31%
Water saturation	16%	20%	27%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Middle Miocene Structural Seagull (MM7 S2) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. The play is defined by a structural position downthrown to a series of major growth faults in offshore Texas, as well as by gas production from small anticlines and fault traps formed over large slumped and faulted blocks of shale. The MM7 S2 play extends in a narrow zone from the Brazos Area northeastward to the central Galveston Area (figure 1). The play's name is derived from Seagull Energy, a company active in the exploration and development of the play.

Updip, the play is bounded by a series of major growth faults, while downdip, the play is limited by the Corsair Fault System. Along strike to the west and east, the play is limited by the sediments of the Middle Middle Miocene Progradational (MM7 P1) play.

Play Characteristics

A series of shelfal slumps and slides in lower middle Miocene (MM4) shale developed downthrown to an updip growth fault system. Later, a relatively thin veneer of sand and shale was deposited over the deformed shale. Gas is trapped in the veneer sands in the small anticlines and normal faults created as a result of the underlying slumping and sliding. These gas reservoirs are often associated with seismic hydrocarbon indicators (bright spots).

The MM7 S2 section averages over 1,500 feet in thickness with the gas-bearing interval usually consisting of about 300 feet of stacked sandy channel-like slump deposits. The sandy interval is highly variable in both thickness and in aerial extent. Overlying the MM7 S2 gas-bearing

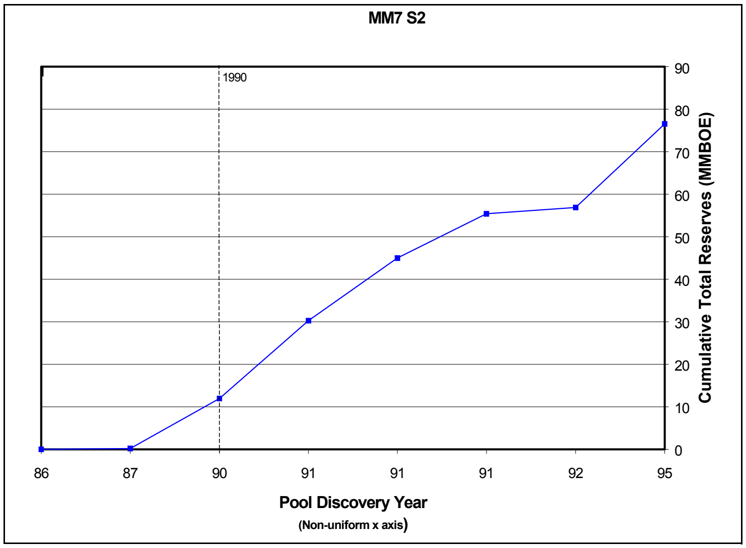


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM7 S2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	7	0.001	0.183	0.033
Cumulative production	--	<0.001	0.133	0.024
Remaining proved	--	<0.001	0.050	0.009
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.240	0.043
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.040	0.007
Mean	4	0.001	0.087	0.016
5th percentile	--	0.002	0.138	0.026
Total Endowment				
95th percentile	--	0.001	0.463	0.084
Mean	11	0.002	0.510	0.093
5th percentile	--	0.003	0.561	0.103

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

interval is a 500-foot-thick or greater shale section. Underlying the hydrocarbon-bearing interval is also a thick shale section, which in places is overpressured. Seals are formed by the juxtaposition of reservoir sands with shales, either structurally (e.g., through faulting) or stratigraphically (e.g., through lateral shale-outs, or by overlying shales).

Discoveries

The MM7 S2 gas play contains total reserves of 0.001 Bbo and 0.423 Tcfg (0.077 BBOE), of which <0.001 Bbo and 0.133 Tcfg (0.024 BBOE) have been produced. The play contains 10 producible sands in seven pools, of which all seven contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1987 in the Brazos 455 field (figure 2). Maximum yearly total reserves of 43 MMBOE were added in 1991 when three pools were found, including the largest pool in the play (20 MMBOE) in the Galveston 395 field (figures 2 and 3). Six of the seven pools in the play were discovered during the 1990's, while the most recent discovery, prior to this study’s cutoff date of January 1, 1999, was in 1995.

The seven discovered pools contain 17 reservoirs, all of which are nonassociated gas. Cumulative production has consisted of 98 percent gas and 2 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM7 S2 play is 1.00. The play contains a mean total endowment of 0.002 Bbo and 0.510 Tcfg (0.093 BBOE) (table 2). Twenty-six percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of <0.001 to 0.002 Bbo and 0.040 to 0.138 Tcfg at the 95th and 5th percentiles, respectively (figure

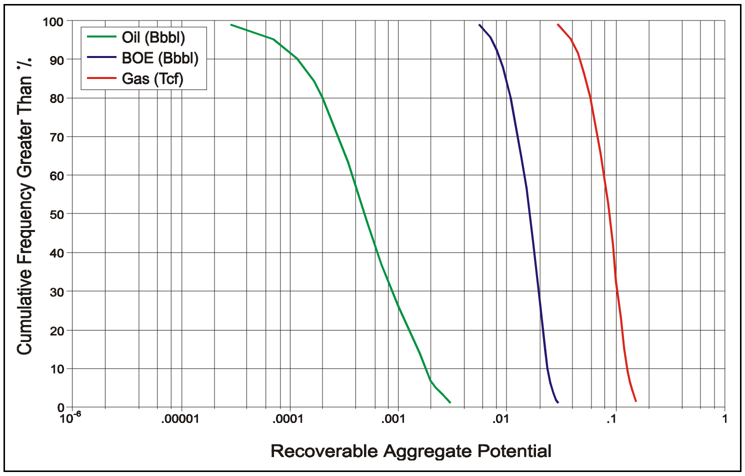


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

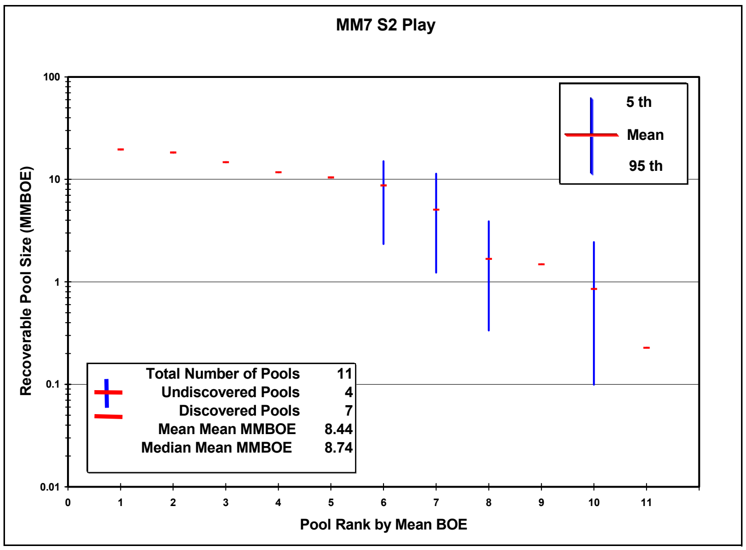


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

4). Mean UCRR are estimated at 0.001 Bbo and 0.087 Tcfg (0.016 BBOE). These undiscovered resources might occur in as many as four pools. The largest undiscovered pool, with a mean size of 9 MMBOE, is forecast as the sixth largest pool in the play (figure 5). The forecast places next three largest undiscovered pools in positions 7, 8, and 10 on the pool rank plot. For all the undiscovered pools in the MM7 S2 play, the mean mean size is 4 MMBOE, which is smaller than the 11 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 8 MMBOE.

The MM7 S2 is an extensively explored play with BOE mean UCRR contributing only 17 percent to the play's BOE mean total endowment. Exploration potential lies in and around existing fields in smaller structures that will be drilled as economics warrant.

Middle Middle Miocene Fan 1 (MM7 F1) Play

***Cibicides opima* through *Bigenerina humblei* biozones**

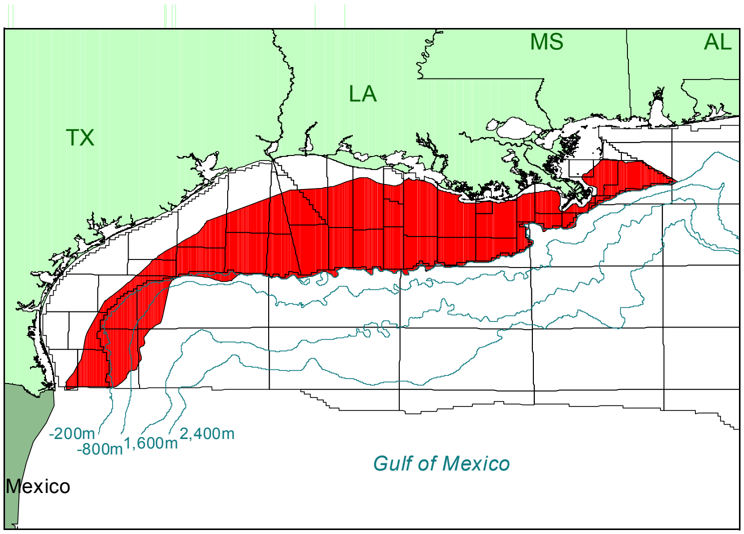


Figure 1. Play location.

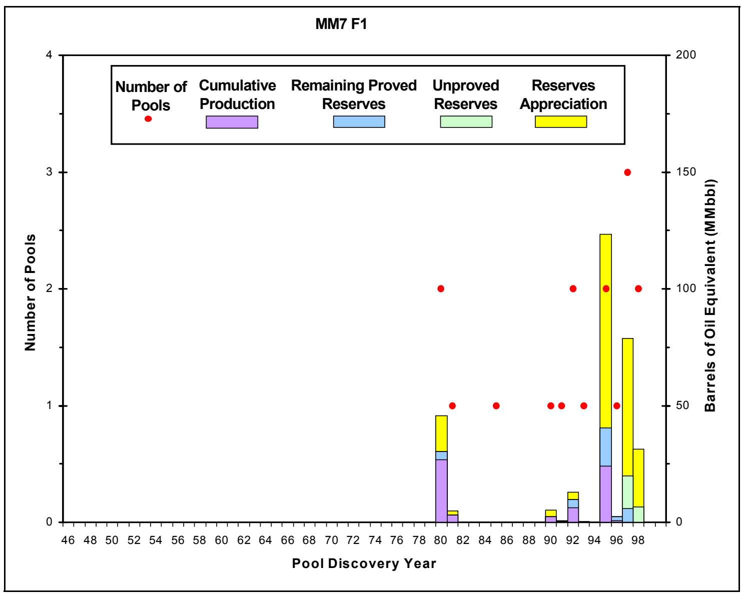


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM7 F1 Play 17 Pools 33 Sands	Minimum	Mean	Maximum
Water depth (feet)	13	146	399
Subsea depth (feet)	9480	12908	16165
Number of sands per pool	1	2	8
Porosity	20%	25%	31%
Water saturation	16%	31%	58%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Middle Miocene Fan 1 (MM7 F1) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The MM7 F1 play 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, the play extends onshore except for in the South Padre Island to Eugene Island Areas, where the play is bordered by the shelf margin and the Middle Middle Miocene Progradational (MM7 P1) play. To the southwest, the MM7 F1 play extends into Mexican national waters. To the northeast, the play onlaps the Cretaceous carbonate slope. Downdip, the play is limited by the Middle Middle Miocene Fan 2 (MM7 F2) play.

Play Characteristics

The MM7 F1 play is characterized by deepwater turbidites deposited in channel/levee complexes, sheet-sand lobes, interlobes and lobe fringes, and slumps. These sediments were deposited on the upper and lower slope, in topographically low areas between salt structure highs and on the abyssal plain. MM7 deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Structural styles associated with MM7 F1 fields include normal faults and, less commonly, salt diapirs with hydrocarbons trapped on diapir flanks or in sediments draped over diapir tops. Stratigraphic traps

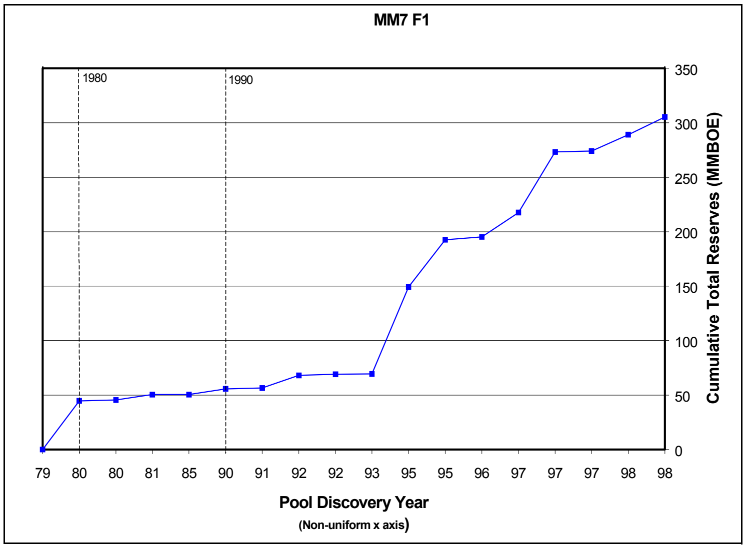


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM7 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	14	0.016	0.444	0.095
Cumulative production	--	0.010	0.303	0.064
Remaining proved	--	0.006	0.141	0.031
Unproved	3	0.010	0.059	0.021
Appreciation (P & U)	--	0.049	0.790	0.189
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.175	1.928	0.525
Mean	68	0.212	2.304	0.622
5th percentile	--	0.263	2.837	0.754
Total Endowment				
95th percentile	--	0.250	3.221	0.830
Mean	85	0.287	3.597	0.927
5th percentile	--	0.338	4.130	1.059

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

are created by permeability barriers, updip sand pinchouts, or updip facies changes. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MM7 F1 play is predominantly a gas play, with total reserves of 0.075 Bbo and 0.1.293 Tcfg (0.305 BBOE), of which 0.010 Bbo and 0.303 Tcfg (0.064 BBOE) have been produced. The play contains 33 producible sands in 17 pools of which 14 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were added in 1980 when the Eugene Island 24 and Main Pass 73 fields were discovered. Maximum yearly total reserves of 123 MMBOE were added in 1995 by the discovery of two pools, including the largest pool in the play (80 MMBOE) in the Main Pass 223 field (figure 2). Forty-seven percent of the play's cumulative production and 17 percent of the play's total reserves have come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1998.

The 17 discovered pools contain 42 reservoirs, of which 38 are nonassociated gas and 4 are undersaturated oil. Cumulative production has consisted of 84 percent gas and 16 percent oil.

Assessment Results

Because of limited data available for the MM7 F1 play, the Middle Lower Miocene Fan 1 (LM2 F1) play was used as an analog to forecast pool sizes in the MM7 F1 play. The LM2 F play was selected because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the MM7 F1 play is

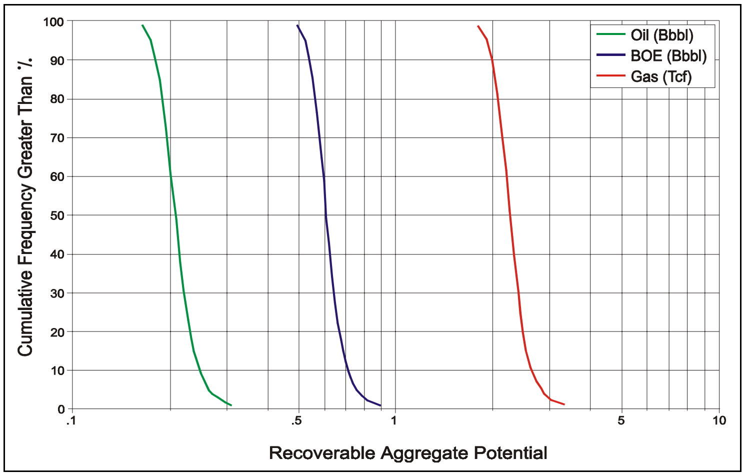


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

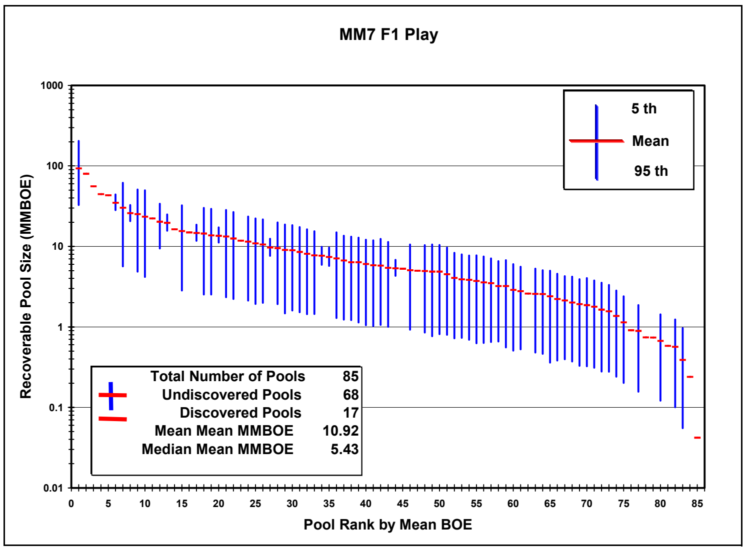


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

1.00. The play contains a mean total endowment of 0.287 Bbo and 3.597 Tcfg (0.927 BBOE) (table 2). Seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.175 to 0.263 Bbo and 1.928 to 2.837 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.212 Bbo and 2.304 Tcfg (0.622 BBOE). These undiscovered resources might occur in as many as 68 pools. The largest undiscovered pool, with a mean size of 93 MMBOE, is also the largest pool in the play (figure 5). The forecast places the next four pools in position 6, 7, 8, and 9. For all the undiscovered pools in the MM7 F1 play, the mean mean size is 9 MMBOE, which is significantly smaller the 18 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 11 MMBOE.

Because of the depth of the prospective section (9,000 to 16,000 feet; table 1), much of the MM7 F1 play area has yet to be tested. BOE mean UCRR contribute 67 percent of the play's BOE mean total endowment.

Middle Middle Miocene Fan 2 (MM7 F2) Play

Cibicides opima through *Bigenerina humblei* biozones

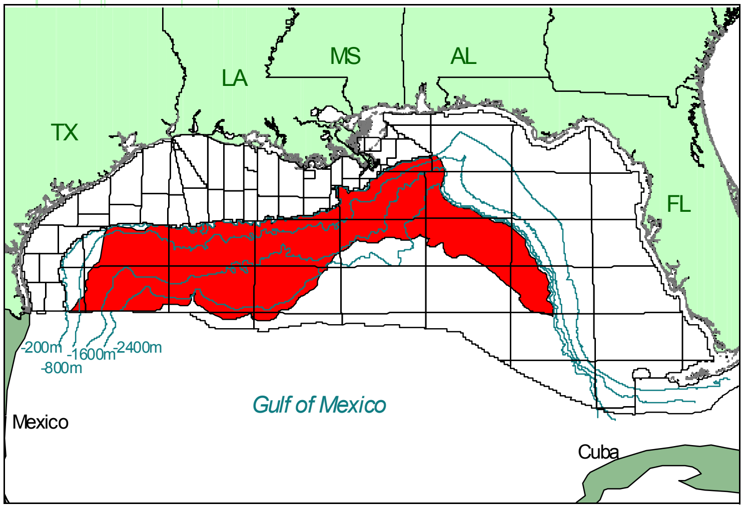


Figure 1. Play location.

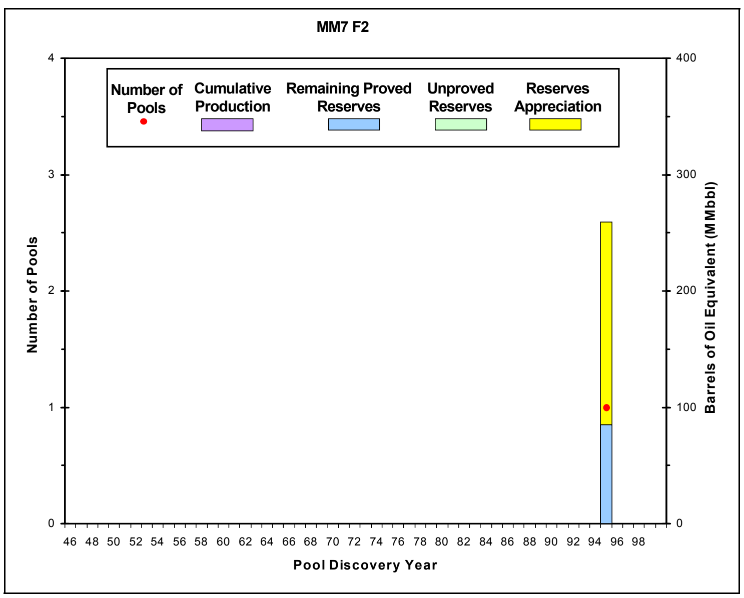


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM7 F2 Play **1 Pool 2 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	1751	1751	1751
Subsea depth (feet)	10293	10293	10293
Number of sands per pool	2	2	2
Porosity	30%	30%	30%
Water saturation	23%	23%	23%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Middle Miocene Fan 2 (MM7 F2) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. The play is also defined by deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The play extends from the East Breaks and Alaminos Canyon Areas to the southwestern Destin Dome and western Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1). Only one field, Viosca Knoll 786 (Petronius), has been discovered in the play.

Updip, the play is bounded by the Middle Middle Miocene Fan 1 (MM7 F1) play. To the southwest, the play extends into Mexican national waters, while to the northeast, the play onlaps the Cretaceous carbonate slope. Downdip, the LPL F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf of Mexico Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

The productive facies in the MM7 F2 pool in the Viosca Knoll 786 field is a channel/levee complex deposited on the upper slope. The field contains hydrocarbons trapped below an unconformity by an updip

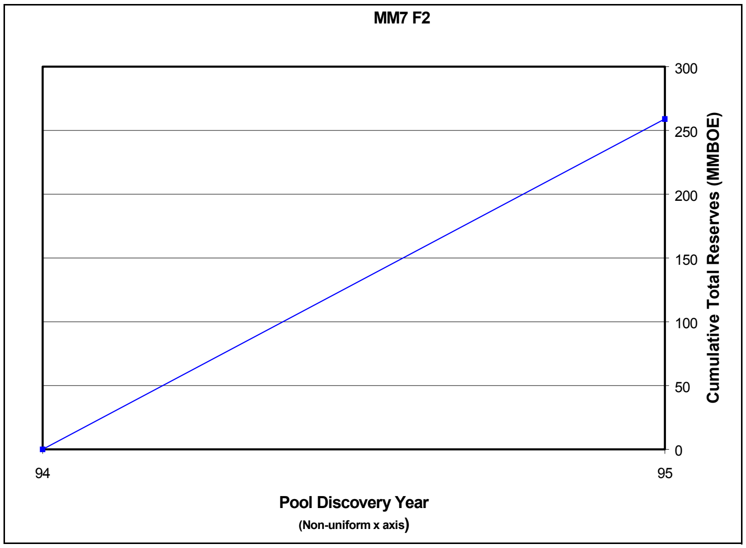


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM7 F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	1	0.052	0.183	0.085
Cumulative production	–	0.000	0.000	0.000
Remaining proved	–	0.052	0.183	0.085
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	0.107	0.375	0.174
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	1.278	5.696	2.333
Mean	94	1.486	6.523	2.646
5th percentile	–	1.759	7.673	3.089
Total Endowment				
95th percentile	–	1.438	6.253	2.592
Mean	95	1.646	7.080	2.905
5th percentile	–	1.919	8.230	3.348

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

sand pinchout. Similar trapping structures within the play are rare and most future discoveries will likely occur in salt-related traps.

Discoveries

The Viosca Knoll 786 (Petronius) MM7 F2 pool (figures 2 and 3) has total reserves of 160 MMbo and 557 Bcfg (259 MMBOE). The pool contains two producible sands and three reservoirs. One reservoir is nonassociated gas, one is undersaturated oil, and one is saturated oil (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). Petronius was discovered in 1995. As of January 1, 1999, the field was not on production.

Assessment Results

The marginal probability of hydrocarbons for the MM7 F2 play is 1.00. The play contains a mean total endowment of 1.646 Bbo and 7.080 Tcfg (2.905 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 1.278 to 1.759 Bbo and 5.696 to 7.673 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 1.486 Bbo and 6.523 Tcfg (2.646 BBOE). These undiscovered resources might occur in as many as 94 pools. The largest undiscovered pool is forecast to have a mean size of 311 MMBOE and is ranked first on the pool rank plot (figure 5). The Petronius pool is forecast as the second largest pool in the play. For all the undiscovered pools in the MM7 F2 play, the mean mean size is 28 MMBOE. The mean mean size for all pools, including both discovered and undiscovered, is 31 MMBOE.

With only one discovered pool and the MM7 F2 play's large areal extent, future discoveries are forecast to be numerous and relatively large. In addition to Petronius, five undiscovered pools are forecast to contain over 100 MMBOE in total reserves. The MM7 F2 play contains

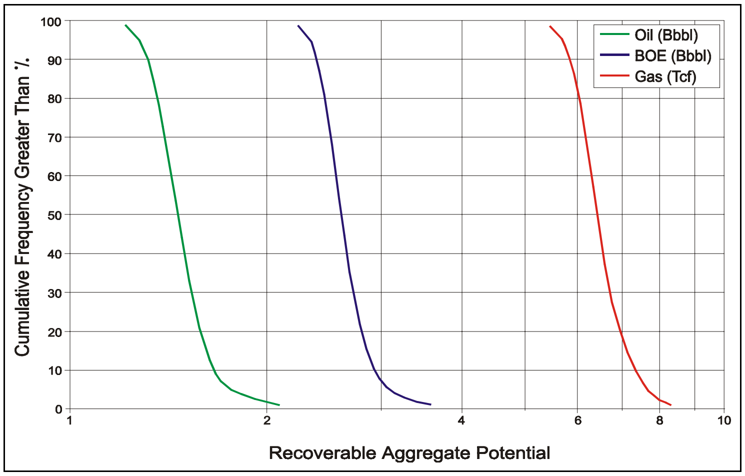


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

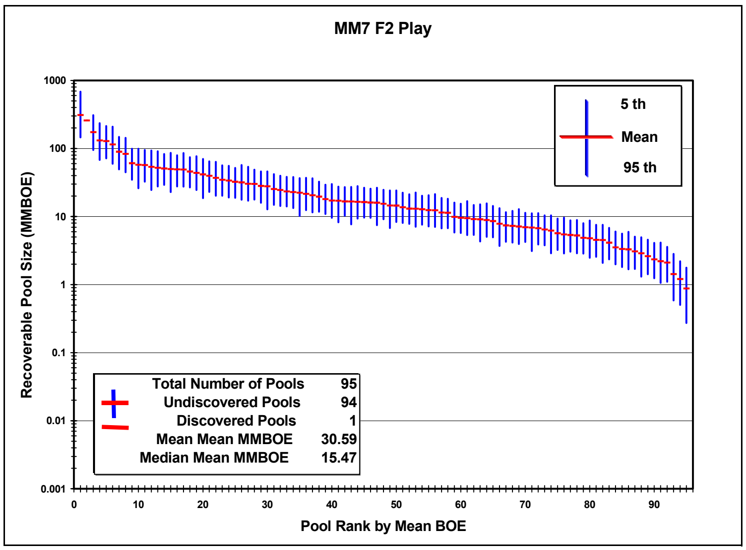


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

an anticipated 2.6 BBOE in mean UCRR, contributing 91 percent to the play's BOE mean total endowment. Exploration potential exists in structures and stratigraphic traps near, against, and below salt, as well as in salt withdrawal anticlines (turtle structures).

Lower Middle Miocene Retrogradational (MM4 R1) Play

Gyroidina "K" through *Amphistegina* "B" biozones

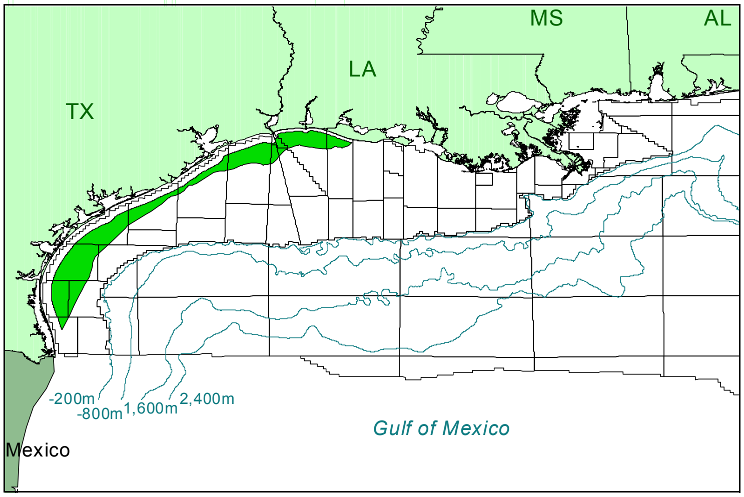


Figure 1. Play location.

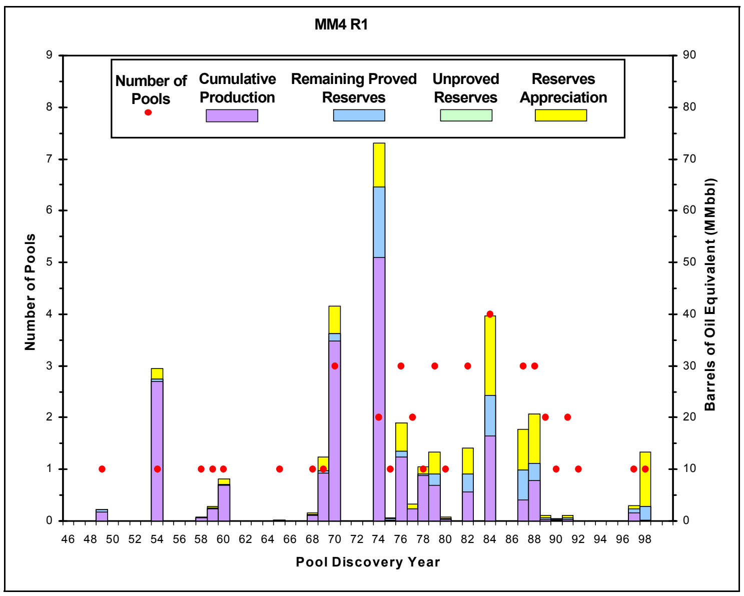


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM4 R1 Play 45 Pools 90 Sands	Minimum	Mean	Maximum
Water depth (feet)	31	74	190
Subsea depth (feet)	3835	6967	13187
Number of sands per pool	1	2	7
Porosity	24%	28%	33%
Water saturation	17%	31%	55%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Middle Miocene Retrogradational (MM4 R1) 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 through the East Cameron Area offshore Louisiana (figure 1).

Updip, the play continues onshore into Texas and Louisiana. To the east, west, and downdip, the play grades either into the sediments of the Lower Middle Miocene Progradational (MM4 P1) play or the Lower Middle Miocene Aggradational (MM4 A1) play.

Play Characteristics

Retrogradational sediments are characterized by the reworking of shelf sands during relative sea level rises. Thin, reworked MM4 R1 sands exhibit an upward-fining, back-stepping log signature and are overlain by a thick shale sequence associated with one of the *Gyroidina* "K," *Cristellaria* 54/*Eponides* 14, *Robulus* 43, or *Amphistegina* "B" flooding events. The MM4 retrogradational interval varies from approximately 100 feet to more than 2,600 feet in thickness, with net sand thicknesses as much as 300 feet. Individual MM4 R1 sands are, at the most, a few tens of feet thick and are interbedded with shales of the same thickness. The overlying shales associated with the *Amphistegina* "B" flooding event are over 1,000 feet thick and mark the transition to the younger middle middle Miocene (MM7) deposits.

Productive MM4 R1 sequences are associated with three distinct marine transgressions. They are, from oldest to youngest, the *Cristellaria* 54/*Eponides* 14, which occurs in the Brazos and Galveston Areas; the *Robulus* 43, which occurs from the Mustang Island to West Cameron

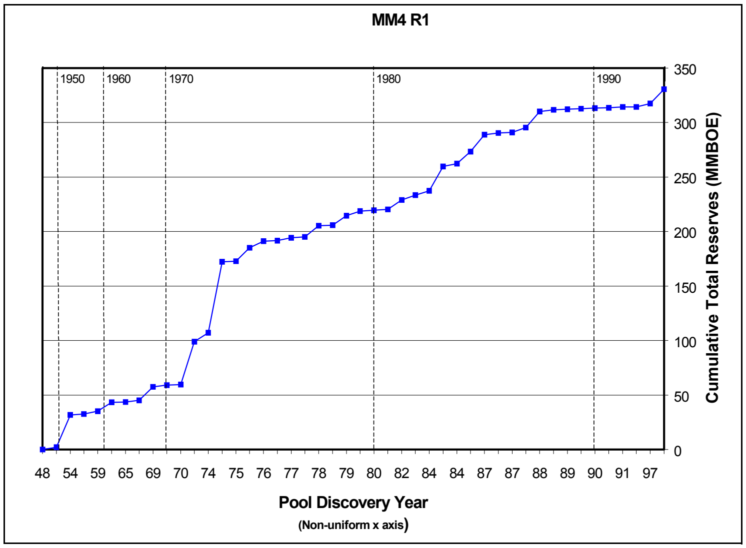


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM4 R1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	45	0.036	1.192	0.248
Cumulative production	–	0.030	0.967	0.202
Remaining proved	–	0.006	0.225	0.046
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	0.007	0.428	0.083
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.003	0.148	0.032
Mean	11	0.008	0.201	0.044
5th percentile	–	0.016	0.269	0.060
Total Endowment				
95th percentile	–	0.045	1.768	0.363
Mean	56	0.050	1.821	0.375
5th percentile	–	0.058	1.889	0.391

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Area; and the *Amphistegina* "B," which occurs from the North Padre Island to East Cameron Area. The lateral expansion of these sequences through MM4 time reflects not only the magnitude of the marine transgressions but also the increased sand influx from delta systems located in the Louisiana area.

The majority of fields in MM4 R1 are structurally associated with normal faults and simple anticlines. Other less common structures are associated with growth fault anticlines, and salt or shale diapirs with traps on the flanks of the diapir or in sediment drape over the diapir. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MM4 R1 gas play contains total reserves of 0.042 Bbo and 1.620 Tcfg (0.331 BBOE), of which 0.030 Bbo and 0.967 Tcfg (0.202 BBOE) have been produced. The play contains 90 producible sands in 45 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the West Cameron 45 field in 1949 (figure 2). The maximum yearly total reserves of 73 MMBOE were added in 1974 when two pools were discovered, including the largest pool in the play in the West Cameron 66 field. The West Cameron 66 field has 65 MMBOE in total reserves. Ninety-nine percent of the play's cumulative production and 95 percent of the play's total reserves have come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, occurred in 1998.

The 45 discovered pools pools contain 183 reservoirs, of which 161 are nonassociated gas, 9 are undersaturated oil, and 13 are saturated oil. Cumulative production has consisted of 85 percent gas and

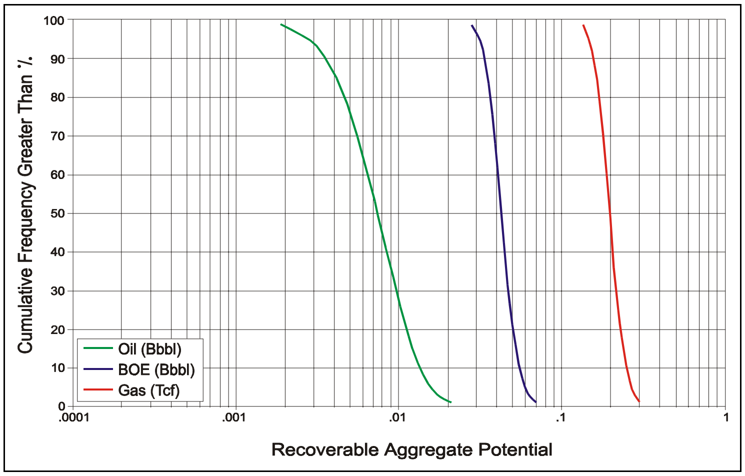


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

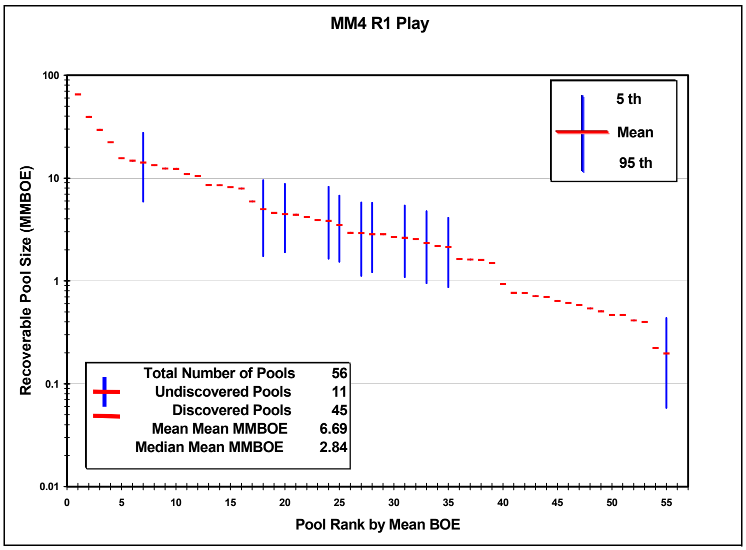


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

15 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM4 R1 play is 1.00. The play contains a mean total endowment of 0.050 Bbo and 1.821 Tcfg (0.375 BBOE) (table 2). Fifty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.003 to 0.016 Bbo and 0.148 to 0.269 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR are estimated at 0.008 Bbo and 0.201 Tcfg (0.044 BBOE). Of the four retrogradational plays, the MM4 R1 play contains the most UCRR. These undiscovered resources might occur in as many as 11 pools. The largest undiscovered pool, with a mean size of 14 MMBOE, is forecast as the seventh largest pool in the play (figure 4). The next four largest undiscovered pools are forecast to occupy positions 18, 20, 24, and 25 on the pool rank plot. For all the undiscovered pools in the MM4 A play, the mean mean size is 4 MMBOE compared with the 7 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 7 MMBOE.

BOE mean UCRR contribute 12 percent to the play's mean total endowment.

Lower Middle Miocene Aggradational (MM4 A1) Play

Gyroidina "K" through *Amphistegina* "B" biozones

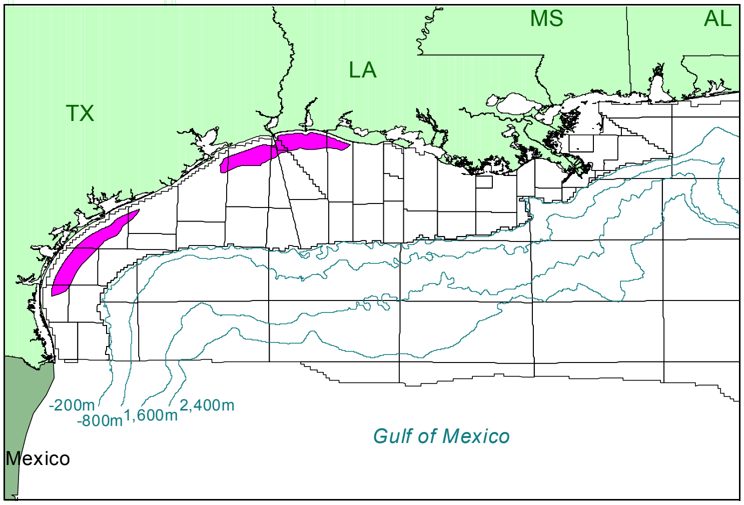


Figure 1. Play location.

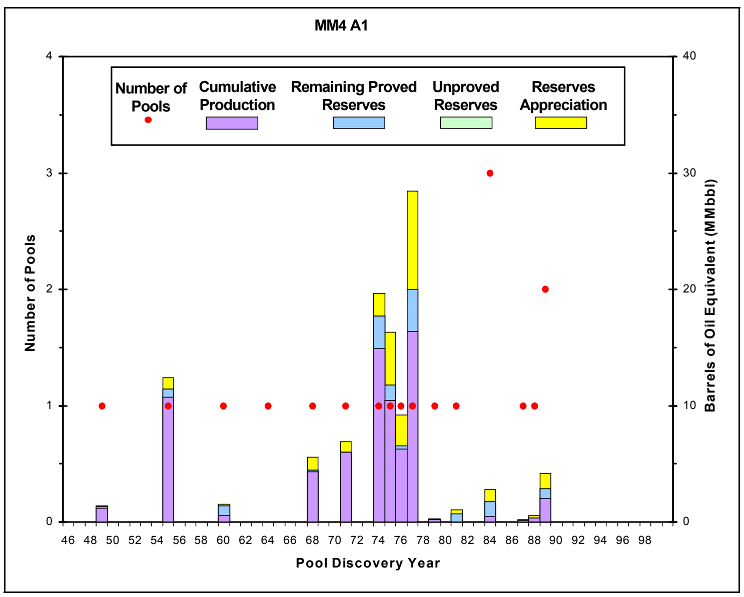


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM4 A1 Play 19 Pools 54 Sands	Minimum	Mean	Maximum
Water depth (feet)	29	56	122
Subsea depth (feet)	4574	7734	10839
Number of sands per pool	1	3	10
Porosity	18%	28%	32%
Water saturation	18%	30%	54%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Middle Miocene Aggradational (MM4 A1) play occurs within the *Gyroidina* "K," *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* "B" biozones. The play occupies two separate areas on the modern GOM shelf: (1) a western region that extends from the North Padre Island to Brazos Areas offshore Texas, and (2) an eastern region that extends from the Galveston Area offshore Texas to the East Cameron Area offshore Louisiana (figure 1).

Updip, the MM4 A1 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 P1) play.

Play Characteristics

The MM4 A1 play is characterized by stacked, blocky, sand-dominated successions representing sediment buildup in fluvial channel/levee complexes, crevasse splays, and point bars; in deltaic distributary channel/levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches, and barrier islands; and in shallow marine shelf delta fringes and slumps. These sands are often coarse grained and exhibit a blocky log signature that in places has an upward-fining character at the top. In productive areas, the MM4 A1 play often comprises a significant portion of the MM4 section in terms of net sand development and total MM4 section thickness. The MM4 aggradational interval varies from approximately 300 feet to more than 2,900 feet in thickness, with net sand thicknesses of as much as 1,100 feet. Individual sands up to a few hundred feet thick are interbedded with shales that are usually only a few tens of feet

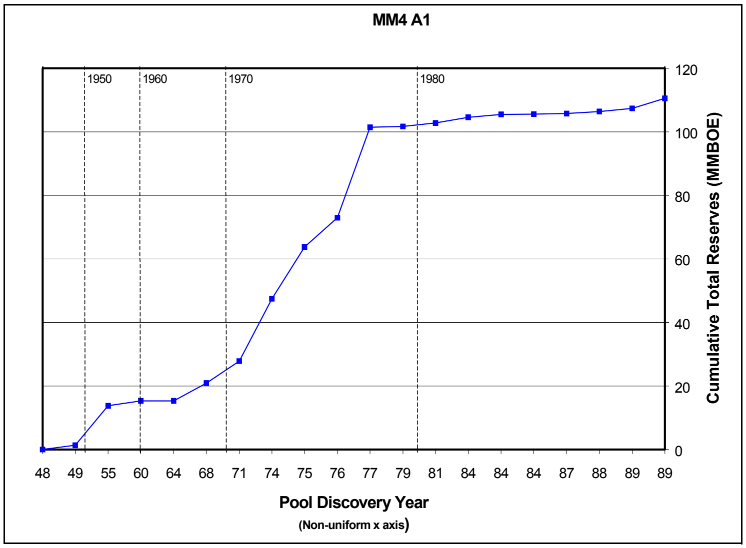


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM4 A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	19	0.011	0.424	0.087
Cumulative production	–	0.010	0.360	0.074
Remaining proved	–	0.001	0.064	0.013
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	–	0.001	0.127	0.024
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	<0.001	0.008	0.002
Mean	4	<0.001	0.018	0.004
5th percentile	–	0.002	0.029	0.006
Total Endowment				
95th percentile	–	0.013	0.559	0.113
Mean	23	0.013	0.569	0.115
5th percentile	–	0.015	0.580	0.117

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

thick.

Most of the fields in the MM4 A1 play are structurally associated with normal faults. Less common are growth fault anticlines and diapir-like shale bodies with traps on the flanks of the shale or in sediment drape over the shale. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MM4 A1 gas play contains total reserves of 0.013 Bbo and 0.551 Tcfg (0.111 BBOE), of which 0.010 Bbo and 0.360 Tcfg (0.074 BBOE) have been produced. The play contains 54 producible sands in 19 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the West Cameron 45 field in 1949 (figure 2). Maximum yearly total reserves were added in 1977 with the discovery of the largest pool in the play, the Matagorda Island 665 field with 28 MMBOE in total reserves (figures 2 and 3). All of the play's cumulative production and total reserves come from pools discovered before 1990, indicative of the maturity of the play. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, occurred in 1989.

The 19 discovered pools contain 68 reservoirs, of which 60 are nonassociated gas, 7 are undersaturated oil, and 1 is saturated oil. Cumulative production has consisted of 87 percent gas and 13 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM4 A1 play is 1.00. The play has a mean total endowment of 0.013 Bbo and 0.569 Tcfg (0.115 BBOE) (table 2). Sixty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally

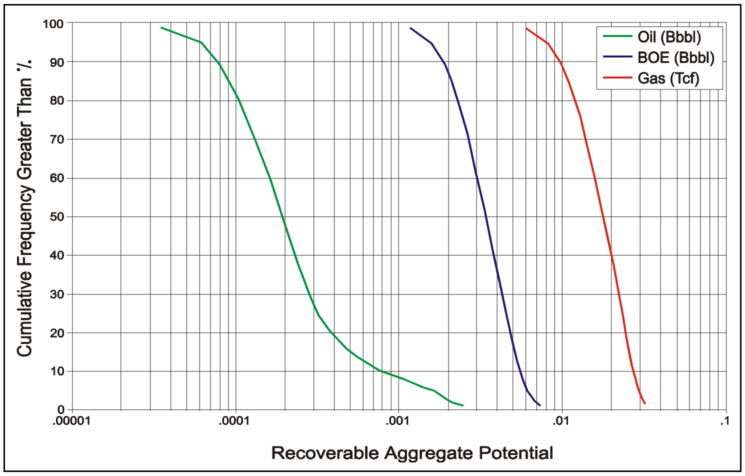


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

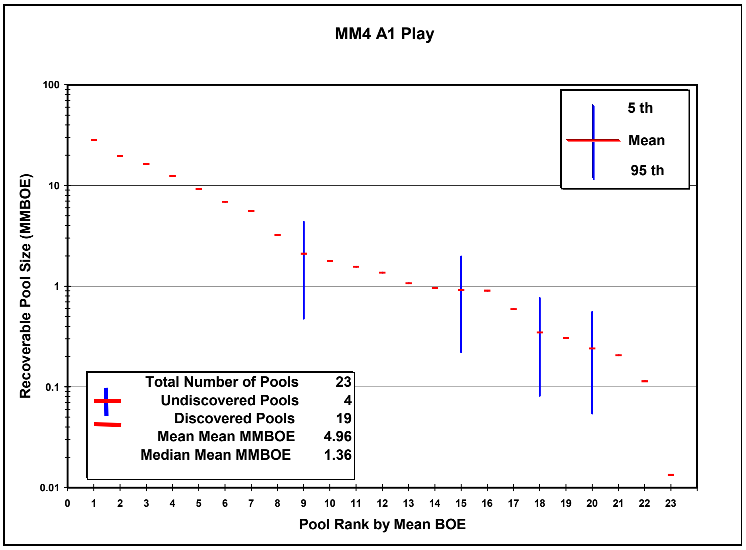


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

recoverable resources (UCRR) range from <0.001 to 0.002 Bbo and 0.008 to 0.029 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR are <0.001 Bbbl and 0.018 Tcfg (0.004 BBOE). These undiscovered resources might occur in as many as four pools. The largest undiscovered pool, with a mean size of 2 MMBOE, is forecast as the ninth largest pool in the play (figure 4). The forecast places the remaining three undiscovered pools in positions 15, 18, and 20 on the pool rank plot. For the undiscovered pools in the MM4 A1 play, the mean mean size is 1 MMBOE compared with the 6 MMBOE mean size of discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5 MMBOE.

The MM4 A1 is a supermature play with mean UCRR contributing only 3 percent to the play's mean total endowment.

Lower Middle Miocene Progradational (MM4 P1) Play

Gyroidina "K" through *Amphistegina* "B" biozones

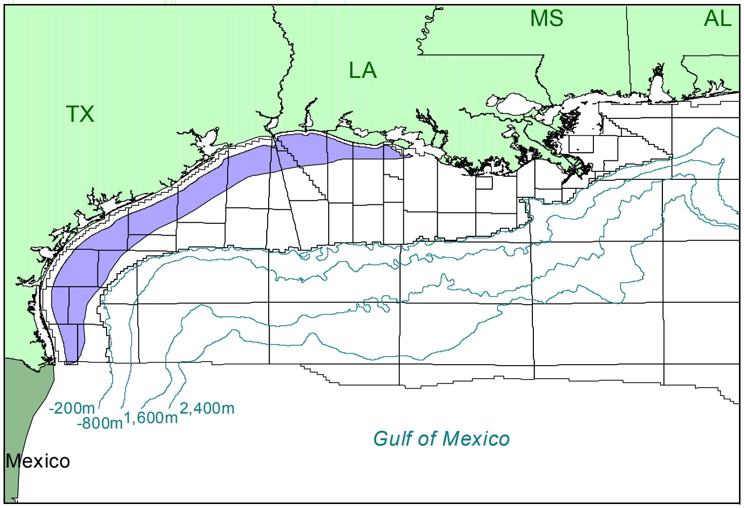


Figure 1. Play location.

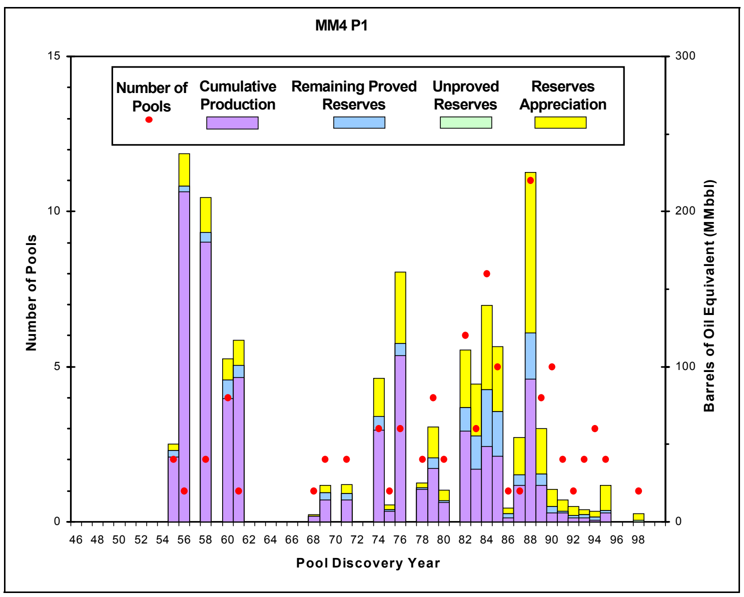


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM4 P1 Play **85 Pools 474 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	11	75	212
Subsea depth (feet)	5510	8917	17500
Number of sands per pool	1	6	18
Porosity	15%	27%	33%
Water saturation	16%	31%	53%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Middle Miocene Progradational (MM4 P1) 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 Eugene Island Area offshore Louisiana (figure 1).

Updip and to the northeast, the play continues onshore into Texas and Louisiana. To the southwest, the play extends into Mexican national waters. Downdip of the Eugene Island through High Island Areas, the play grades into the deposits of the Lower Middle Miocene Fan 1 (MM4 F1) play. Although deep-sea fan sediments have not yet been penetrated west of the High Island Area, it is expected that the MM4 P1 play will grade downdip into deep-sea fan sediments in those areas as well.

Play Characteristics

The MM4 P1 play is characterized by sediments deposited in marine bars, delta fringes, distributary mouth bars, and channel/levee complexes. The thickest sand-dominated intervals likely represent stacked facies of multiple episodes of delta-lobe switching and progradation. The MM4 P1 play is also punctuated by well-developed flooding surfaces, of which the *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* “B” are the most significant.

Most of the fields in the MM4 P1 play are structurally associated with normal faults and simple anticlines. Other common structures include shale diapir-like bodies, with traps on the flanks of the shale or in sediment drape over the shale, and growth faults with rollover anticlines. Seals are provided by the juxtaposition of reservoir sands with shales,

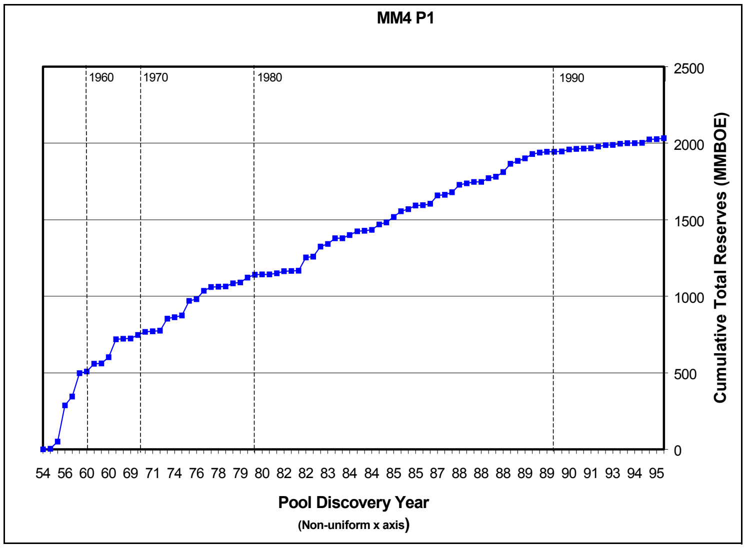


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM4 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	84	0.120	7.530	1.460
Cumulative production	--	0.101	6.344	1.230
Remaining proved	--	0.020	1.186	0.231
Unproved	1	<0.001	0.006	0.001
Appreciation (P & U)	--	0.035	3.006	0.570
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.003	1.073	0.198
Mean	30	0.008	1.250	0.231
5th percentile	--	0.015	1.449	0.266
Total Endowment				
95th percentile	--	0.159	11.615	2.230
Mean	115	0.164	11.792	2.263
5th percentile	--	0.171	11.991	2.298

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The MM4 P1 gas play contains total reserves of 0.156 Bbo and 10.542 Tcfg (2.032 BBOE), of which 0.101 Bbo and 6.344 Tcfg (1.230 BBOE) have been produced. The play contains 474 producible sands in 85 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1955 in the Galveston 189 and West Cameron 71 fields (figure 2). Maximum yearly total reserves were added the next year by the discovery of the Vermilion 14 field with 238 MMBOE in total reserves. A secondary peak in maximum yearly total reserves of 225 MMBOE occurred in 1988 with the discovery of 11 pools (figures 2 and 3). Ninety-eight percent of cumulative production and 96 percent of total reserves in the play were from pools discovered before 1990. Since 1990, 16 pools have been discovered, the largest of which contains 22 MMBOE in total reserves. The most recent discovery, prior to this study's cutoff date of January 1, 1999, occurred in 1998.

The 85 discovered pools contain 810 reservoirs, of which 770 are nonassociated gas, 28 are undersaturated oil, and 12 are saturated oil. Cumulative production has consisted of 92 percent gas and 8 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM4 P1 play is 1.00. The play contains a mean total endowment of 0.164 Bbo and 11.792 Tcfg (2.263 BBOE) (table 2). Fifty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.003 to 0.015 Bbo and 1.073 to 1.449 Tcfg at the 95th and

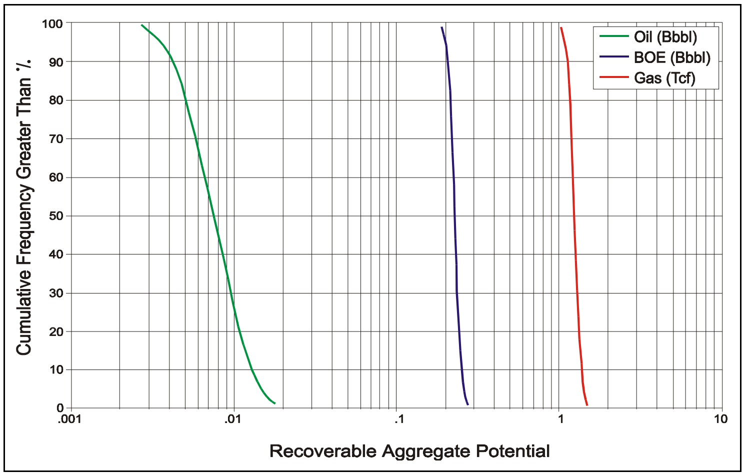


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

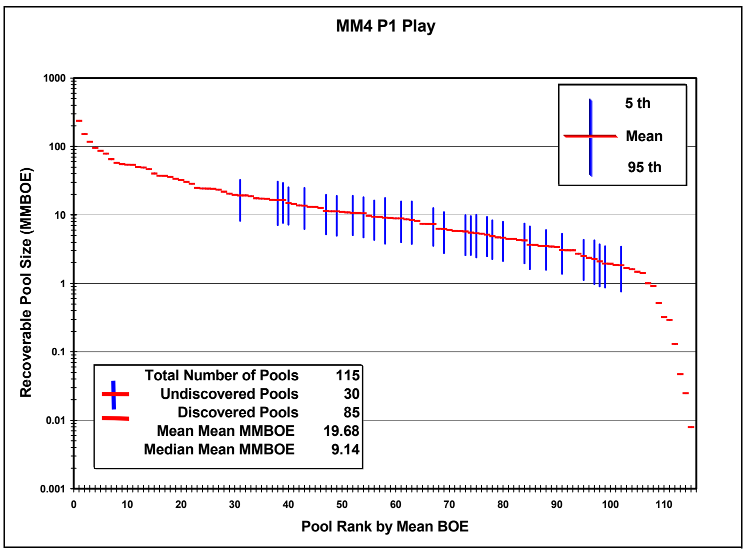


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.008 Bbo and 1.250 Tcfg (0.231 BBOE). These undiscovered resources might occur in as many as 30 pools. The largest undiscovered pool, with a mean size of 19 MMBOE, is forecast as the 31st largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 38, 39, 40, and 43 on the pool rank plot. For all the undiscovered pools in the MM4 P1 play, the mean mean size is 8 MMBOE, which is substantially smaller than the 24 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 20 MMBOE.

The MM4 P1 is a supermature play with UCRR contributing 10 percent to the play's BOE mean total endowment.

Lower Middle Miocene Fan 1 (MM4 F1) Play

Gyroidina "K" through *Amphistegina* "B" biozones

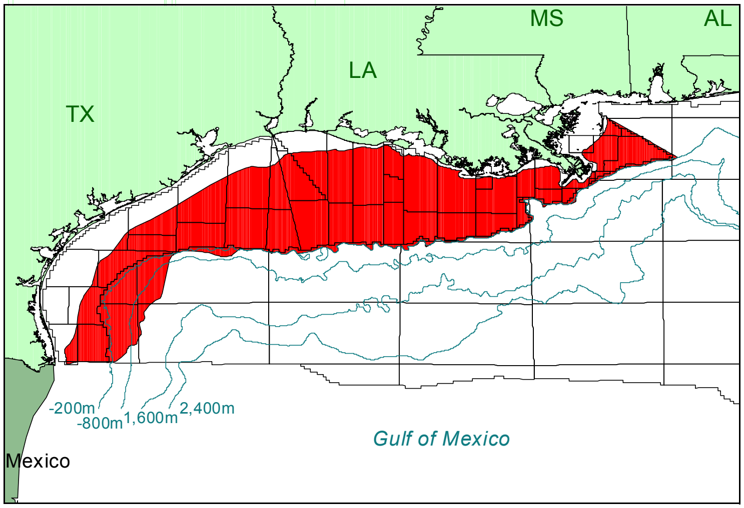


Figure 1. Play location.

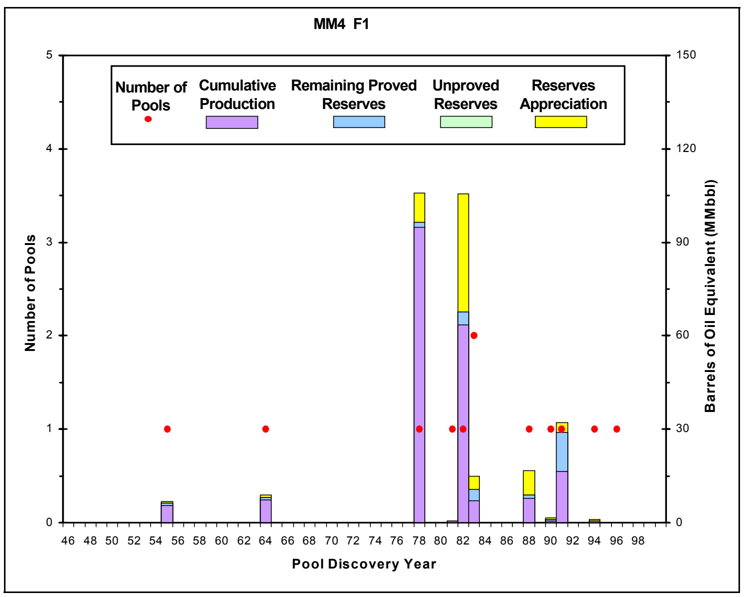


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

MM4 F1 Play 12 Pools 30 Sands	Minimum	Mean	Maximum
Water depth (feet)	25	43	53
Subsea depth (feet)	10141	13946	18000
Number of sands per pool	1	3	8
Porosity	15%	22%	27%
Water saturation	19%	30%	56%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Middle Miocene Fan 1 (MM4 F1) play occurs within the *Gyroidina* "K," *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* "B" biozones. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The MM4 F1 play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip, the MM4 F1 play continues onshore, except for in the South Padre Island to Vermilion Areas. In those areas the play is limited updip by the *Gyroidina* "K" shelf margin and the Lower Middle Miocene Progradational (MM4 P1) play. To the northeast the play onlaps the Lower Cretaceous carbonate slope. Downdip, the play is limited by the updip extent of the conceptual Lower Middle Miocene Fan 2 (MM4 F2) play.

Two separate depocenters were active during MM4 time in the Gulf of Mexico Region. The ancient North Padre Delta system provided sand to offshore Texas, and the ancient Calcasieu Delta System provided sand to offshore Louisiana. However, only sands of the Calcasieu Delta System of Louisiana have proven productive. Fan deposition in the underlying LM4 chronozone is better developed in the Mustang Island to Brazos Areas offshore Texas, while during MM4 time fans appear better developed farther east from the High Island to Vermilion Areas.

Play Characteristics

The productive MM4 F1 play is characterized by deepwater turbidites deposited in deep-sea channel/

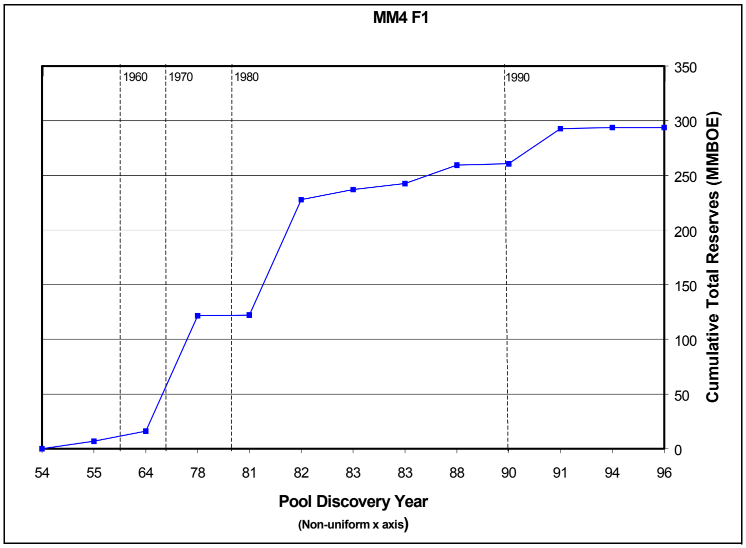


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

MM4 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	12	0.031	1.112	0.229
Cumulative production	--	0.027	0.994	0.204
Remaining proved	--	0.004	0.119	0.025
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.010	0.305	0.065
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.023	1.268	0.253
Mean	48	0.038	1.594	0.321
5th percentile	--	0.058	1.947	0.398
Total Endowment				
95th percentile	--	0.065	2.685	0.547
Mean	60	0.080	3.011	0.615
5th percentile	--	0.100	3.364	0.692

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

levees, sheet-sand lobes, interlobes, fringe lobes, and slumps. Sediments were deposited on the MM4 upper and lower slope in topographically low areas between salt structure highs and on the abyssal plain. These deep-sea fan systems are often overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

Normal faults are the dominant productive structural style in the MM4 F1 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).

Discoveries

The MM4 F1 gas play contains total reserves of 0.042 Bbo and 1.417 Tcfg (0.294 BBOE), of which 0.027 Bbo and 0.994 Tcfg (0.204 BBOE) have been produced. The play contains 30 producible sands in 12 pools of which all contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the East Cameron 49 field in 1955 (figure 2). Maximum yearly total reserves were added in 1978 with the discovery of the largest pool in the play (106 MMBOE) in the Vermilion 14 field. The play's second largest pool (105 MMBOE) was discovered in 1982 in the Vermilion 24 field. These two pools account for over 70 percent of the BOE total reserves in the play (figures 2 and 3). The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1996.

The 12 discovered pools contain 33 reservoirs, of which 32 are nonassociated gas and 1 is undersaturated oil. Cumulative production has consisted of 87 percent gas and 13 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the MM4 F1 play is

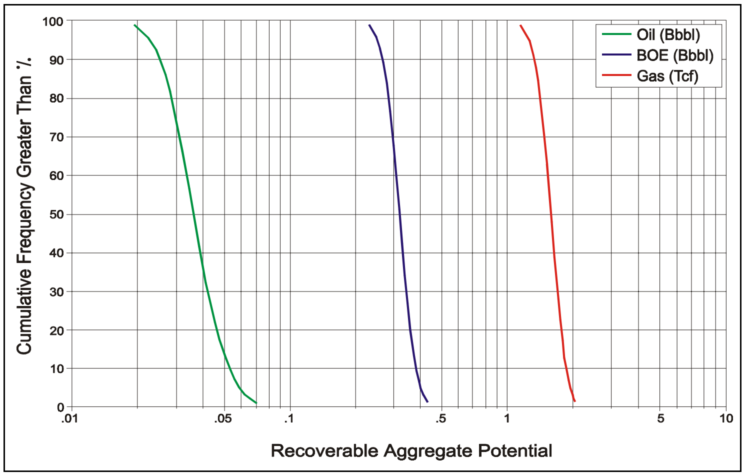


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

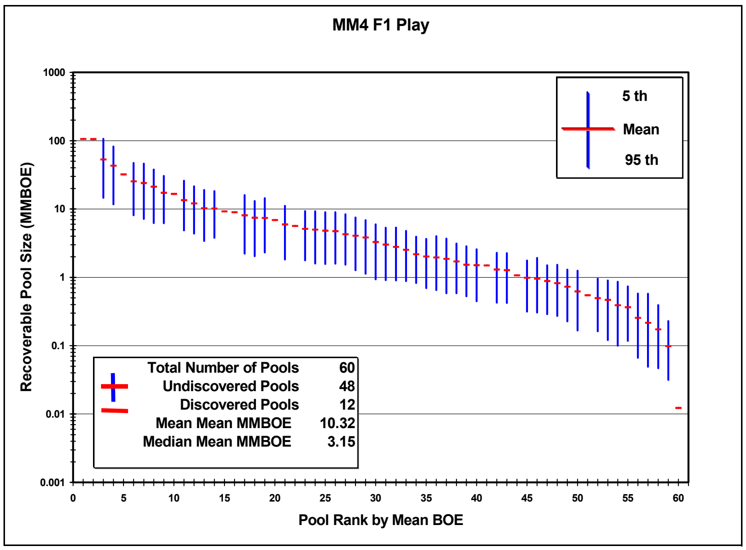


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

1.00. The play contains a mean total endowment of 0.080 Bbo and 3.011 Tcfg (0.615 BBOE) (table 2). A third of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.023 to 0.058 Bbo and 1.268 to 1.947 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.038 Bbo and 1.594 Tcfg (0.321 BBOE). These undiscovered resources might occur in as many as 48 pools. The largest undiscovered pool, with a mean size of 53 MMBOE, is forecast as the third largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 4, 6, 7, and 8 on the pool rank plot. For all the undiscovered pools in the MM4 F1 play, the mean mean size is 7 MMBOE, which is significantly smaller than the 24 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 10 MMBOE.

The MM4 F1 play has not been extensively tested because of its great depth of burial. The most exploration potential is thought to exist on the flanks of salt bodies, and by drilling deeper in and around existing fields. BOE mean UCRR contribute 52 percent to the play's BOE mean total endowment.

Lower Middle Miocene Fan 2 (MM4 F2) Play

Gyroidina "K" through *Amphistegina* "B" biozones

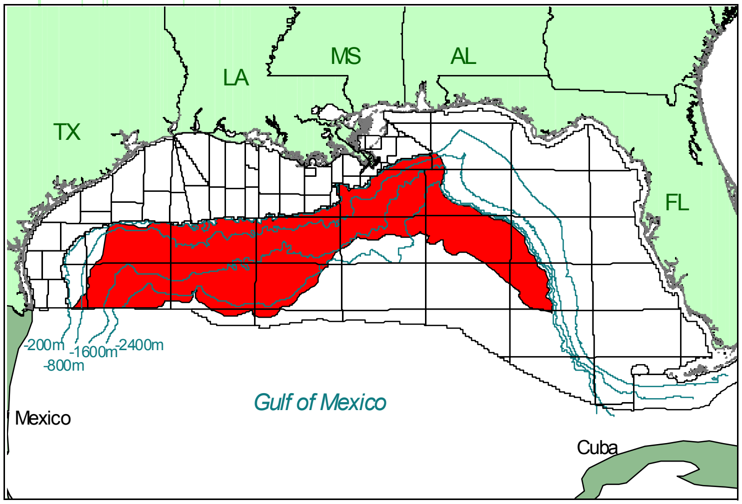


Figure 1. Play location.

MM4 F2 Play 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	--	0.999	5.937	2.121
Mean	80	1.173	7.431	2.495
5th percentile	--	1.391	9.942	3.044
Total Endowment				
95th percentile	--	0.999	5.937	2.121
Mean	80	1.173	7.431	2.495
5th percentile	--	1.391	9.942	3.044

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Lower Middle Miocene Fan 2 (MM4 F2) play occurs within the *Gyroidina* "K," *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* "B" biozones. The play is also defined by hypothesized deep-sea fan sands in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The MM4 F2 play extends from the Port Isabel and Alaminos Canyon Areas offshore Texas to the western Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the play is bounded by the Lower Middle Miocene Fan 1 (MM4 F1) play. To the northeast, the play onlaps the Cretaceous carbonate slope, while to the southwest, the play extends into Mexican national waters. Downdip in the western and central Gulf of Mexico Region, the MM4 F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt or Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Discoveries

The MM4 F2 play contains no discoveries as of January 1, 1999. On the basis of established middle Miocene fan play production, the MM4 F2 play will likely produce a mix

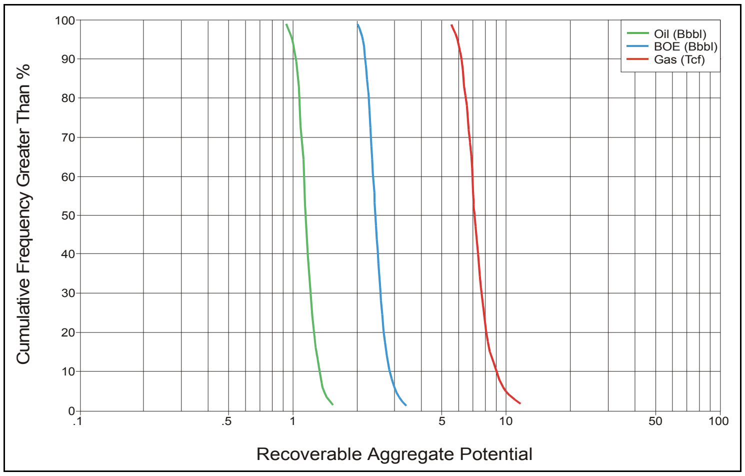


Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

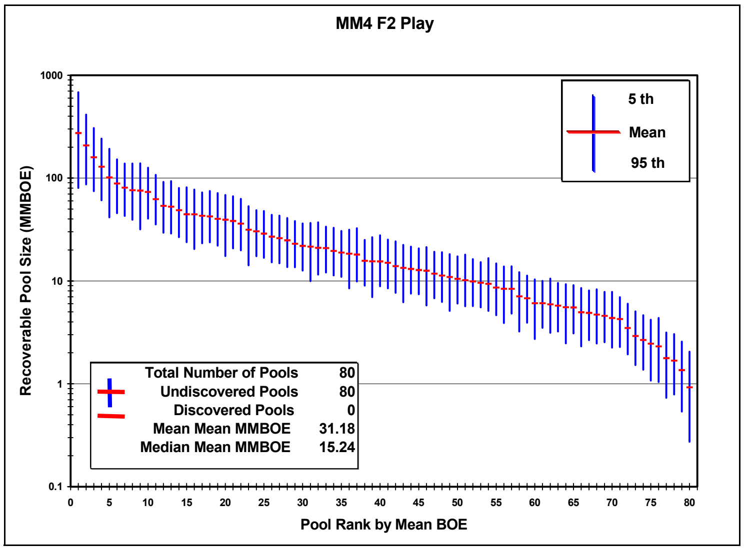


Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

of oil and gas.

Assessment Results

The marginal probability of hydrocarbons for the MM4 F2 play is 1.00. The play contains a mean total endowment of 1.173 Bbo and 7.431 Tcfg (2.495 BBOE) (table 1). Because the MM4 F2 play is a conceptual play with no production to date, the play's mean total endowment equals undiscovered conventionally recoverable resources (UCRR). The play's total endowment and UCRR have a range of 0.999 Bbo to 1.391 Bbo and 5.937 Tcfg to 9.942 Tcfg at the 95th and 5th percentiles, respectively (figure 2).

Assessment results indicate that UCRR might occur in as many as 80 pools (figure 3). The largest undiscovered pool has a mean size of 274 MMBOE. The five largest undiscovered pools together have a mean mean UCRR of 174 MMBOE, while the mean mean size for all undiscovered pools is forecast at 31 MMBOE.

The MM4 F2 play has a large anticipated total endowment and is expected to contain five pools with over 100 MMBOE in total reserves. The greatest exploration potential is thought to exist in structural and stratigraphic traps around, against, and below salt bodies and in Miocene-aged salt-withdrawal anticlines (turtle structures).

Upper Lower Miocene Retrogradational (LM4 R1) Play

Discorbis bolivarensis **biozone**

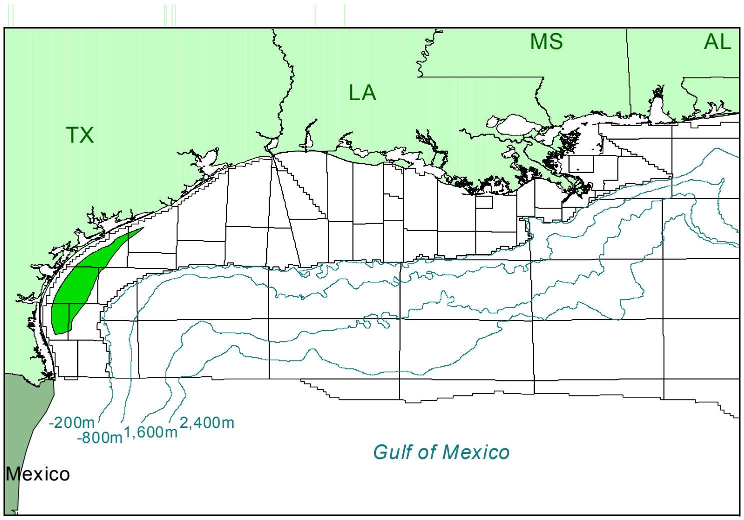


Figure 1. Play location.

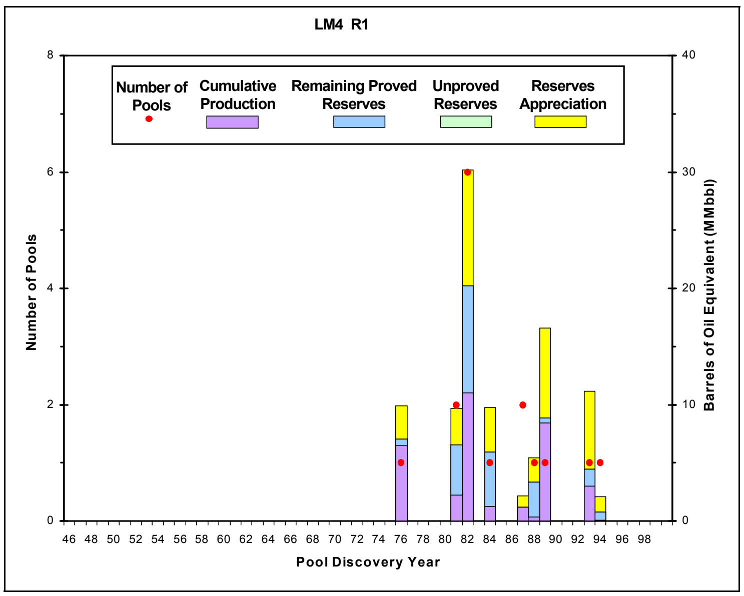


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM4 R1 Play **16 Pools 31 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	72	126	212
Subsea depth (feet)	5230	7542	11091
Number of sands per pool	1	2	4
Porosity	22%	27%	31%
Water saturation	27%	37%	54%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Lower Miocene Retrogradational (LM4 R1) play occurs within the *Discorbis bolivarensis* biozone. This play extends from the North Padre Island Area to the Brazos Area offshore Texas (figure 1).

Updip, the play continues onshore into Texas. Downdip and to the east and west, the play grades into either deposits of the Upper Lower Miocene Aggradational (LM4 A) play or the Upper Lower Miocene Progradational (LM4 P) play.

The LM4 chronozone marks the first known occurrence of retrogradational sediments in the Federal OCS.

Play Characteristics

Retrogradational sediments are characterized by the reworking of shelf sands during relative sea level rises. LM4 R1 sands exhibit an upward-fining, back-stepping log signature and are overlain by a shale sequence associated with the *Discorbis bolivarensis* flooding event. Individual sands are thin, usually a few tens of feet thick at the most, and are separated by thin shales of the same approximate thickness. The LM4 retrogradational section varies from approximately 100 feet to more than 1,500 feet in thickness, with net sand thicknesses as much as 150 feet. The LM4 R1 play appears best developed in the Matagorda Island Area where it exhibits a pronounced back-stepping log character.

Most of the fields in the LM4 R1 play are structurally associated with simple anticlines and normal faults. Other common structures include growth fault anticlines and shale diapir-like bodies with traps on the flanks of shale or in sediment drape over the shale. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally

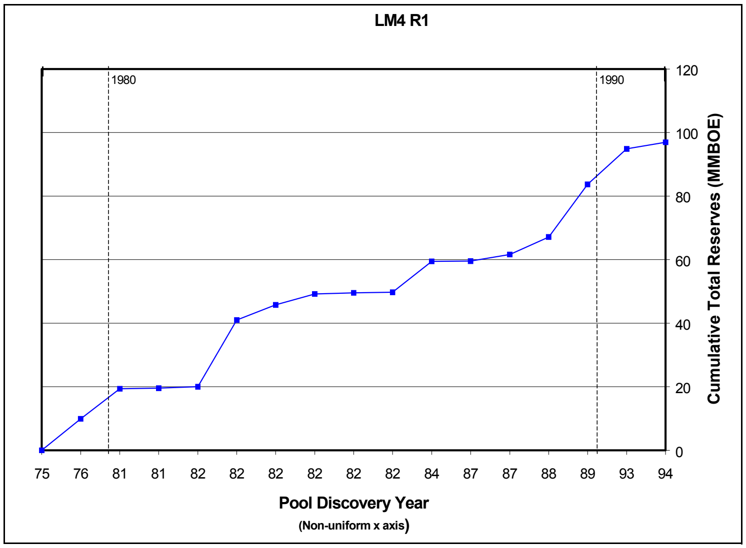


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM4 R1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	16	0.001	0.324	0.058
Cumulative production	--	0.001	0.189	0.034
Remaining proved	--	<0.001	0.135	0.024
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.214	0.039
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.083	0.015
Mean	9	<0.001	0.112	0.020
5th percentile	--	0.001	0.142	0.026
Total Endowment				
95th percentile	--	0.001	0.621	0.112
Mean	25	0.001	0.650	0.117
5th percentile	--	0.002	0.680	0.123

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

(e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LM4 R1 gas play contains total reserves of 0.001 Bbo and 0.538 Tcfg (0.097 BBOE), of which 0.001 Bbo and 0.189 Tcfg (0.034 BBOE) have been produced. The play contains 31 producible sands in 16 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in 1976 in the Mustang Island 757 field (figure 2). Maximum yearly total reserves of 30 MMBOE were added in 1982 when six pools were discovered. The largest pool in the play (20 MMBOE in total reserves) is in the Matagorda Island 703 field discovered in 1982. Ninety-one percent of the play's cumulative production and 86 percent of its total reserves come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1994.

The 16 discovered pools contain 47 reservoirs, all of which are nonassociated gas.

Assessment Results

The marginal probability of hydrocarbons for the LM4 R1 play is 1.00. The play has a mean total endowment of 0.001 Bbo and 0.650 Tcfg (0.117 BBOE) (table 2). Twenty-nine percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable oil resources are insignificant (<0.001 Bbbl) and that undiscovered conventionally recoverable gas resources have a range of 0.083 to 0.142 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean undiscovered conventionally recoverable gas resources are 0.112 Tcfg (0.020 BBOE). These undiscovered resources might occur in as many as nine pools. The largest undiscovered pool, with a mean size of 5 MMBOE,

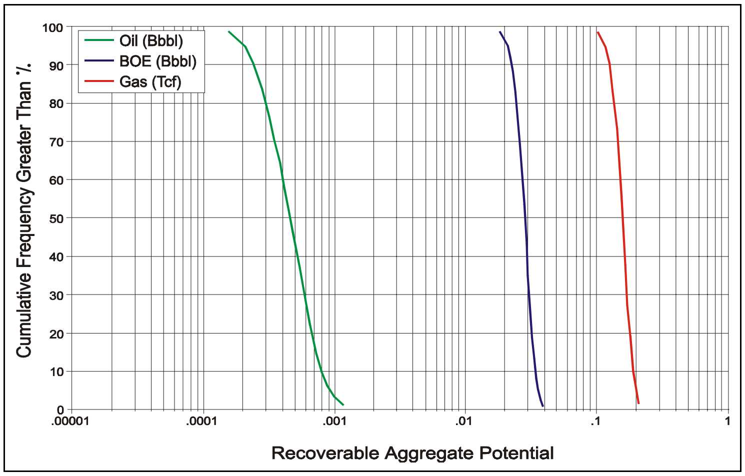


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

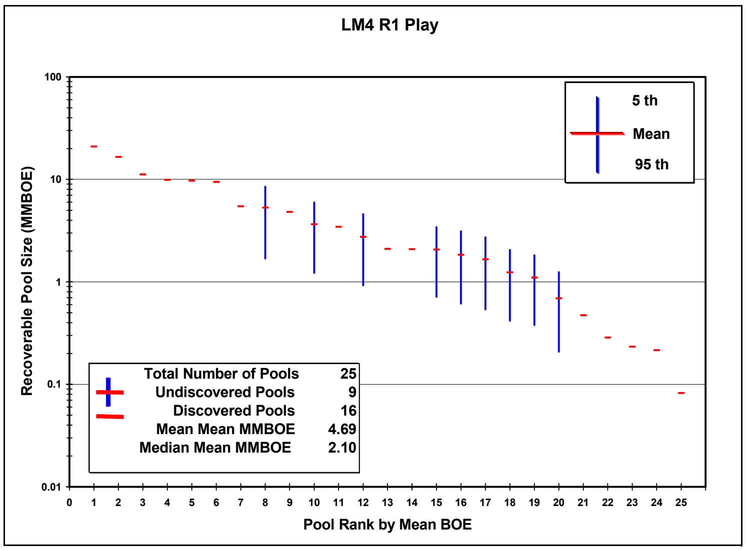


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

is forecast as the eighth largest pool in the play (figure 4). The next four largest undiscovered pools occupy positions 10, 12, 15, and 16 on the pool rank plot. For all the undiscovered pools in the LM4 R1 play, the mean mean size is 2 MMBOE compared with the 6 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5 MMBOE.

BOE mean undiscovered conventionally recoverable resources contribute 17 percent to the play's BOE mean total endowment. A relatively few, smaller pools will likely be discovered by drilling in and around existing fields.

Upper Lower Miocene Aggradational (LM4 A1) Play

Marginulina ascensionensis **and** ***Discorbis bolivarensis*** **biozones**

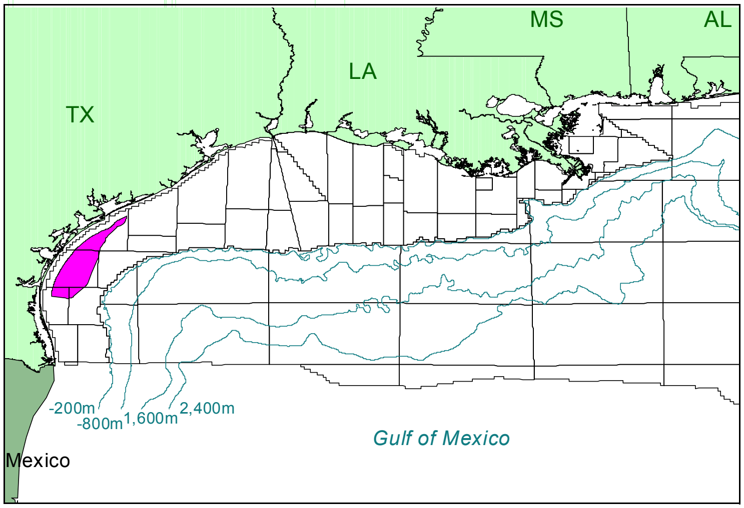


Figure 1. Play location.

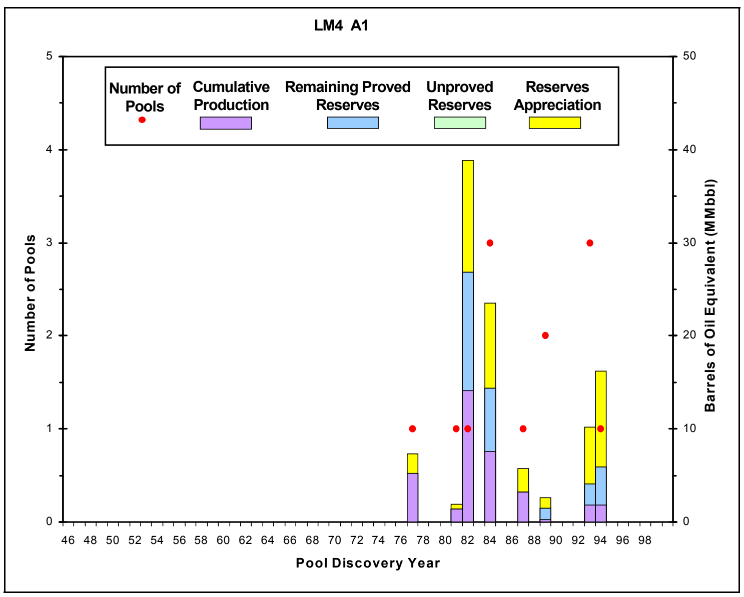


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM4 A1 Play 13 Pools 41 Sands	Minimum	Mean	Maximum
Water depth (feet)	78	141	212
Subsea depth (feet)	6294	7915	11949
Number of sands per pool	1	3	11
Porosity	21%	26%	30%
Water saturation	16%	31%	40%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Lower Miocene Aggradational (LM4 A1) play occurs within the *Marginulina ascensionensis* and *Discorbis bolivarensis* biozones. This play extends from the North Padre Island Area to the Matagorda Island Area offshore Texas (figure 1).

Updip, the play continues onshore into Texas. To the east, west, and downdip, the play grades into the deposits of the Upper Lower Miocene Progradational (LM4 P1) play.

Play Characteristics

The LM4 A1 play is characterized by stacked sands that were deposited in channel/levee complexes, crevasse splays, distributary mouth bars, delta-fringes, and shelf environments. These sands are typically coarse-grained and exhibit a blocky log signature. The LM4 A1 play comprises a significant portion of the LM4 section in terms of net sand development, reaching a thickness of approximately 1,500 feet.

Most of the fields in the LM4 A1 play are structurally associated with normal faults and growth fault anticlines. Less common trapping structures include diapir-like shale bodies with traps located on the flanks of the shale, or in sediment drape over the shale. 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

The LM4 A1 gas play contains total reserves of 0.002 Bbo and 0.587 Tcfg (0.106 BBOE), of which 0.001 Bbo and 0.196 Tcfg (0.035 BBOE) have been produced. The play contains 41 producible sands in

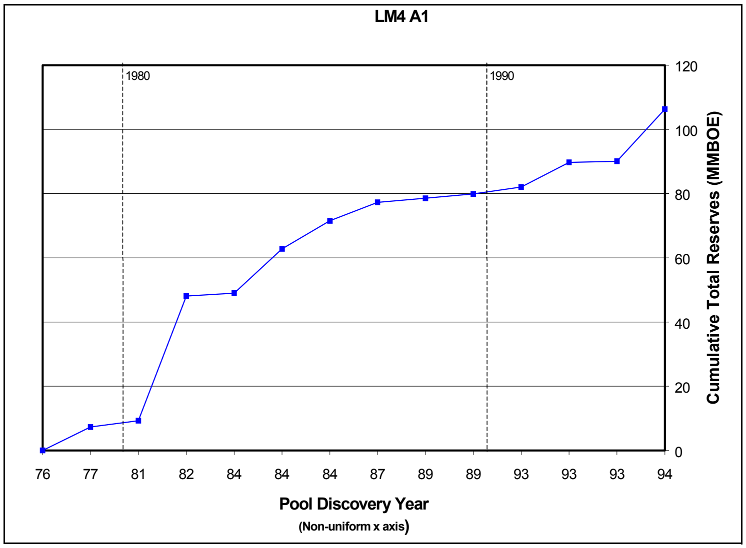


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM4 A1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	13	0.001	0.345	0.062
Cumulative production	--	0.001	0.196	0.035
Remaining proved	--	0.001	0.149	0.027
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.242	0.044
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.124	0.023
Mean	8	0.001	0.161	0.029
5th percentile	--	0.001	0.199	0.036
Total Endowment				
95th percentile	--	0.002	0.711	0.129
Mean	21	0.003	0.748	0.135
5th percentile	--	0.003	0.786	0.142

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

13 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the Mustang Island 757 field in 1977 (figure 2). Maximum yearly total reserves were added in 1982 with the discovery of the largest pool in the play, the Mustang Island 31A with 39 MMBOE in mean total reserves (figures 2 and 3). Ninety percent of the play's cumulative production and 75 percent of the play's total reserves come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1994.

The 13 discovered pools contain 50 reservoirs, all of which are nonassociated gas.

Assessment Results

The marginal probability of hydrocarbons for the LM4 A1 play is 1.00. The play has a mean total endowment of 0.003 Bbo and 0.748 Tcfg (0.135 BBOE) (table 2). Twenty-six percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of <0.001 to 0.001 Bbo and 0.124 to 0.199 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.001 Bbo and 0.161 Tcfg (0.029 BBOE). These undiscovered resources might occur in as many as eight pools. The largest undiscovered pool, with a mean size of 7 MMBOE, is forecast as the sixth largest pool in the play (figure 5). The next four largest pools occupy positions 9, 10, 11 and 12 on the pool rank plot. For all the undiscovered pools in the LM4 A1 play, the mean mean size is 4 MMBOE compared to the 8 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 6 MMBOE.

BOE mean UCRR contribute 21 percent to the play's BOE mean total endowment. Hydrocarbons have been discovered to date only in the

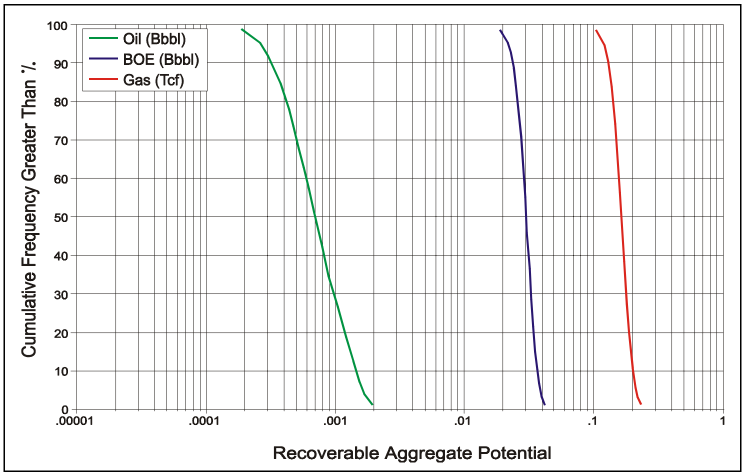


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

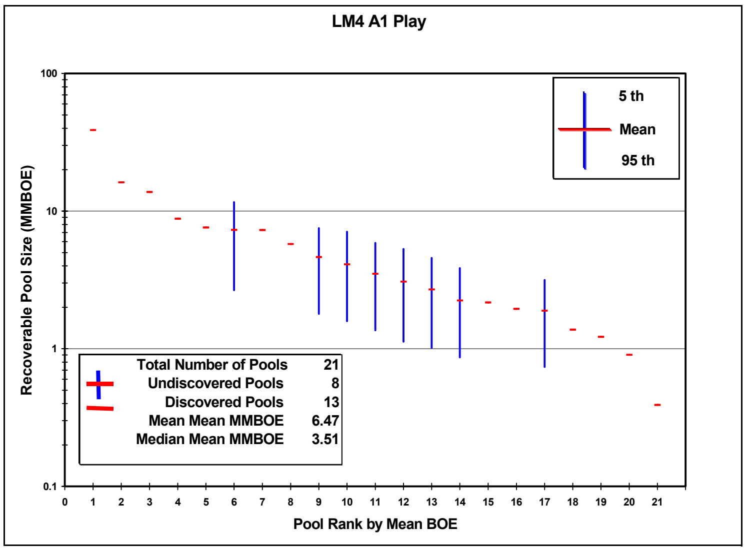


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Matagorda Island and Mustang Island Areas of the play.

Upper Lower Miocene Progradational (LM4 P1) Play

Marginulina ascensionensis and *Discorbis bolivarensis* biozones

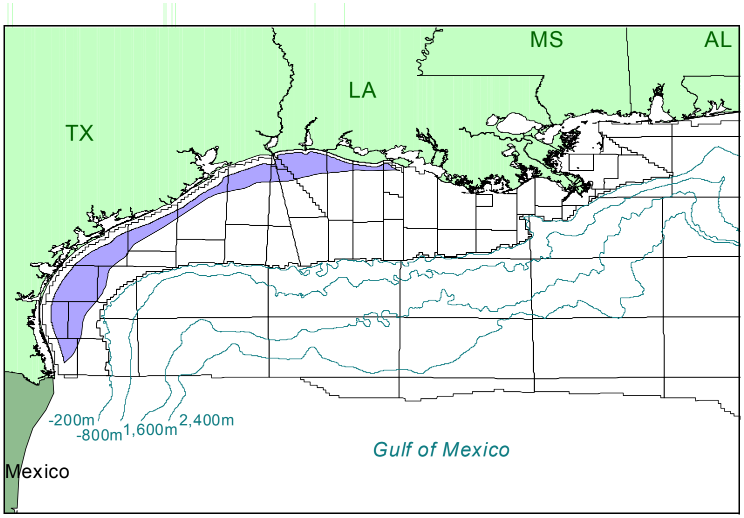


Figure 1. Play location.

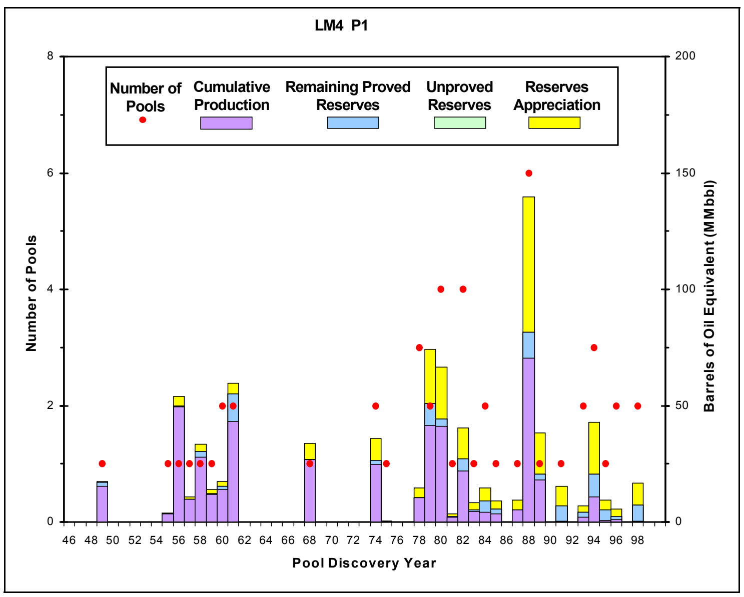


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM4 P1 Play 51 Pools 175 Sands	Minimum	Mean	Maximum
Water depth (feet)	29	68	156
Subsea depth (feet)	6190	9643	13022
Number of sands per pool	1	3	12
Porosity	16%	26%	35%
Water saturation	16%	29%	58%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Lower Miocene Progradational (LM4 P1) 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 1 (LM4 F1) play.

Play Characteristics

Sediments in the LM4 P1 play represent major episodes of outbuilding of both the shelf and the slope. Sands in the play were deposited in distributary mouth bars, delta-fringes, marine bars, and channel/levee complexes. The thickest sand-dominated intervals likely represent multiple episodes of delta-lobe switching and progradation. In the Brazos and Galveston Areas, progradational sediments are relatively sand poor and represent delta-fringe deposits at the most distal edges of LM4 delta systems.

Most of the fields in the LM4 P1 play are structurally associated with normal faults. Other common structures include shale diapir-like bodies, with traps on the flanks of the shale or in sediment drape over the shale, and growth fault anticlines. Fewer hydrocarbon accumulations are associated with permeability barriers, updip pinchouts or facies changes, deep salt domes, and rotational slump blocks.

Discoveries

The LM4 P1 gas play contains total reserves of 0.047 Bbo and 4.213 Tcfg (0.796 BBOE), of which 0.032 Bbo and 2.438 Tcfg (0.465

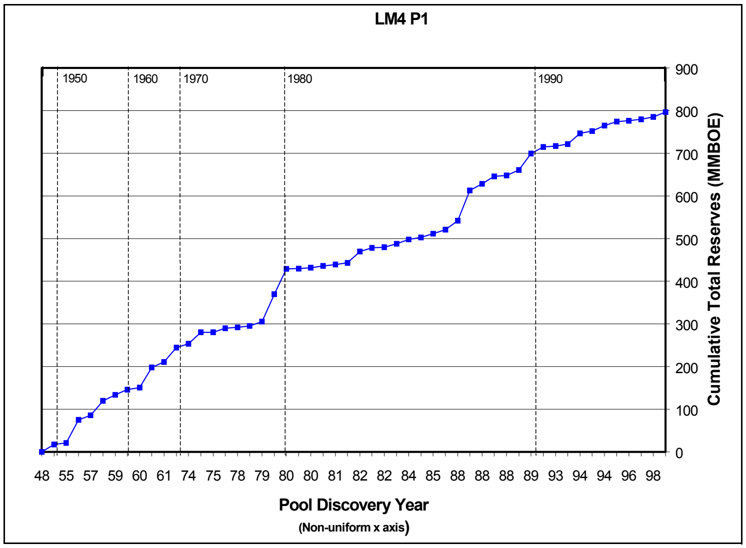


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM4 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	51	0.037	2.914	0.555
Cumulative production	--	0.032	2.438	0.465
Remaining proved	--	0.005	0.476	0.090
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.010	1.298	0.241
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.006	0.731	0.138
Mean	21	0.010	0.920	0.174
5th percentile	--	0.016	1.122	0.212
Total Endowment				
95th percentile	--	0.053	4.944	0.934
Mean	72	0.057	5.133	0.970
5th percentile	--	0.063	5.335	1.008

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

BBOE) have been produced. The play contains 175 producible sands in 51 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves in the play were discovered in the West Cameron 45 field in 1949 (figure 2). Maximum yearly total reserves of 140 MMBOE were added in 1988 with the discovery of six pools. The largest pool in the play, Matagorda Island 604, was also discovered in 1988 and contains 71 MMBOE in total reserves. Ninety-seven percent of the play's cumulative production and 88 percent of the play's total reserves come from pools discovered before 1990. The most recent discoveries, prior to this study's cutoff date of January 1, 1999, were in 1998.

The 51 discovered pools contain 334 reservoirs, of which 315 are nonassociated gas, 11 are undersaturated oil, and 8 are saturated oil. Cumulative production has consisted of 93 percent gas and 7 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the LM4 P1 play is 1.00. The play contains a mean total endowment of 0.057 Bbo and 5.133 Tcfg (0.970 BBOE) (table 2). Forty-eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.006 to 0.016 Bbo and 0.731 to 1.122 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.010 Bbo and 0.920 Tcfg (0.174 BBOE). These undiscovered resources might occur in as many as 21 pools. The largest undiscovered pool, with a mean size of 29 MMBOE, is forecast as the 9th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 14, 17, 20, and 29 on the pool rank plot. For all the undiscovered pools in the LM4 P1 play, the mean mean size is 8 MMBOE compared with the 16

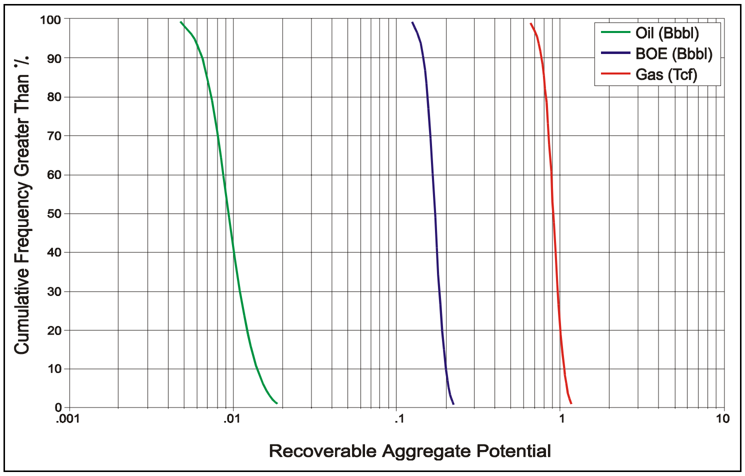


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

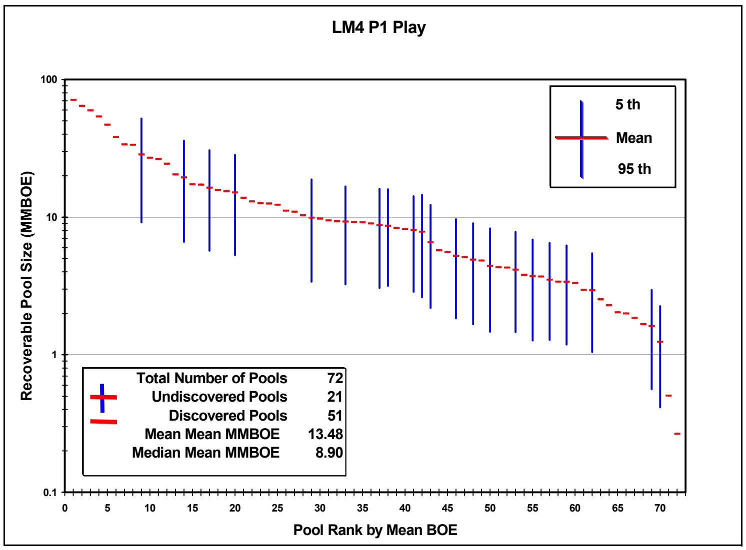


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 13 MMBOE.

The LM4 P1 play lies within an extensively drilled area in the Gulf of Mexico Region. Exploration potential is limited to subtle traps in and around existing fields, deeper sections within existing fields, or in areas downdip of existing pools where wells may not have penetrated deeply enough to reach the LM4 P1 section. BOE mean UCRR contribute 18 percent to the play's BOE mean total endowment.

Upper Lower Miocene Fan 1 (LM4 F1) Play

Marginulina ascensionensis and *Discorbis bolivarensis* biozones

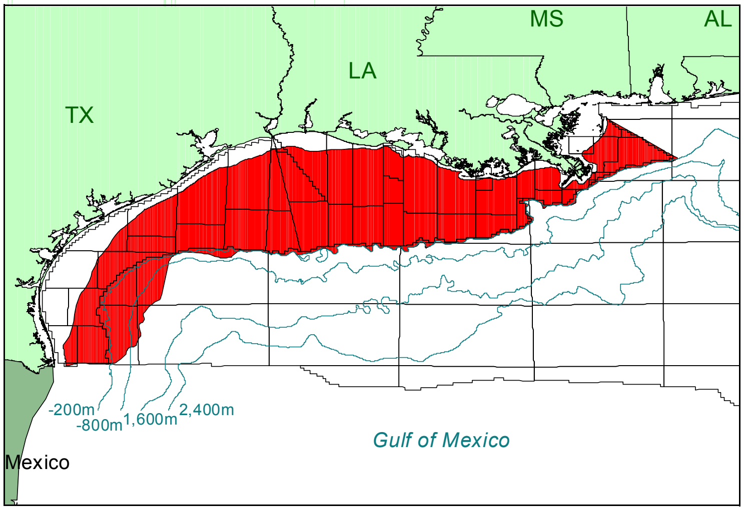


Figure 1. Play location.

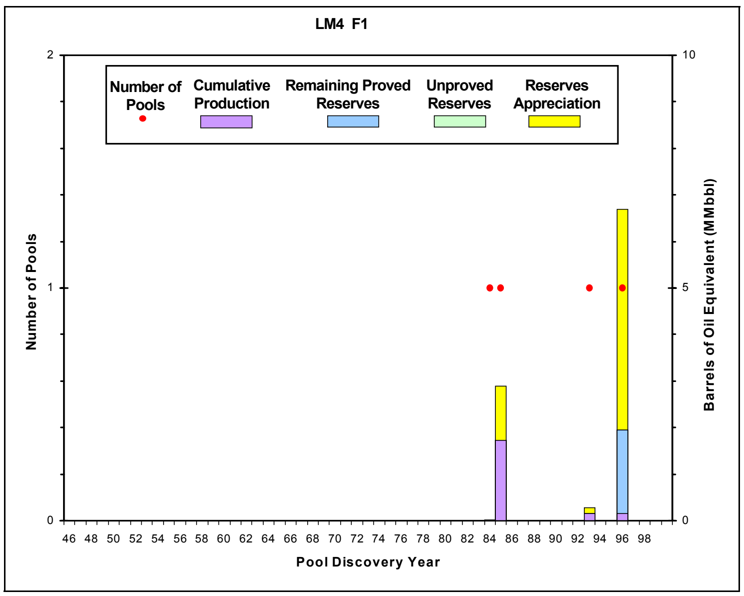


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM4 F1 Play 4 Pools 7 Sands	Minimum	Mean	Maximum
Water depth (feet)	40	103	189
Subsea depth (feet)	12694	13459	14035
Number of sands per pool	1	2	2
Porosity	23%	25%	26%
Water saturation	20%	29%	38%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Lower Miocene Fan 1 (LM4 F1) play occurs within the *Marginulina ascensionensis* and *Discorbis bolivarensis* biozones. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. This play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Main Pass Area east of the present-day Mississippi River Delta (figure 1)

Updip, the play extends onshore, except from the South Padre Island to western Brazos Areas to the west, and the eastern Galveston to western Vermilion Areas to the east. In these areas, the play is limited by the shelf/slope break associated with the *Marginulina ascensionensis* biozone and grades into the sediments of the Upper Lower Miocene Progradational (LM4 P1) play. To the northeast the play onlaps the Cretaceous carbonate slope. Downdip, the LM4 F1 play is limited by the Upper Lower Miocene Fan 2 (LM4 F2) play.

Play Characteristics

The LM4 F1 play is characterized by deepwater turbidites deposited basinward of the LM4 shelf margin on the upper and lower slopes, in topographically low areas between salt structure highs and on the abyssal plain. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, fringe lobes, and slumps. The LM4 F1 section is typically overlain by thick shale intervals representative of zones of sand bypass on the shelf, or sand-poor zones on the slope.

LM4 F1 structural styles include anticlines, normal faults, and growth fault anticlines. Seals are pro-

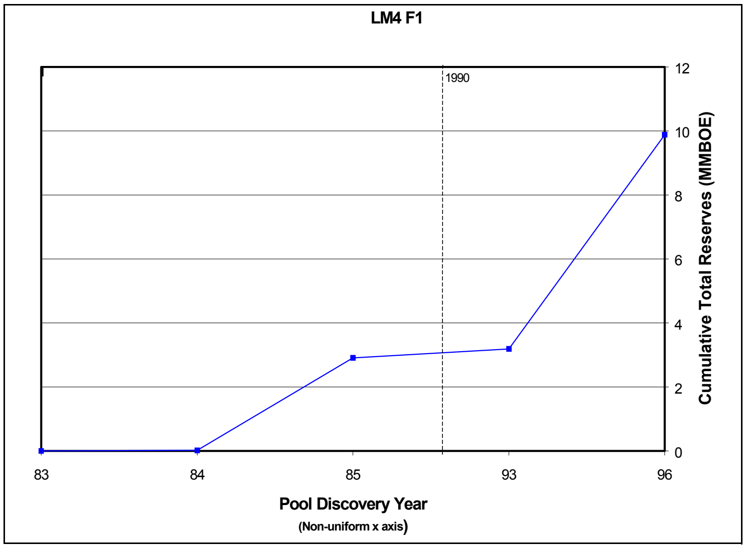


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM4 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	4	<0.001	0.020	0.004
Cumulative production	--	<0.001	0.010	0.002
Remaining proved	--	<0.001	0.010	0.002
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.033	0.006
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.015	0.894	0.180
Mean	25	0.036	1.223	0.253
5th percentile	--	0.067	1.672	0.350
Total Endowment				
95th percentile	--	0.015	0.947	0.190
Mean	29	0.036	1.276	0.263
5th percentile	--	0.067	1.725	0.360

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

vided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LM4 F1 gas play contains total reserves of <0.001 Bbo and 0.053 Tcfg (0.010 BBOE), of which <0.001 Bbo and 0.010 Tcfg (0.002 BBOE) have been produced. The play contains only seven producible sands, each with one nonassociated gas reservoir, in four pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). All four pools contain proved reserves. The first reserves in the play were discovered in the Mustang Island 90A field in 1984 (figure 2). The largest pool, with 7 MMBOE in total reserves, was found in 1996 in the West Cameron 130 field (figures 2 and 3). Eighty-four percent of the play's cumulative production and 29 percent of the play's total reserves are from pools discovered before 1990. The most recent discovery was the West Cameron 130 field in 1996.

Cumulative production from the seven nonassociated gas reservoirs has consisted of 91 percent gas and 9 percent oil.

Assessment Results

Because of limited data for the LM4 F1 play, the Upper Pliocene Fan 1 (UP F1) play was used as an analog to forecast pool sizes in the LM4 F1 play. The UP F1 play was selected because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the LM4 F1 play is 1.00. The play contains a mean total endowment of 0.036 Bbo and 1.276 Tcfg (0.263 BBOE) (table 2). Less than 1 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally

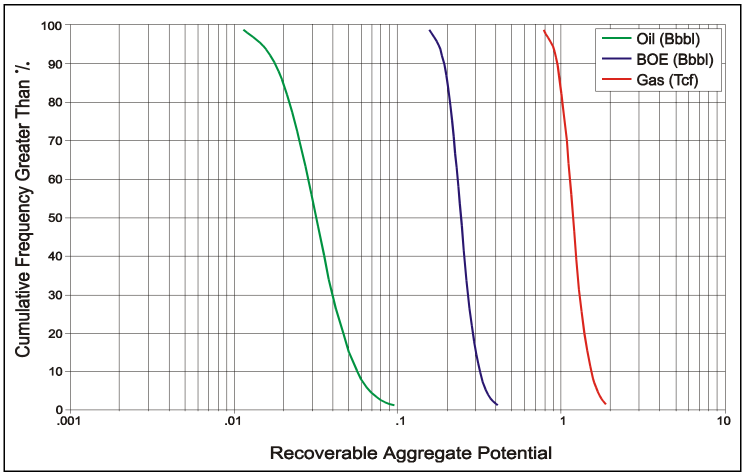


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

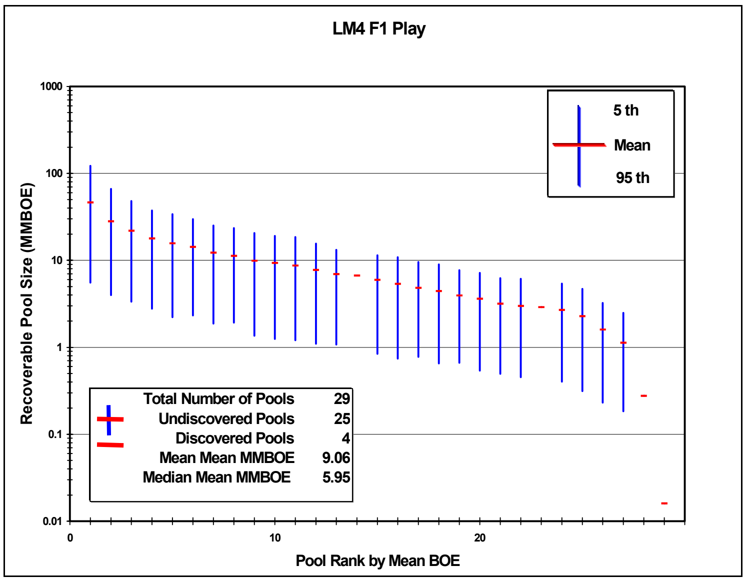


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

recoverable resources (UCRR) have a range of 0.015 to 0.0.067 Bbo and 0.894 to 1.672 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.036 Bbo and 1.223 Tcfg (0.253 BBOE). These undiscovered resources might occur in as many as 25 pools, with the 13 largest pools forecast as undiscovered accumulations (figure 5). For all the undiscovered pools in the LM4 F1 play, the mean mean size is 10 MMBOE, which is significantly larger than the 2 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 9 MMBOE.

The LM4 F1 is an immature play with resources in undiscovered pools contributing 96 percent to the play's BOE mean total endowment. The LM4 F1 play is not penetrated by many wellbores because of its great depth (table 1).

Upper Lower Miocene Fan 2 (LM4 F2) Play

Marginulina ascensionensis and *Discorbis bolivarensis* biozones

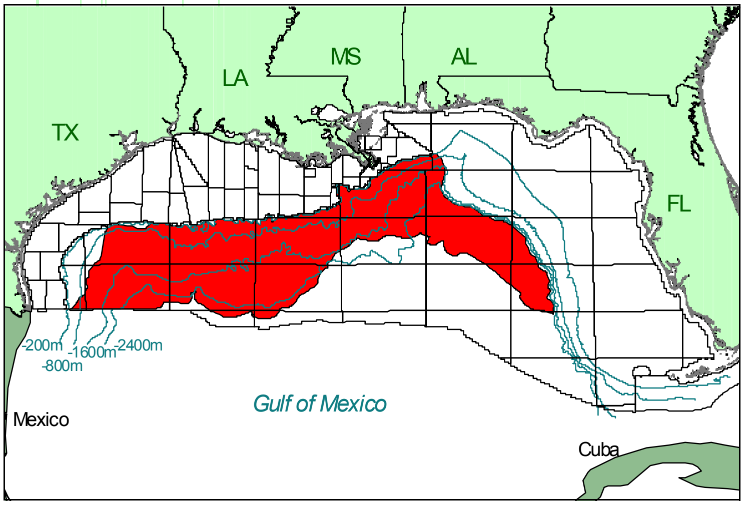


Figure 1. Play location.

LM4 F2 Play 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	--	2.408	7.688	3.842
Mean	85	3.114	9.952	4.885
5th percentile	--	4.113	14.393	6.489
Total Endowment				
95th percentile	--	2.408	7.688	3.842
Mean	85	3.114	9.952	4.885
5th percentile	--	4.113	14.393	6.489

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Upper Lower Miocene Fan 2 (LM4 F2) play is the third largest play in the Gulf of Mexico Region on the basis of BOE undiscovered conventionally recoverable resources (UCRR). The play occurs within the *Marginulina ascensionensis* and *Discorbis bolivarensis* biozones and is also defined by hypothesized deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The LM4 F2 play extends from the Port Isabel and Alaminos Canyon Areas offshore Texas to the western Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to the The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the play is bounded by the Upper Lower Miocene Fan 1 (LM4 F1) play. To the northeast, the play onlaps the Cretaceous carbonate slope, while to the southwest, the play extends into Mexican national waters. Downdip in the western and central Gulf Region, the LM4 F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Discoveries

The LM4 F2 play contains no discoveries as of January 1, 1999. On the basis of established middle

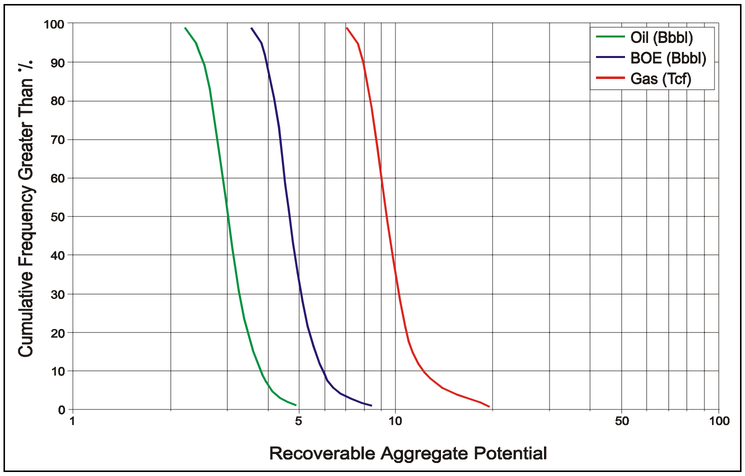


Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

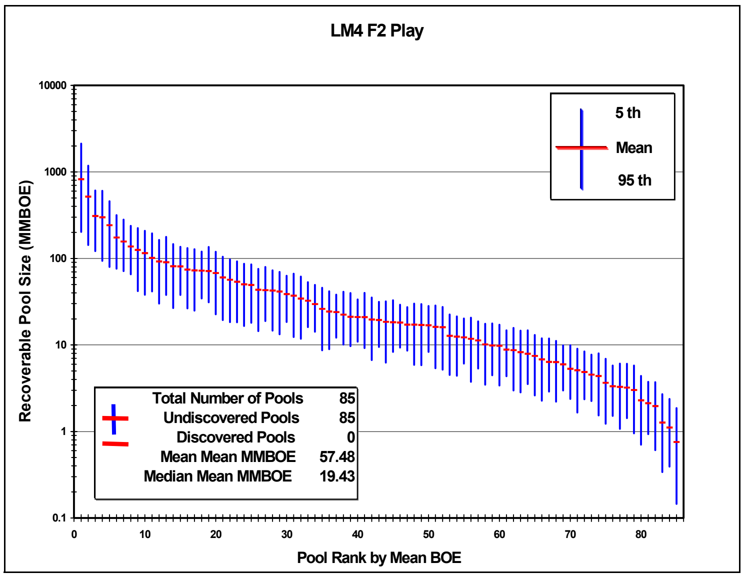


Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Miocene fan play production, the LM4 F2 play will likely produce a mix of oil and gas.

Assessment Results

The marginal probability of hydrocarbons for the LM4 F2 play is 1.00. The play contains a mean total endowment of 3.114 Bbo and 9.952 Tcfg (4.885 BBOE) (table 2). Because the LM4 F2 play is a conceptual play with no production to date, the play's mean total endowment equals undiscovered conventionally recoverable resources (UCRR). The play's total endowment and UCRR have a range of 2.408 to 4.113 Bbo and 7.688 to 14.393 Tcfg at the 95th and 5th percentiles, respectively (figure 2).

Assessment results indicate that UCRR might occur in as many as 85 pools (figure 3). The largest undiscovered pool has a mean size of 824 MMBOE. The five largest undiscovered pools together have a mean mean UCRR of 439 MMBOE, while the mean mean size for all undiscovered pools is forecast at 57 MMBOE.

The LM4 F2 play has a large total endowment and is expected to contain 11 pools with over 100 MMBOE in total reserves. The greatest exploration potential is thought to exist in structural and stratigraphic traps around, against, and below salt bodies and in Miocene-aged salt-withdrawal anticlines (turtle structures).

Middle Lower Miocene Progradational (LM2 P1) Play

Siphonina davisi biozone

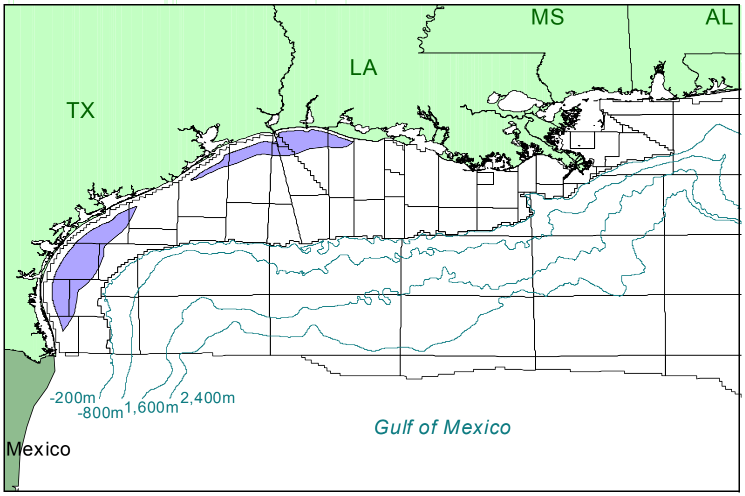


Figure 1. Play location.

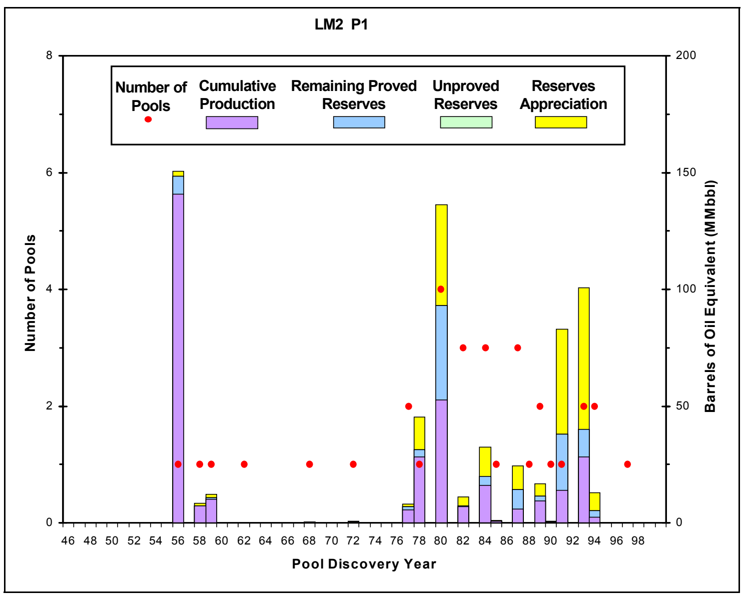


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM2 P1 Play 33 Pools 109 Sands	Minimum	Mean	Maximum
Water depth (feet)	24	76	180
Subsea depth (feet)	6285	9991	14678
Number of sands per pool	1	3	16
Porosity	16%	26%	33%
Water saturation	16%	31%	47%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Lower Miocene Progradational (LM2 P1) play occurs within the *Siphonina davisi* biozone. The play is located in two separate regions: a western region extending from the South Padre Island Area to the Brazos Area offshore Texas and an eastern region extending from the Galveston 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 deposits of the Middle Lower Miocene Fan 1 (LM2 F1) play.

The locations of the two regions of the LM2 P1 play are a result of sand deposition from two separate delta systems during LM2 time. Because both delta systems were located largely to the north of Federal waters, primarily only LM2 progradational and deep-sea fan facies extend into the Federal OCS.

Play Characteristics

Sediments in the LM2 P1 play represent major regressive episodes of outbuilding of both the shelf and slope. In a few places retrogradational, reworked sands with a thinning and backstepping log signature cap the play. Because these retrogradational sandstones are poorly developed and discontinuous, they are included as part of the LM2 P1 play. The thickest progradational sand sequences occur near the top of the LM2 chronozone in both offshore Texas and Louisiana. These thick, sand-dominated intervals represent multiple episodes of delta-lobe switching and progradation. Depositional environments represented in the LM2 P1 play include the more distal delta components such as distributary mouth bars, delta fringes,

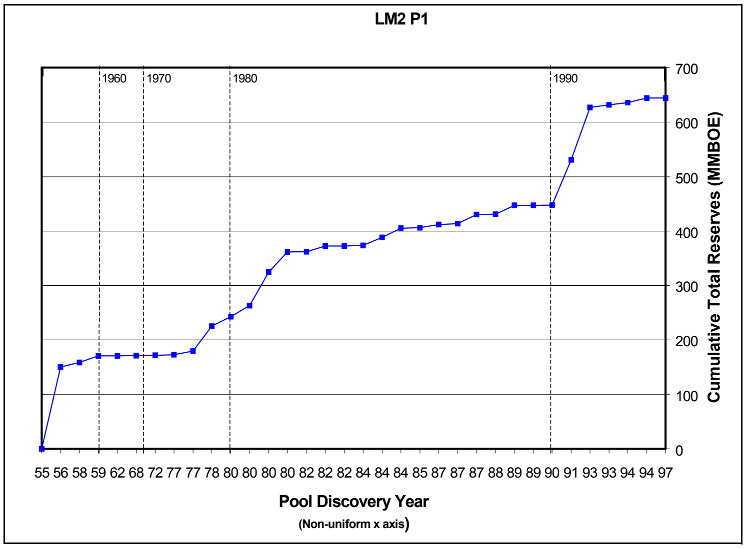


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM2 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	33	0.027	2.298	0.436
Cumulative production	--	0.021	1.734	0.330
Remaining proved	--	0.006	0.564	0.107
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.007	1.130	0.208
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.005	0.547	0.106
Mean	11	0.012	0.842	0.162
5th percentile	--	0.024	1.184	0.228
Total Endowment				
95th percentile	--	0.040	3.975	0.750
Mean	44	0.047	4.270	0.806
5th percentile	--	0.059	4.612	0.872

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

and offshore marine bars.

Most of the fields the in LM2 P1 play are structurally associated with normal faults. Less common structures include growth fault anticlines, shale diapir-like bodies with traps on the flanks of the shale or in sediment drape over the shale, 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).

Discoveries

The LM2 P1 gas play contains total reserves of 0.035 Bbo and 3.428 Tcfg (0.644 BBOE), of which 0.021 Bbo and 1.734 Tcfg (0.330 BBOE) have been produced. The play contains 109 producible sands in 33 pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first and largest pool in the play was discovered in the West Cameron 45 field in 1956 (figure 2). The West Cameron 45 field also added the maximum yearly total reserves of 150 MMBOE (figures 2 and 3). Discoveries were most common during the mid-1970's through the mid-1990's. Eighty-six percent of the play's cumulative production and 69 percent of the play's total reserves have come from pools discovered before 1990. Of note are the 96 MMBOE Mustang Island 805 pool discovered in 1993 and the 83 MMBOE West Cameron 76 pool discovered in 1991. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1997.

The 33 discovered pools contain 209 reservoirs, of which 196 are nonassociated gas, 6 are undersaturated oil, and 7 are saturated oil. Cumulative production has consisted of 94 percent gas and 6 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the LM2 P1 play is 1.00. The play contains a mean total

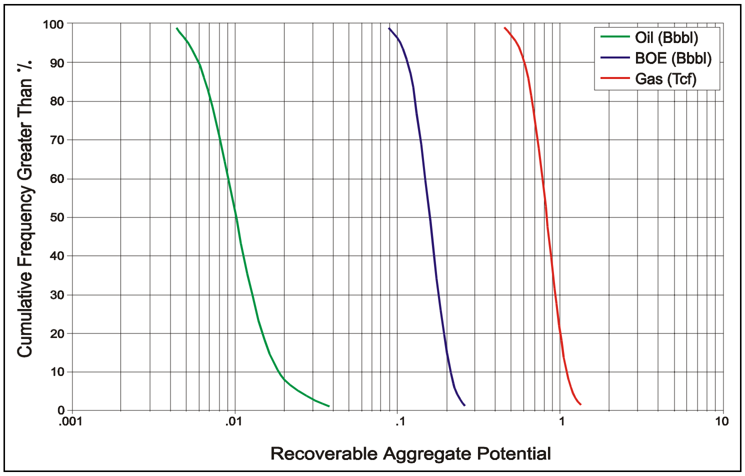


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

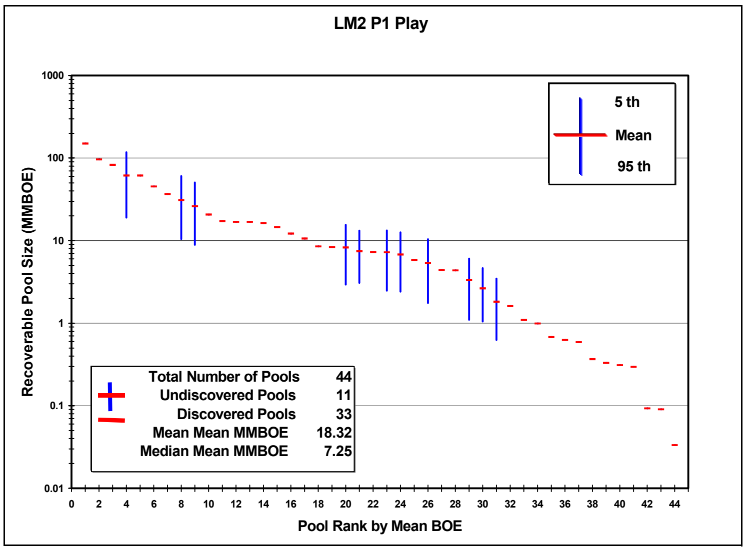


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

endowment of 0.047 Bbo and 4.270 Tcfg (0.806 BBOE) (table 2). Forty-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.005 to 0.024 Bbo and 0.547 to 1.184 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.012 Bbo and 0.842 Tcfg (0.162 BBOE). These undiscovered resources might occur in as many as 11 pools. The largest undiscovered pool, with a mean size of 62 MMBOE, is forecast as the 4th largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 8, 9, 20, and 21 on the pool rank plot. For all the undiscovered pools in the LM2 P1 play, the mean mean size is 15 MMBOE compared with the 20 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 18 MMBOE.

BOE mean UCRR contribute 20 percent to the play's BOE mean total endowment. With two approximately 100 MMBOE discoveries during the 1990's, the LM2 P1 play may yet contain significant discoveries. The greatest exploration potential is thought to exist in deeper drilling.

Middle Lower Miocene Fan 1 (LM2 F1) Play

***Siphonina davisi* biozone**

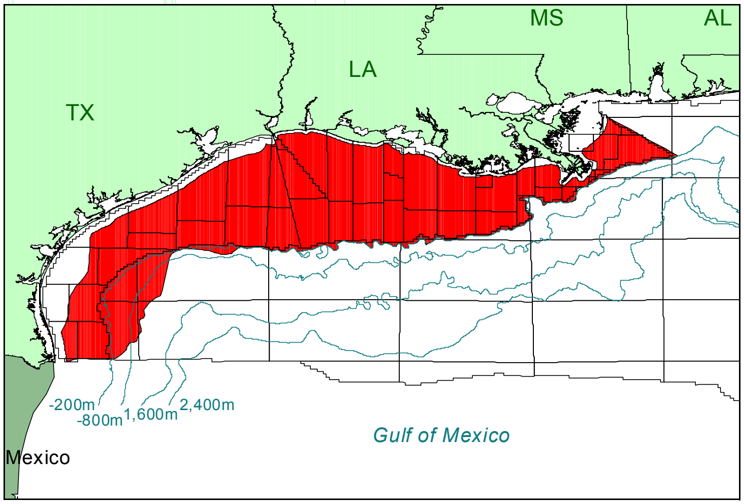


Figure 1. Play location.

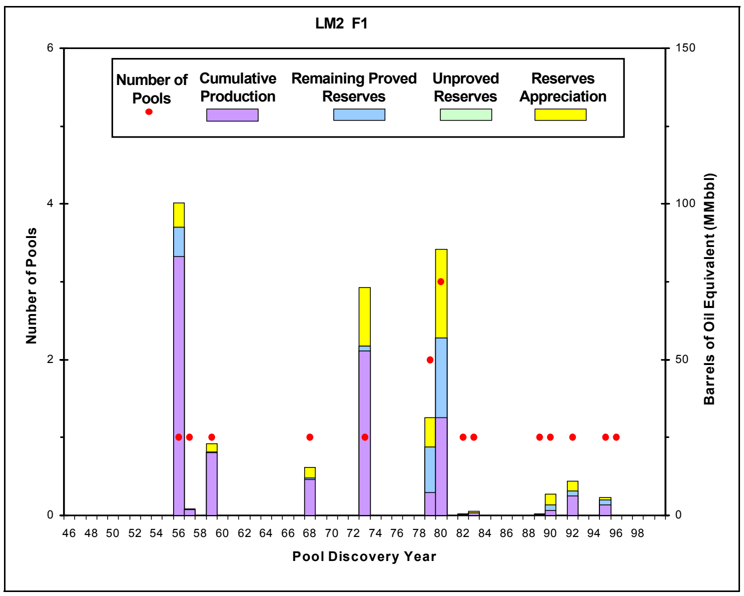


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM2 F1 Play **17 Pools 54 Sands**	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	29	55	103
Subsea depth (feet)	9536	12151	15079
Number of sands per pool	1	3	9
Porosity	19%	26%	31%
Water saturation	20%	29%	39%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Middle Lower Miocene Fan 1 (LM2 F1) play occurs within the *Siphonina davisi* biozone. The play is also defined by deep-sea fan sediments in an extensional structural regime of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The LM2 F1 play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Viosca Knoll and Main Pass 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. In these areas, 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 P1) play. To the southwest, the LM2 F1 play extends into Mexican national waters, while to the northeast, the play onlaps the Cretaceous carbonate slope. Downdip the play is limited by the Middle Lower Miocene Fan 2 (LM2 F2) play.

Play Characteristics

The LM2 F1 play is characterized by deepwater turbidites deposited basinward of the LM2 shelf margin on the LM2 upper and lower slopes, in topographically low areas between structural highs, and on the abyssal plain. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, fringes, and slumps. These deep-sea fan systems are often overlain by thick shale intervals representative of sand bypass on the shelf, or sand-poor areas on the slope.

Most of fields in the LM2 F1 play are structurally associated with normal faults. Other less common trapping structures include growth

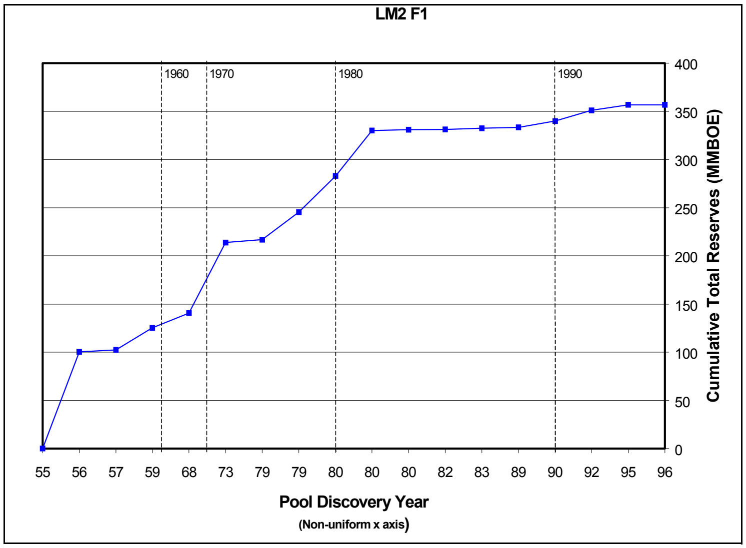


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM2 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	17	0.014	1.484	0.278
Cumulative production	--	0.012	1.177	0.221
Remaining proved	--	0.003	0.306	0.057
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.003	0.423	0.079
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.016	1.122	0.225
Mean	30	0.041	1.497	0.308
5th percentile	--	0.086	1.884	0.400
Total Endowment				
95th percentile	--	0.034	3.028	0.582
Mean	47	0.059	3.403	0.665
5th percentile	--	0.104	3.790	0.757

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

faults with rollover anticlines and shale diapir-like bodies with traps on the flanks of the shale or in sediment drape over the shale. 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

The LM2 F1 gas play contains total reserves of 0.018 Bbo and 1.906 Tcfg (0.357 BBOE), of which 0.012 Bbo and 1.177 Tcfg (0.221 BBOE) have been produced. The play contains 54 producible sands in 17 pools, all of which contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves, the largest pool in the play, and maximum yearly total reserves were discovered in 1956 in the West Cameron 71 field (100 MMBOE) (figures 2 and 3). Ninety-five percent of the play's cumulative production and 93 percent of the play's total reserves have come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1996.

The 17 discovered pools contain 123 reservoirs, of which 122 are nonassociated gas and 1 is saturated oil. Cumulative production has consisted of 95 percent gas and 5 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the LM2 F1 play is 1.00. The play contains a mean total endowment of 0.059 Bbo and 3.403 Tcfg (0.665 BBOE) (table 2). Thirty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.016 to 0.086 Bbo and 1.122 to 1.884 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at

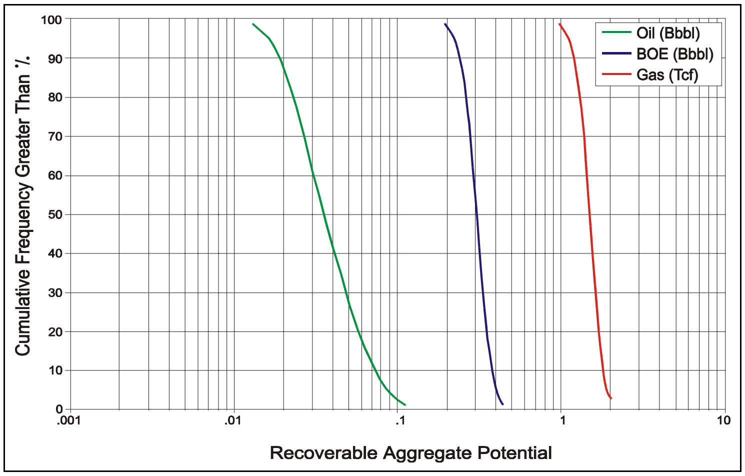


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

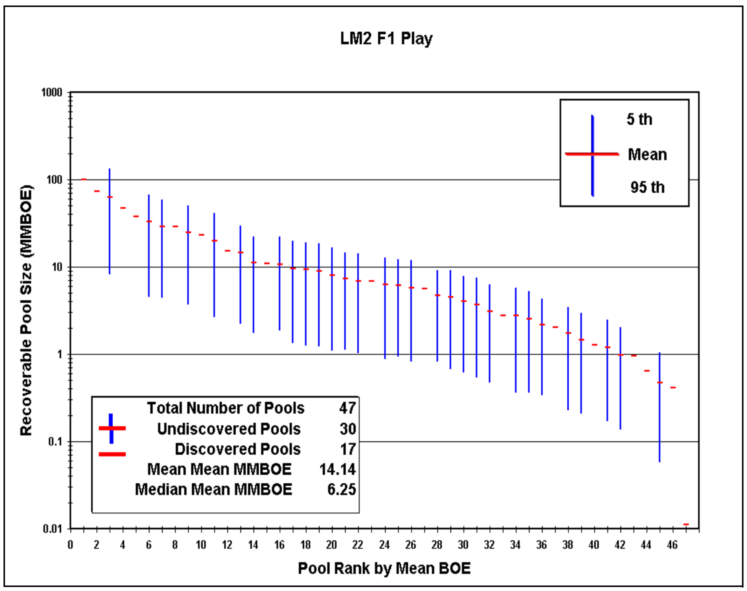


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

0.041 Bbo and 1.497 Tcfg (0.308 BBOE). These undiscovered resources might occur in as many as 30 pools. The largest undiscovered pool, with a mean size of 63 MMBOE, is forecast as the third largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 6, 7, 9, and 11 on the pool rank plot. For all the undiscovered pools in the LM2 F1 play, the mean mean size is 10 MMBOE compared with the 21 MMBOE mean size of discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 14 MMBOE.

BOE mean UCRR contribute 46 percent to the play's BOE mean total endowment. Future discoveries are expected to be made in structural and stratigraphic traps around salt and shale bodies, as well as in salt-withdrawal anticlines (turtle structures).

Middle Lower Miocene Fan 2 (LM2 F2) Play

Siphonina davisi biozone

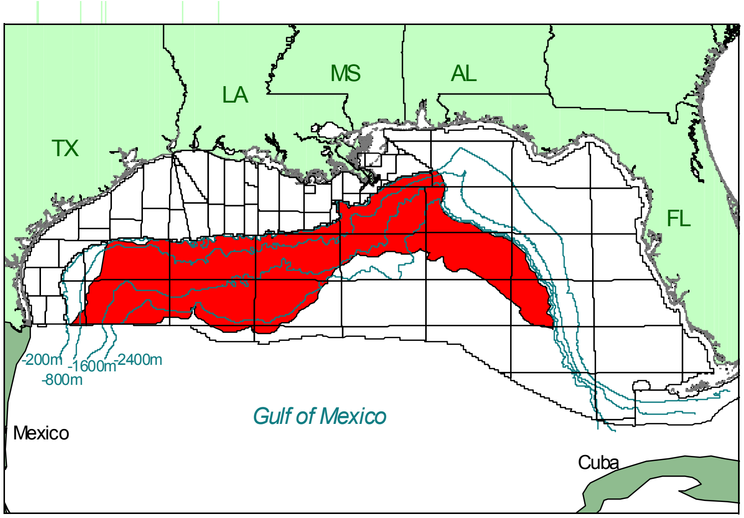


Figure 1. Play location.

LM2 F2 Play 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	--	2.312	7.903	3.769
Mean	85	3.109	9.979	4.885
5th percentile	--	4.513	13.343	6.784
Total Endowment				
95th percentile	--	2.312	7.903	3.769
Mean	85	3.109	9.979	4.885
5th percentile	--	4.513	13.343	6.784

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Middle Lower Miocene Fan 2 (LM2 F2) play is the third largest play in the Gulf of Mexico Region on the basis of undiscovered conventionally recoverable resources (UCRR). The play occurs within the *Siphonina davisi* biozone and is also defined by hypothesized deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico Region slope. The LM2 F2 play extends from the Port Isabel and Alaminos Canyon Areas offshore Texas to the Destin Dome and De-soto Canyon Areas east of the present-day Mississippi River Delta, and southeast to the The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the play is bounded by the Middle Lower Miocene Fan 1 (LM2 F1) play. To the southwest, the play extends into Mexican waters, while to the northeast, the play onlaps the Cretaceous carbonate slope. Downdip in the western and central Gulf of Mexico Region, the LM4 F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Discoveries

The LM2 F2 play contains no discoveries as of January 1, 1999. On the basis of established middle Miocene fan play production, the LM2 F2 play will likely produce a mix of oil

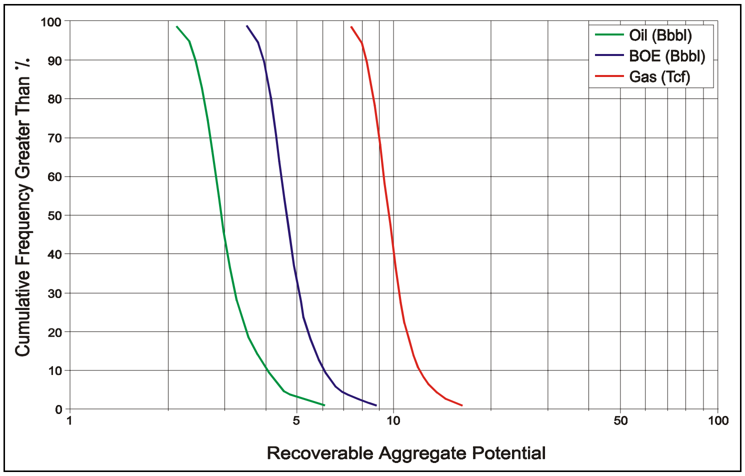


Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

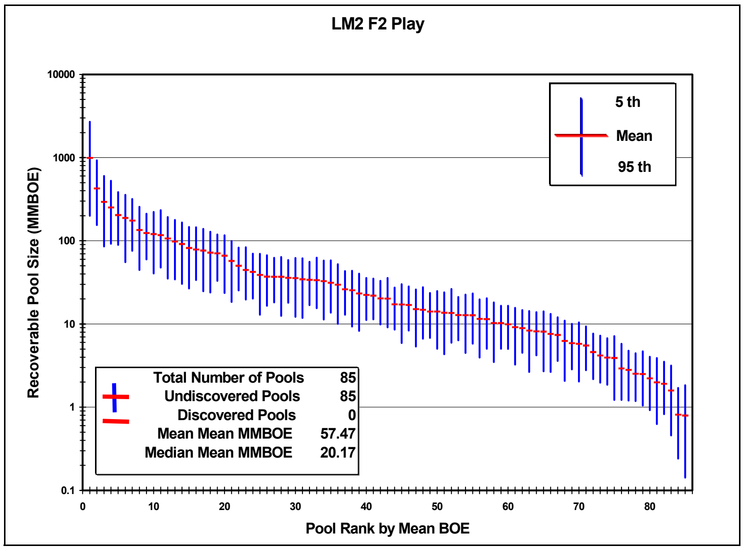


Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

and gas.

Assessment Results

The marginal probability of hydrocarbons for the LM2 F2 play is 1.00. The play contains a mean total endowment of 3.109 Bbo and 9.979 Tcfg (4.885 BBOE) (table 1). Because the LM2 F2 play is a conceptual play with no production to date, the play's mean total endowment equals UCRR. The play's total endowment and UCRR have a range of 2.312 to 4.513 Bbo and 7.903 to 13.343 Tcfg at the 95th and 5th percentiles, respectively (figure 2).

Assessment results indicate that UCRR might occur in as many as 85 pools (figure 3). The largest undiscovered pool has a mean size of 990 MMBOE. The five largest undiscovered pools together have a mean mean UCRR of 433 MMBOE, while the mean mean size of all undiscovered pools is forecast at 57 MMBOE.

The LM2 F2 play has a large total endowment and is expected to contain 12 pools with over 100 MMBOE in total reserves, including 5 with over 200 MMBOE (figure 2). The greatest exploration potential is thought to exist in structural and stratigraphic traps around, against, and below salt bodies and in Miocene-aged salt-withdrawal anticlines (turtle structures).

Lower Lower Miocene Progradational (LM1 P1) Play

Lenticulina hanseni biozone

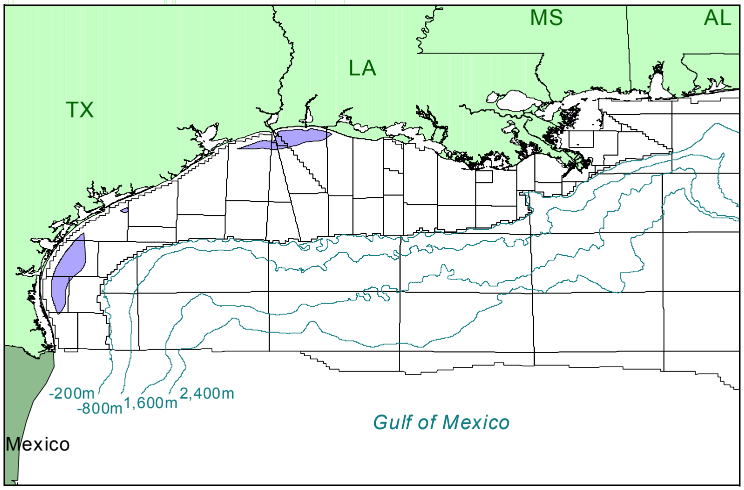


Figure 1. Play location.

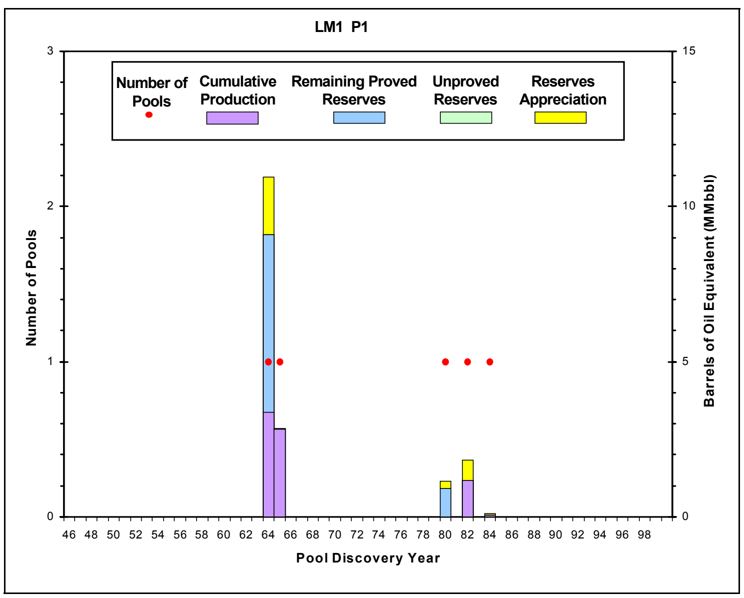


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM1 P1 Play 5 Pools 15 Sands	Minimum	Mean	Maximum
Water depth (feet)	17	30	37
Subsea depth (feet)	11024	11530	11915
Number of sands per pool	1	3	9
Porosity	21%	26%	31%
Water saturation	21%	30%	35%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Lower Miocene Progradational (LM1 P1) play occurs within the *Lenticulina hanseni* biozone. The play is located in two separate regions: a western region extending from the North Padre to Brazos Area offshore Texas and an eastern region extending from the High Island Area offshore Texas to the East Cameron Area offshore Louisiana (figure 1).

Updip and along strike in the western region, 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 1 (LM1 F1) play. Similarly, updip and along strike in the eastern region the play continues onshore into Texas and Louisiana. Downdip, the play grades into the deposits of the LM1 F1 play.

The locations of the two regions of the LM1 P1 play are a result of sand deposition in two separate delta systems during LM1 time, the North Padre Delta System in Texas and the Calcasieu Delta System in Louisiana. Because both delta systems were located largely to the north of Federal waters, primarily only LM1 progradational and deep-sea fan facies extend into the Federal OCS.

Play Characteristics

Sediments in the LM1 P1 play represent major regressive episodes of outbuilding on both the shelf and upper slope. Because only the distal parts of the delta systems extended into Federal waters, productive LM1 P1 sands were deposited primarily in delta-fringe environments. Rare reworked retrogradational sands with a thinning and backstepping log signature locally cap the play and are included as part of LM1 P1 play. The sand-rich

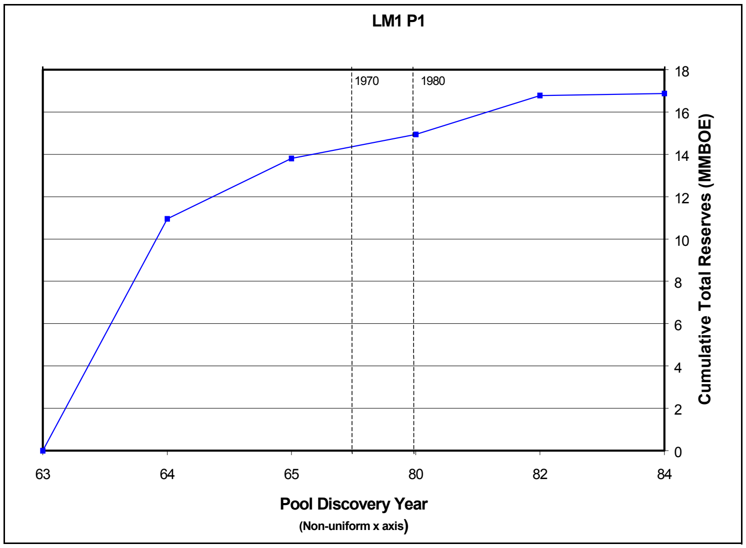


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM1 P1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	5	0.001	0.074	0.014
Cumulative production	--	0.001	0.039	0.007
Remaining proved	--	<0.001	0.036	0.007
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.015	0.003
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.035	0.007
Mean	5	0.001	0.044	0.009
5th percentile	--	0.002	0.053	0.011
Total Endowment				
95th percentile	--	0.001	0.124	0.024
Mean	10	0.002	0.133	0.026
5th percentile	--	0.003	0.142	0.028

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

sequences in the LM1 P1 play are often overlain and underlain by thick marine shales that are a few hundred to a few thousand feet thick.

Fields in the LM1 P1 play are structurally associated with normal faults, growth faults with rollover anticlines, 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).

Discoveries

The LM1 P1 gas play contains total reserves of 0.001 Bbo and 0.089 Tcfg (0.017 BBOE), of which 0.001 Bbo and 0.039 Tcfg (0.007 BBOE) have been produced. The play contains 15 producible sands in five pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first reserves, the largest pool, and maximum yearly total reserves in the play were discovered in 1964 in the West Cameron 17 field (11 MMBOE) (figures 2 and 3). The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1984.

The five discovered pools contain 19 reservoirs, all of which are nonassociated gas.

Assessment Results

The marginal probability of hydrocarbons for the LM1 P1 play is 1.00. The play has a mean total endowment of 0.002 Bbo and 0.133 Tcfg (0.026 BBOE) (table 2). Twenty-seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of <0.001 to 0.002 Bbo and 0.035 to 0.0.53 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.001 Bbo and 0.044 Tcfg (0.009 BBOE). These undiscovered resources might occur in as many as five pools. The largest undiscovered pool, with a mean size of 2 MMBOE,

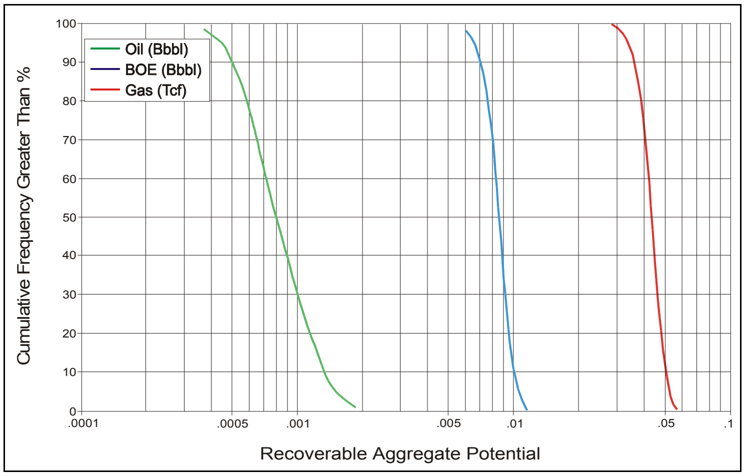


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

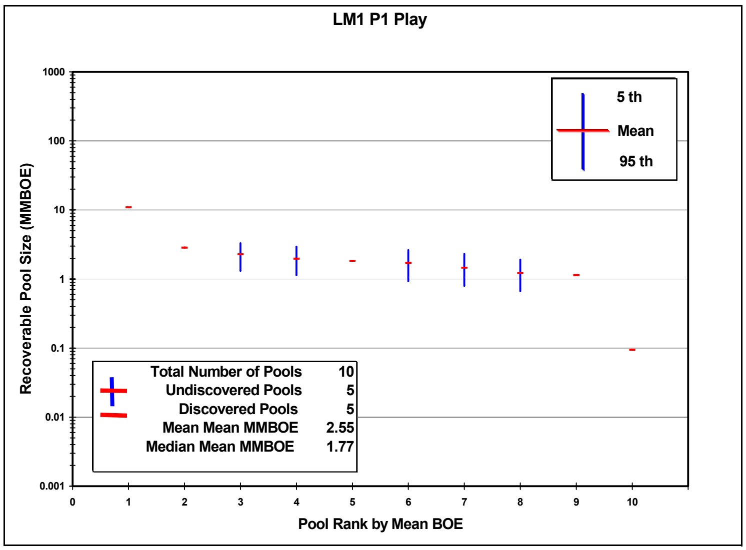


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

is forecast as the 3rd largest pool in the play (figure 5). The forecast places the remaining undiscovered pools in positions 4, 6, 7, and 8 on the pool rank plot. The mean mean size of undiscovered pools is 2 MMBOE compared with the 3 MMBOE mean size of discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 3 MMBOE.

BOE mean UCRR contribute 35 percent to the play's BOE mean total endowment; however, only a mean of 9 MMBOE is forecast to be discovered from a few relatively deep reservoirs (table 2).

Lower Lower Miocene Fan 1 (LM1 F1) Play

***Lenticulina hanseni* biozone**

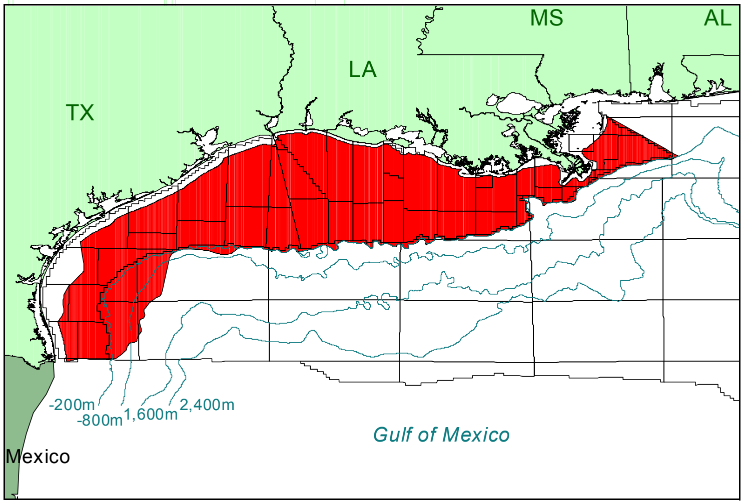


Figure 1. Play location.

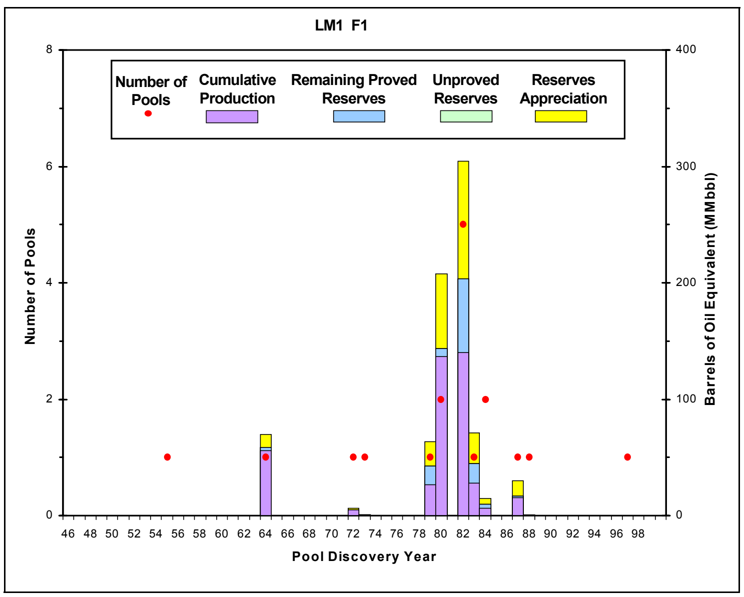


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LM1 F1 Play 18 Pools 52 Sands	Minimum	Mean	Maximum
Water depth (feet)	17	54	121
Subsea depth (feet)	11272	13990	18250
Number of sands per pool	1	3	8
Porosity	16%	23%	31%
Water saturation	16%	33%	50%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Lower Miocene Fan 1 (LM1 F1) play occurs within the *Lenticulina hanseni* biozone. The play is also defined by deep-sea fan sediments in an extensional structural regime of of salt-withdrawal basins and extensive listric faulting located on the modern Gulf of Mexico Region shelf. The LM1 F1 play extends from the South Padre Island and Port Isabel Areas offshore Texas to the Viosca Knoll and Main Pass Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Texas and Louisiana. To the southwest, the LM1 F1 play extends into Mexican national waters, while to the northeast, the play onlaps the Cretaceous carbonate slope. Downdip, the play is limited by the Lower Lower Miocene Fan 2 (LM1 F2) play.

Play Characteristics

The LM1 F1 play is characterized by deepwater turbidites deposited basinward of the LM1 shelf margin on the LM1 upper and lower slope, in topographically low areas between salt structure highs, and on the abyssal plain. Component depositional facies include channel/levee complexes, sheet-sand lobes, interlobes, lobe fringes, and slumps. These deep-sea fan systems are often overlain by thick shale intervals representative of sand bypass on the shelf, or sand-poor areas on the slope.

Most of fields in the LM1 F1 play are structurally associated with normal faults. Other less common trapping structures include growth faults with rollover anticlines, rotational slump blocks and shale diapir-like bodies with traps on the flanks of the shale or in sediment drape over the shale. Seals are provided by the

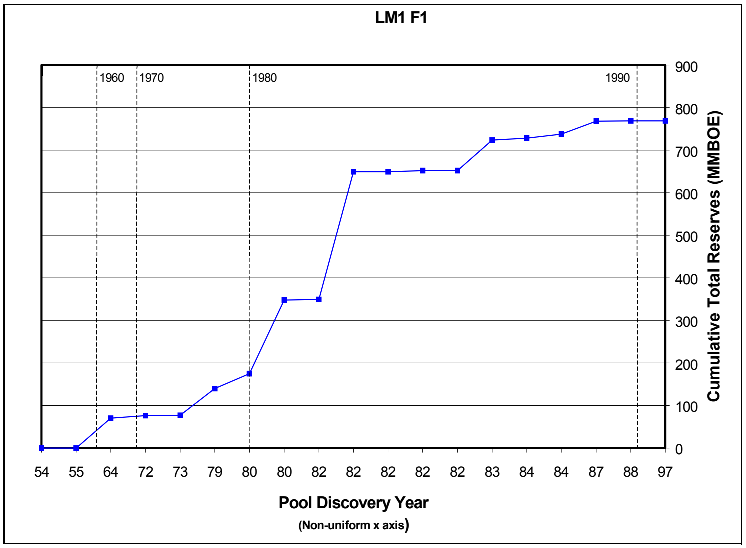


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LM1 F1 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	18	0.021	2.831	0.525
Cumulative production	--	0.016	2.241	0.414
Remaining proved	--	0.005	0.590	0.110
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.010	1.319	0.244
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.017	1.813	0.343
Mean	37	0.029	2.550	0.483
5th percentile	--	0.046	3.415	0.646
Total Endowment				
95th percentile	--	0.048	5.963	1.112
Mean	55	0.060	6.700	1.252
5th percentile	--	0.077	7.564	1.415

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

The LM1 F1 gas play contains total reserves of 0.031 Bbo and 4.150 Tcfg (0.769 BBOE), of which 0.016 Bbo and 2.241 Tcfg (0.414 BBOE) have been produced. The play contains 52 producible sands in 18 pools, all of which contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). 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 18 pools were found. Maximum yearly total reserves of 304 MMBOE were added in 1982 with the discovery of five pools, including the largest pool in the play in the Matagorda Island 623 field (300 MMBOE). Almost all of the play's cumulative production and total reserves have come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1997.

The 18 discovered pools contain 85 reservoirs, of which 82 are nonassociated gas and 3 are undersaturated oil. Cumulative production has consisted of 96 percent gas and 4 percent oil.

Assessment Results

The marginal probability of hydrocarbons for the LM1 F1 play is 1.00. The play contains a mean total endowment of 0.060 Bbo and 6.700 Tcfg (1.252 BBOE) (table 2). Thirty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.017 to 0.046 Bbo and 1.813 to 3.415 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at

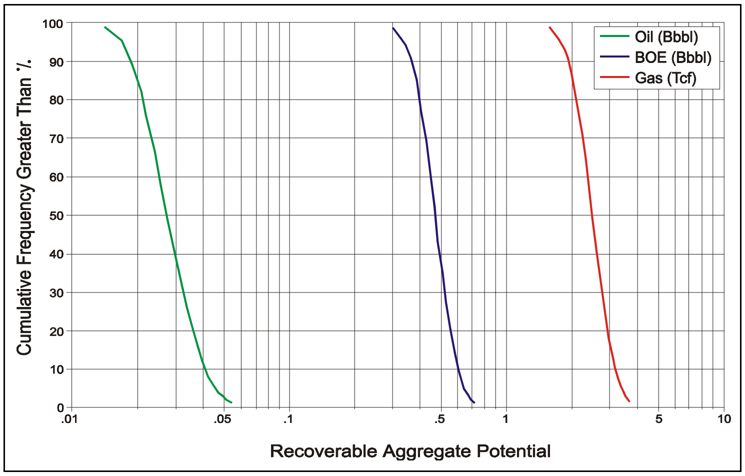


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

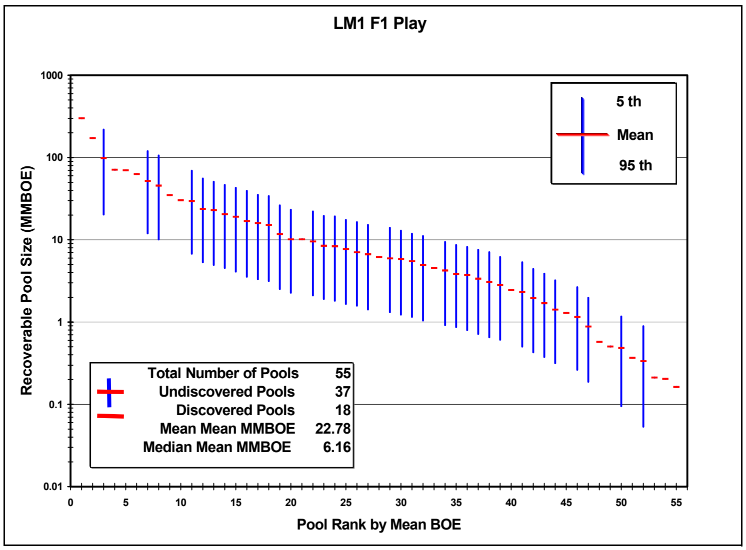


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

0.029 Bbo and 2.550 Tcfg (0.483 BBOE). These undiscovered resources might occur in as many as 37 pools. The largest undiscovered pool, with a mean size of 99 MMBOE, is forecast to be the third largest pool in the play (figure 5). The forecast places the next four largest undiscovered pools in positions 7, 8, 11, and 12 on the pool rank plot. For all the undiscovered pools in the LM1 F1 play, the mean mean size is 13 MMBOE compared with the 43 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 23 MMBOE.

BOE mean UCRR contribute 39 percent to the play's BOE mean total endowment. The greatest exploration potential lies deeper in, and downdip of, discovered fields where the LM1 section is deeply buried (table 2).

Lower Lower Miocene Fan 2 (LM1 F2) Play

Lenticulina hanseni biozone

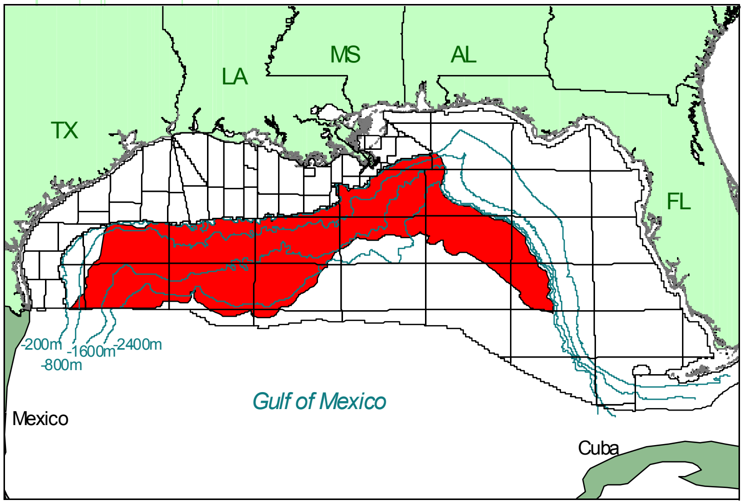


Figure 1. Play location.

LM1 F2 Play 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	--	0.835	2.644	1.346
Mean	70	1.001	3.666	1.653
5th percentile	--	1.217	5.598	2.137
Total Endowment				
95th percentile	--	0.835	2.644	1.346
Mean	70	1.001	3.666	1.653
5th percentile	--	1.217	5.598	2.137

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Lower Lower Miocene Fan 2 (LM1 F2) play occurs within the *Lenticulina hanseni* biozone and is also defined by hypothesized deep-sea fan sediments in a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern Gulf of Mexico slope. The LM1 F2 play extends from the Port Isabel and Alaminos Canyon Areas offshore Texas to the western Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta, and southeast to the The Elbow and Vernon Areas offshore Florida (figure 1).

Updip, the play is bounded by the Lower Lower Miocene Fan 1 (LM1 F1) play. To the northeast, the play onlaps the Cretaceous carbonate slope, while to the southwest, the play extends into Mexican national waters. Downdip in the western and central Gulf of Mexico Region, the LM1 F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Discoveries

The LM1 F2 conceptual play contains no discoveries to date. On the basis of other fan 2 plays, the LM1 F2 is expected to produce both gas and oil.

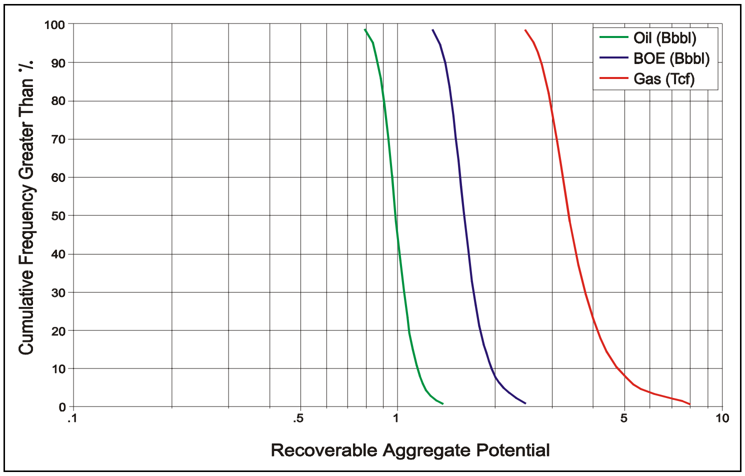


Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

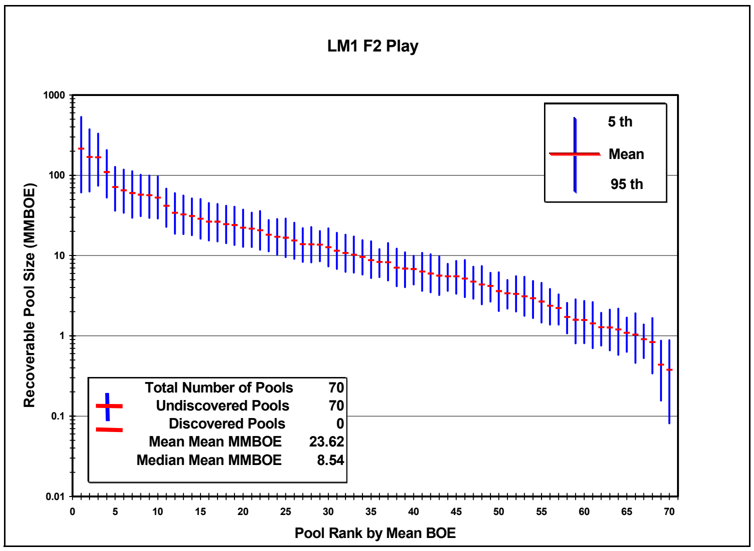


Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Assessment Results

The marginal probability of hydrocarbons for the LM1 F2 play is 1.00. The play contains a mean total endowment of 1.001 Bbo and 3.666 Tcfg (1.653 BBOE) (table 2). Because the LM1 F2 play is a conceptual play with no production to date, the play's mean total endowment equals undiscovered conventionally recoverable resources (UCRR). The play's total endowment and UCRR have a range of 0.835 to 1.217 Bbo and 2.644 to 5.598 Tcfg at the 95th and 5th percentiles, respectively (figure 2).

Assessment results indicate that UCRR might occur in as many as 70 pools (figure 3). The largest undiscovered pool has a mean size of 214 MMBOE. The five largest undiscovered pools together have a mean mean UCRR of 146 MMBOE, while the mean mean size of all undiscovered pools is forecast at 24 MMBOE.

The LM1 F2 play has a large total endowment with four pools of over 100 MMBOE in total reserves expected to be discovered. The greatest exploration potential is thought to exist in structural and stratigraphic traps around, against, and below salt bodies and in Miocene-aged salt-withdrawal anticlines (turtle structures).

Upper to Middle Oligocene Fan (UO-MO F1 F2) Play

***Heterostegina texana* and *Discorbis* zone/*Robulus* "A" biozones**

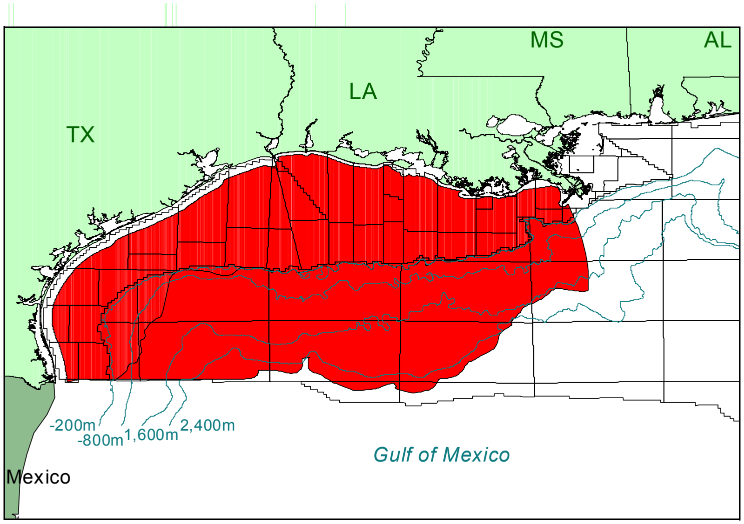


Figure 1. Play location.

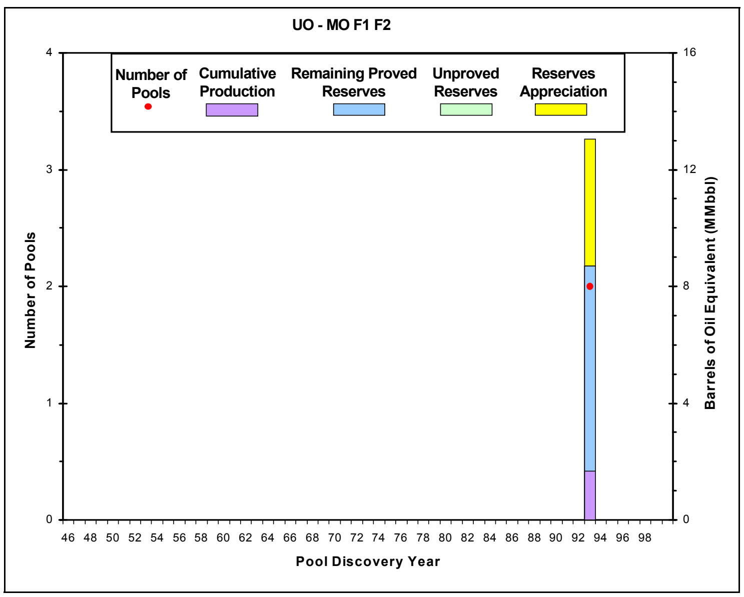


Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UO-MO F1 F2 Play 2 Pools 6 Sands	Minimum	Mean	Maximum
Water depth (feet)	85	85	85
Subsea depth (feet)	9205	11440	13674
Number of sands per pool	1	3	5
Porosity	21%	25%	29%
Water saturation	30%	39%	48%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper to Middle Oligocene Fan (UO-MO F1 F2) play occurs within the *Heterostegina texana* and *Discorbis* zone/*Robulus* "A" biozones. The play is also defined by deep-sea fan sediments underlying the modern Gulf of Mexico Region shelf and slope. This play covers most of offshore Texas eastward to the mouth of the modern Mississippi River (figure 1). Only one field, Mustang Island 859, has been discovered in the play.

Updip, the play extends onshore. To the northeast, the play undergoes a facies change to nonporous carbonates, while to the southwest, the play extends into Mexican national waters. Downdip in the western and central Gulf of Mexico Region, the UO-MO F1 F2 play is limited by the farther downdip occurrence of either (1) the Sigsbee Salt Canopy Escarpment, where the farthest extent of large salt bodies overrides the abyssal plain, or (2) the downdip limit of the Perdido Fold Belt and Mississippi Fan Fold Belt plays. Downdip in the eastern Gulf of Mexico Region, the play is limited by the southern extent of Louann Salt deposition, as defined by the downdip extent of the Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play.

Play Characteristics

The UO-MO F1 F2 play in the Mustang Island 859 field is characterized by deepwater turbidites deposited basinward of the shelf margin on the upper slope in topographically low areas between structural highs. Component depositional facies include channel/levee complexes and sheet-sand lobes.

Hydrocarbons in the Mustang Island 859 field are trapped by normal faults. Seals are provided by

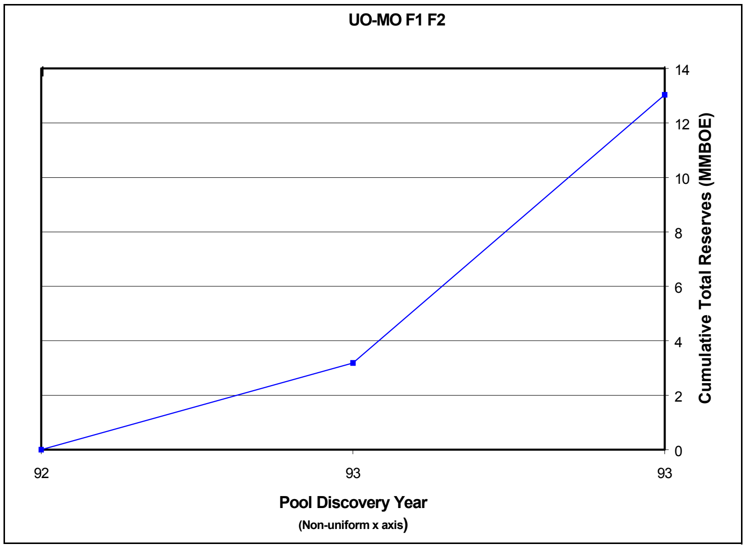


Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UO-MO F1 F2 Play Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2	0.001	0.044	0.009
Cumulative production		<0.001	0.008	0.002
Remaining proved	--	0.001	0.035	0.007
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.022	0.004
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.011	0.617	0.125
Mean	29	0.024	0.785	0.164
5th percentile	--	0.042	0.973	0.209
Total Endowment				
95th percentile	--	0.012	0.683	0.138
Mean	31	0.025	0.851	0.177
5th percentile	--	0.043	1.039	0.222

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

the juxtaposition of reservoir sands with shales through faulting, and by overlying shales.

Discoveries

The UO-MO F1 F2 gas play contains total reserves of 0.001 Bbo and 0.066 Tcfg (0.013 BBOE), of which <0.001 Bbo and 0.008 Tcfg (0.002 BBOE) have been produced. The first and only reserves in the play were discovered in 1993 in the Mustang Island 859 field (figures 2 and 3). Oligocene reserves in the field occur in six producible sands and seven nonassociated gas reservoirs (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). One of the producible sands and corresponding reservoirs is in the upper Oligocene section, while the remaining five sands and six reservoirs are in the middle Oligocene section. To aid in the generation of the pool rank plot, the upper Oligocene reservoir and the middle Oligocene reservoirs were treated as separate pools (figures 4 and 5). The middle Oligocene pool is larger with 10 MMBOE in total reserves; the upper Oligocene pool is smaller with 3 MMBOE in total reserves.

Cumulative production from the middle Oligocene pool has consisted of 90 percent gas and 10 percent oil, while the upper Oligocene pool has not yet produced.

Assessment Results

Because of limited data for the UO-MO F1 F2 play, the Lower Lower Miocene Fan 1 (LM1 F) play was used as an analog to forecast pool sizes in the UO-MO F1 F2 play. The LM1 F play was selected because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the UO-MO F1 F2 play is 1.00. The play contains a mean total endowment of 0.025 Bbo and 0.851 Tcfg (0.177 BBOE) (table 2). About 1 percent of this BOE mean

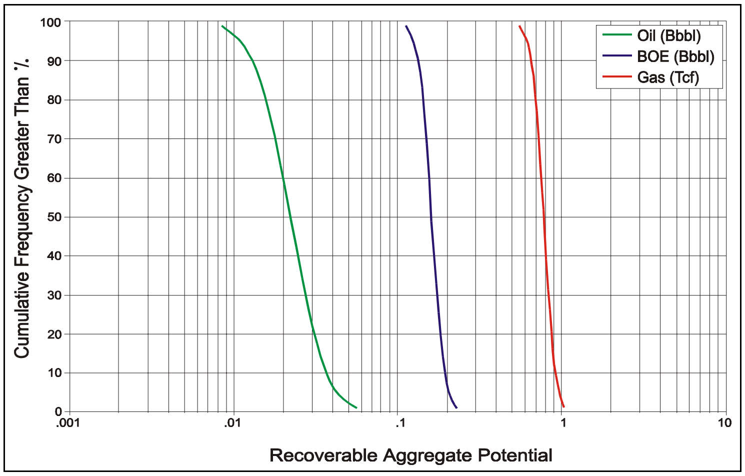


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

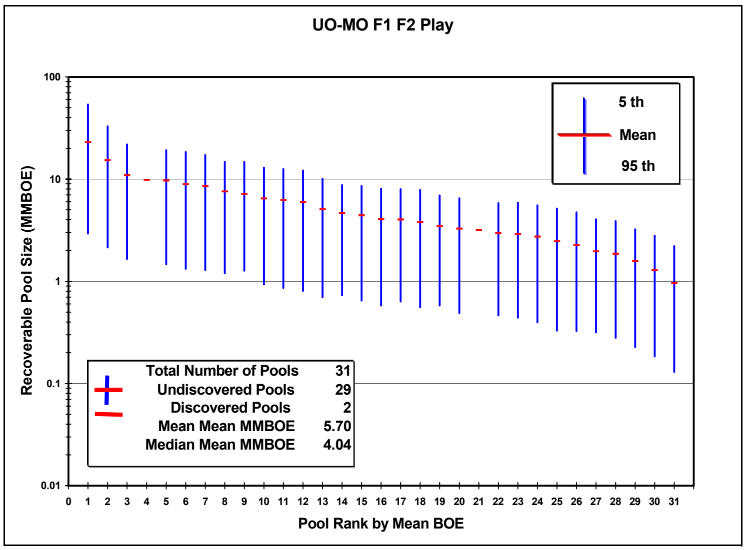


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.011 to 0.0.042 Bbo and 0.617 to 0.973 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.024 Bbo and 0.785 Tcfg (0.164 BBOE). These undiscovered resources might occur in as many as 29 pools. The larger discovered pool in the play is ranked fourth on the pool rank plot, while the smaller discovered pool is ranked 21st (figure 5). For all the undiscovered pools in the UO-MO F1 F2 play, the mean mean size is 6 MMBOE, which is comparable to the 7 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 6 MMBOE.

The UO-MO F1 F2 is an immature play with BOE mean UCRR contributing 93 percent to the play's BOE mean total endowment. An analysis of seismic and paleontological data indicates that fan sands may occur as deep as the base of the middle Oligocene section throughout State and Federal waters in the south Texas area. However, in the few wells that have penetrated Oligocene strata east of the modern Mississippi River Delta, the upper Oligocene section consists of mostly of nonporous carbonates. The UO-MO F1 F2 play is under-explored because of its great depth (table 1).

Lower Tertiary Buried Hill Drape (LE-LL BC1) Play

Globorotalia uncinata through *Globorotalia wilcoxensis*

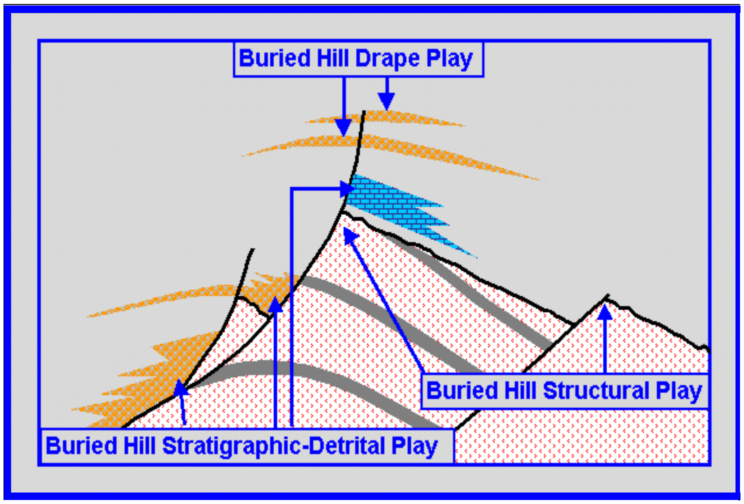


Figure 1. Diagrammatic cross-section illustrating the Buried Hills plays, after Zhai and Zha (1982).

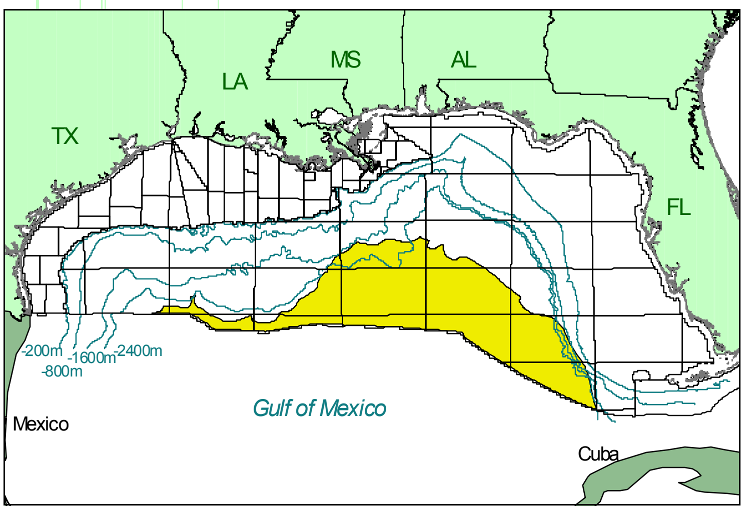


Figure 2. Play location.

Buried Hill Conceptual Plays	
Buried Hill Drape Plays	Lower Tertiary Buried Hill Drape (LE-LL BC1) Play
	Cretaceous Buried Hill Drape (UK5-LK3 BC2) Play
	Upper Jurassic Buried Hill Drape (UJ4-BC1) Play
Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital (UK5-UJ4 BC3) Play	
Mesozoic Structural Buried Hill (UK5-LTR BC4) Play	

Figure 3. General stratigraphic relationships of the conceptual Buried Hill plays.

Play Description

The conceptual Lower Tertiary Buried Hill Drape (LE-LL BC1) play is defined by source, reservoir, and seal lithologies consisting of seismically correlated sediments of probable Lower Tertiary age, and by compaction of sediments over buried hill features found in the ultra-deep-water Gulf of Mexico Region (figure 1). The play is recognized primarily in the Walker Ridge and Lund Areas. However, there are indications that the play exists from Alaminos Canyon to the Dry Tortugas Area. Seismic data across much of this area are sparse, and the play is extended through Henderson, Lloyd, Vernon, NG 16-8, NG16-12 and Howell Hook by analogy (figure 2). The play is bounded to the northwest and northeast by the depositional limit of the Louann Salt, while the OCS boundary defines the southern and western limits of the play.

The following discussion is from Post (2000), unless otherwise noted.

Play Characteristics

Buried hills are a series of paleostructural highs that originated during the Mesozoic-rifting event that formed the Gulf of Mexico (refer to the Mesozoic Structural Buried Hill (UK5-LTR BC4) play). Regional seismic analyses indicate that throughout the Late Jurassic, Cretaceous, and Tertiary, the buried hills were onlapped and then buried by sediments (refer to the Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital [UK5-UJ4 BC3] play, the upper Jurassic Buried Hill Drape [UJ4 BC1] play, and Cretaceous Buried Hill Drape [UK5-LK3 BC2] play; figure 3). As the hills were buried, structural closure developed by differential compaction of these sediments over the more rigid, less compacting, buried hills. The amount

LE-LL BC1 Lwr Tertiary Buried Hill Drape Marginal Probability = 0.05	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	6	0.006	0.008	0.007
5th percentile	--	0.000	0.000	0.000
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	6	0.006	0.008	0.007
5th percentile	--	0.000	0.000	0.000

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

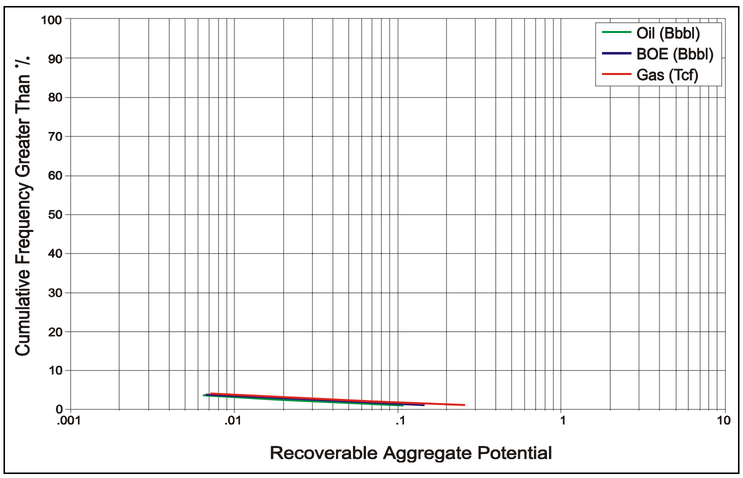


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

of closure decreases upsection until only very subtle closures exist in the lower Tertiary section.

Reflecting increased water depth and siliciclastic input, earlier upper Cretaceous deepwater mudstones, marls, chalks and fine-grained siliciclastics were succeeded by influxes of coarser-grained siliciclastic turbidites. Typical reservoir facies in turbidites include channel complexes and sheet sands.

Geochemical typing of hydrocarbon seeps in the northwestern half of the Lund Area (Wenger *et al.*, 1994; Hood *et al.*, *in press*) shows that these hydrocarbons come from Late Jurassic source rocks (centered on the Oxfordian). Geohistory modeling indicates that several other source intervals could also provide hydrocarbons for the LE-LL BC1 play. These are most likely to include source beds from the Late Jurassic (centered on the Tithonian), the Pre-Mid-Cretaceous Sequence Boundary (MCSB) Early Cretaceous (centered on the Aptian), or the Post-MCSB Late Cretaceous (centered on the Turonian). Additionally, if present, syn-rift, graben-fill source rocks, equivalent to the “Rosewood axial shift sequence” (White *et al.*, 1999), could furnish hydrocarbons for the play. Development of cross-stratal migration pathways to facilitate reservoir charge is an important issue to consider in charging these reservoirs. Wenger *et al.* (1994) and Hood *et al.* (*in press*) do not show any seeps in the southeastern half of the Lund Area.

Seals for traps and reservoirs are likely to be fine-grained deepwater deposits.

Discoveries

No wells have been drilled in the LE-LL BC1 play prior to this study’s January 1, 1999 cutoff date.

Assessment Results

The marginal probability of hydrocarbons for the LE-LL BC1 play is 0.05. The play contains a mean

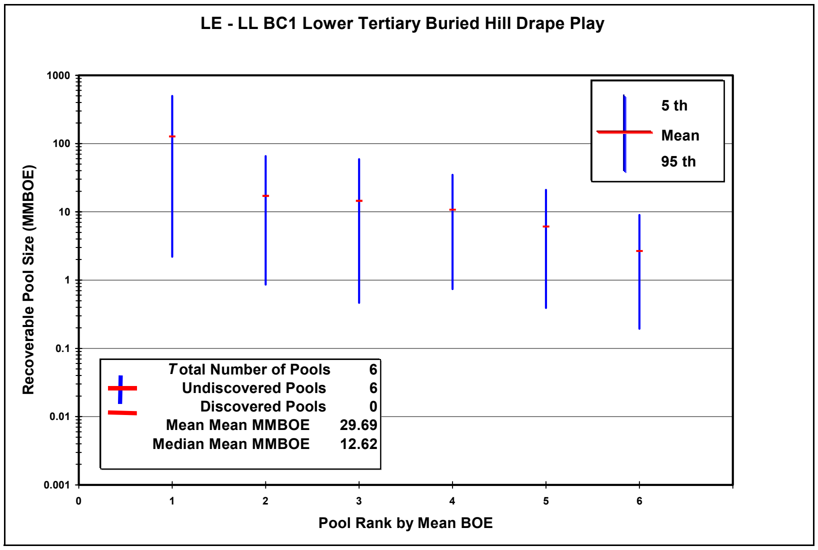


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

total endowment of 0.006 Bbo and 0.008 Tcfg (0.007 BBOE) (table 1; figure 4).

Undiscovered conventionally recoverable resources (UCRR) equal mean total endowment. These undiscovered resources might occur in as many as six pools. The largest undiscovered pool has a mean size of 127 MMBOE (figure 5). The mean mean size of the six undiscovered pools is 30 MMBOE.

Buried hills represent a prolific play type that produces in Southeast and East Asia, North and South America, Africa, Europe, and Australasia. A number of references were used to develop the analogs used in this play. Among the best are Landes *et al.*, 1960; Chung-Hsiang P'An, 1982; Zhai and Zha, 1982; Zheng, 1988; Yu and Li, 1989; Horn, 1990; Tong and Huang, 1991; Areshev *et al.*, 1992; Tran Canh *et al.*, 1994; Blanche and Blanche, 1997; and Sladen, 1997.

Reservoir characteristics for the Lower Tertiary Buried Hill Drape were developed using analogs based on chalk reservoirs from the Danish and Norwegian sectors of the North Sea.

Exploration Future

Although most of the Mesozoic source rocks in the Gulf of Mexico could provide hydrocarbons to the play's reservoirs, the primary risk in this play appears to be defining the cross-stratal vertical migration routes from these older source rocks to the younger reservoirs.

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Lower Tertiary Clastic Gas (LO-LL C1) Play

Textularia warreni through *Globorotalia uncinata* biozones

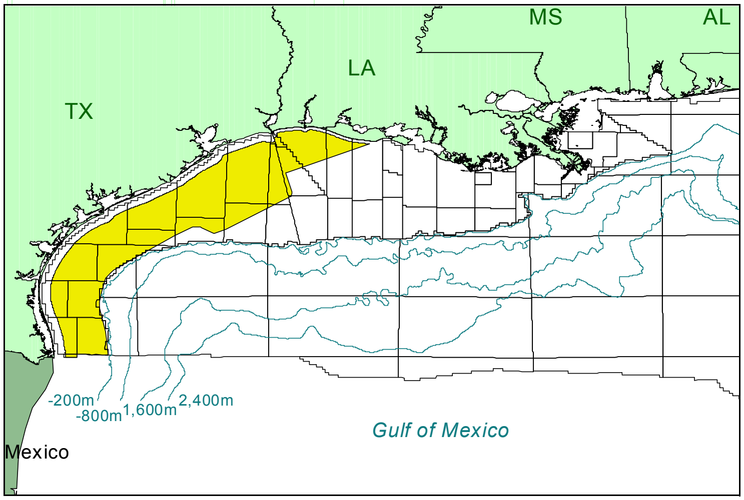

Figure 1. Play location.

LO-LL C1 Lwr Tertiary Clastic Gas 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	--	0.004	3.065	0.567
Mean	42	0.022	4.821	0.880
5th percentile	--	0.052	8.037	1.451
Total Endowment				
95th percentile	--	0.004	3.065	0.567
Mean	42	0.022	4.821	0.880
5th percentile	--	0.052	8.037	1.451

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Lower Tertiary Clastic Gas (LO-LL C1) play is defined by (1) *Textularia warreni* through *Globorotalia uncinata* biozones, (2) its location mostly on the modern offshore Texas shelf (figure 1), and (3) anticipated gas production. The play extends along depositional strike from the South Padre Island Area offshore Texas to the northern East Cameron Area offshore Louisiana.

Updip to the north and northwest, the play extends onshore into Texas and Louisiana. Downdip to the east and southeast, the play is bounded by the updip limit of the Lower Tertiary Clastic Gas/Oil (LO-LL C2) play, which also marks the updip occurrence of oil. To the south, the play extends into Mexican national waters.

The following discussion is from Blood (2000), unless otherwise noted.

Play Characteristics

The LO-LL C1 play combines deep-sea fan sediments of the lower Tertiary and the Midway, Wilcox, Claiborne, and Vicksburg Formations. Potential reservoirs exist in widespread lobe sheet sands that were deposited on a relatively flat and unconfined surface. The lobes may be shingled and stacked into thick, larger, nearly continuous sand bodies (Grecula *et al*., 2000 and Rehmer *et al*., 2000). These potential reservoirs occur at depths greater than 20,000 feet subsea and generally lie below a structurally deformed shale canopy. Areas where potential reservoirs lay at depths greater than 30,000 feet subsea were not considered prospective.

Source rocks in the play's area are thought to be formed from either lower Tertiary or upper Mesozoic pelagic sediments. Wagner *et al.*

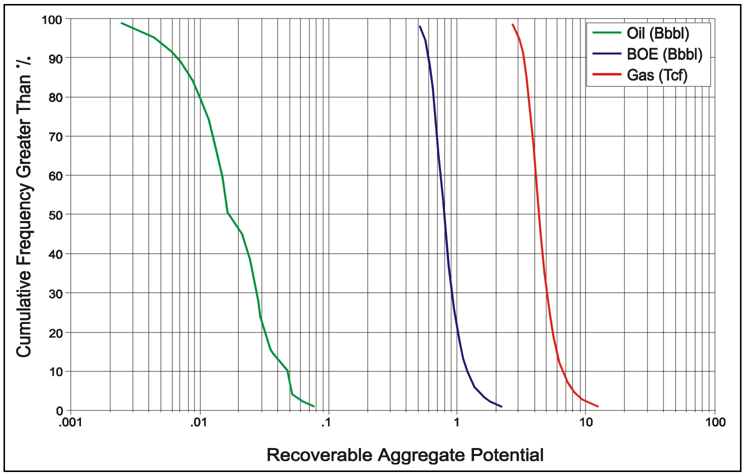

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

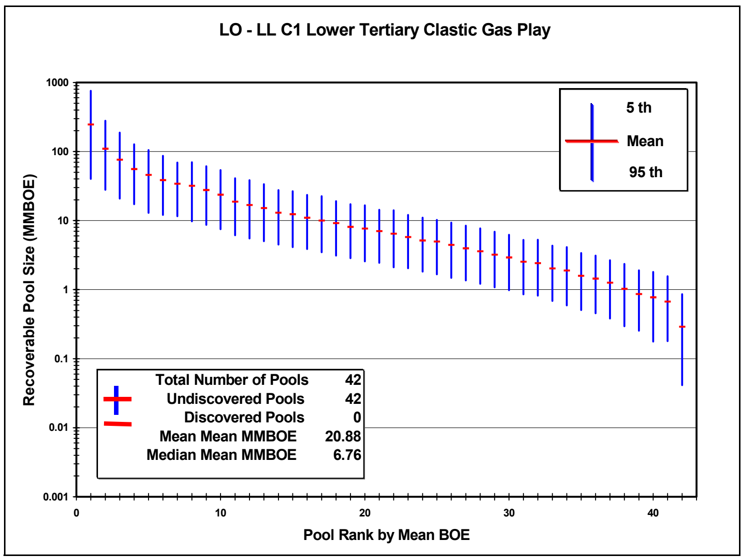

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

(1994) place mostly lower Tertiary terrestrial organic sources within the play's geographic boundaries. Piggott and Pulham (1993) place mostly upper Mesozoic carbonates with gas-producing organic matter in the same area. Either case produces mostly gas. In addition, the play is largely overlain by a shale canopy that retains heat, resulting in higher temperatures than would be expected for such deep reservoirs. Thus, any liquid hydrocarbons have likely been altered to thermogenic dry gas.

Significant structural features of the LO-LL C1 play are salt-cored anticlines and salt-cored ridges. The cores of these folds are remnants of a nearly uniform autochthonous salt sheet that was deformed by the downdip movement of younger slope sediments. Potential seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

No wells have been drilled in the LO-LL C1 play prior to this study's January 1, 1999 cutoff date.

Assessment Results

The marginal probability of hydrocarbons for the UK5-UJ4 S1 play is 1.00. The play contains a mean total endowment of 0.022 Bbo and 4.821 Tcfg (0.880 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.004 to 0.052 Bbo and 3.065 to 8.037 Tcfg at the 95th and 5th percentiles, respectively (figure 2). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 42 pools, the largest of which has a mean size of 247 MMBOE (figure 3). The mean mean size of the five largest undiscovered pools is 107 MMBOE, while the mean mean size of all 42 undiscovered pools is 21

MMBOE.

Exploration Future

The LO-LL C2 play's great depth and its location below a structurally deformed shale canopy are two technical concerns for explorationists. Other technical concerns include developing and maintaining reservoir-quality porosity and permeability in the prospective interval, and the extent to which deep-sea fan sands were deposited over the play's area.

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Lower Tertiary Clastic Gas/Oil (LO-LL C2) Play

Textularia warreni through *Globorotalia uncinata* biozones

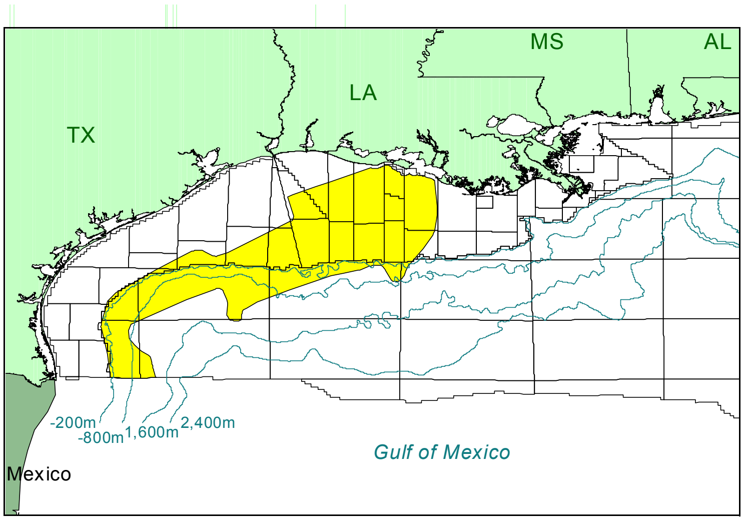

Figure 1. Play location.

LO-LL C2 Lwr Tertiary Clastic Gas & Oil 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	--	0.687	2.830	1.256
Mean	55	1.237	3.878	1.927
5th percentile	--	2.339	5.498	3.231
Total Endowment				
95th percentile	--	0.687	2.830	1.256
Mean	55	1.237	3.878	1.927
5th percentile	--	2.339	5.498	3.231

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Lower Tertiary Clastic Gas/Oil (LO-LL C2) play is defined by (1) the *Textularia warreni* through *Globorotalia uncinata* biozones, (2) the play's location mostly on the modern offshore Texas slope and western offshore Louisiana shelf (figure 1), and (3) anticipated oil and gas production. The play extends along depositional strike from the Port Isabel and Alaminos Canyon Areas offshore Texas to the eastern Eugene Island Area offshore Louisiana.

Updip to the west and northwest, the play is limited to the updipmost occurrence of oil, which coincides with the downdip boundary of the Lower Tertiary Clastic Gas (LO-LL C1) play. Downdip to the east and southeast, the play is limited by the anticipated downdip occurrence of gas. To the south, the play extends into Mexican national waters, while to the northeast, the play extends onshore into Louisiana and, in the offshore, to the eastward interpreted limit of lower Tertiary fan deposition.

The following discussion is from Blood (2000), unless otherwise noted.

Play Characteristics

The LO-LL C2 play combines deep-sea fan sediments of the lower Tertiary and the Midway, Wilcox, Claiborne, and Vicksburg Formations. Potential reservoirs exist in widespread lobe sheet sands that were deposited on a relatively flat and unconfined surface. The lobes may be shingled and stacked into thick, nearly continuous sand bodies (Grecula *et al.*, 2000 and Rehmer *et al.*, 2000). These potential reservoirs occur at depths greater than 20,000 feet subsea and generally lie below allochthonous salt. Areas where potential reservoirs lay at depths greater than 30,000 feet subsea were

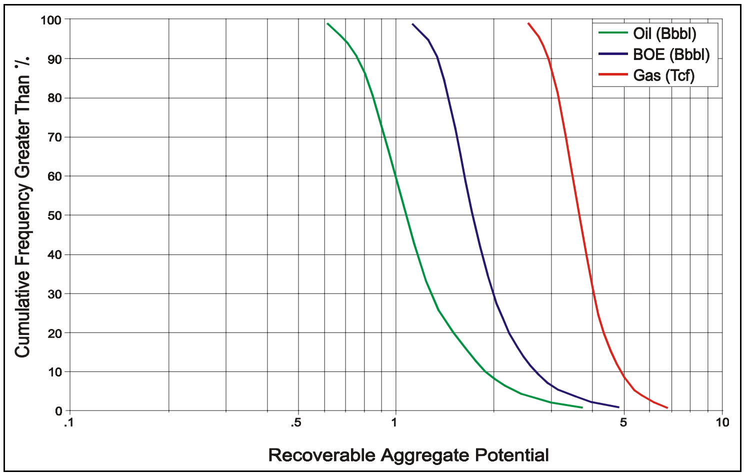

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

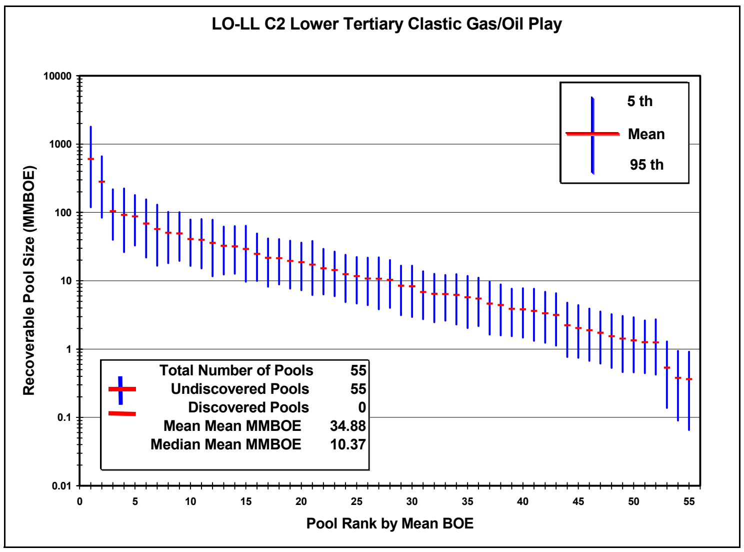

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

not considered prospective.

Source rocks in the play's area are thought to be formed from both lower Tertiary and upper Mesozoic pelagic sediments. Wagner *et al.* (1994) places lower Tertiary with terrestrial and upper Cretaceous marine organic sources within the play's geographic boundaries. Piggott and Pulham (1993) place upper Mesozoic carbonates with gas-producing organic matter and an Eocene oil source in the same area. Either case produces oil and gas. In addition, the play is mostly overlain by allochthonous salt that conducts heat, resulting in lower temperatures than would be expected at the depth of the anticipated reservoirs. This reduces the chances for oil to have been altered to thermogenic dry gas.

Significant structural features of the LO-LL C2 play are salt-cored anticlines and salt-cored ridges. The cores of these folds are remnants of a nearly uniform autochthonous salt sheet that sourced the overlying salt canopy through now near-vertical welds. Potential seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Discoveries

No wells have been drilled in the LO-LL C2 play prior to this study's January 1, 1999, cutoff date.

Assessment Results

The marginal probability of hydrocarbons for the LO-LL C2 play is 1.00. The play contains a mean total endowment of 1.237 Bbo and 3.878 Tcfg (1.927 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.687 to 2.339 Bbo and 2.830 to 5.498 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as

55 pools, the largest of which has a mean size of 608 MMBOE (figure 4). The mean mean size of the five largest undiscovered pools is 235 MMBOE and the mean mean size of all 55 pools is 35 MMBOE.

Exploration Future

The LO-LL C2 play's great depth and location below an allochthonous salt canopy are two technical concerns facing explorationists in this play. Other technical concerns include developing and maintaining reservoir-quality porosity and permeability in the prospective interval, and the extent to which deep-sea fan sands were deposited over the play's area.

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Rehmer, Donald E., Philip R. C. Dudley, and Arnold Bouma. 2000. Abstract: Architectural and reservoir characteristics of fine-grained depositional lobes, Tanqua Karoo, south Africa: AAPG Bulletin, vol. 84, No. 13 (Supplement).

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Cenozoic Fan 3 (UPL-LL F3) Play

Globorotalia uncinata **through** ***Sangamon Fauna***

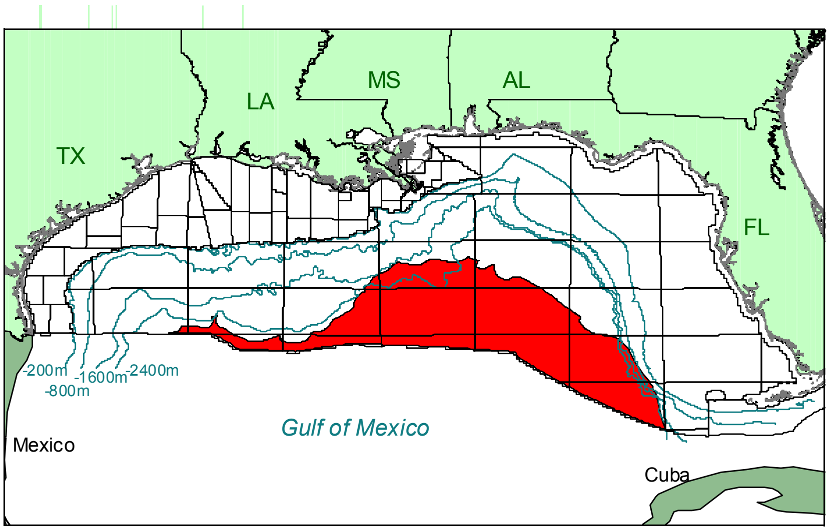

Figure 1. Play location.

Play Description

The conceptual and unassessed Cenozoic Fan 3 (UPL-LL F3) play is located south of the Sigsbee Escarpment in the deepest water portions of the northern Gulf of Mexico (figure 1). Primary objectives include relatively undeformed deepwater fan sands of the middle Miocene through Pleistocene section, but the entire Cenozoic section is prospective. Water depths over the play area range from 7,500 to 11,000 feet and drilling depths are anticipated to range from 15,000 to 20,000 feet subsea.

Play Characteristics

Seismic facies analysis (DeVay *et al*., 2000; Galloway *et al*., 2000) suggests the probability of Miocene deepwater fans extending to the most distal reaches of U.S. waters in the Central Gulf of Mexico. Middle Miocene fans form an apron outboard of the Sigsbee Escarpment/Mississippi Fan Fold Belt (refer to the various Mississippi Fan Fold Belt plays) and may include material eroded from the crests of folds in the fold belt.

Pliocene and Pleistocene fans were deposited across the southernmost areas of the play.

Channel-levee faces are apparent on recently acquired 3-D seismic surveys located outboard of the Sigsbee Escarpment. High-amplitude continuous reflectors in the abyssal plain are thought to be unconfined sheet sands. These can be traced up-dip to feeder channels emanating from the Sigsbee Escarpment and low areas between Mississippi Fan Fold Belt structures (Stephens, 1999).

Prospects are primarily stratigraphic in combination with regional dip, though in places compactional drape over underlying basement highs creates subtle structural closures. In the Tertiary section of the southern half of the Walker Ridge and Lund Areas, regional dip is to the north.

Discoveries

The UPL-LL F3 conceptual play contains no discoveries to date; however, on the basis of geohistorical analysis (Post, 2000), the play is expected to produce oil.

Assessment Results

The UPL-LL F3 play was not assessed prior to this study's cutoff date of January 1, 1999.

Exploration Future

Vertical migration of hydrocarbons between Mesozoic source rocks and Cenozoic reservoir beds is a major risk in the play. In addition, different velocities used in various seismic depth models strongly influence geohistorical analyses and estimated drilling depths.

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Cenozoic Perdido Fold Belt (UPL-LL X1) Play

Globorotalia uncinata* through *Sangamon Fauna

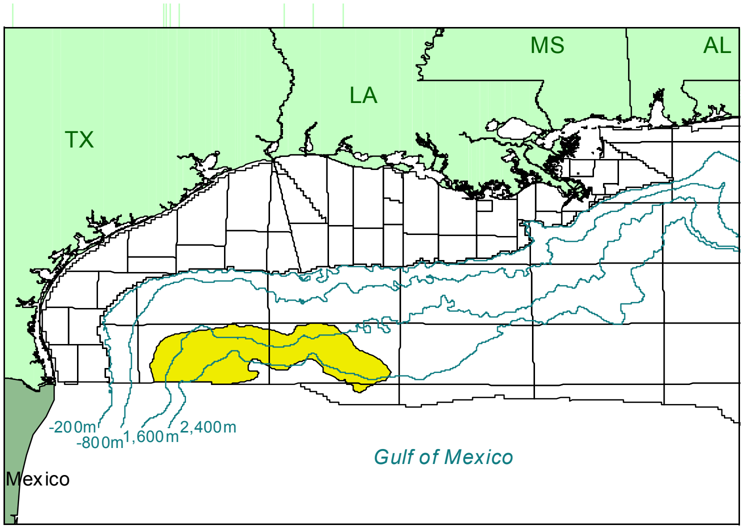

Figure 1. Play location.

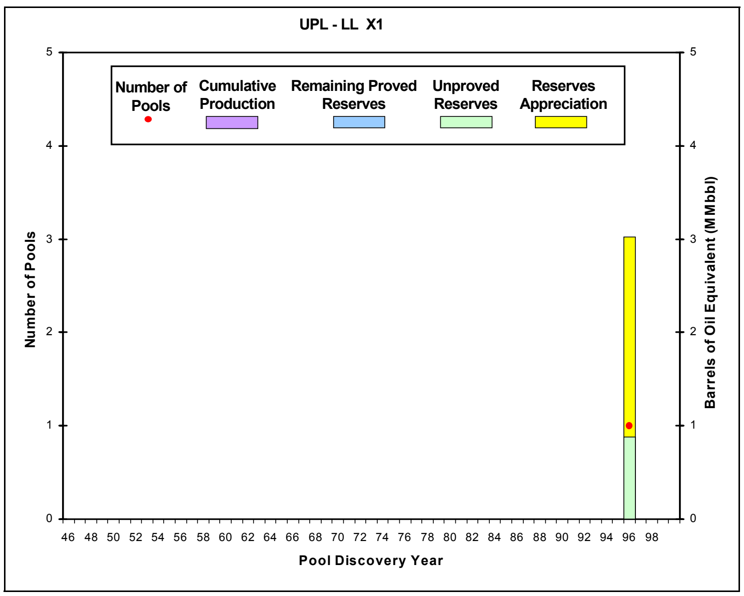

Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UPL-LL X1 Cenozoic Perdido Fold Belt			
1 Pool 3 Sands	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	7620	7620	7620
Subsea depth (feet)	9866	10297	10728
Number of sands per pool	1	2	2
Porosity	21%	27%	32%
Water saturation	30%	46%	61%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes. For internal accounting purposes, the one pool was split into two pools, one with one sand and the other with two.

Play Description

The established Cenozoic Perdido Fold Belt (UPL-LL X1) play is defined by Cenozoic deep-sea fan deposition and large north-east-southwest trending salt-cored folds. Only one well has been drilled in the play and production has yet to be established. The following discussion is from Post (2000), unless otherwise noted.

Basinward of the Sigsbee Salt Canopy, the play extends from the southeastern part of the Alaminos Canyon Area offshore Texas into Mexican national waters (figure 1). North, east, and west of this area, salt canopies obscure subsalt geometries, making it difficult to define the play area. However, interpretation of regional seismic data suggests that the play may extend eastward into the eastern part of the Keathley Canyon Area offshore Louisiana. The northeastern play boundary may either occur abruptly at a transfer zone or by a transition into the Cenozoic Mississippi Fan Fold Belt (UPL-LL X2) play. Although the northern limit of the play is interpretive because of the deterioration of seismic data quality under the Salt Canopy, the most basinward, counter-regional faults/salt welds related to the development of the canopy provide a geologically reasonable northward limit.

Play Characteristics

The Perdido Fold Belt is located at the basinward limit of a balanced and linked, complex system in which updip sedimentary loading and gravity-driven collapse associated with extension are accommodated by the extrusion of salt canopies and downdip contraction. Folding in the Perdido Fold Belt, resulting from downdip contraction, has created some of the largest structural closures in the Gulf of Mex-

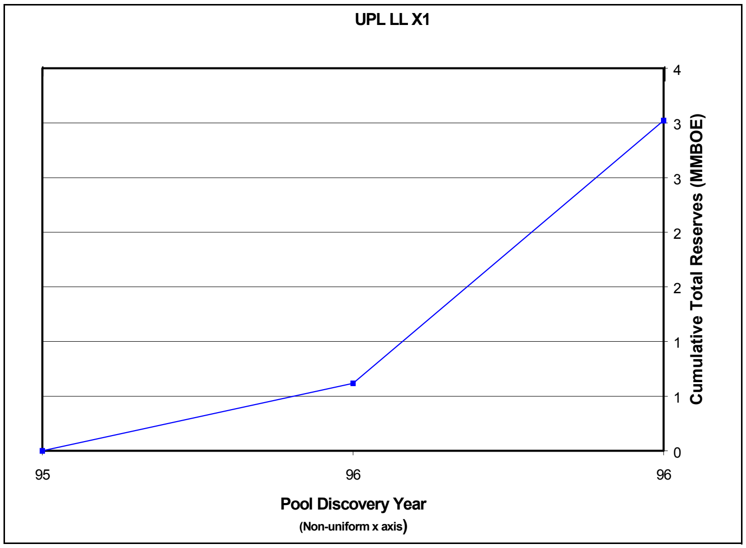

Figure 3. Plot of pools showing cumulative reserves by discovery order. In this figure, sands have been elevated to pool status. Note the non-uniform x axis.

UPL-LL X1 Cenozoic Perdido Fan FB 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	1	<0.001	0.005	0.001
Appreciation (P & U)	--	<0.001	0.011	0.002
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.523	1.274	0.793
Mean	26	0.989	2.204	1.381
5th percentile	--	2.025	3.967	2.565
Total Endowment				
95th percentile	--	0.523	1.290	0.796
Mean	27	0.989	2.220	1.384
5th percentile	--	2.025	3.983	2.568

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

ico Region. Where the play is exposed basinward of the Sigsbee Salt Canopy in the Alaminos Canyon Area, individual structural culminations can exceed 40,000 acres and have vertical closures of up to 4,000 feet. The folds occur in a series of subparallel salt-cored buckle folds with symmetrical to asymmetrical geometries, with high-angle reverse faults on one or both fold limbs.

The main stage of fold development involved Late Jurassic to Eocene sediments and occurred primarily during the Early Oligocene to possibly Early Miocene in response to updip Paleogene sedimentary loading and accompanying extension. (Ages are after Berggren *et al.*, 1995.) Deformation on the most basinward folds appears to terminate at the end of the Early Oligocene, whereas deformation on folds to the northwest may have continued into the Late Oligocene or Early Miocene, as evidenced by the thicker salt cores and higher relief. A minor phase of reactivation in the Middle and Late Miocene affects some folds. A late stage of localized secondary uplift occurs from the Pliocene to present-day in those folds that have the thickest Louann Salt and are closest to the Sigsbee Salt Canopy. Possible causes for this most recent phase of structural uplift may be renewed shortening or a broad loading phenomenon related to the emplacement of the Sigsbee Salt Canopy (Trudgill *et al.*, 1999; Fiduk *et al.*, 1999).

Discoveries

One well (AC600) has been drilled in the Cenozoic section of the play prior to this study's cutoff date of January 1, 1999. Mechanical difficulties prevented the well from reaching its primary Mesozoic age reservoir targets. Publicly available paleontologic data indicate that most of the Oligocene section is missing (because of erosion or non-deposition), corresponding to the main stage of fold development (see above). The well penetrated approximately 1,400 feet of Eocene section

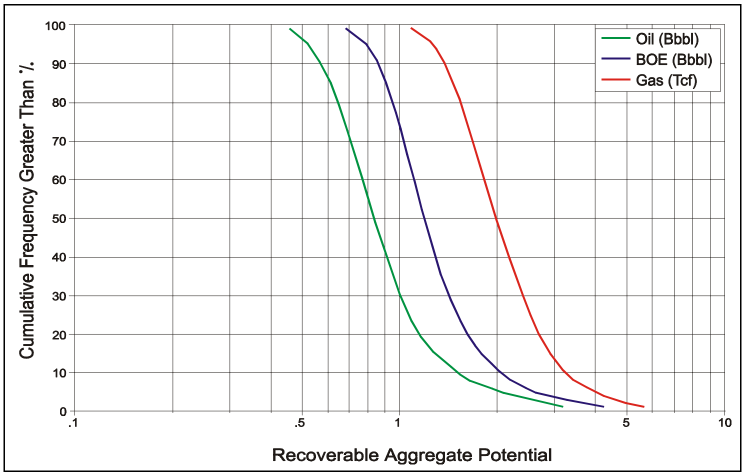

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

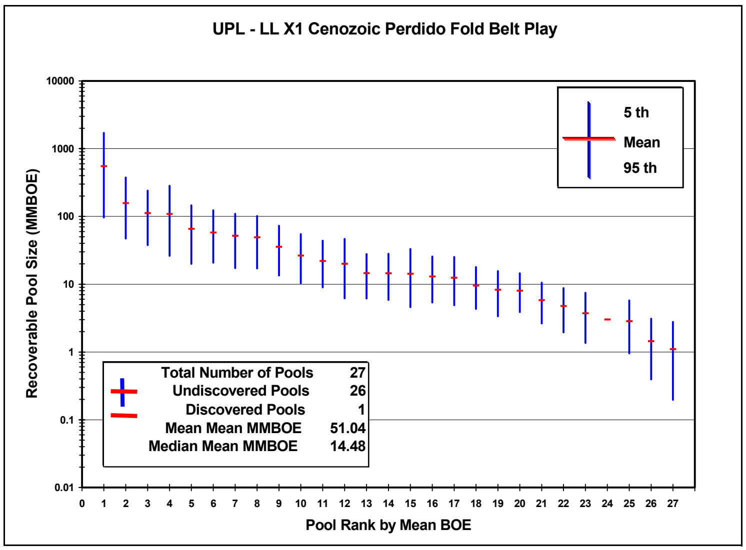

Figure 5. Pool rank plot showing the one discovered pool (red line) and the number of pools forecast as remaining to be discovered (blue bars).

without reaching the base of the Eocene. Well data indicate that the Cenozoic section that was penetrated consisted mainly of fine-grained, pelagic deposits, with interspersed thin, coarser grained, siliciclastic deep-sea fan deposits. On the basis of MMS guidelines, the well was qualified as productive, encountering more than 15 feet of producible sand in one section. Because this well failed to reach its objectives, the stratigraphy of the deeper Mesozoic units is still speculative.

The UPL-LL X1 play contains total reserves from the Alaminos Canyon 600 field of <0.001 Bbo and 0.016 Tcfg (0.003 BBOE) (figure 2). Production has not been established. The pool contains three reservoirs in three sands (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). Two of the three reservoirs are nonassociated gas and one is undersaturated oil.

In the Perdido Fold Belt, hydrocarbon seeps in the Alaminos Canyon Area have been geochemically typed to two Late Jurassic source intervals (centered on the Oxfordian, and centered on the Tithonian), and the Lower Tertiary (centered on the Eocene) by Wenger *et al.* (1994), and Hood *et al.* (*in press*).

Assessment Results

The marginal probability of hydrocarbons for the UPL-LL X1 play is 1.00. The play contains a mean total endowment of 0.989 Bbo and 2.220 Tcfg (1.384 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.523 to 2.025 Bbo and 1.274 to 3.967 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR are estimated at 0.989 Bbo and 2.204 Tcfg (1.381 BBOE). These undiscovered resources might occur in as many as 26 pools. The largest undiscovered pool is forecast as the first pool in the play and has a mean size of 553 MMBOE (figure 4). The next four largest undiscovered pools in the play occupy positions 2, 3, 4, and 5 on the pool rank plot. The mean mean size of the five largest undiscovered pools is 200 MMBOE and the mean mean size of all 27 pools, including the discovered pool, is 51 MMBOE.

Exploration Future

The play contains some of the largest known structural closures in the Gulf of Mexico Region. In addition, hydrocarbon seeps within the play's area indicate hydrocarbon generation, expulsion, and migration. The potential for future significant discoveries within this virtually untested deepwater play appears promising, though the presence of extensive, reservoir-quality, deepwater fan sands remains the play's primary risk.

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Cenozoic Mississippi Fan Fold Belt (UPL-LL X2) Play

Globorotalia uncinata through *Sangamon Fauna*

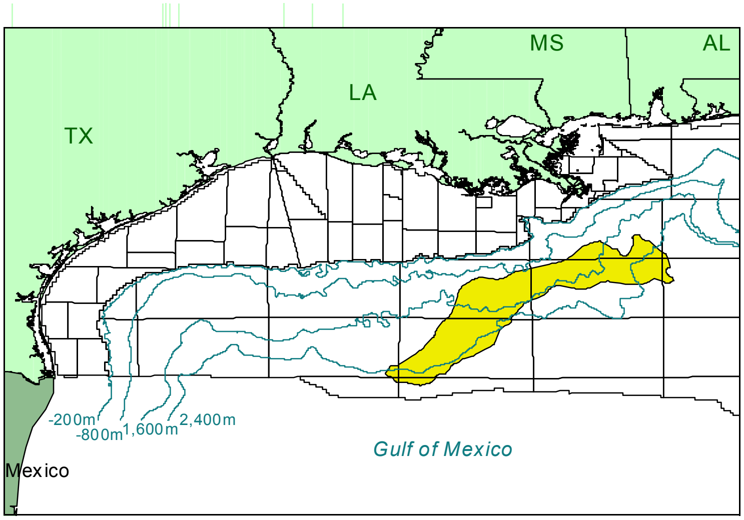

Figure 1. Play location.

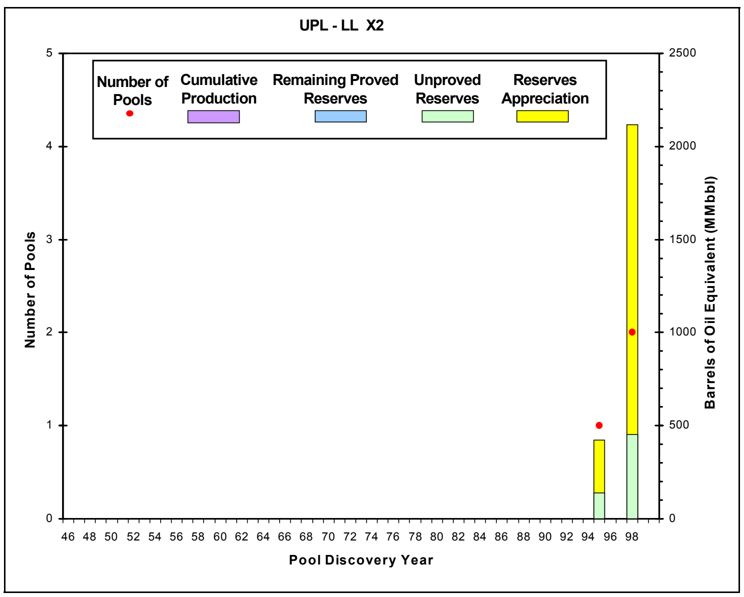

Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UPL-LL X2 Cenozoic Miss. Fan Fold Belt			
3 Pools 10 Sands	**Minimum**	**Mean**	**Maximum**
Water depth (feet)	6133	6201	6560
Subsea depth (feet)	12906	16538	20421
Number of sands per pool	1	1	2
Porosity	25%	28%	30%
Water saturation	16%	24%	48%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Cenozoic Mississippi Fan Fold Belt (UPL-LL X2) play is defined by Cenozoic deep-sea fan deposition and a series of east-northeast trending salt-cored folds. The play is one of the largest in the Gulf of Mexico Region and contains some of the largest discoveries made in the Region to date. The following discussion is from Post (2000), unless otherwise noted.

The UPL-LL X2 play extends from the Walker Ridge Area to the Mississippi Canyon Area (figure 1). Landward, the fold belt extends under the Sigsbee Salt Canopy where the most basinward, counter-regional fault/salt weld related to salt canopy development is used as a geologically reasonable updip limit for the play. To the northeast, the play boundary is difficult to define because of structural overprinting. Regional analysis suggests that it may be coincident with the Pearl River Transfer. The southwestern play boundary may occur at either another transfer zone or by a transition into the Perdido Fold Belt. Because the boundary lies beneath the Salt Canopy, the connection and relationship between the two fold belts remains speculative.

Although fold belt structures generally extend basinward to the depositional limit of underlying Louann Salt, there are indications in the northeastern part of the area that folding may extend beyond this limit. Continued updip extension during the Pliocene to Recent caused downdip compression regardless of whether the salt décollement is present. Exhausting the supply of mobile salt shifts the detachment to an incompetent unit above the salt, probably a shale unit.

Play Characteristics

The Mississippi Fan Fold Belt

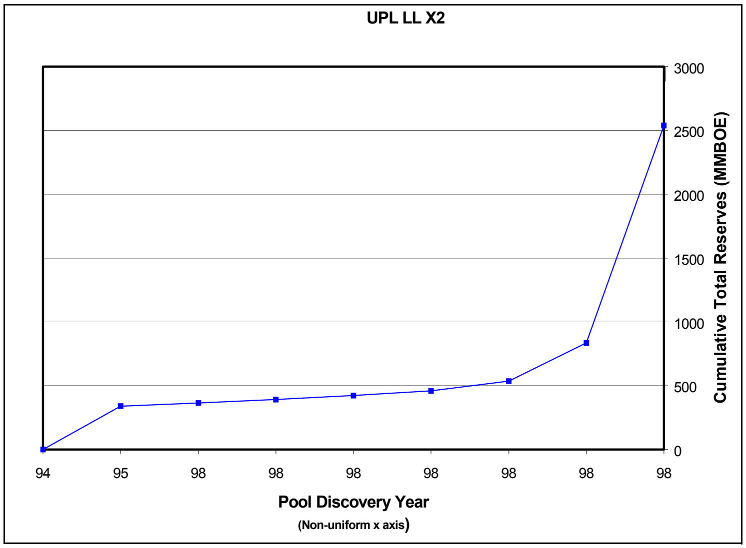

Figure 3. Plot of pools showing cumulative reserves by discovery order. In this figure, sands have been elevated to pool status. Note the non-uniform x axis.

UPL-LL X2 Cenozoic Miss. Fan Fold Belt 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	3	0.301	1.629	0.591
Appreciation (P & U)	--	0.951	5.600	1.947
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	3.675	9.647	5.528
Mean	82	4.363	11.628	6.432
5th percentile	--	5.183	13.876	7.462
Total Endowment				
95th percentile	--	4.927	16.875	8.066
Mean	85	5.615	18.856	8.970
5th percentile	--	6.435	21.104	10.000

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

is located at the basinward limit of a balanced and linked, complex system in which updip sedimentary loading and gravity-driven collapse associated with extension are accommodated by the extrusion of salt canopies and downdip contraction. Although thinning of the Late Jurassic–Cretaceous seismic is seen on some seismic lines through the MFFB, this is interpreted to indicate a local, early structural growth stage contemporaneous with deposition of this section (Rowan *et al.,* 2000). A regional early stage of fold development occurred during the Late Oligocene to Middle Miocene; however, timing of the main folding and thrusting event for UPL-LL X2 is related to the development of the thick Middle to Late Miocene siliciclastic depocenters in southeast Louisiana. Fold growth continued with minor thrusting during the Late Miocene through the Pleistocene. Folds in the play consist of a series of east - northeast - south-southwest trending, subparallel, salt-cored folds. The folds are asymmetric, basinward-vergent, with landward-dipping, typically listric reverse faults that cut the basinward limb of the fold.

Discoveries

The UPL-LL X2 play is a mixed oil and gas play, with total reserves of 1.252 Bbo and 7.228 Tcfg (2.538 BBOE), none of which has been produced. The play consists of 10 sands in three pools (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). The first UPL-LL X2 reserves were discovered in 1995 in the Atwater 575 field (Neptune-AT, 422 MMBOE in total reserves) (figure 2); however, the largest pool in the play is the Green Canyon 826 field (Mad Dog) discovered in 1998 with 1,702 MMBOE in total reserves. The third pool in the play, also discovered in 1998, is Green Canyon 699 field (Atlantis, 412 MMBOE in total reserves). The average size of the three discovered pools is 846 MMBOE in total reserves. These

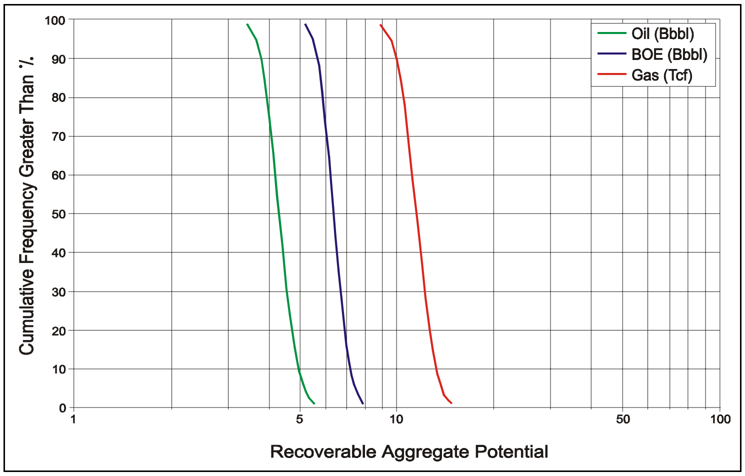

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

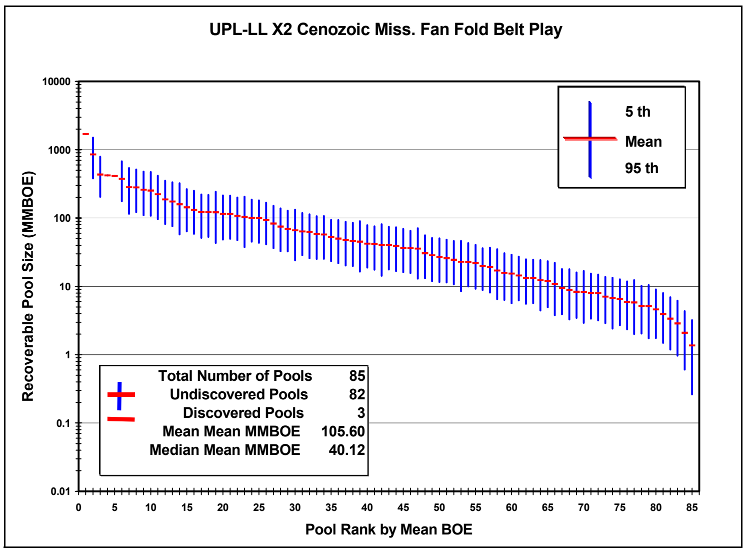

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

three discoveries were made prior to this study's cutoff date of January 1, 1999.

The three discovered pools contain 10 reservoirs, of which seven are nonassociated gas and three are undersaturated oil.

Assessment Results

The marginal probability of hydrocarbons for the UPL-LL X2 play is 1.00. The play contains a mean total endowment of 5.615 Bbo and 18.856 Tcfg (8.970 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 3.675 to 5.183 Bbo and 9.647 to 13.876 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR are estimated at 4.363 Bbo and 11.628 Tcfg (6.432 BBOE). These undiscovered resources might occur in as many as 82 pools. The largest undiscovered pool has a mean size of 856 MMBOE in forecast total reserves (figure 4). The next four largest undiscovered pools occupy positions 3, 6, 7, and 8 on the pool rank plot. The mean mean size of the five largest undiscovered pools is 442 MMBOE and the mean mean size of all pools, including discovered and undiscovered, is 106 MMBOE.

Exploration Future

The UPL-LL X2 play has potential for numerous significant discoveries. The play ranks as largest in the Gulf of Mexico Region on the basis of both BOE mean total endowment and BOE mean UCRR. The play accounts for nearly 7 percent of the BOE mean total endowment and 9 percent of the BOE mean UCRR for the entire Gulf of Mexico Region. BOE mean UCRR contribute 72 percent to the play's mean total endowment.

Discoveries made to date occur immediately in front of and extend a short distance under the

Sigsbee Salt Canopy. The large, untested area of this play that lies totally beneath the salt canopy has stratigraphy similar to that of the tested area immediately adjacent to the front of the salt canopy, with traps and migration pathways possibly related to canopy emplacement. Thus far, hydrocarbons have been found in lower and middle Miocene rocks.

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Lower Upper Cretaceous Clastic Tuscaloosa Formation (UK2 C1) Play *Rotalipora cushmani* biozone

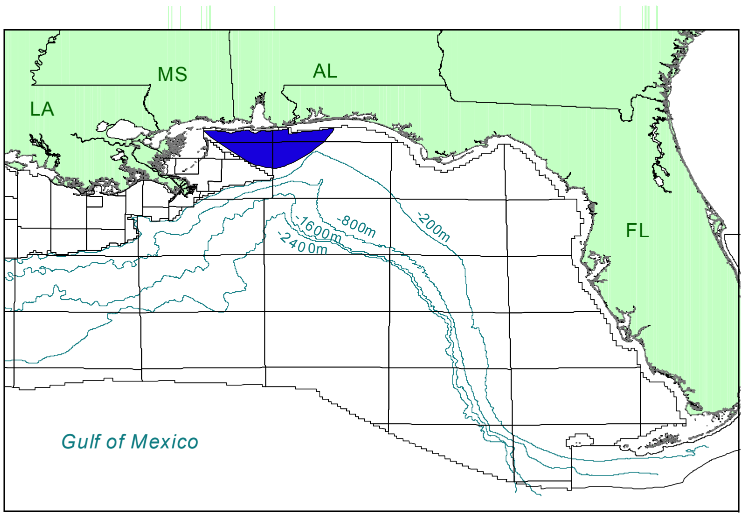

Figure 1. Play location.

UK2 C1 Tuscaloosa 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

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The frontier Lower Upper Cretaceous Clastic Tuscaloosa Formation (UK2 C1) play occurs within the *Rotalipora cushmani* biozone and is defined by aggradational and progradational sands of the Tuscaloosa Formation. The play extends from the Mobile and Viosca Knoll Areas offshore Mississippi and Alabama to the Pensacola and Destin Dome Areas offshore Florida (figure 1). Updip, the UK2 C1 play extends onshore where it is productive, while downdip the play's boundary occurs where upper Cretaceous sands interfinger with prodelta shales. No significant accumulations of hydrocarbon have been encountered to date in the numerous Federal OCS wells that have penetrated the UK2 C1 play. In the 1995 assessment (Lore *et al.*, 1999), this play was referred to as the Upper Cretaceous Clastic (UK CL) play.

Play Characteristics

Onshore, the UK2 C1 play consists of progradational deltaic sands, aggradational stacked barrier bar and channel sands, and reworked retrogradational sands. In the Federal OCS, however, the Tuscaloosa has a more distal depositional setting and sands tend to be of lower reservoir quality.

Significant structural features in the play are anticlines and faults, both related to salt movement. Potential source rocks are Oxfordian laminated carbonate mudstones represented by the basal part of the upper Jurassic Smackover Formation. Potential seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapirism) or stratigraphically (e.g., lateral shale-outs, overlying shales).

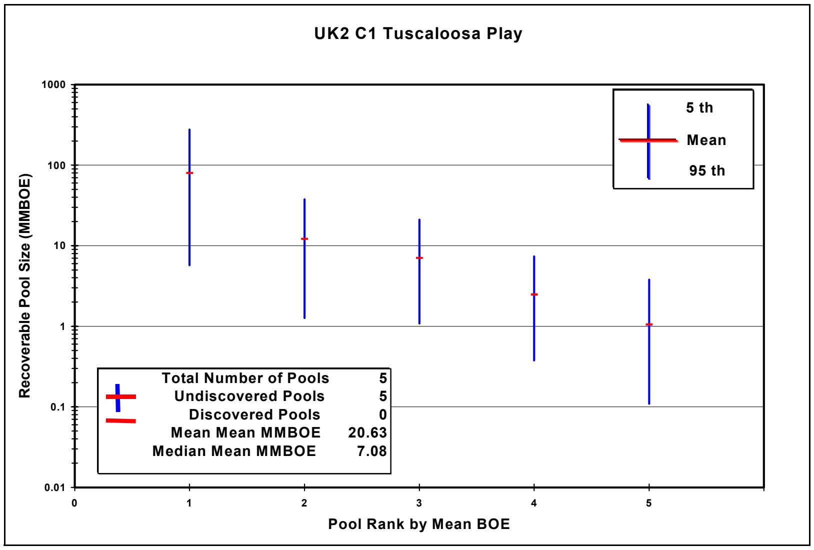

Figure 2. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Discoveries

Of Federal OCS wells that have penetrated the Tuscaloosa Formation, no significant hydrocarbon accumulations have yet been encountered. A minor gas show was encountered in the Tuscaloosa formation in an Exxon well drilled in Destin Dome Block 162. However, the show occurred in basal fluvial sands that are not considered part of the typically prospective Tuscaloosa section.

Assessment Results

Because the UK2 C1 play is not currently productive in the Federal OCS, the productive Tuscaloosa and Eutaw Formation sands of onshore Louisiana, Mississippi, and Alabama were used as reservoir analogs (refer to the Methodology section for a discussion of reservoirs, sands, and pools). The analogs are not perfect: onshore, prolific reservoirs are common in well-developed retrogradational sands that, in the Federal offshore, are poorly developed.

Exploration in the onshore Tuscaloosa and Eutaw Formations is at a mature stage. Analog fields contain an average of 63 percent oil, 3 percent gas, and 34 percent mixed hydrocarbons. Production from the analog fields ranges from <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 in the UK2 C1 play is 0.56. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) are estimated to be 0.000 to 0.190 Bbo and 0.000 to 0.257 Tcfg at the 5th and 95th percentiles, respectively (table 1 and figure 2). Mean UCRR are forecast at 0.045 Bbo and 0.070 Tcfg (0.057 BBOE). These undiscovered resources might occur in as many as five pools, which have an unrisked mean size range of 1 to 80 MMBOE (figure 4) and an unrisked mean mean size of 21 MMBOE.

The low number of anticipated discoveries in the UK2 C1 play is caused by poor reservoir sand development in the offshore and the large number of dry holes that have already tested the play in the Federal OCS.

Reference

Lore, G.L., K.M. Ross, B.J. Bascle, L.D. Nixon, and R.J. Klazynski. 1999. Assessment of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1995: Minerals Management Service OCS Report MMS 99-0034, CD-ROM.

Upper Lower Cretaceous Carbonate Andrew Formation (LK8 B1) Play *Cythereis fredericksburgensis* and *Lenticulina washitaensis* biozones

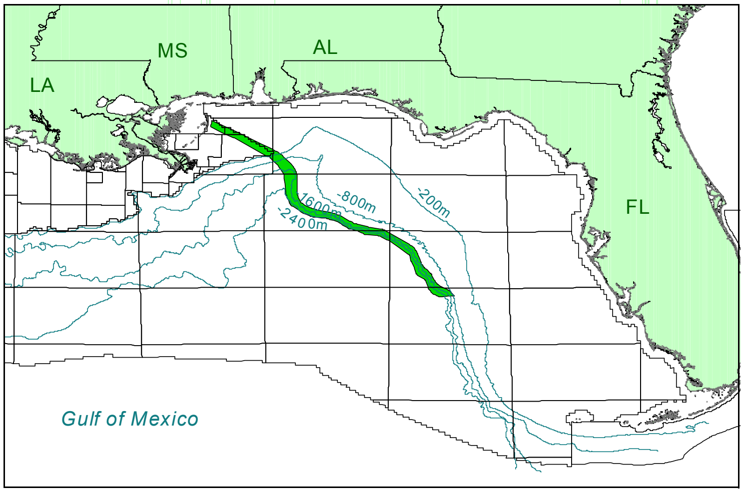

Figure 1. Play location.

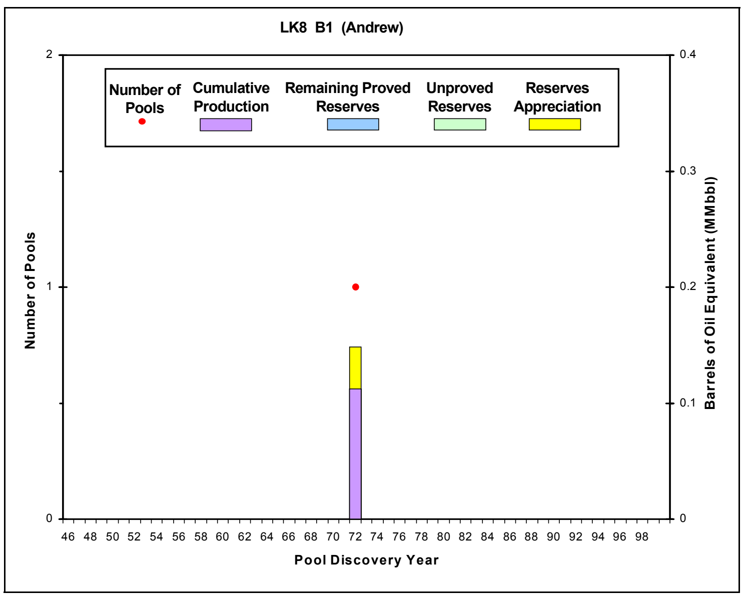

Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LK8 B1 Andrew 1 Pool 1 pay zone	Minimum	Mean	Maximum
Water depth (feet)	288	288	288
Subsea depth (feet)	8656	8656	8656
Number of zones per pool	1	1	1
Porosity	20%	20%	20%
Water saturation	26%	26%	26%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Lower Cretaceous Carbonate Andrew Formation (LK8 B1) play occurs within the *Cythereis fredericksburgensis* and *Lenticulina washitaensis* biozones. The "Andrew limestone" is a term used by drilling operators to describe undifferentiated carbonates of Washita-Fredericksburg age. Only one field has produced in the play.

The Andrew play is located along a narrow Lower Cretaceous shelf edge rudist reef zone that extends from the Chandeleur through the Vernon Areas. However, southeast of The Elbow Area, the reef trend is lumped with the Lower Cretaceous Carbonate Sunniland Formation (LK8-LK3 B1) play. The extent of the LK8 B1 play is shown in figure 1. In the 1995 assessment (Lore *et al.,* 1999), the LK8 B1 play was included in the Lower Cretaceous Carbonate (LK CB) play.

The LK8 B1 play is limited updip to the northeast by a muddy back-reef platform facies. Downdip to the southwest, the play is bound by a forereef facies of dark shales and carbonate muds.

Play Characteristics

The is defined by shelf-edge rudist reef facies of the lower Cretaceous Andrew Formation (Albian age). The reef facies is flanked by oolitic packstone and grainstone talus adjacent to, and trending subparallel to, the shelf-edge boundstones. Updip are nonporous lagoonal wackestones and mudstones interbedded with basin-wide shales that represent transgressive units (Yurewicz *et al.*, 1993). Anhydrites were deposited in the highly restrictive backreef platform (Petty, 1995).

The single field in the play, Main Pass 253, produces from the reefal and flanking talus facies. Res-

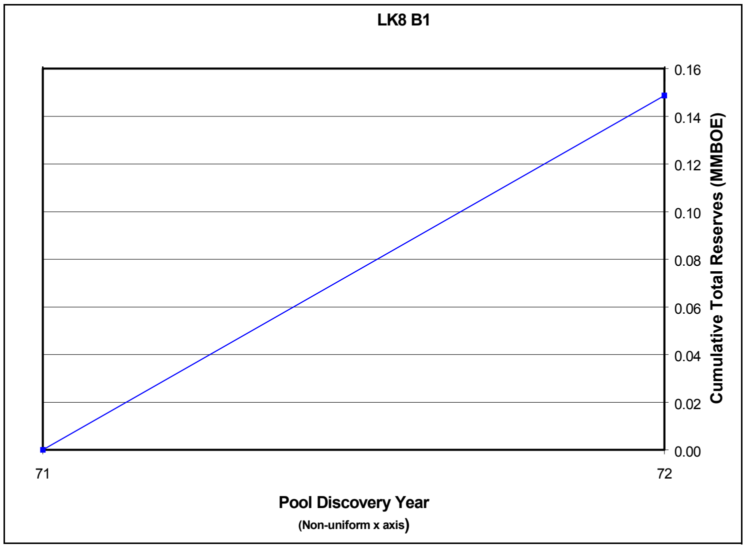

Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LK8 B1 Andrew Formation 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	--	0.005	0.021	0.010
Mean	5	0.030	0.046	0.038
5th percentile	--	0.074	0.085	0.089
Total Endowment				
95th percentile	--	0.005	0.021	0.010
Mean	6	0.030	0.046	0.038
5th percentile	--	0.074	0.085	0.089

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

ervoir porosity and permeability are controlled by a combination of primary fabric, digenetic leaching, and dolomitization. Hydrocarbons are trapped in small anticlines located within the porous and permeable facies. Source rocks are thought to be localized organic-rich lagoonal carbonates, deepwater limestones, and shales. Marine shales, micrites, and anhydrites provide seals for the play.

Discoveries

Chevron's Main Pass 253 field was discovered in 1972 (figures 2 and 3), and the field contains one saturated oil reservoir (table 1). Total reserves and cumulative production combined are <0.001 Bbo (0.1 MMBOE). The field is now depleted. A second field, Main Pass 221, was discovered by Exxon in 1973, but it was never developed.

Assessment Results

The marginal probability of hydrocarbons for the LK8 B1 play is 1.00. The play has a mean total endowment of 0.030 Bbo and 0.046 Tcfg (0.038 BBOE) (table 2). Less than 1 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.005 to 0.074 Bbo and 0.021 to 0.085 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.030 Bbo and 0.046 Tcfg (0.038 BBOE). These UCRR might occur in as many as five pools. The largest undiscovered pool has a mean size of 25 MMBOE (figure 5). The mean mean size for all pools, including both discovered and undiscovered, is 6 MMBOE.

Exploration Future

BOE mean UCRR contribute more than 99 percent to the LK8 B1 play's BOE mean total endowment. Most wells that test the Andrew Formation in the Federal OCS are

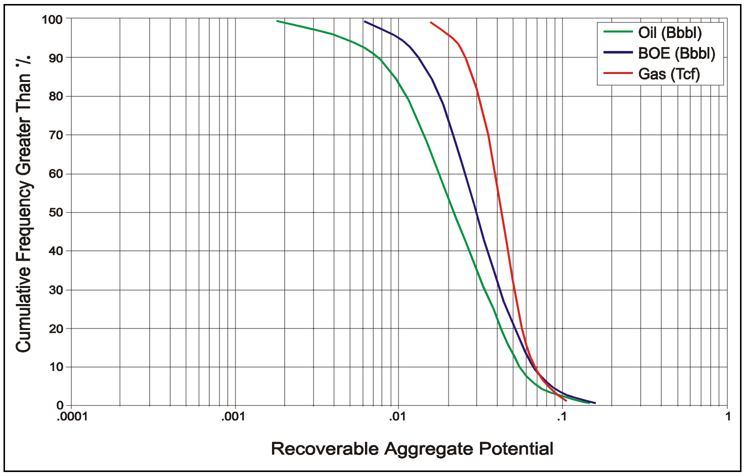

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

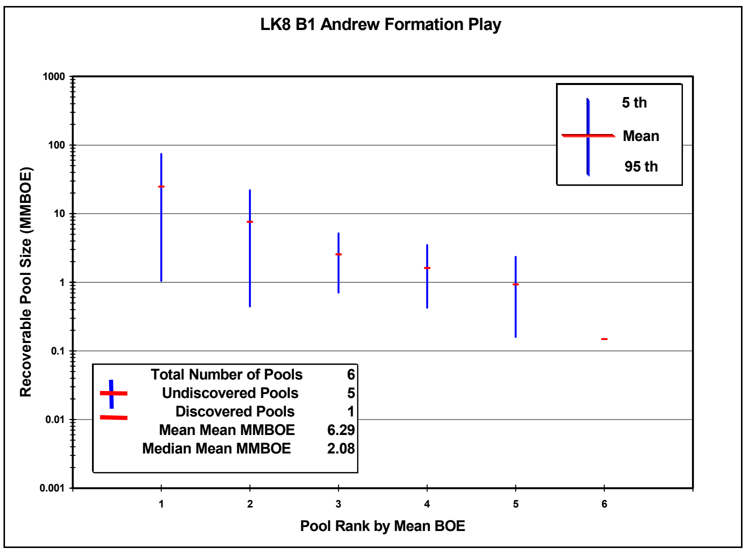

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

located in the Main Pass Area. Although the forecast number of undiscovered pools is small, the remaining area of the play remains relatively unexplored.

References

Lore, G.L., K.M. Ross, B.J. Bascle, L.D. Nixon, and R.J. Klazynski. 1999. Assessment of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1995: Minerals Management Service OCS Report MMS 99-0034, CD-ROM.

Petty, A.J. 1999. Petroleum exploration and stratigraphy of the Lower Cretaceous James Limestone (Aptian) and Andrews Formation (Albian): Main Pass, Viosca Knoll, and Mobile Area, northeastern Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. XLIX, p. 440-450.

Yurewicz, D.A., T.B. Marler, K.A. Meyerholtz, and F.X. Siroky. 1993. Early Cretaceous carbonate platform, north rim of the Gulf of Mexico, Mississippi and Louisiana, *in* J.A. Toni Simo, R.W. Scott, and J.-P. Masse (eds.), Cretaceous carbonate platforms: American Association of Petroleum Geologists Memoir 56, p. 81-96.

Middle Lower Cretaceous Carbonate Mooringsport Formation (LK6 B1) Play

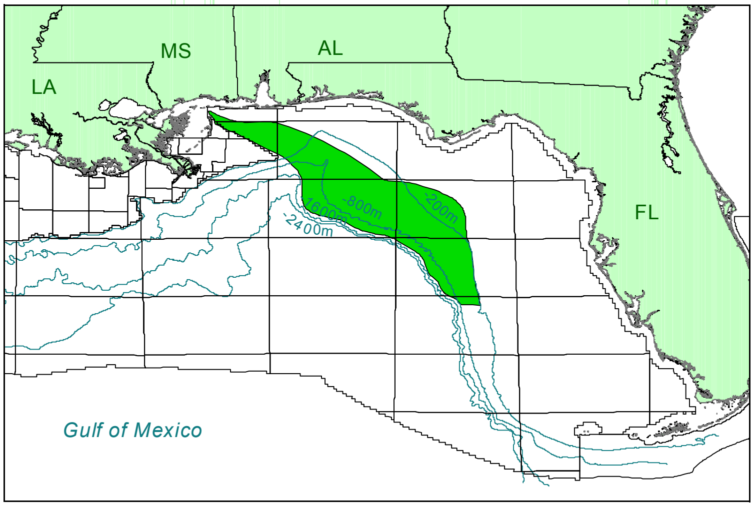

Figure 1. Play location.

Play Description

The conceptual and unassessed Middle Lower Cretaceous Carbonate Mooringsport Formation (LK6 B1) play is stratigraphically equivalent to the Sunniland Formation of the South Florida basin (refer to the Lower Cretaceous Carbonate Sunniland Formation play, LK8-LK3 B1). However, the LK6 B1 play is located to the west and north of the Sunniland play and extends from the Elbow Area to offshore Mississippi. The location of the play is shown in figure 1. In the 1995 assessment (Lore *et al.,* 1999), this play was included in the Lower Cretaceous Carbonate (LK CB) play.

The LK6 B1 play was not assessed in this study because the Mooringsport Formation overlies regional sealing anhydrites of the Ferry Lake and Rodessa Formations that restrict the vertical migration of hydrocarbons. However, hydrocarbon accumulations may exist in the LK6 B1 play near the shelf edge where underlying anhydrites thin or disappear altogether. The LK6 B1 play produces in such a setting in the Waveland Field of onshore southern Mississippi.

Potential reservoirs in the LK6 B1 play consist of patch reef and associated talus, much like the Lower Lower Cretaceous James Limestone (LK3 B1) play.

Reference

Lore, G.L., K.M. Ross, B.J. Bascle, L.D. Nixon, and R.J. Klazynski. 1999. Assessment of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1995: Minerals Management Service OCS Report MMS 99-0034, CD-ROM.

Lower Lower Cretaceous James Limestone (LK3 B1) Play

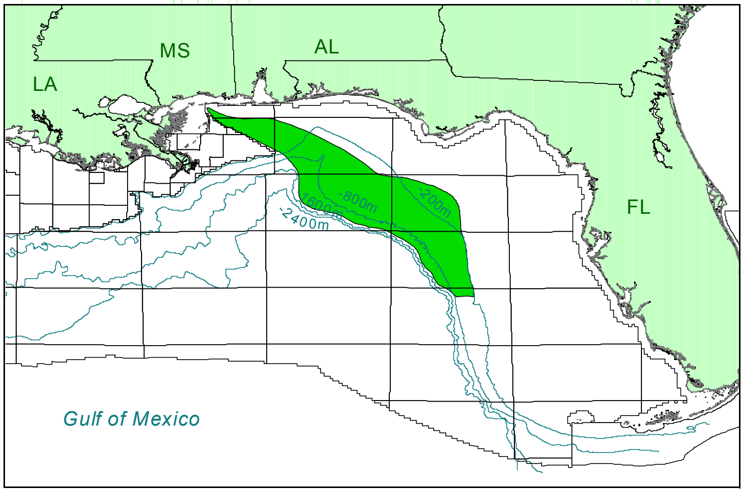

Figure 1. Play location.

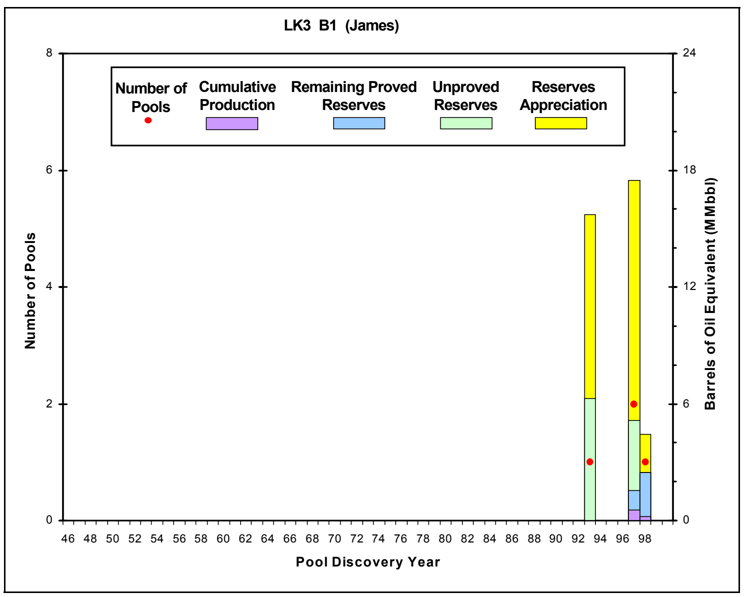

Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

LK3 B1 James 4 Pools 8 pay zones	Minimum	Mean	Maximum
Water depth (feet)	82	107	121
Subsea depth (feet)	14345	14903	15149
Number of zones per pool	1	2	3
Porosity	10%	12%	14%
Water saturation	35%	44%	51%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Lower Lower Cretaceous Carbonate James Limestone (LK3 B1) play is defined by patch reef and reef talus of the Lower Cretaceous James Limestone. In the 1995 assessment (Lore *et al.*, 1999), this play was included in the Lower Cretaceous Carbonate (LK CB) play.

The LK8 B1 play extends from the Mobile area southeastward along the Lower Cretaceous shelf edge through the northern Viosca Knoll, Destin Dome, Desoto Canyon, Florida Middle Ground, and The Elbow Areas (figure 1). The play contains four fields.

Updip to the northeast, the play is limited by backreef lagoonal carbonate muds, while downdip to the southwest, the play grades into a forereef facies of dark shales and carbonate muds.

Play Characteristics

The James Limestone is a member of the Pearsall Formation. The Pearsall Formation consists of three members: (1) the uppermost Bexar Shale, (2) the James Limestone, and (3) the basal Pine Island Shale. A poorly developed, 10-foot-thick Bexar Shale Member is found in the Federal OCS. The Pine Island Shale Member found onshore in the Pearsall Formation is a carbonate in the Federal OCS that is lithologically indistinguishable from the James Limestone. In the offshore, the James Limestone and Pine Island Shale Members are commonly identified by operators as the upper and lower James Limestone (Petty, 1999).

The four fields in the play are part of a patch reef trend oriented northwest to southeast. The patch reefs are typically elliptical with their three-to-five-mile long axis oriented

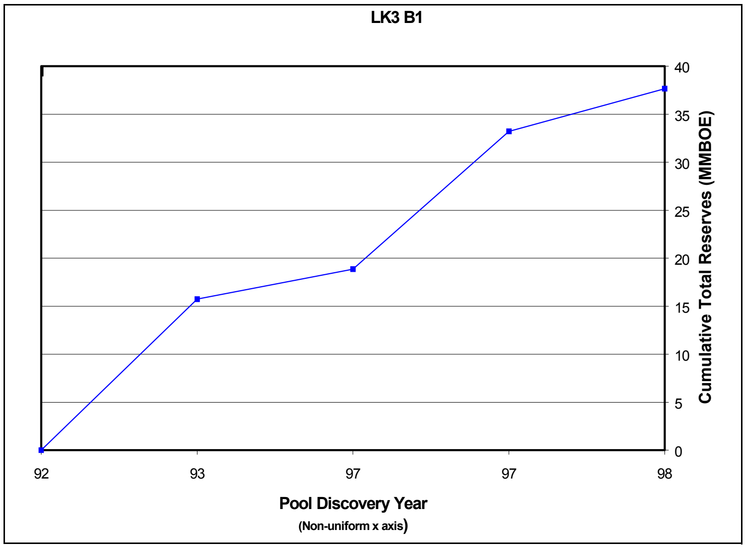

Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

LK3 B1 James Limestone Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2	<0.001	0.022	0.004
Cumulative production	--	0.000	0.004	0.001
Remaining proved	--	<0.001	0.018	0.003
Unproved	2	<0.001	0.055	0.010
Appreciation (P & U)	--	<0.001	0.134	0.024
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.008	0.128	0.036
Mean	14	0.019	0.216	0.058
5th percentile	--	0.036	0.315	0.083
Total Endowment				
95th percentile	--	0.008	0.339	0.074
Mean	18	0.019	0.427	0.096
5th percentile	--	0.036	0.526	0.121

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

perpendicularly to the basin. The reefs consist of a central core of rudist boundstone surrounded by concentric deposits of grainstone and packstone bioclastic debris. This bioclastic debris is then surrounded by grainstones redistributed by wave action across the interior platform. Lower energy lagoonal mudstones, marine shales, and anhydrite interfinger with these grainstones and provide seals. Patch reef log signatures are characterized by erratic spontaneous potential and high resistivity curves. Pay-zone thicknesses in the four fields range from about 10 to 100 feet on well logs, with most fields containing more than one porosity/ pay zone. Pay zones are often, but not always, associated with seismic hydrocarbon indicators (bright spots).

Hydrocarbon traps are formed by small anticlines located within porous areas of the patch reefs. These porous zones occur in dolomitized reefal material and in flanking talus. Reservoir permeability and porosity are controlled by a combination of primary fabric, diagenetic leaching, and dolomitization. Potential source rocks are laminated shales and micrites of the Lower Cretaceous Smackover Formation (Petty and Post, 2000).

Discoveries

The LK3 B1 play is a gas play with total reserves of <0.001 Bbo and 0.211 Tcfg (0.038 BBOE). No oil and 0.004 Tcfg (0.001 BBOE) have been produced. The play contains eight pay zones in four pools (table 1; refer to the Methodology section for a discussion of pools; “pay zones” in carbonate pools are the equivalent of “sands” in clastic pools). The first hydrocarbons in the play were discovered in Viosca Knoll Block 296 Well No. 1 in 1993. This well found non-commercial gas in two zones totaling 14 net feet. The well was plugged and abandoned. The Viosca Knoll 252 field contains the largest pool in the play, with 16 MMBOE in total reserves. Maximum yearly total reserves of 17 MMBOE were added

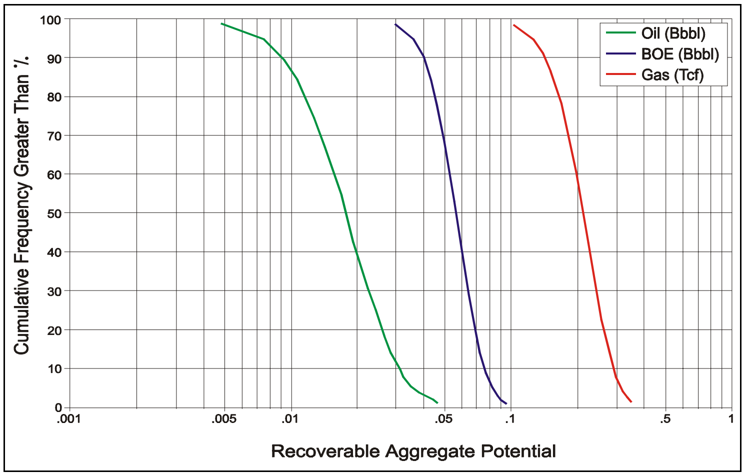

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

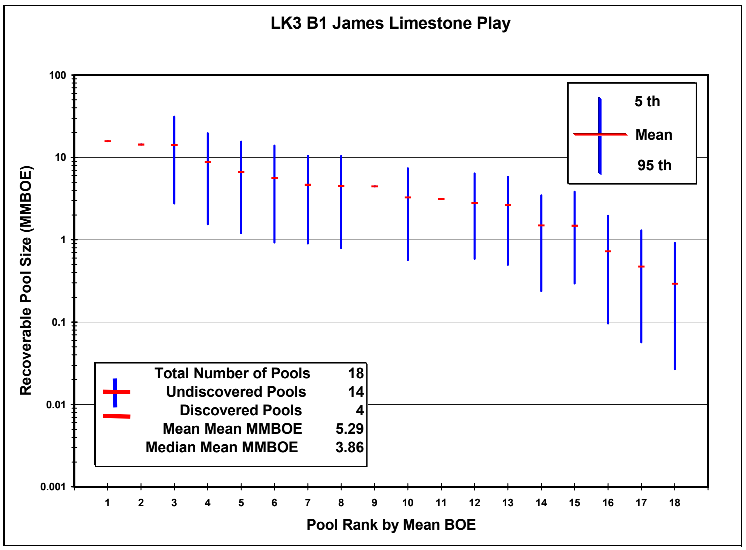

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

with the discovery of the Viosca Knoll 114 and Viosca Knoll 69 fields in 1997 (figure 3). The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in the Mobile 991 field in 1998. Of the four fields in the play, only pools from the Viosca Knoll 69 and Mobile 991 fields have produced.

Assessment Results

The marginal probability of hydrocarbons for the LK3 B1 play is 1.00. The play contains a mean total endowment of 0.019 Bbo and 0.427 Tcfg (0.096 BBOE) (table 2). One percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.008 to 0.036 Bbo and 0.128 to 0.315 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.019 Bbo and 0.216 Tcfg (0.058 BBOE). These undiscovered resources might occur in as many as 14 pools. The largest undiscovered pool, with a mean size of 14 MMBOE, is forecast as the third largest pool in the play (figure 5). The forecast places the next four pools in positions 4, 5, 6, and 7. For all the undiscovered pools in the LK3 B1 play, the mean mean size is 4 MMBOE, which is smaller than the 9 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5 MMBOE.

Exploration Future

Although barrier reef complexes are important stratigraphic features along the Lower Cretaceous shelf edge, more prolific oil and gas fields have been discovered in patch reefs and debris mounds located behind the shelf-edge reef trend (Sams, 1982). Grainstone/packstone bioclastic debris and reworked interior platform grainstones hold the greatest exploration potential. Additionally, relatively unexplored regions of Lower Cretaceous carbonates lie in the Desoto Canyon and Florida Middle Ground Areas, on the Sarasota Arch, and in the South Florida Basin adjacent to the Lower Cretaceous shelf-edge reef trend (Petty, 1999).

References

Lore, G.L., K.M. Ross, B.J. Bascle, L.D. Nixon, and R.J. Klazynski. 1999. Assessment of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1995: Minerals Management Service OCS Report MMS 99-0034, CD-ROM.

Petty, A.J. 1999. Petroleum exploration and stratigraphy of the Lower Cretaceous James Limestone (Aptian) and Andrews Formation (Albian): Main Pass, Viosca Knoll, and Mobile Area, northeastern Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. XLIX, p. 440-450.

Petty, A.J. and P.J. Post. 2000. Unpublished internal Minerals Management Service report.

Sams, R.H. 1982. Gulf coast stratigraphic traps in the Lower Cretaceous carbonates: Oil and Gas Journal, Feb. 22, v. 80, p. 177-187.

Lower Lower Cretaceous Carbonate Sligo Formation (LK3 B2) Play

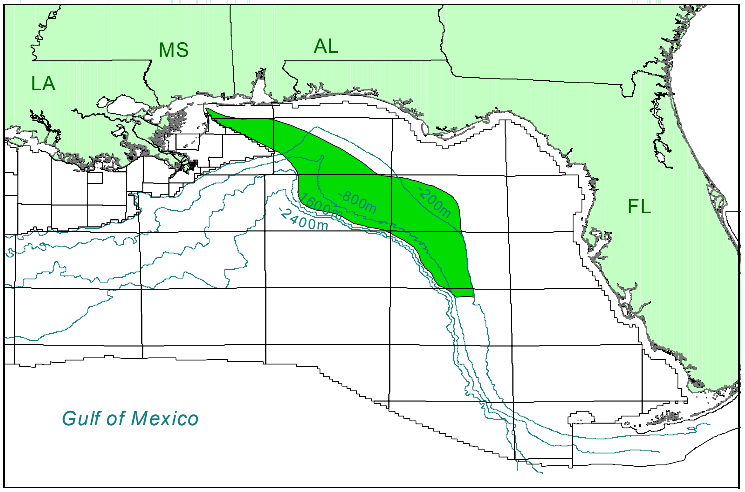

Figure 1. Play location.

LK3 B2 Sligo Formation 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	–	<.001	0.042	0.009
Mean	4	0.016	0.210	0.054
5th percentile	–	0.077	0.562	0.168
Total Endowment				
95th percentile	–	<.001	0.042	0.009
Mean	4	0.016	0.210	0.054
5th percentile	–	0.077	0.562	0.168

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The frontier Lower Lower Cretaceous Carbonate Sligo Formation (LK3 B2) play is defined by reef and reef talus of the Sligo Formation. The LK3 B2 play extends from the Mobile area southeastward along the Lower Cretaceous shelf edge through the northern Viosca Knoll, Destin Dome, DeSoto Canyon, Florida Middle Ground, and The Elbow Areas (figure 1). The play contains no fields in the Gulf of Mexico Region as of January 1, 1999. In the 1995 assessment (Lore *et al.*, 1999), this play was included in the Lower Cretaceous Carbonate (LK CB) play.

Updip to the northeast, the play is limited by backreef lagoonal wackestones and mudstones interbedded with regional transgressive marine shales (Yurewicz et al., 1993). Downdip to the southwest, the play grades into a forereef facies of dark shales and carbonate muds.

Play Characteristics

Objectives in the LK3 B2 play include algal/rudist reef boundstones flanked by grainstone talus and oolitic packstones. The grainstones and packstones trend subparallel to the boundstone reefs. Porous zones occur within dolomitized reefal material and in flanking talus. Potential hydrocarbon traps are formed by small anticlines located within such porous zones. Reservoir permeability and porosity are controlled by a combination of primary fabric, diagenetic leaching, and dolomitization. Potential source rocks are laminated shales and micrites of the Lower Cretaceous Smackover Formation (Petty and Post, 2000).

Discoveries

No discoveries have been declared in the LK3 B2 play prior to this study's January 1, 1999, cutoff

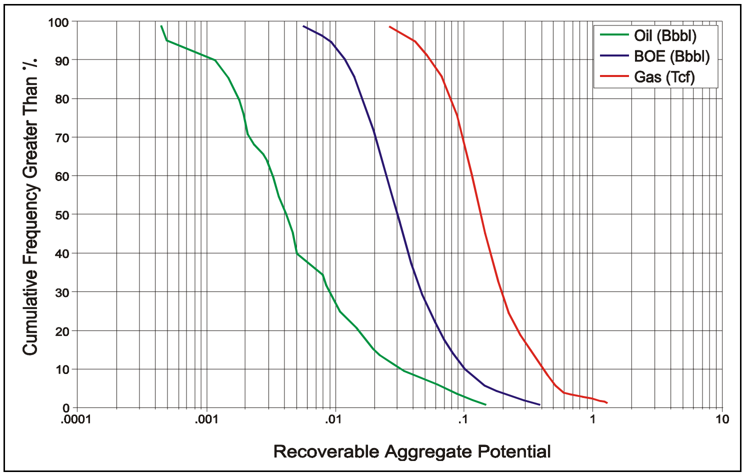

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

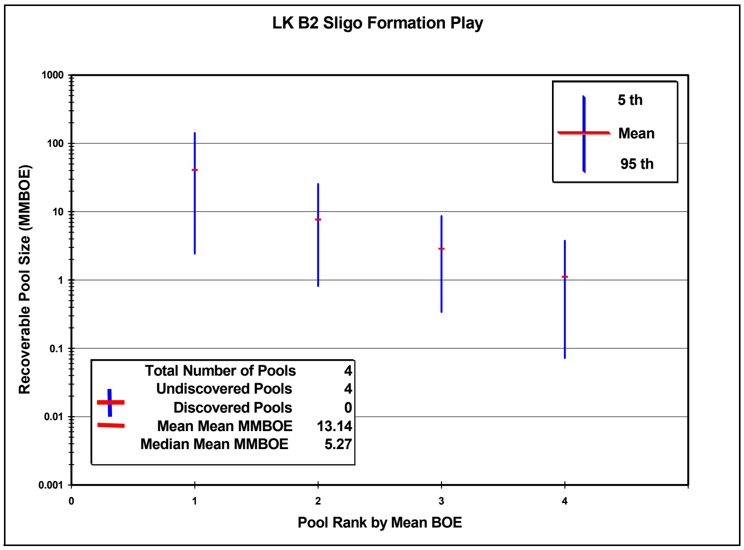

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

date. The Sligo Formation has been cored in two wells in the Gulf of Mexico Region, one in the Pensacola 948 block and the other in the Mobile 821 block. The Main Pass 253 number 6 well targeted a large Sligo reef, but did not reach the objective.

Assessment Results

The marginal probability of hydrocarbons for the LK3 B2 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of <0.001 to 0.077 Bbo and 0.042 to 0.562 Tcfg at the 95th and 5th percentiles, respectively (figure 2). Mean UCRR are estimated at 0.016 Bbo and 0.210 Tcfg (0.054 BBOE). The play's total endowment equals UCRR. These undiscovered resources might occur in as many as four pools (figure 4). The largest undiscovered pool has a mean size of 41 MMBOE. For all four undiscovered pools in the LK3 B2 play, the mean mean size is 13 MMBOE.

References

Lore, G.L., K.M. Ross, B.J. Bascle, L.D. Nixon, and R.J. Klazynski. 1999. Assessment of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1995: Minerals Management Service OCS Report MMS 99-0034, CD-ROM.

Petty, A.J. and P.J. Post. 2000. Unpublished internal Minerals Management Service report.

Yurewicz, D.A., T.B. Marler, K.A. Meyerholtz, and F.X. Siroky. 1993. Early Cretaceous carbonate platform, north rim of the Gulf of Mexico, Mississippi and Louisiana: *in* J.A. Toni Simo, R.W. Scott, and J.-P. Masse (eds.), Cretaceous carbonate platforms: American Association of Petroleum Geologists Memoir 56, p. 81-96.

Lower Cretaceous Carbonate Sunniland Formation (LK8-LK3 B1) Play *Orbitolina texana* biozone

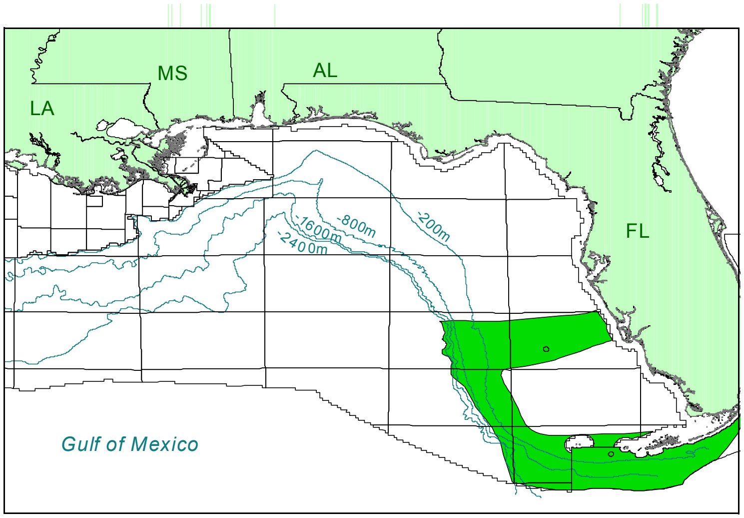

Figure 1. Play location.

LK8- LK3 B1 Sunniland 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	--	0.236	0.017	0.239
Mean	33	0.421	0.030	0.426
5th percentile	--	0.782	0.056	0.792
Total Endowment				
95th percentile	--	0.236	0.017	0.239
Mean	33	0.421	0.030	0.426
5th percentile	--	0.782	0.056	0.792

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The frontier Lower Cretaceous Carbonate Sunniland Formation (LK8-LK3 B1) play occurs within the *Orbitolina texana* biozone. The play is located along the perimeter of the Lower Cretaceous Carbonate South Florida Basin (LK8-LK3 B2) play (figure 1). In the 1995 assessment (Lore et al., 1999), this play was referred to as the Lower Cretaceous Sunniland Carbonate (LK SUN) play.

To the north, a facies change from carbonates to siliciclastics limits the LK8-LK3 B1 play. To the south and west, the play is limited by rudistid bioherms of various Lower Cretaceous shelf-margin carbonate plays (LK3 B1, LK3 B2, LK6 B1, and LK8 B1). To the east, the play continues onshore into Florida as the producing Sunniland Trend.

Play Characteristics

The LK8-LK3 B1 play comprises 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. Potential reservoirs in the LK8-LK3 B1 play primarily include patch reefs built up on local basement highs. Other reservoirs might include platform grainstones and reef talus. Potential source rocks are thought to exist in locally occurring, Early Cretaceous carbonates. Early Cretaceous marine shales, carbonate mudstones, and anhydrites provide seals for the LK8-LK3 B1 play.

Discoveries

Approximately 400 wells have been drilled in 14 fields in the onshore Sunniland Trend (including the Marquesa Keys wells). About 100 MMBOE has been produced in the Trend. The first discovery was the Sunniland Field, Collier County, Flor-

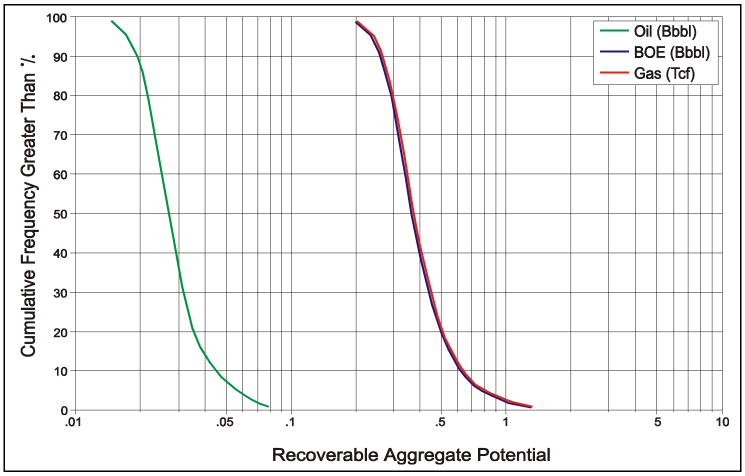

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

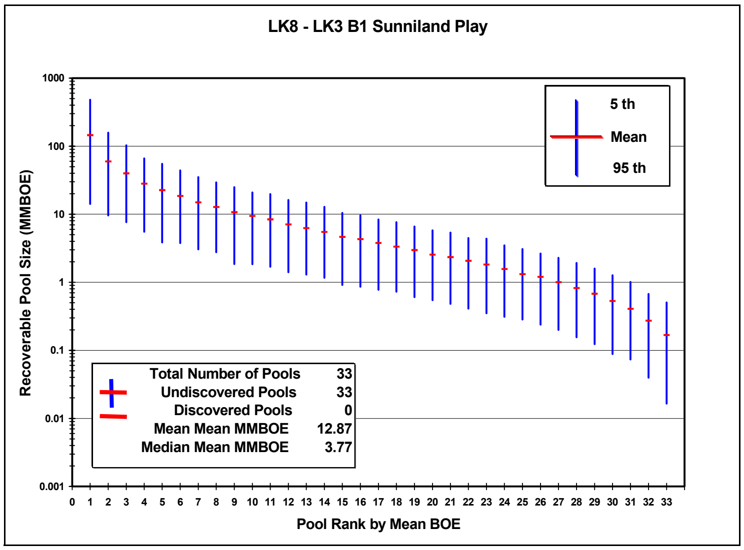

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

ida, in 1943. The most recent discovery, prior to this study's cutoff date of January 1, 1999, occurred in 1985 in the Corkscrew Field, Collier County, Florida.

The LK8-LK3 B1 play is not currently productive in the Federal OCS. Two wells in the offshore State waters of the Florida Straits contained hydrocarbons. Seven wells in the Federal OCS have tested the LK8-LK3 B1 play. Two of these wells encountered oil shows: 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.

Assessment Results

Because the LK8-LK3 B1 play is not productive in the Federal OCS area, the productive Sunniland Trend of onshore Florida was used as an analog for this assessment. Development of the Sunniland Trend onshore is at a mature stage, with approximately 90 percent of the analog area being explored. Analog fields average greater than 90 percent oil with production from the analog fields ranging from <1 to 43 MMBOE. Net pay ranges from <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^{o} API, and GOR's of 10 to 890 scf/stb.

The marginal probability of hydrocarbons in the LK8-LK3 B1 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.236 to 0.782 Bbo and 0.017 to 0.056 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 2). Mean UCRR are estimated at 0.421 Bbo and 0.030 Tcfg (0.426 BBOE). These undiscovered resources might occur in as many as 33 pools (figure 3). These pools have a mean mean size of 13 MMBOE.

Lower Cretaceous Carbonate South Florida Basin (LK8-LK3 B2) Play *Choffatella decipiens* through *Dictyoconus walnutensis* biozones

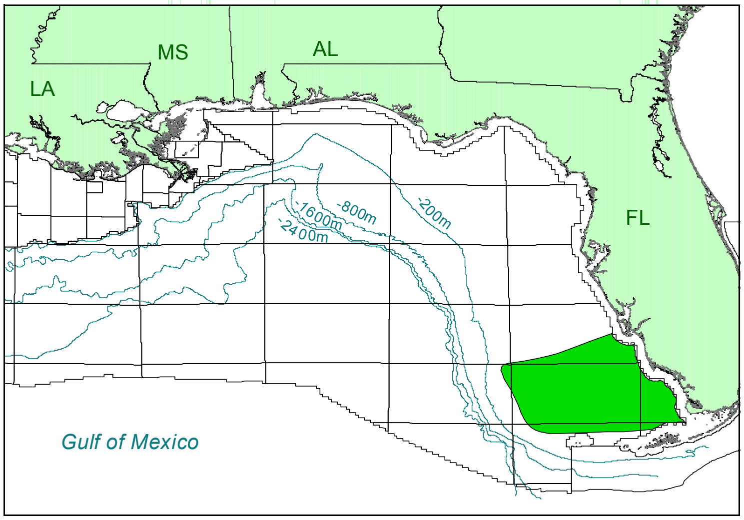

Figure 1. Play location.

LK8- LK3 B2 S. Florida Basin 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	--	0.375	0.027	0.380
Mean	58	0.583	0.046	0.591
5th percentile	--	0.964	0.089	0.981
Total Endowment				
95th percentile	--	0.375	0.027	0.380
Mean	58	0.583	0.046	0.591
5th percentile	--	0.964	0.089	0.981

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Lower Cretaceous Carbonate South Florida Basin (LK8-LK3 B2) play occurs within the *Choffatella decipiens*, *Orbitolina texana*, and *Dictyoconus walnutensis* biozones. The play is located in the interior of the South Florida Basin (figure 1). The LK8-LK3 B2 play is bounded in all directions by the Lower Cretaceous Carbonate Sunniland Formation (LK8-LK3 B2) play. In the 1995 assessment (Lore et al., 1999), this play was referred to as the Lower Cretaceous South Florida Basin Carbonate (LK SFB) play.

Play Characteristics

The LK8-LK3 B2 play consists of platform limestones, patch reefs, reef talus, and porous dolomites of the Bone Island, Pumpkin Bay, and Sunniland Formations, and the Brown Dolomite Zone of the Lehigh Acres Formation. Potential traps are mainly stratigraphic and are related to platform limestones, patch reefs, and reef talus. Potential source rocks are thought to be locally occurring, Early Cretaceous carbonates. Early Cretaceous marine shales, micrites, and anhydrites provide seals for the LK8-LK3 B2 play.

Discoveries

No Federal OCS wells have been drilled in this play.

Assessment Results

Because the LK8-LK3 B2 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). Development of the Sunniland Trend onshore is at a mature stage, with approximately 90 percent of the analog area being explored. Analog fields average greater than 90 percent oil with production ranging from

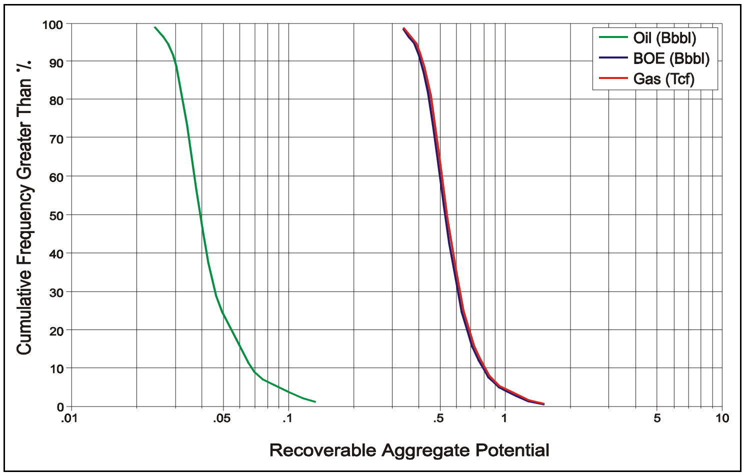

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

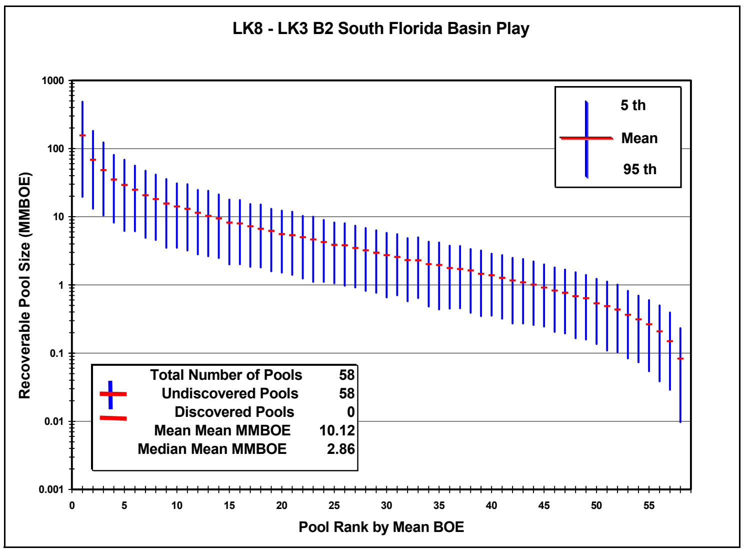

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

<1 to 43 MMBOE. Net pay ranges from <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^{o} API, and GOR's of 10 to 890 scf/stb.

The marginal probability of hydrocarbons for the LK8-LK3 B2 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.375 to 0.964 Bbo and 0.027 to 0.089 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 2). Mean UCRR are estimated at 0.583 Bbo and 0.046 Tcfg (0.591 BBOE). These undiscovered resources might occur in as many as 58 pools, which have a mean size range of <1 to 156 MMBOE (figure 3). These pools have a mean mean size of 10 MMBOE in total reserves. The five largest undiscovered pools have a mean mean size of 67 MMBOE in total reserves.

Lower Cretaceous Clastic (LK8-LK3 C3) Play

***Schuleridea lacustris* through *Lenticulina washitaensis* biozones**

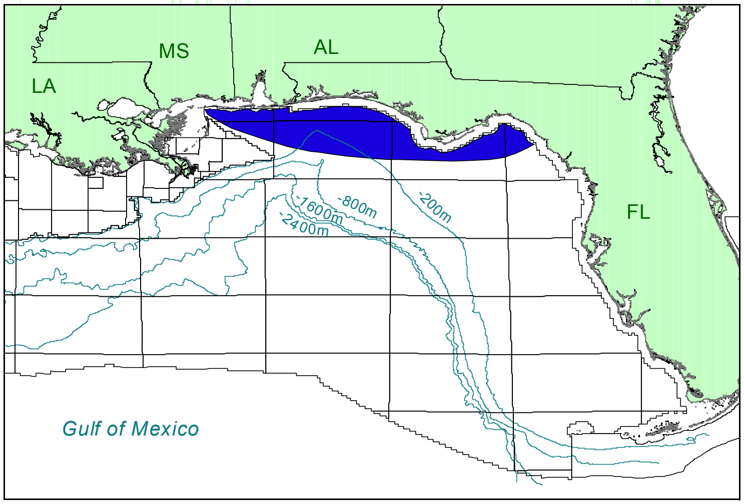

Figure 1. Play location.

LK8 - LK3 C3 Lwr Cretaceous Clastic Marginal Probability = 0.64	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

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The frontier Lower Cretaceous Clastic (LK8-LK3 C3) play occurs within the *Schuleridea lacustris, Eocytheropteron trinitiensis*, *Cythereis fredericksburgensis*, *Fossocytheridea lenoirensis*, and *Lenticulina washitaensis* biozones. The play is also defined by a mostly aggradational depositional style, with some progradational, resulting from siliciclastic sedimentation in barrier bar and channel facies of the Hosston, Paluxy, and Dantzler Formations. In the 1995 assessment (Lore *et al.,* 1999), this play was designated the LK CL play.

The LK8-LK3 C3 play extends south from Mississippi, Alabama, and Florida offshore State waters into the northern portions of the Mobile, Destin Dome, Apalachicola, and Gainesville Areas (figure 1). The downdip limit is located where lower Cretaceous clastic sands interfinger with prodelta shales.

Play Characteristics

The Hosston Formation has a gross interval thickness 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 thickest over the Destin Dome, but thins to the south away from its source area. Structural traps in the play are related to salt tectonics and faulting, while stratigraphic traps are related to facies changes. The upper Jurassic Smackover Formation is the main source rock for the LK8-LK3 C3 play, while lower Cretaceous marine shales provide seals.

Discoveries

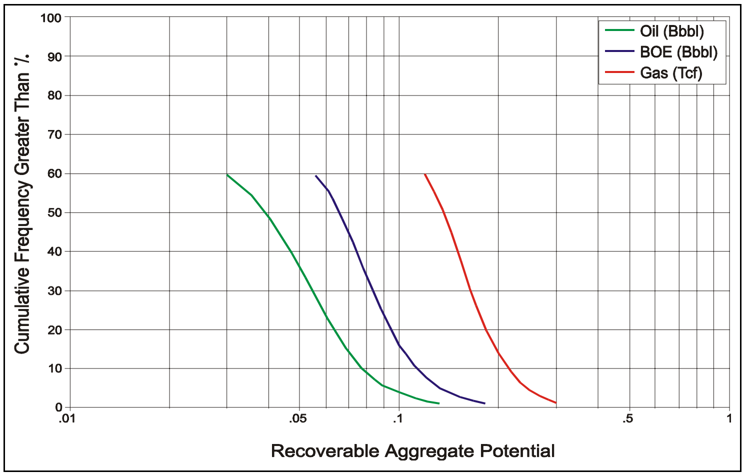

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

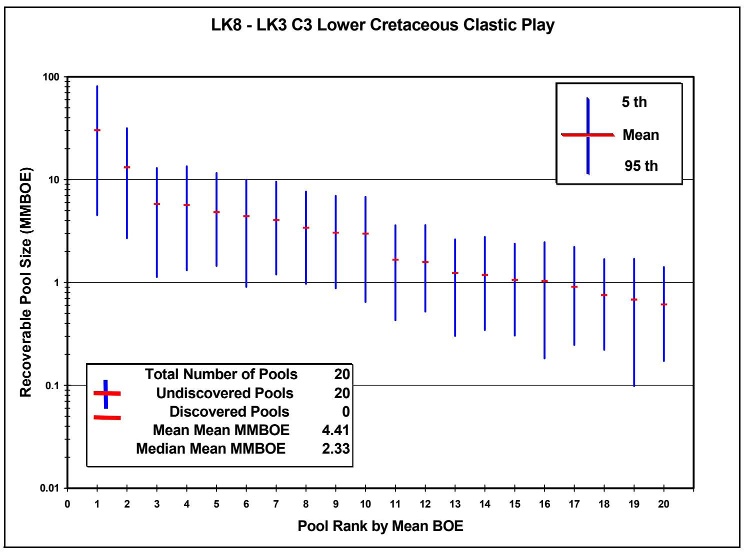

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Of the Federal OCS wells that penetrated this play, all were dry; however, this play was probably not the primary exploration target for these wells.

Assessment Results

Because the LK8-LK3 C3 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). Drilling in the analog area is at a mature stage with approximately 75 percent of the analog area being 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 LK8-LK3 C3 play is 0.64. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) 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). Mean UCRR are estimated at 0.037 Bbo and 0.110 Tcfg (0.057 BBOE). These undiscovered resources might occur in as many as 20 pools. These pools have an unrisked mean size range of <1 to 30 MMBOE (figure 4) and an unrisked mean mean size forecast at 4 MMBOE.

Reference

Lore, G.L., K.M. Ross, B.J. Bascle, L.D. Nixon, and R.J. Klazynski. 1999. Assessment of conventionally recoverable hydrocarbon resources of the Gulf of

Mexico and Atlantic Outer Continental Shelf as of January 1, 1995: Minerals Management Service OCS Report MMS 99-0034, CD-ROM.

Cretaceous Buried Hill Drape (UK5-LK3 BC2) Play

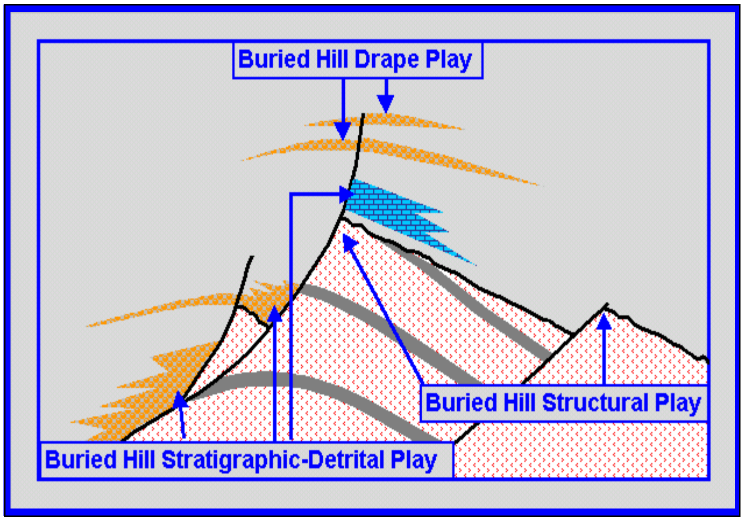

Figure 1. Diagrammatic cross-section illustrating the Buried Hills plays, after Zhai and Zha (1982).

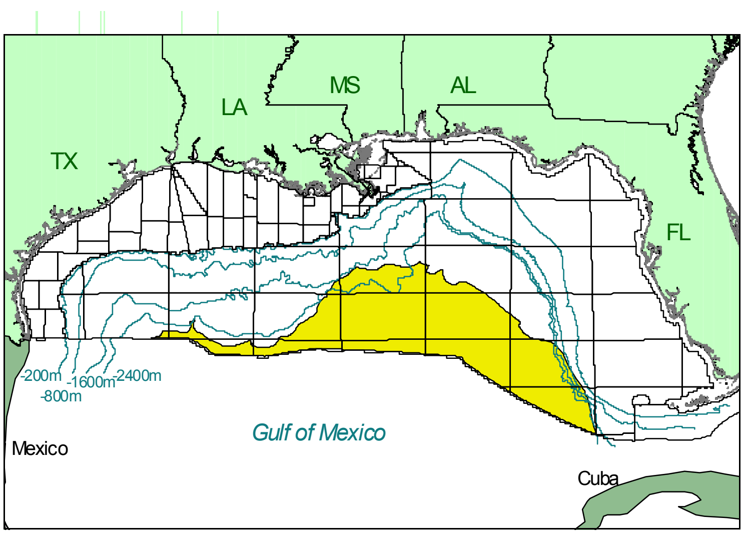

Figure 2. Play location.

<table>
<tr><th colspan="2">Buried Hill Conceptual Plays</th></tr>
<tr><td rowspan="3">Buried Hill Drape Plays</td><td>Lower Tertiary Buried Hill Drape (LE-LL BC1) Play</td></tr>
<tr><td>Cretaceous Buried Hill Drape (UK5-LK3 BC2) Play</td></tr>
<tr><td>Upper Jurassic Buried Hill Drape (UJ4-BC1) Play</td></tr>
<tr><td colspan="2">Upper Cretaceous to Upper Jurassic Buried Hill
Stratigraphic-Detrital (UK5-UJ4 BC3) Play</td></tr>
<tr><td colspan="2">Mesozoic Structural Buried Hill (UK5-LTR BC4) Play</td></tr>
</table>

Figure 3. General stratigraphic relationships of the conceptual Buried Hill plays.

Play Description

The conceptual Cretaceous Buried Hill Drape (UK5-LK3 BC2) play is defined by source, reservoir, and seal lithologies consisting of seismically correlated sediments of probable Cretaceous age, and by compaction of sediments over buried hill features found in the ultra-deepwater Gulf of Mexico Region (figure 1). The play is recognized primarily in the Walker Ridge and Lund Areas. However, it appears that the UK5-LK3 BC2 play may extend from Alaminos Canyon to the Dry Tortugas Areas through areas of sparse seismic data (figure 2). The play is bounded to the northwest and northeast by the depositional limit of the Louann Salt, while the OCS boundary defines the southern and western limits of the play.

The following discussion is from Post (2000), unless otherwise noted.

Play Characteristics

Buried hills are a series of paleostructural highs that originated during the Mesozoic rifting event that formed the Gulf of Mexico (refer to the Mesozoic Structural Buried Hill [UK5-LTR BC4] play; figure 3). Regional seismic analyses indicate that during the Latest Cretaceous, some of the buried hills were onlapped and buried by sediments (refer to the Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital [UK5-UJ4 BC3] play; figure 3). As the hills were buried, structural closure developed by differential compaction of these sediments over the more rigid, less compacting, buried hills.

Reflecting increased water depth and siliciclastic input, earlier high-energy upper Jurassic carbonate and siliciclastic deposits directly related to the buried hills, or high-energy upper Jurassic carbonate and

UK5-LK3 BC2 Cretaceous Buried Hill Drape Marginal Probability = 0.08	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	14	0.028	0.109	0.048
5th percentile	--	0.169	0.601	0.290
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	14	0.028	0.109	0.048
5th percentile	--	0.169	0.601	0.290

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

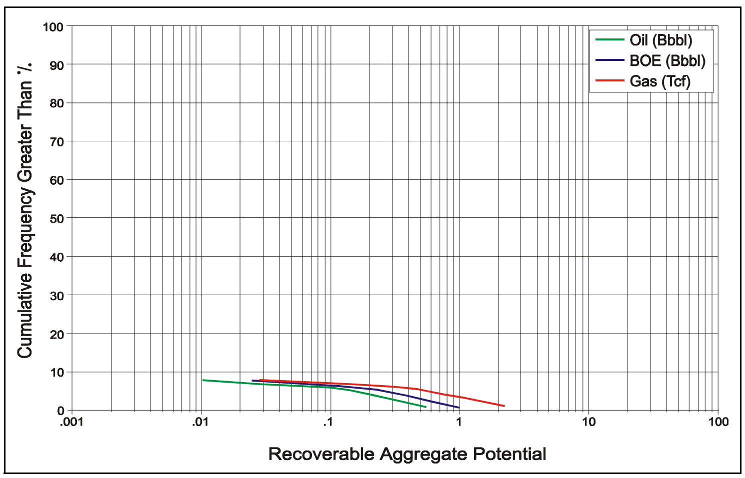

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

siliciclastic sediments deposited over the buried hills, were succeeded by deepwater mudstones, marls, chalks and siliciclastics (refer to the Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital [UK5-UJ4 BC3] play and to the Upper Jurassic Buried Hill Drape [UJ4 BC1] play). In addition, redeposited chalks could have developed during the Late Cretaceous as water depths over the buried hills were increasing. In their depositional setting and reservoir characteristics, these chalks are likely to be more analogous to the prolific chalk reservoirs of the Danish and Norwegian sectors of the North Sea (Scholle, 1977a, 1977b; Megson, 1992; Kristensen *et al.*, 1995; Brasher and Vagle, 1996) than to chalks found in the more updip parts of the Gulf of Mexico chalks, e.g., the Austin Chalk. As compaction over the buried hills continued, some fracture enhancement of the reservoirs may have occurred.

Geochemical typing of hydrocarbon seeps in the northwestern half of the Lund Area (Wenger *et al.*, 1994; Hood *et al.*, *in press*) shows that these hydrocarbons come from Late Jurassic source rocks (centered on the Oxfordian). Geohistory modeling indicates that several other source intervals could also provide hydrocarbons for the UK5-LK3 BC2 play. These are most likely to include source beds from the Late Jurassic (centered on the Tithonian), the Pre-Mid Cretaceous Sequence Boundary (MCSB), Early Cretaceous (centered on the Aptian), or the Post-MCSB Late Cretaceous (centered on the Turonian). Additionally, if present, syn-rift graben-fill source rocks, equivalent to the “Rosewood axial shift sequence” (White *et al.*, 1999), could furnish hydrocarbons for the play. Development of cross-stratal migration pathways to facilitate reservoir charge is an important issue to consider in charging these reservoirs. Wenger *et al.* (1994) and Hood *et al.* (*in press*) do not show any seeps in the southeastern half of the Lund

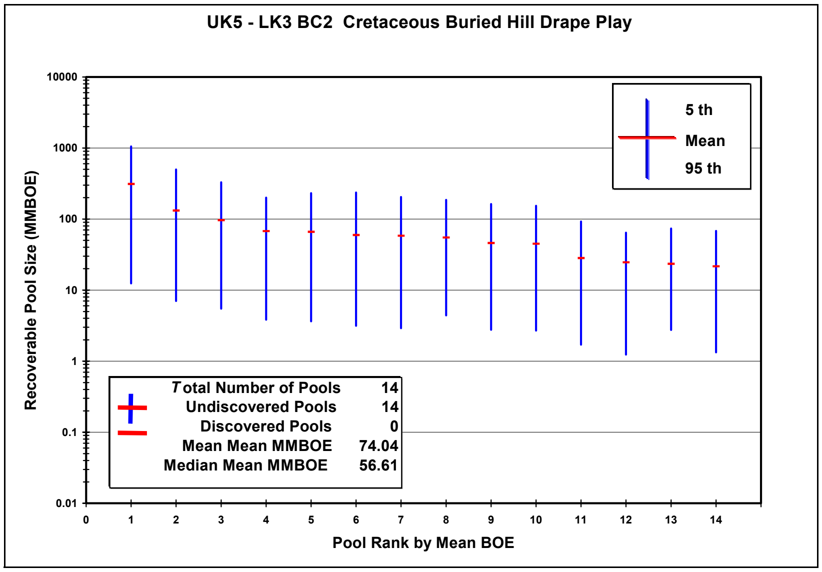

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Area.

Seals for traps and reservoirs are likely to be either source rocks or other fine-grained deepwater deposits.

Discoveries

No wells have been drilled in the UK5-LK3 BC2 play prior to this study's January 1, 1999, cutoff date.

Assessment Results

The marginal probability of hydrocarbons for the UK5-LK3 BC2 play is 0.08. The play contains a mean total endowment of 0.028 Bbo and 0.109 Tcfg (0.048 BBOE) (table 1).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 0.169 Bbo and 0.000 to 0.601 Tcfg at the 95th and 5th percentiles, respectively (table 1; figure 4). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 14 pools. The largest undiscovered pool has a mean size of 312 MMBOE (figure 5). The mean mean size of the five largest undiscovered pools is 135 MMBOE.

Buried hills represent a prolific play type that produces in Southeast and East Asia, North and South America, Africa, Europe, and Australasia. A number of references were used to develop the analogs used in this play. Among the best are Landes *et al.,* 1960; Chung-Hsiang P'An, 1982; Zhai and Zha, 1982; Zheng, 1988; Yu and Li, 1989; Horn, 1990; Tong and Huang, 1991; Areshev *et al.,* 1992; Tran Canh et al., 1994; Blanche and Blanche, 1997; and Sladen, 1997.

Reservoir characteristics for the Cretaceous Buried Hill Drape were developed using analogs based on chalk reservoirs from the Danish and Norwegian sectors of the North Sea.

Exploration Future

Although most of the Mesozoic source rocks in the Gulf of Mexico could provide hydrocarbons to the play's reservoirs, the primary risk in this play appears to be defining the cross-stratal vertical migration routes from these older source rocks to the younger reservoirs. In addition, delineation of the objective reservoirs will be difficult in this play.

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Cretaceous Perdido Fold Belt (UK5-LK3 X4) Play

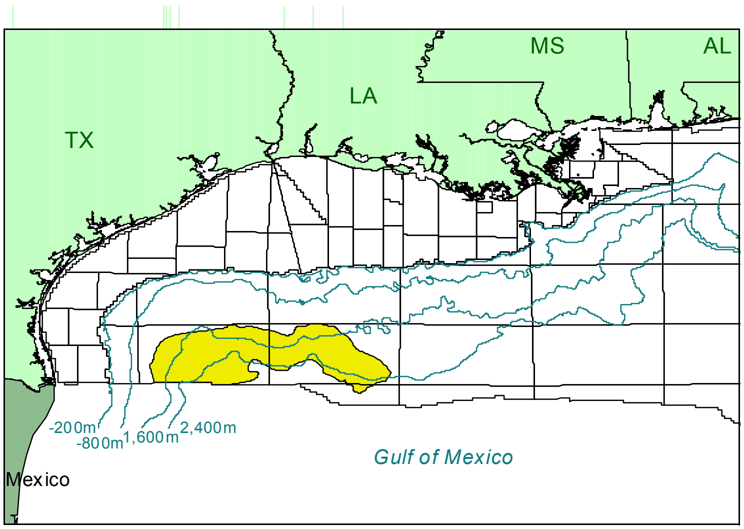

Figure 1. Play location.

UK5-LK3 X4 Cretaceous Perdido Fold Belt Marginal Probability = 0.40	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	1.012	4.280	1.773
5th percentile	--	4.426	18.769	7.498
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	20	1.012	4.280	1.773
5th percentile	--	4.426	18.769	7.498

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Cretaceous Perdido Fold Belt (UK5-LK3 X4) play is defined by source, reservoir, and seal lithologies consisting of seismically correlated sediments of probable Cretaceous age, and large northeast-southwest trending salt-cored folds. The play is located in the Alaminos Canyon and Keathley Canyon Areas of the Gulf of Mexico Region (figure 1), with much of the play extending under salt. The following discussion is from Post (2000), unless otherwise noted.

Basinward of the Sigsbee Salt Canopy, the play extends from the Alaminos Canyon Area offshore Texas into Mexican national waters. North, east, and west of this area, salt canopies obscure subsalt geometries making it difficult to define the play area. However, interpretation of regional seismic data suggests that the play may extend eastward into the Keathley Canyon Area offshore Louisiana. The northeastern play boundary may either occur at a transfer zone or by a transition into the Mississippi Fan Fold Belt (UPL-LL X2) play. Although the northern limit of the play is interpretive because of the deterioration of seismic data quality under the Salt Canopy, the most basinward, counter-regional faults/salt welds related to the development of the canopy provide a geologically reasonable northward limit.

Play Characteristics

The structure and stratigraphy of the basin have been inferred using geologic (from onshore and shallow water wells) and geophysical data (seismic, gravity and magnetics), as well as models of the evolution of the Gulf of Mexico basin (Adams, 1997; Marton and Buffler, 1994; Bartok, 1993; Pindell, 1993; Ewing, 1991; Sawyer *et al.*, 1991; Woods et al., 1991; Salvador, 1991a

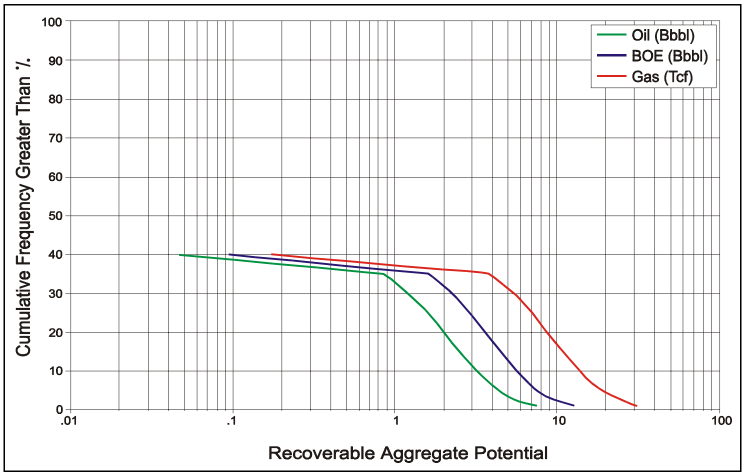

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

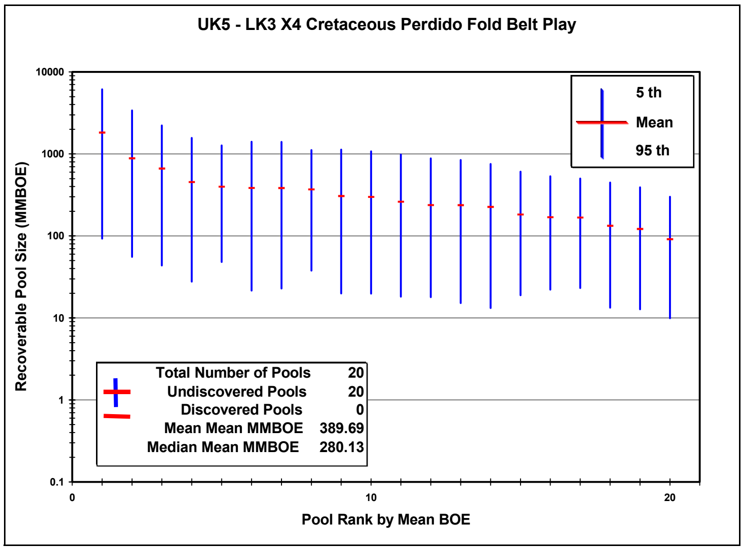

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

and b; McFarlan, 1991; Sohl *et al.*, 1991; Van Siclen, 1984). These data indicate that the Late Jurassic Louann Salt section overlies either Triassic syn-rift sediments, attenuated continental crust, oceanic crust, or sub-aerially erupted late-rift to early-drift onset mafics/volcanics that pre-date seafloor spreading. Late Jurassic to Early Cretaceous age limestones, calcareous to possibly non-calcareous mudstones, marls, and chalks probably succeed the salt. Overlying the Mid-Cretaceous (Mid-Cenomanian) Sequence Boundary are probable Late Cretaceous limestones, chalks, marls, and shales possibly interbedded with deepwater siliciclastic sediments (probably derived from Laramide orogenic structures).

Reservoir development in postulated Cretaceous limestones is likely to rely on fracture-enhanced porosity and permeability. A variety of porosity and permeability preserving and/or enhancing mechanisms may help create viable Mesozoic chalk reservoirs. These include overpressuring, early hydrocarbon migration, fracturing after lithification, redeposition of chalks by gravity flows and currents, and absence of reservoir quality intervals above or below the chalk. Interbedded shales, mudstones, chalks, and marls may provide seals for reservoirs.

Structurally, the Perdido Fold Belt is located at the basinward limit of a balanced and linked, complex system in which updip sedimentary loading and gravity-driven collapse associated with extension are accommodated by the extrusion of salt canopies and downdip contraction. Folding in the Perdido Fold Belt resulting from downdip contraction has created some of the largest structural closures in the Gulf of Mexico Region. Where the play is exposed basinward of the Sigsbee Salt Canopy in the Alaminos Canyon Area, individual structural culminations can exceed 40,000 acres and have vertical closures of up to 4,000 feet. The folds occur in a series of subparallel salt-cored buckle folds with symmetrical to asymmetrical geometries, with high-angle reverse faults on one or both fold limbs.

The main stage of fold development involved Late Jurassic to Eocene sediments and occurred primarily during the Early Oligocene to possibly Early Miocene in response to updip Paleogene sedimentary loading and accompanying extension. (Ages are after Berggren *et al.,* 1995.) Deformation on the most basinward folds appears to terminate at the end of the Early Oligocene, whereas deformation on folds to the northwest may have continued into the Late Oligocene or Early Miocene, as evidenced by the thicker salt cores and higher relief. A minor phase of reactivation in the Middle and Late Miocene affects some folds. A late stage of localized secondary uplift occurs from the Pliocene to present-day in those folds that have the thickest Louann Salt and are closest to the Sigsbee Salt Canopy. Possible causes for this most recent phase of structural uplift may be renewed shortening or a broad loading phenomenon related to the emplacement of the Sigsbee Salt Canopy (Trudgill *et al.*, 1999; Fiduk *et al.*, 1999).

Discoveries

One well (AC600) has been drilled in the Cenozoic section of the play prior to this study's cutoff date of January 1, 1999. Mechanical difficulties prevented the well from reaching its primary Mesozoic age reservoir targets, and thus the stratigraphy of the deeper Mesozoic units remains speculative. Reservoir characteristics of the play were forecast primarily using analogs developed from chalk reservoirs in the Danish and Norwegian sectors of the North Sea.

Hydrocarbon seeps in the Alaminos Canyon Area have been geochemically typed to two Late Jurassic source intervals (centered on the Oxfordian, and centered on the Tithonian), and the Lower Tertiary (centered on the Eocene) by Wenger *et al.* (1994), and Hood *et al.* (*in press*).

Assessment Results

The marginal probability of hydrocarbons for the UK5-LK3 X4 play is 0.40. The play contains a mean total endowment of 1.012 Bbo and 4.280 Tcfg (1.773 BBOE) (table 1).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 4.426 Bbo and 0.000 to 18.769 Tcfg at the 95th and 5th percentiles, respectively (table 1; figure 3). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 20 pools. The largest undiscovered pool has a mean size of 1,819 MMBOE (figure 4). The mean mean size of the five largest undiscovered pools is 844 MMBOE and the mean mean size of all 20 undiscovered pools is 390 MMBOE. Nineteen of the 20 undiscovered pools are forecast to contain more than 100 MMBOE in proved reserves.

Exploration Future

Hydrocarbon seeps within the play's area indicate hydrocarbon generation, expulsion, and migration. In addition, the play contains some of the largest known structural closures in the Gulf of Mexico Region. The potential for future significant discoveries within this untested deepwater play appears promising, though the presence of adequate porosity and permeability in possible deepwater carbonate and siliciclastic reservoirs remains the primary risk for the play.

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Cretaceous Mississippi Fan Fold Belt (UK5-LK3 X5) Play

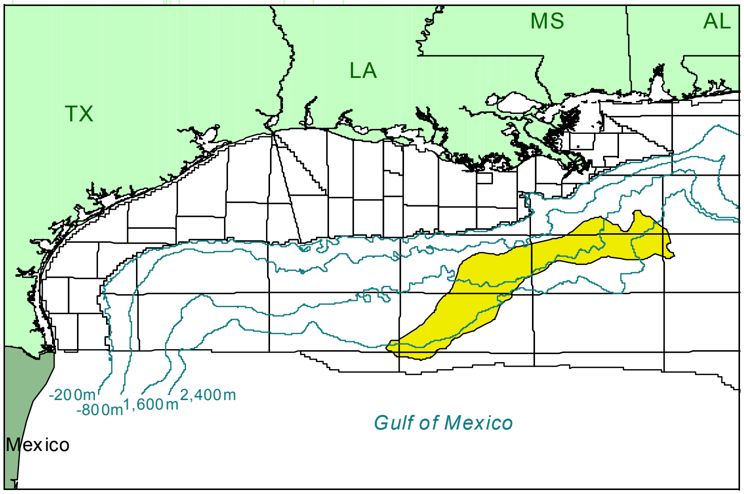

Figure 1. Play location.

UK5-LK3 X5 Cretaceous Miss Fan Fold Belt Marginal Probability = 0.40	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	22	1.257	5.075	2.160
5th percentile	--	5.298	21.421	8.902
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	22	1.257	5.075	2.160
5th percentile	--	5.298	21.421	8.902

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Cretaceous Mississippi Fan Fold Belt (UK5-LK3 X5) play is defined by source, reservoir, and seal lithologies consisting of seismically correlated sediments of probable Cretaceous age, and a series of east-northeast trending salt-cored folds. The play is located primarily in the Walker Ridge, Green Canyon, Atwater Valley, and southern Mississippi Canyon Areas of the Gulf of Mexico Region (figure 1), with much of the play extending under salt. The following discussion is from Post (2000), unless otherwise noted.

Landward, the fold belt extends under the Sigsbee Salt Canopy where the most basinward, counter-regional fault/salt weld related to salt canopy development is used as a geologically reasonable updip limit for the play. To the northeast, the play boundary is difficult to define because of structural overprinting. Regional analysis suggests that it may be coincident with the Pearl River Transfer. The southwestern play boundary may occur at either another transfer zone or by a transition into the Perdido Fold Belt. Because the boundary lies beneath the Salt Canopy, the connection and relationship between the two fold belts remains speculative.

Although fold belt structures generally extend basinward to the depositional limit of underlying Louann Salt, there are indications in the northeastern part of the area that folding may extend beyond this limit. Continued updip extension during the Pliocene to Recent caused downdip compression regardless of whether the salt décollement is present. Exhausting the supply of mobile salt shifts the detachment to an incompetent unit above the salt, probably a shale unit.

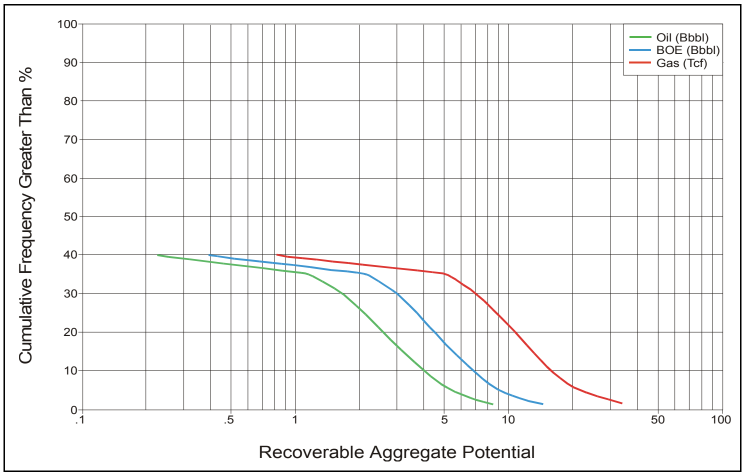

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

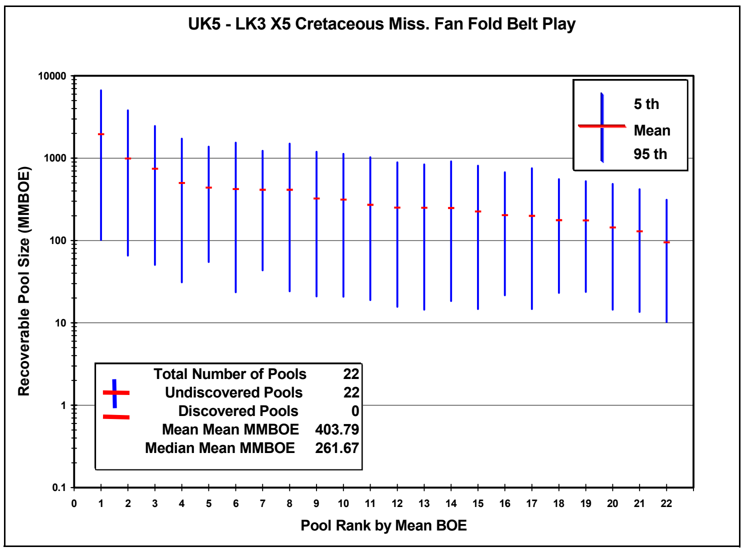

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Play Characteristics

The structure and stratigraphy of the basin have been inferred using geologic (from onshore and shallow-water wells) and geophysical data (seismic, gravity and magnetics), as well as models of the evolution of the Gulf of Mexico basin (Adams, 1997; Marton and Buffler, 1994; Bartok, 1993; Pindell, 1993; Ewing, 1991; Sawyer *et al.*, 1991; Woods *et al*., 1991; Salvador, 1991a and b; McFarlan, 1991; Sohl *et al.*, 1991; Van Siclen, 1984). These data indicate that the Late Jurassic Louann Salt section overlies either Triassic syn-rift sediments, attenuated continental crust, oceanic crust, or sub-aerially erupted late-rift to early-drift onset mafics/volcanics that pre-date seafloor spreading. Late Jurassic to Early Cretaceous age limestones, calcareous to possibly noncalcareous mudstones, marls, and chalks probably succeed the salt. The Mid-Cretaceous (Mid-Cenomanian) Sequence Boundary is overlain by Late Cretaceous limestones, chalks, marls, and shales, possibly interbedded with deepwater siliciclastic sediments (probably derived from Laramide orogenic structures).

Postulated reservoirs are deepwater limestone, chalks, and siliciclastics. Reservoir development in Cretaceous deepwater limestones is likely to rely on fracture-enhanced porosity and permeability. Viable Cretaceous chalk reservoirs will likely rely upon a variety of porosity and permeability preserving and/or enhancing mechanisms, including overpressuring, early hydrocarbon migration, fracturing after lithification, redeposition of chalks by gravity flows and currents, and absence of reservoir quality intervals above or below the chalk. Post Mid-Cretaceous Sequence Boundary deepwater siliciclastics interbebbed with carbonates offer the third postulated reservoir type. Interbedded shales, mudstones, chalks, and marls may provide seals for reservoirs.

Structurally, the Mississippi

Fan Fold Belt is located at the basinward limit of a balanced and linked, complex system in which updip sedimentary loading and gravity-driven collapse associated with extension is accommodated by the extrusion of salt canopies and downdip contraction. Structures in the play consist of a series of east-northeast to south-southwest-trending, subparallel, salt-cored folds. The folds are asymmetric, basinward-vergent, with landward-dipping, typically listric reverse faults that cut the basinward limb of the fold.

The Late Jurassic-Cretaceous seismic interval thins on some structures in the play. This is interpreted to indicate a possible local, early structural growth stage contemporaneous with deposition in this section (Rowan *et al.*, 2000). The later, regional, early stage of fold development occurred between the Late Oligocene to Middle Miocene. The main growth stage of the folds, coincident with break-thrust development, took place during the Middle to Late Miocene in response to increased rates of sedimentation updip (Rowan *et al.*, 2000). Fold growth continued with only minor thrusting from the Late Miocene to Pleistocene.

Discoveries

No wells have penetrated the Cretaceous section of the Mississippi Fan Fold Belt prior to this study's cutoff date of January 1, 1999. However, some of the largest fields in the Gulf of Mexico Region have been discovered in siliciclastics of the overlying Cenozoic Mississippi Fan Fold Belt (UPL-LL X2) play. Reservoir characteristics of the UK5-LK3 X5 play were forecast using analogs developed from chalk reservoirs in the Danish and Norwegian sectors of the North Sea.

In the eastern part of the play, two Late Jurassic source units, one centered on the Tithonian and the other centered on the Oxfordian, have been geochemically typed as being the sources for hydrocarbon seeps in the area. Tithonian sourced seeps are reported in the northern Atwater Valley Area and the northern part of the west-adjacent Green Canyon Area. In the southern part of Atwater Valley, the southeastern part of Green Canyon, the northeast portion, and the southern half of the Walker Ridge Area hydrocarbon seeps are typed as originating from Oxfordian source beds. A mixture of Tithonian and Oxfordian sourced seeps are found over most of the southern part of Green Canyon and in the northwestern part of the Walker Ridge Area (Wenger *et al.*, 1994; Hood *et al.*, *in press*).

Assessment Results

The marginal probability of hydrocarbons for the UK5-LK3 X5 play is 0.40. The play contains a mean total endowment of 1.257 Bbo and 5.075 Tcfg (2.160 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 5.298 Bbo and 0.000 to 21.421 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 22 pools, the largest of which has a mean size of 1,952 MMBOE (figure 4). The mean mean size of the five largest undiscovered pools is 925 MMBOE and the mean mean size of all undiscovered pools is 404 MMBOE. Twenty-one of the 22 undiscovered pools are forecast to contain BOE mean UCRR of over 100 MMBOE.

Exploration Future

Hydrocarbon seeps within the play's area indicate hydrocarbon generation, expulsion, and migration. In addition, large hydrocarbon accumulations exist in the overlying Cenozoic section. The potential for future significant discoveries within this untested deepwater play appears promising, though the presence of adequate porosity and permeability in possible carbonate and siliciclastic reservoirs remains the primary risk.

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Upper Jurassic Carbonate Smackover Formation (UJ4 B1) Play *Pseudo-cyclammina jaccardi* biozone

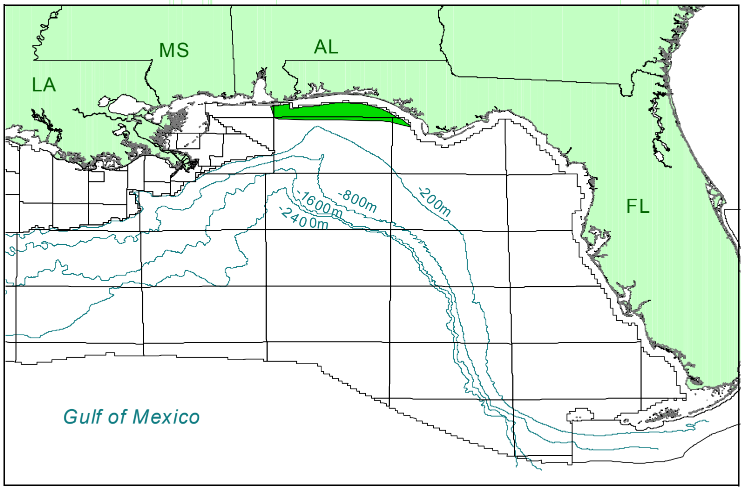

Figure 1. Play location.

UJ4 B1 Smackover Formation 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	--	0.004	0.013	0.008
Mean	5	0.059	0.104	0.078
5th percentile	--	0.205	0.309	0.265
Total Endowment				
95th percentile	--	0.004	0.013	0.008
Mean	5	0.059	0.104	0.078
5th percentile	--	0.205	0.309	0.265

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The frontier Upper Jurassic Carbonate Smackover (UJ4 B1) play occurs within the *Pseudo-cyclammina jaccardi* biozone. The play in Federal waters is located primarily in the Pensacola and northern Destin Dome Areas of the Gulf of Mexico Region (figure 1). Updip, the play extends onshore where it is productive, while downdip in the southern Destin Dome Area, the play grades into nonporous carbonate mudstones and shales. As of January 1, 1999, no Smackover fields have been discovered in the Federal OCS. In the 1995 assessment (Lore *et al.,* 1999), this play was referred to as the Upper Jurassic Smackover Carbonate (UU SMK) play.

Play Characteristics

The upper Smackover section consists of inner ramp, high-energy oolitic grainstones alternating with carbonate mudstones. Localized reefs and grainstone shoals developed on basement highs, over salt pillow structures, and over topographic highs related to large sand dunes of the underlying Norphlet Formation (refer to the Upper Jurassic Aggradational Norphlet Formation (UJ4 A1) play). Porosity in the grainstones is enhanced by dolomitization and subaerial leaching of carbonate cements. The downdip and lower Smackover section consists of laminated lime mudstones, wackestones, some porous packstones, siliciclastic siltstones, and shales.

Any paleostructural highs that favored reef and grainstone shoal development are drilling objectives. Later faulting along the flanks of these highs created fault traps, although most Smackover traps possess a strong stratigraphic component. Basal anhydrites of the overlying Buckner Formation create

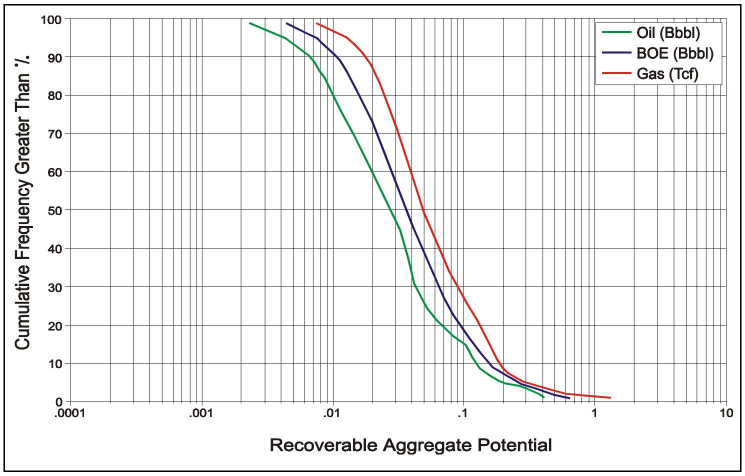

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

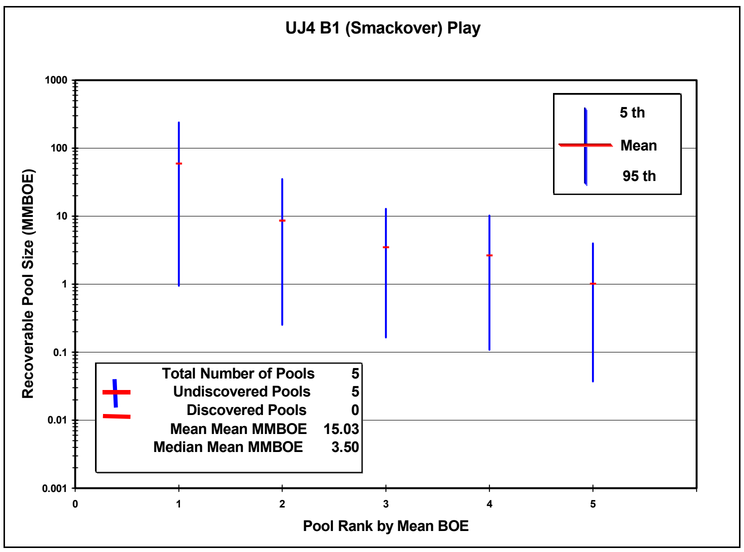

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

seals at the top of the Smackover section, while carbonate mudstones, anhydrites, and shales form seals within the formation. The Smackover is self-sourcing, with hydrocarbons being derived from the low-energy, algal-rich, laminated carbonate mudstones located near the base of the section.

Discoveries

While no Smackover field discoveries have been made in the Federal OCS, Texaco's well in Pensacola Block 996 encountered a 33-foot condensate show in the upper Smackover while drilling for deeper objectives. In addition, two wells in Pensacola Block 948 encountered shows while drilling through the Smackover.

Onshore drilling is at a mature stage of exploration. Onshore Smackover fields contain an average of 41 percent oil, 9 percent gas, and 50 percent mixed hydrocarbons. Field production ranges from less than 1 to 482 MMBOE. Net pay ranges from 4 to 335 feet at depths of 11,392 to 18,425 feet. Fields are characterized by porosities ranging from 8 to 28 percent, oil gravities ranging from 19 to 54^{o} API, and GOR's ranging from 144 to 12,400 scf/stb.

Assessment Results

Because the Smackover play has not produced in the Federal OCS, Smackover reservoirs located in onshore Louisiana, Mississippi, and Alabama were used as analogs for this assessment.

The marginal probability of hydrocarbons for the UJ4 B1 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.004 to 0.205 Bbo and 0.013 to 0.309 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 2). Mean UCRR are estimated at 0.059 Bbo and 0.104 Tcfg

(0.078 BBOE). These undiscovered resources might occur in as many as five pools, which have a mean size range of 59 to 1 MMBOE and a mean size of 15 MMBOE (figure 3).

The Smackover play in the Federal OCS is relatively unexplored, although porosity and seals have been found in all 16 wells that have penetrated the upper Smackover section. The productive onshore Smackover trend associated with the Pickens-Pollard Fault System extends into the Destin Dome Area of offshore Florida.

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Upper Jurassic Oolitic Carbonate (UJ4 B2) Play

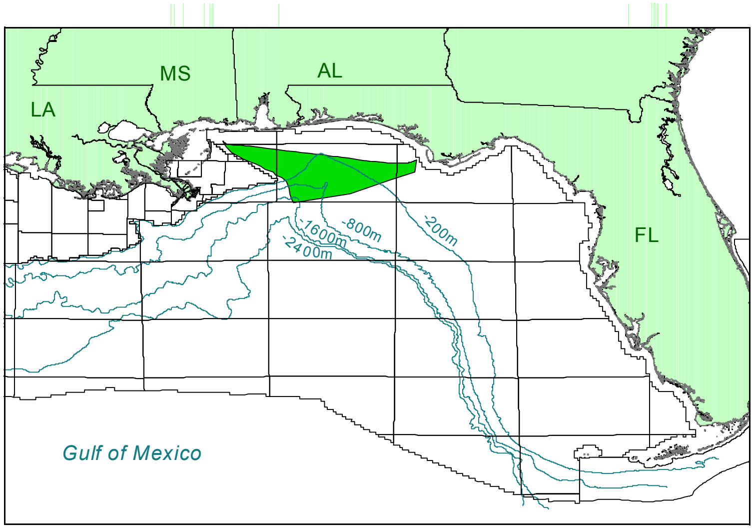

Figure 1. Play location.

Play Description

The conceptual and unassessed Upper Jurassic Oolitic Carbonate (UJ4 B2) play is located in the Viosca Knoll, Destin Dome, and western Apalachicola Areas of offshore Alabama and Florida (figure 1). The analog for the UJ4 B2 play is the Cotton Valley limestone play of east Texas. Production has been established in oolitic shoals, carbonate buildups, and pinnacle-like carbonate buildups (Montgomery *et al.,* 1999a, 1999b). Traps are mostly stratigraphic and occur in heterogeneous porosity zones within the buildups. Equivalent facies have not yet been encountered in the offshore Gulf of Mexico; therefore, the UJ4 B2 play was not assessed.

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Upper Jurassic Clastic Cotton Valley Group (UJ4 C1) Play *Rheinholdella* "A" biozone

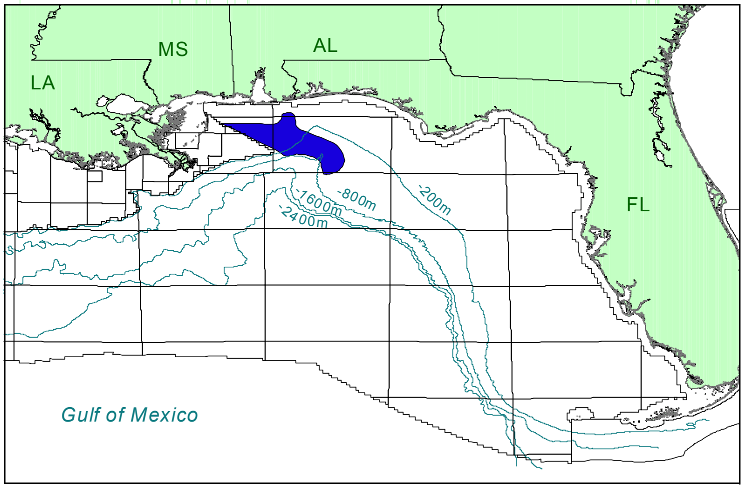

Figure 1. Play location.

UJ4 C1 Cotton Valley Group 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	--	0.004	0.064	0.021
Mean	13	0.015	0.296	0.067
5th percentile	--	0.032	0.785	0.155
Total Endowment				
95th percentile	--	0.004	0.064	0.021
Mean	13	0.015	0.296	0.067
5th percentile	--	0.032	0.785	0.155

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The frontier Upper Jurassic Clastic Cotton Valley Group (UJ4 C1) play occurs within the *Rheinholdella* "A" biozone and is defined by siliciclastics located below the carbonate Knowles Member of the Cotton Valley Group and above lithologically similar siliciclastics of the Haynesville Group. The play extends from the Viosca Knoll Area offshore Alabama into the Pensacola and Destin Dome Areas offshore Florida, and by extension, through the Apalachicola and northeast DeSoto Canyon Areas to the Florida Middle Ground Arch (figure 1). Updip to the north, the UJ4 C1 play extends onshore, while downdip to the south, siliciclastics grade into marine shales. Several offshore wells have encountered gas in the UJ4 C1 play, but production in the offshore has yet to be established.

Play Characteristics

Fine-grained sand, silt, and mud in the UJ4 C1 play were deposited in delta plain, restricted lagoon, and barrier bar environments. Delta plain siliciclastics were located along the landward perimeter of the Destin Salt Basin (figure 2), but were later reworked into barrier bars. These barrier bars can be stacked, resulting in sand-rich sections up to 2,000 feet thick. The thickest sections encountered to date have been located in Viosca Knoll Blocks 117 and 251.

Hydrocarbons are likely to be found in traps with a strong stratigraphic component. Potential source rocks for the play are Oxfordian laminated lime mudstones of the lower part of the Smackover Formation. Seals are provided by the lagoonal and marine shales that encase the barrier bar sands and, updip, by thin interbedded carbonate mudstones.

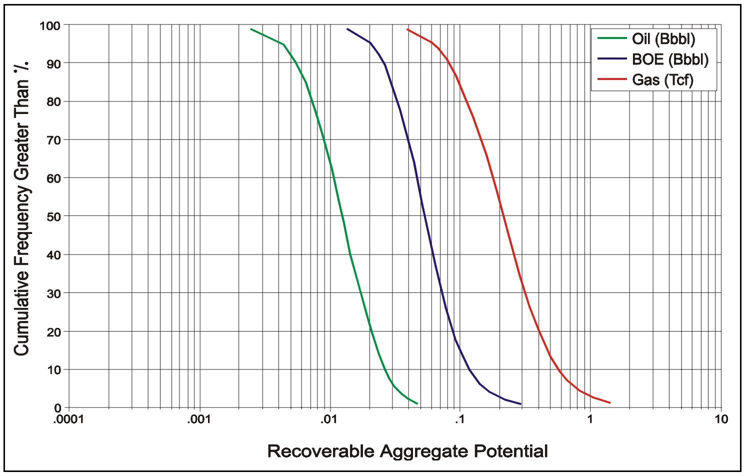

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

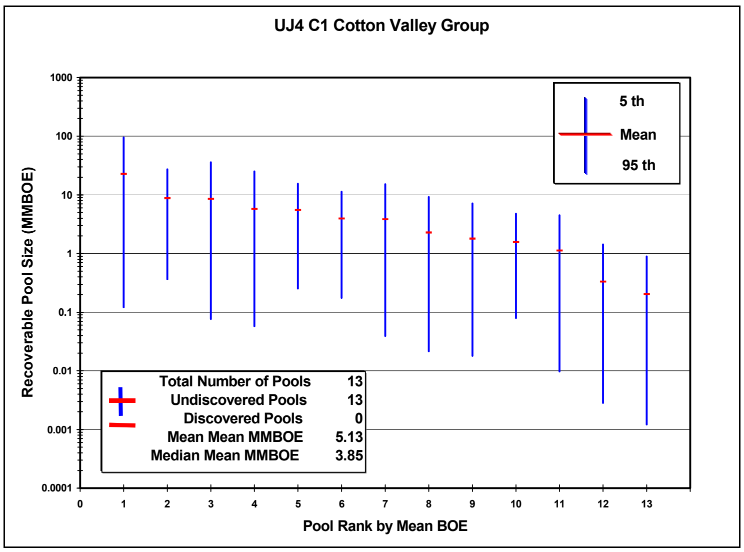

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Discoveries

The first well to target Cotton Valley clastics was drilled in Viosca Knoll 251 by Chevron in 1997. The well encountered gas in multiple zones within upper Cotton Valley clastics. Gas in the UJ4 C1 play was also encountered in wells drilling to the deeper Norphlet Formation in Viosca Knoll Block 117 in 1986 and in Mobile Block 991 in 1987.

Assessment Results

The marginal probability of hydrocarbons in the UJ4 C1 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) are estimated to be 0.004 to 0.032 Bbo and 0.064 to 0.785 Tcfg at the 95th and 5th percentiles, respectively (table 1; figure 2). Mean UCRR are forecast at 0.015 Bbo and 0.296 Tcfg (0.067 BBOE). The play's total endowment equals UCRR. These undiscovered resources might occur in as many as 13 pools that have an unrisked mean size range of <1 to 23 MMBOE (figure 3) and an unrisked mean mean size of 5 MMBOE.

The resource potential of the play is limited by reservoirs consisting of fine-grained sand with relatively low porosities. Higher porosities in eolian facies of barrier bar sands may be encountered with additional drilling. The deeper portions of the Destin Dome Salt Basin may also contain better reservoir-quality sands.

Upper Jurassic Buried Hill Drape (UJ4 BC1) Play

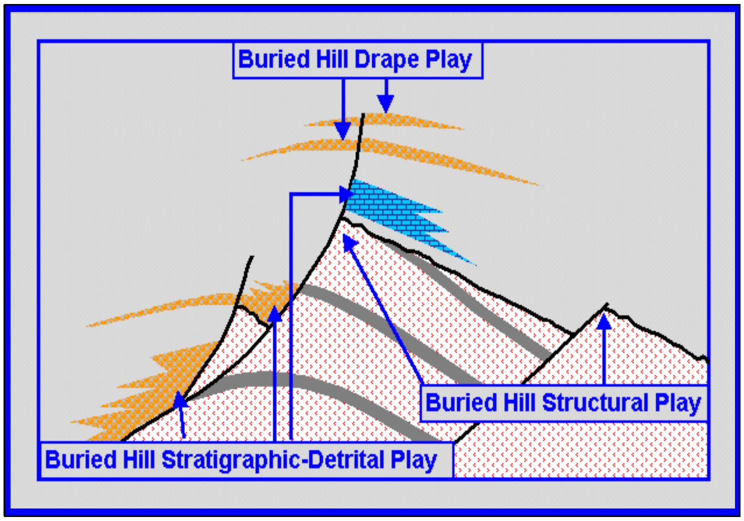

Figure 1. Diagrammatic cross-section illustrating the Buried Hills plays, after Zhai and Zha (1982).

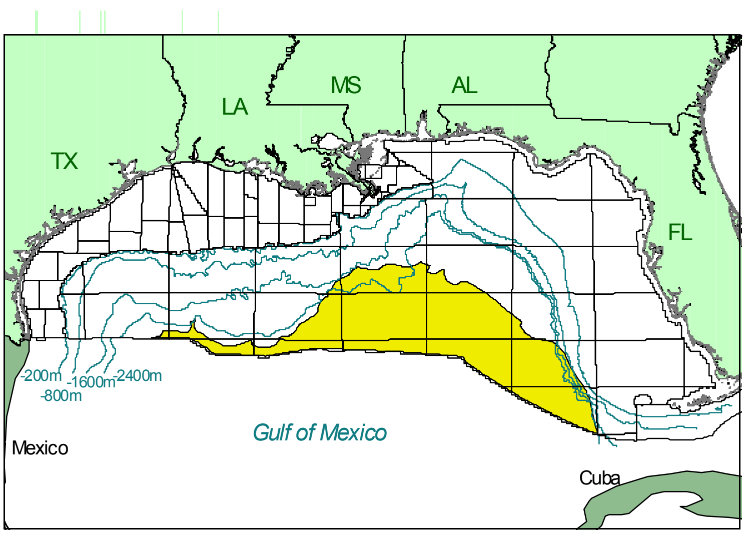

Figure 2. Play location.

Buried Hill Conceptual Plays	
Buried Hill Drape Plays	Lower Tertiary Buried Hill Drape (LE-LL BC1) Play
	Cretaceous Buried Hill Drape (UK5-LK3 BC2) Play
	Upper Jurassic Buried Hill Drape (UJ4-BC1) Play
Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital (UK5-UJ4 BC3) Play	
Mesozoic Structural Buried Hill (UK5-LTR BC4) Play	

Figure 3. General stratigraphic relationships of the conceptual Buried Hill plays.

Play Description

The conceptual Upper Jurassic Buried Hill Drape (UJ4 BC1) play is defined by source, reservoir, and seal lithologies consisting of seismically correlated sediments of probable Upper Jurassic age, and by compaction of those sediments over buried hill features found in the ultra-deepwater Gulf of Mexico Region (figure 1). Although the play is recognized primarily in the Walker Ridge and Lund Areas, it appears to extend from Alaminos Canyon into Keathley Canyon, Henderson, Lloyd, Vernon, NG 16-8, NG16-12, Howell Hook, and possibly into the Dry Tortugas Areas (figure 2) where seismic data are sparse. The play is bounded to the northwest and northeast by the depositional limit of the Louann Salt, while the OCS boundary defines the southern and western limits of the play.

The following discussion is from Post (2000), unless otherwise noted.

Play Characteristics

Buried hills (refer to the Mesozoic Structural Buried Hill [UK5-LTR BC4] play) are a series of paleo-structural highs that originated during the Mesozoic rifting that formed the Gulf of Mexico. This breakup event formed a series of northeast-southwest trending rift-related footwall structural highs (Bartok, 1993) linked by a system of northwest-southeast trending transfer faults/zones.

Depending upon the rate of subsidence, older high-energy carbonate and siliciclastic deposits directly related to the buried hills (refer to the Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital [UK5-UJ4 BC3] play; figure 3) are succeeded over the buried hill crests by similar high-energy deposits or by deepwater marls and

UJ4 BC1 Jurassic Buried Hill Drape Marginal Probability = 0.08	Number Number of Pools	Oil Oil (Bbbl)	Gas Gas (Tcf)	BOE 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	14	0.009	0.016	0.012
5th percentile	–	0.045	0.090	0.065
Total Endowment				
95th percentile	–	0.000	0.000	0.000
Mean	14	0.009	0.016	0.012
5th percentile	–	0.045	0.090	0.065

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

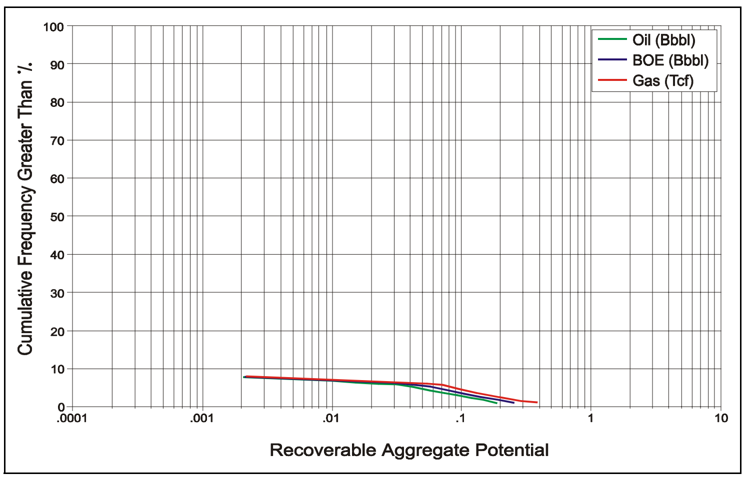

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

chalks.

Structural closure in these units developed by differential compaction of sediments over the more rigid, less compacting, buried hills. High-energy siliciclastic depositional environments are likely to have reservoirs deposited in local beach, barrier system, or deltaic environments; high-energy carbonate depositional environments might include grainstone facies. If low-energy environments predominate, then chalks and marls are the most likely reservoirs if porosities are preserved, as in the Danish sector of the North Sea.

Source rocks for the postulated clastic and carbonate reservoirs of the UJ4 BC1 play are likely to be Oxfordian or Kimmeridgian-Tithonian in age. These units are well-documented source rocks in the Gulf of Mexico OCS. They are likely to be in close juxtaposition, laterally and/or vertically, with the reservoirs, or connected to the reservoirs through vertical migration conduits. Hydrocarbon seeps in this region of the Gulf of Mexico OCS have been geochemically typed to Late Jurassic (centered on Oxfordian) source rocks (Wenger *et al.,* 1994).

Fine-grained rocks, including the source rocks, are also possible seals for the reservoirs.

Discoveries

No wells have been drilled in the UJ4 BC1 play prior to this study's January 1, 1999, cutoff date.

Assessment Results

Buried hills represent a prolific play type that produces in Southeast and East Asia, North and South America, Africa, Europe, and Australasia. A number of references were used to develop the analogs used in this play. Among the best are: Landes *et al.*, 1960; Chung-Hsiang P'An, 1982; Zhai and Zha, 1982; Zha, 1984; Zheng, 1988; Yu and Li, 1989; Horn, 1990; Tong and Huang, 1991; Areshev *et al.,* 1992; Tran Canh *et al.*, 1994; Blanche and Blanche,

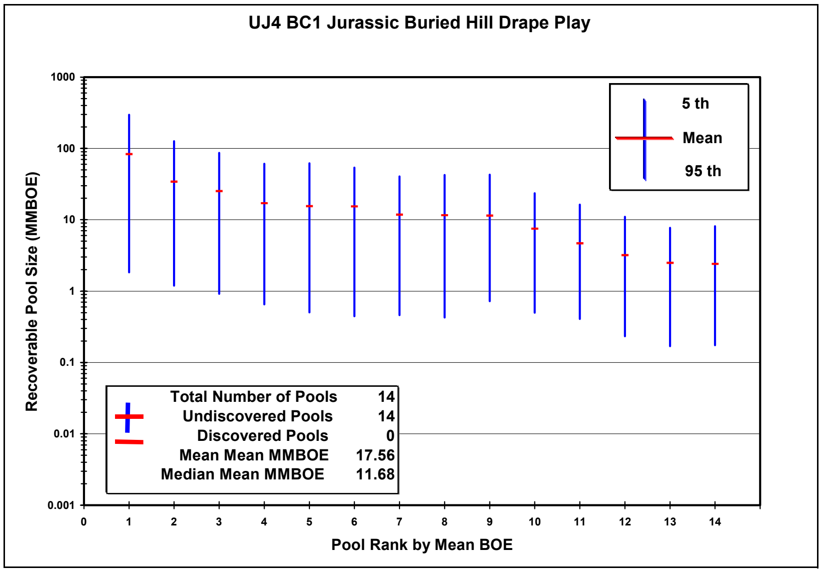

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

1997; and Sladen, 1997. Reservoir characteristics for the Upper Jurassic Buried Hill Drape were developed using depth dependent analogs. Reservoirs above 19,000 feet used analogs from selective, deep, Upper Jurassic carbonate Smackover reservoirs. Below 19,000 feet, clastic, Upper Jurassic Norphlet reservoirs parameters were used.

The marginal probability of hydrocarbons for the UJ4 BC1 play is 0.08. The play contains a mean total endowment of 0.009 Bbo and 0.016 Tcfg (0.012 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 0.045 Bbo and 0.000 to 0.090 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 14 pools. The largest undiscovered pool has a mean size of 83 MMBOE (figure 5). The mean mean size of the five largest undiscovered pools is 35 MMBOE.

Exploration Future

Developing and maintaining reservoir-quality porosity and permeability in prospective Late Jurassic objectives is an important issue facing explorationists in this play. Using available seismic, gravity, and magnetic data to understand the geohistory of the buried hills and overlying reservoirs will significantly advance the understanding, evolution, and evaluation of this play.

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Upper Jurassic Aggradational Norphlet Formation (UJ4 A1) Play

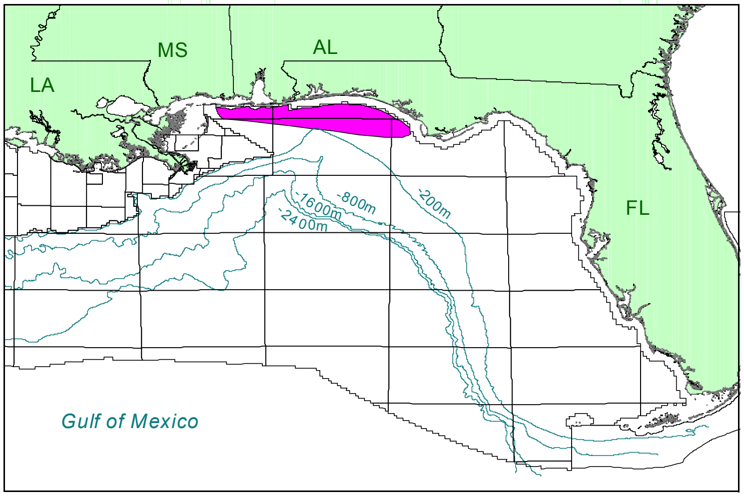

Figure 1. Play location.

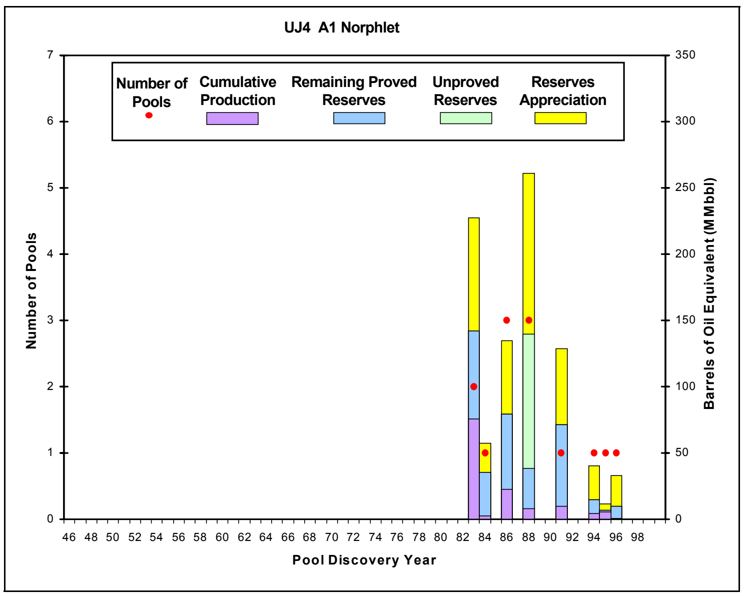

Figure 2. Exploration history graph showing reserves addition and number of pool discoveries by year.

UJ4 A1 Norphlet 13 Pools 13 Sands	Minimum	Mean	Maximum
Water depth (feet)	37	64	206
Subsea depth (feet)	21243	21913	22612
Number of sands per pool	1	1	1
Porosity	10%	12%	15%
Water saturation	19%	34%	52%

Table 1. Pool attributes. Values are volume-weighted averages of individual reservoir attributes.

Play Description

The established Upper Jurassic Aggradational Norphlet Formation (UJ4 A1) play is defined by an aggradational depositional style resulting from upbuilding of eolian dune and interdune facies of the Upper Jurassic Norphlet Formation. The play is located in the Mobile, Viosca Knoll, Pensacola, Destin Dome, and Apalachicola Areas offshore Mississippi, Alabama, and Florida (figure 1). An important feature of this prolific gas play is that producing sands are all at average depths greater than 20,000 feet (table 1). In the 1995 assessment (Lore *et al.*, 1999), this play was referred to as the Upper Jurassic Aggradational (UU A) play.

Updip, the play continues onshore into Mississippi, Alabama, and Florida. Downdip, eolian dune sands grade into marine shales and carbonate mudstones in the northern Viosca Knoll, Destin Dome, and Apalachicola Areas.

Play Characteristics

Sediments in the Norphlet were derived from erosion of the exposed southern Appalachian Mountains. To the north, conglomeratic and red bed lithofacies were deposited in alluvial fan, alluvial plain, and wadi environments. Farther to the south, quartzose sands were deposited in eolian dune, wadi, beach/shoreface, and intertidal facies. These Norphlet sands can be over 1,000 feet thick. The uppermost portion of the Norphlet section represents beach/shoreface sands that were reworked by the transgression associated with the overlying Upper Jurassic Smackover Formation (refer to the Upper Jurassic Carbonate Smackover Formation [UJ4 B1] play).

Reservoir porosities are higher than expected at such great

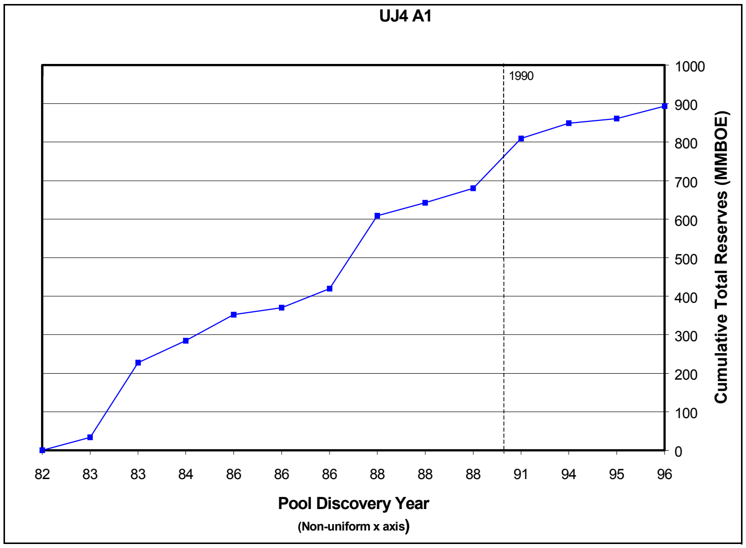

Figure 3. Plot of pools showing cumulative reserves by discovery order. Note the non-uniform x axis.

UJ4 A1 Norphlet Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	12	<0.001	2.232	0.397
Cumulative production	–	<0.001	0.726	0.129
Remaining proved	–	<0.001	1.506	0.268
Unproved	1	0.000	0.569	0.101
Appreciation (P & U)	–	<0.001	2.220	0.395
Undiscovered Conventionally Recoverable Resources				
95th percentile	–	0.444	5.757	1.534
Mean	30	0.713	6.492	1.868
5th percentile	–	1.016	7.249	2.241
Total Endowment				
95th percentile	–	0.444	10.777	2.428
Mean	43	0.713	11.512	2.762
5th percentile	–	1.016	12.269	3.135

Table 2. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

depths, in large part because chlorite rims around sand grains preclude later cementation. Reservoir porosities are also enhanced by grain dissolution and decementation. Porosities in upper portions of Norphlet dune facies are commonly reduced, possibly because of reworking of the dunes by the transgressing Smackover sea. Moderately to highly geopressured reservoirs occur in the southern and western Mobile and western Destin Dome Areas. The overlying lower Smackover Formation, consisting of laminated carbonate mudstones, is both the source and seal for hydrocarbons in the Norphlet.

Most of the fields in the UJ4 A1 play are structurally associated with low-relief elongate faulted anticlines formed over salt pillows.

Discoveries

The first Norphlet Formation discovery was onshore in the Pelahatchie Field, Rankin County, Mississippi, in 1967. Subsequently, more than 40 Norphlet fields were discovered onshore. The play did not become a Federal OCS target until the 1979 gas discovery in the Lower Mobile Bay/Mary Ann Field in Alabama State waters. Since 1983, 13 Federal OCS pools have been discovered (figure 2).

The UJ4 A1 gas play contains total reserves of <0.001 Bbo and 5.020 Tcfg (0.894 BBOE), of which 0.726 Tcfg (0.129 BBOE) have been produced. The play contains 13 producible sands in 13 pools, of which 12 contain proved reserves (table 1; refer to the Methodology section for a discussion of reservoirs, sands, and pools). Producing sands are all at average depths of greater than 20,000 feet.

The first reserves in the play were discovered in the Mobile 823 field in 1983. The Mobile 823 field also contains the largest pool in the play, with 193 MMBOE in total reserves (figures 2 and 3). Maximum yearly total reserves of 261 MMBOE were added in 1988 with the discov-

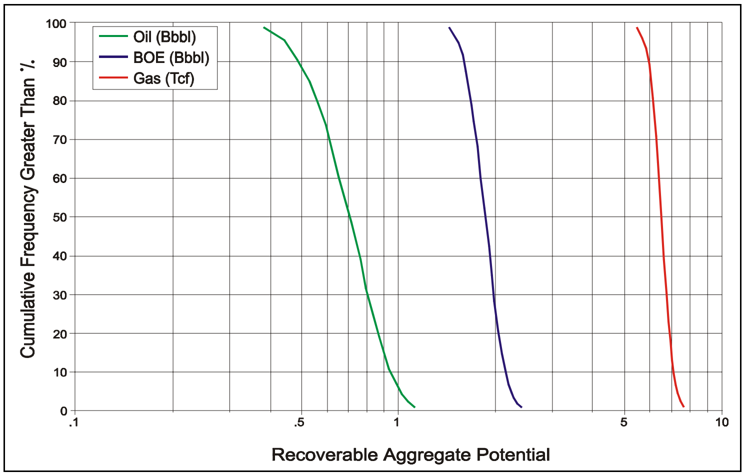

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

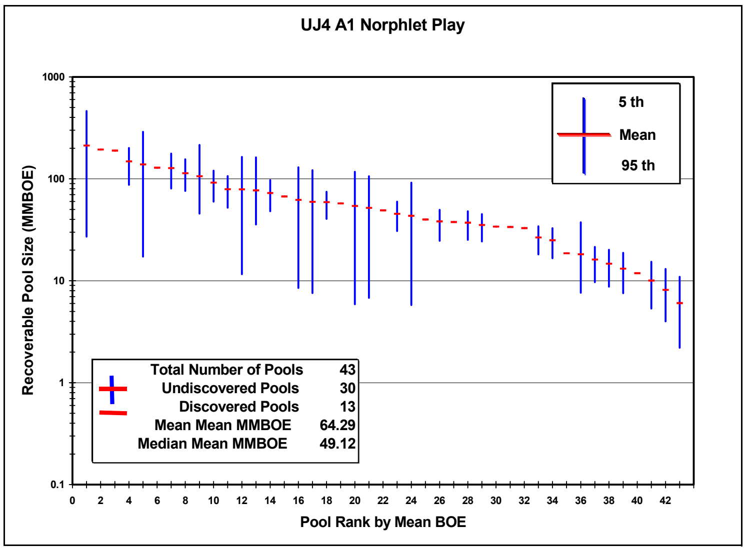

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

ery of three pools. Eighty-four percent of cumulative production and 76% of total reserves come from pools discovered before 1990. The most recent discovery, prior to this study's cutoff date of January 1, 1999, was in 1996.

The 13 discovered pools contain 18 reservoirs, all of which are nonassociated gas. Of the 12 aggradational plays in the Gulf of Mexico Region, the UJ4 A1 play contains the most total reserves.

Assessment Results

The marginal probability of hydrocarbons for the UJ4 A1 play is 1.00. The play contains a mean total endowment of 0.713 Bbo and 11.512 Tcfg (2.762 BBOE) (table 2). Only 5 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.444 to 1.016 Bbo and 5.757 to 7.249 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR are estimated at 0.713 Bbo and 6.492 Tcfg (1.868 BBOE). These undiscovered resources might occur in as many as 30 pools. The largest undiscovered pool, with a mean size of 212 MMBOE, is forecast as the largest pool in the play (figure 5). The forecast results place the next four largest undiscovered pools in positions 4, 5, 7, and 8 on the pool rank plot. For all the undiscovered pools in the UJ4 A1 play, the mean mean size is 62 MMBOE, which is similar to the 69 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 64 MMBOE. Of the 12 aggradational plays in the Gulf of Mexico Region, the UJ4 A1 is the largest on the basis of mean total endowment and mean UCRR.

BOE mean UCRR contribute 68 percent to the play's BOE mean total endowment. The eolian dune facies offers the greatest potential for additional offshore hydrocarbon accumulations. The dune facies is highly variable in thickness, but the largest accumulations of sand lie in the Pensacola and Destin Dome Areas. Although the play is typically a dry gas play, oil and condensate have been encountered in the Destin Dome Area.

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Upper Jurassic Perdido Fold Belt (UJ4 X1) Play

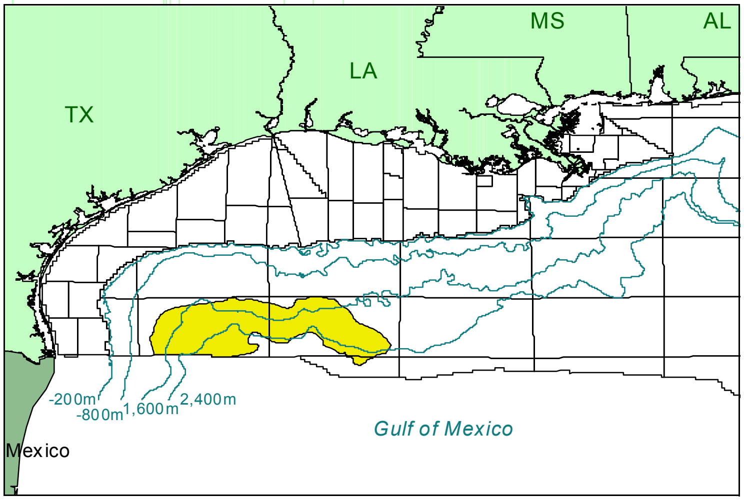

Figure 1. Play location.

UJ4 X1 Jurassic Perdido Fold Belt Marginal Probability = 0.40	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	19	0.148	0.368	0.213
5th percentile	--	0.635	1.837	0.940
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	19	0.148	0.368	0.213
5th percentile	--	0.635	1.837	0.940

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Upper Jurassic Perdido Fold Belt (UJ4 X1) play is defined by source, reservoir, and seal lithologies consisting of seismically correlated sediments of probable Upper Jurassic age and large northeast-southwest trending salt-cored folds. The play is located in the Alaminos Canyon and Keathley Canyon Areas of the Gulf of Mexico Region (figure 1) with much of the play extending under salt. The following discussion is from Post (2000), unless otherwise noted.

Basinward of the Sigsbee Salt Canopy, the play extends from the Alaminos Canyon Area offshore Texas into Mexican national waters. North, east, and west of this area, salt canopies obscure subsalt geometries, making it difficult to define the play area. However, interpretation of regional seismic data suggests that the play may extend eastward into the Keathley Canyon Area offshore Louisiana. The northeastern play boundary may either occur at a transfer zone or by a transition into the Mississippi Fan Fold Belt (UPL-LL X2) play. Although the northern limit of the play is interpretive because of the deterioration of seismic data quality under the Salt Canopy, the most basinward, counter-regional faults/ salt welds related to the development of the canopy provide a geologically reasonable northward limit.

Play Characteristics

The structure and stratigraphy of the basin have been inferred using geologic (from onshore and shallow water wells) and geophysical data (seismic, gravity and magnetics), as well as models of the evolution of the Gulf of Mexico basin (Adams, 1997; Marton and Buffler, 1994; Bartok, 1993; Pindell, 1993; Ewing, 1991; Sawyer *et al.,* 1991; Woods *et al*., 1991; Salvador, 1991a

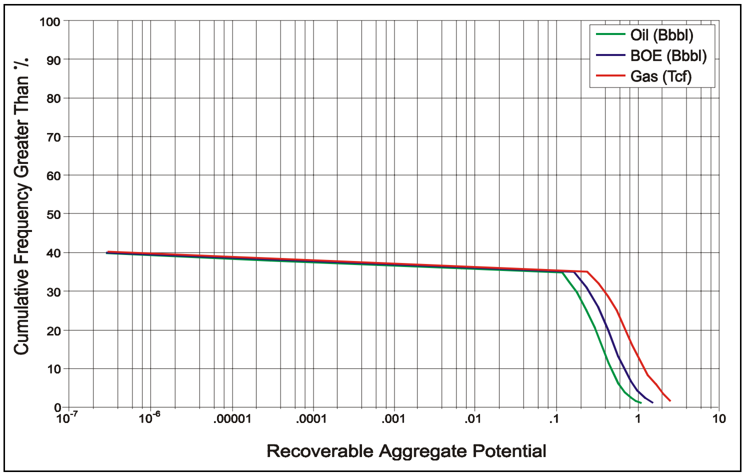

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

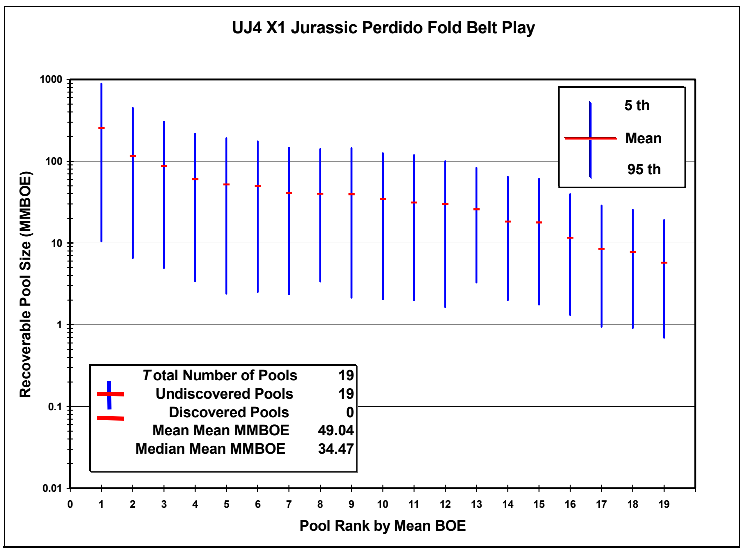

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

and b; McFarlan, 1991; Sohl *et al.*, 1991; Van Siclen, 1984). These data indicate that the Late Jurassic Louann Salt section overlies either Triassic syn-rift sediments, attenuated continental crust, oceanic crust, or sub-aerially erupted late-rift to early-drift onset mafics/volcanics that pre-date seafloor spreading. Late Jurassic to Early Cretaceous age limestones, calcareous to possibly non-calcareous mudstones, marls, and chalks probably succeed the salt.

Reservoir development in postulated Late Jurassic deepwater limestones is likely to rely on fracture-enhanced porosity and permeability. A variety of porosity and permeability preserving and/or enhancing mechanisms may help create viable Mesozoic chalk reservoirs. These include overpressuring, early hydrocarbon migration, fracturing after lithification, redeposition of chalks by gravity flows and currents, and absence of reservoir quality intervals above or below the chalk. Interbedded shales, mudstones, chalks, and marls may provide seals for reservoirs.

Structurally, the Perdido Fold Belt is located at the basinward limit of a balanced and linked complex system in which updip sedimentary loading and gravity-driven collapse associated with extension are accommodated by the extrusion of salt canopies and downdip contraction. Folding in the Perdido Fold Belt resulting from downdip contraction has created some of the largest structural closures in the Gulf of Mexico Region. Where the play is exposed basinward of the Sigsbee Salt Canopy in the Alaminos Canyon Area, individual structural culminations can exceed 40,000 acres and have vertical closures of up to 4,000 feet. The folds occur in a series of subparallel salt-cored buckle folds with symmetrical to asymmetrical geometries, with high-angle reverse faults on one or both fold limbs.

The main stage of fold development involved Late Jurassic to Eocene sediments and occurred primarily during the Early Oligocene to possibly Early Miocene in response to updip Paleogene sedimentary loading and accompanying extension. (Ages are after Berggren *et al.,* 1995.) Deformation on the most basinward folds appears to terminate at the end of the Early Oligocene, whereas deformation on folds to the northwest may have continued into the Late Oligocene or Early Miocene, as evidenced by the thicker salt cores and higher relief. A minor phase of reactivation in the Middle and Late Miocene affects some folds. A late stage of localized secondary uplift occurs from the Pliocene to present-day in those folds that have the thickest Louann Salt and are closest to the Sigsbee Salt Canopy. Possible causes for this most recent phase of structural uplift may be renewed shortening or a broad loading phenomenon related to the emplacement of the Sigsbee Salt Canopy (Trudgill *et al.*, 1999; Fiduk *et al.*, 1999).

Discoveries

One well (AC600) has been drilled in the Cenozoic section of the play prior to this study's cutoff date of January 1, 1999. Mechanical difficulties prevented the well from reaching its primary Mesozoic age reservoir targets and thus the stratigraphy of the deeper Mesozoic units remains speculative. Reservoir characteristics of the play were based on depth-dependent analogs. If the reservoirs were above 19,000 feet then selective, deep, Upper Jurassic carbonate Smackover reservoirs were used. Below 19,000 feet, Upper Jurassic clastic Norphlet reservoirs provide the analogs.

Hydrocarbon seeps in the Alaminos Canyon Area have been geochemically typed to two Late Jurassic source intervals (centered on the Oxfordian, and centered on the Tithonian), and the Lower Tertiary (centered on the Eocene) by Wenger *et al.* (1994), and Hood *et al.* (*in press*).

Assessment Results

The marginal probability of hydrocarbons for the UJ4 X1 play is 0.40. The play contains a mean total endowment of 0.148 Bbo and 0.368 Tcfg (0.213 BBOE) (table 2).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 0.635 Bbo and 0.000 to 1.837 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 19 pools, the largest of which has a mean size of 255 MMBOE (figure 4). The mean mean size of the five largest undiscovered pools is 114 MMBOE and the mean mean size of all pools is 49 MMBOE.

Exploration Future

Hydrocarbon seeps within the play's area indicate hydrocarbon generation, expulsion, and migration. In addition, the play contains some of the largest known structural closures in the Gulf of Mexico Region. The potential for future significant discoveries within this untested deepwater play appears promising, though the presence of adequate porosity and permeability in possible carbonate reservoirs remains the primary risk for the play.

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Upper Jurassic Mississippi Fan Fold Belt (UJ4 X2) Play

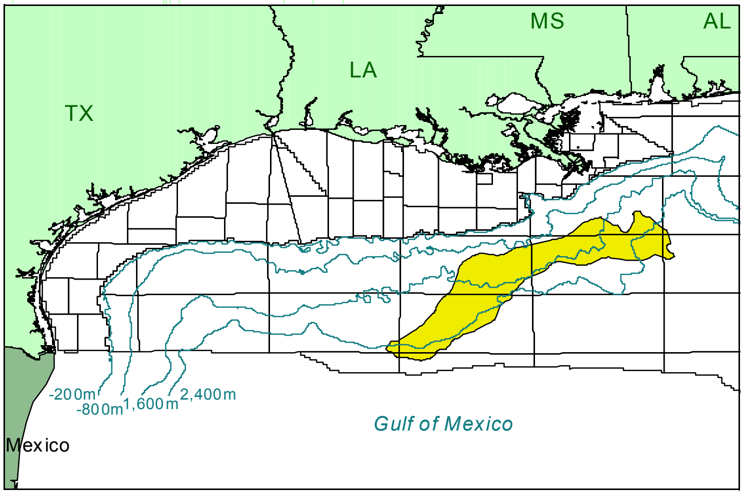

Figure 1. Play location.

UJ4 X2 Jurassic Miss Fan Fold Belt Marginal Probability = 0.40	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	21	0.189	0.395	0.259
5th percentile	--	0.804	1.730	1.093
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	21	0.189	0.395	0.259
5th percentile	--	0.804	1.730	1.093

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

Play Description

The conceptual Upper Jurassic Mississippi Fan Fold Belt (UJ4 X2) play is defined by source, reservoir, and seal lithologies consisting of seismically correlated sediments of probable Upper Jurassic age, and a series of east-northeast trending salt-cored folds. The play is located primarily in the Walker Ridge, Green Canyon, Atwater Valley, and southern Mississippi Canyon Areas of the Gulf of Mexico Region (figure 1) with much of the play extending under salt. The following discussion is from Post (2000), unless otherwise noted.

Landward, the fold belt extends under the Sigsbee Salt Canopy where the most basinward, counter-regional fault/salt weld related to salt canopy development is used as a geologically reasonable updip limit for the play. To the northeast, the play boundary is difficult to define because of structural overprinting. Regional analysis suggests that it may be coincident with the Pearl River Transfer. The southwestern play boundary may occur at either another transfer zone or by a transition into the Perdido Fold Belt. Because the boundary lies beneath the Salt Canopy, the connection and relationship between the two fold belts remain speculative.

Although fold belt structures generally extend basinward to the depositional limit of underlying Louann Salt, there are indications in the northeastern part of the area that folding may extend beyond this limit. Continued updip extension during the Pliocene to Recent caused downdip compression regardless of whether the salt décollement is present. Exhausting the supply of mobile salt shifts the detachment to an incompetent unit above the salt, probably a shale unit.

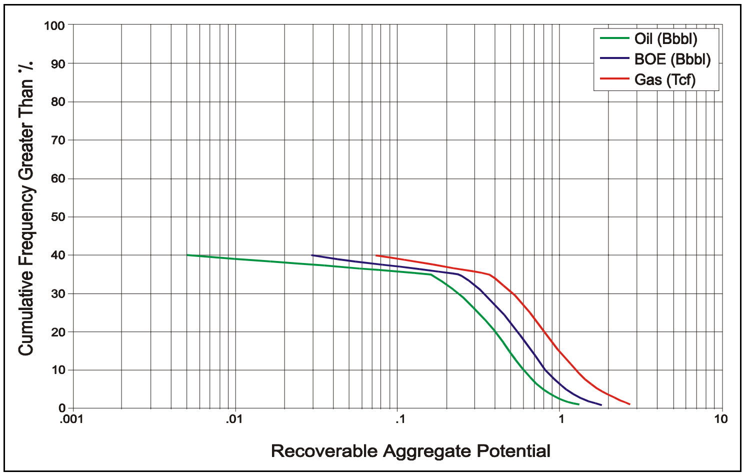

Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

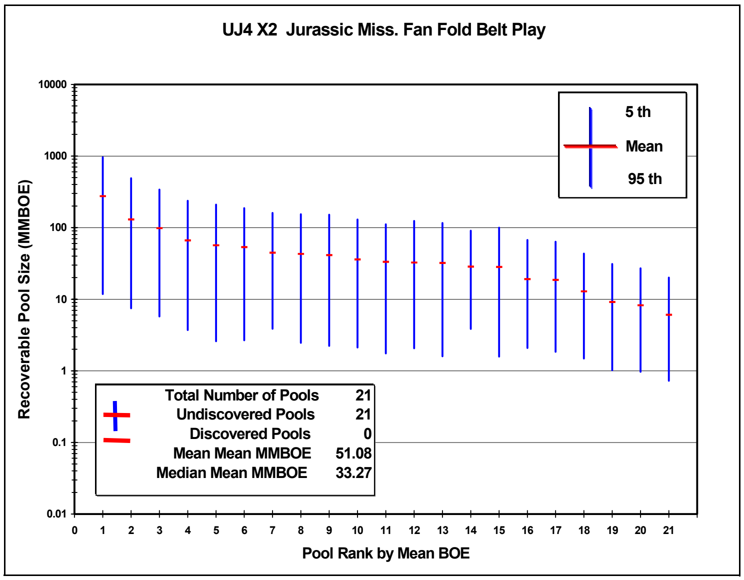

Figure 3. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Play Characteristics

The structure and stratigraphy of the basin have been inferred using geologic (from onshore and shallow water wells) and geophysical data (seismic, gravity and magnetics) as well as models of the evolution of the Gulf of Mexico basin (Adams, 1997; Marton and Buffler, 1994; Bartok, 1993; Pindell, 1993; Ewing, 1991; Sawyer *et al.,* 1991; Woods *et al.,* 1991; Salvador, 1991a and b; McFarlan, 1991; Sohl *et al.,* 1991; Van Siclen, 1984). These data indicate that the Late Jurassic Louann Salt section overlies either Triassic syn-rift sediments, attenuated continental crust, oceanic crust, or subaerially erupted late-rift to early-drift onset mafics/volcanics that pre-date seafloor spreading. Late Jurassic to Early Cretaceous age limestones, calcareous to possibly non-calcareous mudstones, marls, and chalks probably succeed the salt.

Postulated reservoirs on most structures in the play are deepwater limestone and chalk deposits. Porosity and permeability in limestones will probably depend on fracture enhancement. Structures with a demonstrated early growth stage, e.g., Rowan *et al.* (2000), may create early, localized, high-energy carbonate depositional environments. A variety of conditions may be responsible for the creation and/or enhancement of porosity and permeability in Mesozoic chalk reservoirs. These include overpressuring, early hydrocarbon migration, fracturing after lithification, redeposition of chalks by gravity flows and currents, and absence of reservoir quality intervals above or below the chalk. Interbedded shales, mudstones, chalks, and marls may provide seals for reservoirs.

Structurally, the Mississippi Fan Fold Belt is located at the basinward limit of a balanced and linked, complex system in which updip sedimentary loading and gravity-driven collapse associated with extension are accommodated by the extrusion of salt canopies and downdip contraction. Structures in the play consist of a series of east-northeast-south-southwest trending, subparallel, salt-cored folds. The folds are asymmetric, basinward-vergent, with landward-dipping, typically listric reverse faults that cut the basinward limb of the fold.

The Late Jurassic-Cretaceous seismic interval thins on some structures in the play. This is interpreted to indicate a possible local, early structural growth stage contemporaneous with deposition in this section (Rowan *et al.,* 2000). Later, a regional, early stage of fold development occurred between the Late Oligocene to Middle Miocene. The main growth stage of the folds, coincident with break-thrust development, took place during the Middle to Late Miocene in response to increased rates of sedimentation updip (Rowan *et al.,* 2000). Fold growth continued with only minor thrusting from the Late Miocene to Pleistocene.

Discoveries

No wells have penetrated the Upper Jurassic section of the Mississippi Fan Fold Belt prior to this study's cutoff date of January 1, 1999. However, some of the largest fields in the Gulf of Mexico Region have been discovered in siliciclastics of the overlying Cenozoic Mississippi Fan Fold Belt (UPL-LL X2) play. Reservoir characteristics of the UJ4 X2 play were selected on the basis of depth-dependent analogs. If the reservoirs were above 19,000 feet, then selective, deep, Upper Jurassic carbonate Smackover reservoirs were used. Below 19,000 feet, Upper Jurassic clastic Norphlet reservoirs provided the analogs.

In the eastern part of the play, two Late Jurassic source units, one centered on the Tithonian and the other centered on the Oxfordian, have been geochemically typed as being the sources for hydrocarbon seeps in the area. Tithonian-sourced seeps are reported in the northern Atwater Valley Area and the northern part of the west-adjacent Green Canyon Area. In the southern part of Atwater Valley, the southeastern part of Green Canyon, the northeast portion, and the southern half of the Walker Ridge Area hydrocarbon seeps are typed as originating from Oxfordian source beds. A mixture of Tithonian and Oxfordian sourced seeps is found over most of the southern part of Green Canyon and in the northwestern part of the Walker Ridge Area (Wenger *et al.*, 1994; Hood *et al., in press*).

Assessment Results

The marginal probability of hydrocarbons for the UJ4 X2 play is 0.40. The play contains a mean total endowment of 0.189 Bbo and 0.395 Tcfg (0.259 BBOE) (table 1).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 0.804 Bbo and 0.000 to 1.730 Tcfg at the 95th and 5th percentiles, respectively (figure 2). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 21 pools. The largest undiscovered pool has a mean size of 274 MMBOE (figure 3). The mean mean size of the five largest undiscovered pools is 125 MMBOE and the mean mean size of all pools is 51 MMBOE.

Exploration Future

Hydrocarbon seeps within the play's area indicate hydrocarbon generation, expulsion, and migration. In addition, large hydrocarbon accumulations exist in the overlying Cenozoic section. The potential for future significant discoveries within this untested deepwater play appears promising, though the presence of adequate porosity and permeability in possible carbonate reservoirs remains the primary risk for the play.

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Upper Jurassic to Middle Jurassic Florida Basal Clastic (UJ4-MJ C4) Play

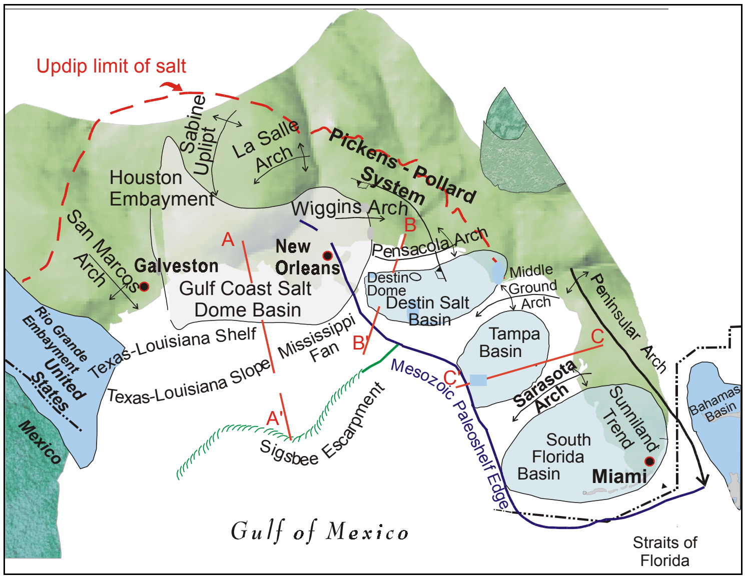

Figure 1. Physiographic map of the Gulf of Mexico Region.

Play Description

The conceptual and unassessed Upper Jurassic to Middle Jurassic Florida Basal Clastic (UJ4-MJ C4) play is defined by siliciclastics eroded from mostly pre-Jurassic basement rocks associated with the Florida Platform. The play extends from the South Florida and Tampa Basins across the Florida Peninsular Arch into the Bahamas Basin (figure 1) and northward on the east coast of Florida where the play time-transgresses into the Lower Cretaceous to Upper Jurassic Transition Zone (LK8-UJ4 BC5) play. The play may also extend northward into the Atlantic Region along the east coast of Florida .

Potential reservoirs were deposited as alluvial fans, barrier island/beach systems, and fluvial deltas immediately overlying the basement rocks. Basal clastic sands penetrated to date have been less than 150 feet thick and are rich in mica and feldspar. The play was not assessed because of the poor quality of the potential reservoir sands. However, the Great Isaac well in the Bahamas Basin (figure 1) did contain a hydrocarbon show.

In the 1995 assessment (Lore *et al.,* 1999), this play was referred to as the Middle Jurassic to Upper Jurassic Florida Basal Clastic (MU-UU FBCL) play.

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Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital (UK5-UJ4 BC3) Play

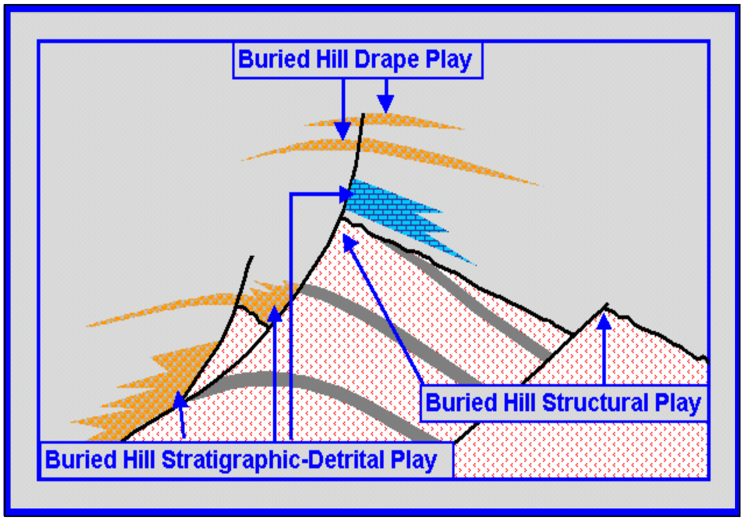

Figure 1. Diagrammatic cross-section model illustrating the Buried Hills plays, after Zhai and Zha (1982).

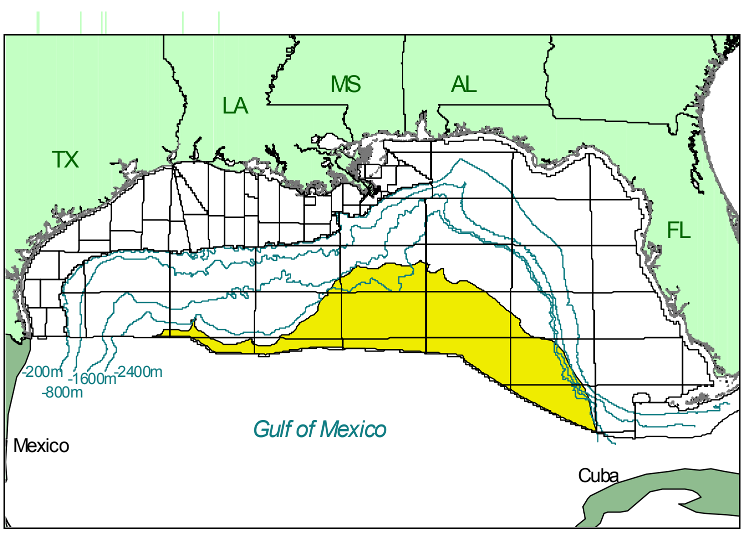

Figure 2. Play location.

Buried Hill Conceptual Plays	
Buried Hill Drape Plays	Lower Tertiary Buried Hill Drape (LE-LL BC1) Play
	Cretaceous Buried Hill Drape (UK5-LK3 BC2) Play
	Upper Jurassic Buried Hill Drape (UJ4-BC1) Play
Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital (UK5-UJ4 BC3) Play	
Mesozoic Structural Buried Hill (UK5-LTR BC4) Play	

Figure 3. General stratigraphic relationships of the conceptual Buried Hill plays.

Play Description

The conceptual Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital (UK5-UJ4 BC3) play is defined by those clastic and carbonate deposits whose origin is directly associated with or derived from the buried hills delineated in the ultra-deepwater Gulf of Mexico OCS (figure 1), and by seismically correlated sediments of probable Jurassic and Cretaceous age. The buried hills (refer to the Mesozoic Structural Buried Hill [UK5-LTR BC4] play) are a series of paleostructural highs that originated during the Mesozoic rifting event that formed the Gulf of Mexico.

The play is recognized primarily in the Walker Ridge and Lund Areas. It may be extrapolated from the Alaminos Canyon through Vernon protraction areas, and south through the Dry Tortugas (figure 2). The play is bounded to the northwest and northeast by the depositional limit of the Louann Salt. To the south, the play continues into Mexican national waters.

The following discussion is from Post (2000), unless otherwise noted.

Play Characteristics

The buried hills formed primarily during the Late Middle Triassic (?) to Late Middle Jurassic rifting episode(s) that created the Gulf of Mexico. This break-up event formed a series of northeast-southwest trending rifts (Bartok, 1993). A system of northwest-southeast trending transfer faults/zones divides the rifted terrain into segments linking the entire terrain and conserving the overall amount of extension or extensional strain (Nelson *et al.,* 1992). Initially, the rift fabric formed a rugged topography characterized by internal drainage and a lacustrine depositional environment. During the Late Middle Jurassic, marine water from the

UK5-UJ4 BC3 Buried Hill Stratigraphic Det. Marginal Probability = 0.24	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	10	0.140	0.233	0.181
5th percentile	--	0.398	0.933	0.610
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	10	0.140	0.233	0.181
5th percentile	--	0.398	0.933	0.610

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

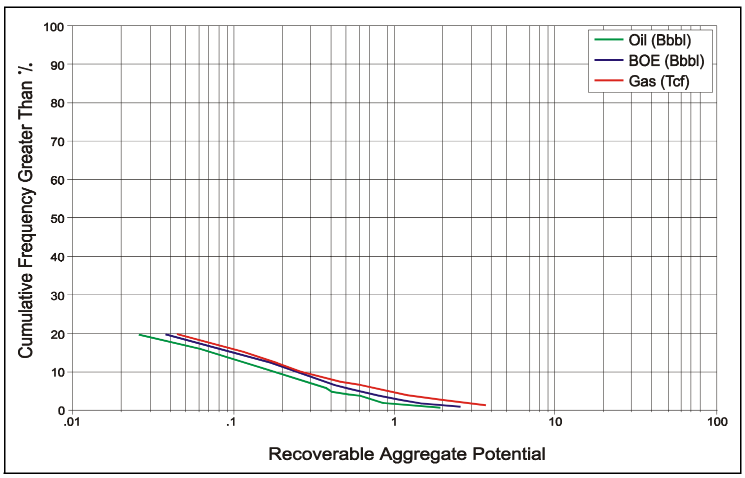

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

Pacific first entered the incipient Gulf of Mexico basin (Salvador, 1991a; Bartok, 1993). These marine waters became concentrated through evaporation in the prevailing arid climate, resulting in deposition of the Louann Salt. During this time, the footwall highs associated with the rifts served as local provenance areas, their erosion providing siliciclastic sediments to limited areas.

By the Early Late Jurassic, the marine connection with the Pacific had become more established and a widespread, prolonged marine transgression covered the area (Salvador, 1991; Bartok, 1993; Marton and Buffler, 1994). The transgression probably reached its maximum extent near the end of the deposition of a postulated lower, thinly bedded, laminated carbonate mudstones facies of the Oxfordian, equivalent to the updip Smackover and Zuloaga Formations (Salvador, 1991b). During this marine transgression, a mixed high-energy carbonate/clastic environment characterized deposition surrounding the buried hills.

Beginning in the latest Jurassic and earliest Cretaceous, seismic data show 'reef-like' anomalies on the flanks of some of the buried hills. These 'reef-like' anomalies provide the stratigraphic part of the play's name. In several instances, it appears that detritus/talus may be derived from these anomalies. This mixed environment most likely continued as the buried hills gradually became submerged. Regional seismic analyses indicate that gradually even the highest relief buried hills were onlapped by sediments during the latest Cretaceous and earliest Tertiary. Over time, the detritus/talus-to-deepwater carbonate percentage probably declined as the area available to provide detritus/talus became progressively smaller.

During the evolution and erosion of buried hills, a variety of reservoir objectives may have developed either on or adjacent to the buried hills, or in the nearby grabens.

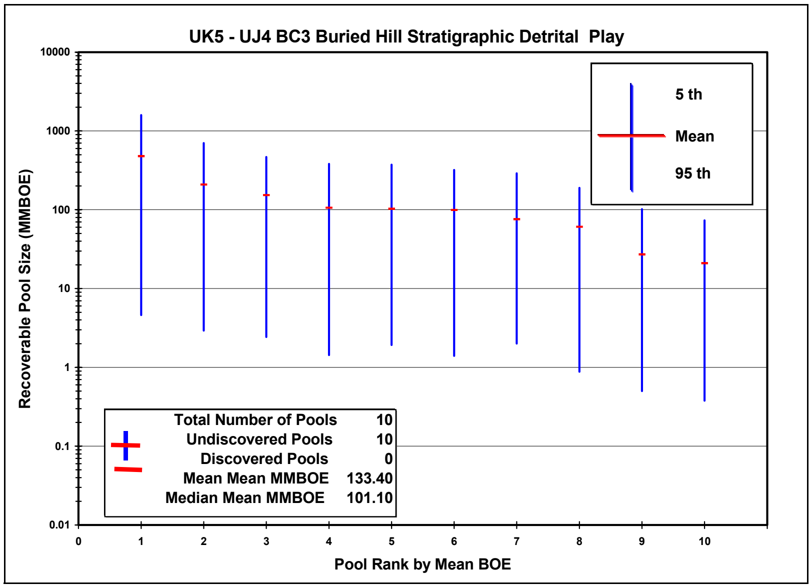

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

Locally derived clastics deposited as alluvial deltas, barrier island-beach systems, fluvial deltas, or fans are potential reservoirs in siliciclastic dominated sequences; whereas high-energy carbonate grainstones, reefs, and carbonate detrital talus/breccias are the most likely reservoirs in the carbonate dominated facies.

Source rocks for the postulated clastic and carbonate reservoirs of the UK5-UJ4 BC3 play are likely to be Oxfordian, Kimmeridgian-Tithonian, Barremian-Hauterivian, Aptian or Albian in age. These units are well-documented source rocks in the Gulf of Mexico OCS. They are likely to be in close juxtaposition, laterally and/or vertically, with the reservoirs, or connected to the reservoirs through vertical migration conduits. Hydrocarbon seeps in this region of the Gulf of Mexico OCS have been geochemically typed to Late Jurassic (centered on Oxfordian) source rocks (Wenger *et al.*, 1994).

Fine-grained rocks, including source rocks, are also possible seals for the reservoirs.

Discoveries

No wells have been drilled in the UK5-UJ4 BC3 play prior to this study's January 1, 1999, cutoff date.

Assessment Results

Buried hills represent a prolific play type that produces in Southeast and East Asia, North and South America, Africa, Europe, and Australasia. Detrital carbonate reservoir parameters from the Tampico-Misantla basin provided the primary analog used to estimate the hydrocarbons in this play.

A number of references were used to develop the analog used in this play. Among these are: Landes *et al.*, 1960; Chung-Hsiang P'An, 1982; Zhai and Zha, 1982; Zheng, 1988; Yu and Li, 1989; Horn, 1990; Tong and Huang, 1991; Areshev *et al.,* 1992; Tran Canh *et al.*, 1994; Blanche and Blanche, 1997; and Sladen, 1997.

The marginal probability of hydrocarbons for the UK5-UJ4 BC3 play is 0.24. The play contains a mean total endowment of 0.140 Bbo and 0.233 Tcfg (0.181 BBOE) (table 1).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 0.398 Bbo and 0.000 to 0.933 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 10 pools (figure 5). The largest undiscovered pool has a mean size of 478 MMBOE, while the mean mean of the five largest undiscovered pools is 210 MMBOE.

Exploration Future

Developing and maintaining reservoir-quality porosity and permeability in the prospective stratigraphic and detrital objectives is an important issue facing explorationists in this play. Using available seismic, gravity, and magnetic data to understand the geohistory of the buried hills and potential reservoirs will significantly advance the understanding, evolution, and evaluation of this play.

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Mesozoic Structural Buried Hill (UK5-LTR BC4) Play

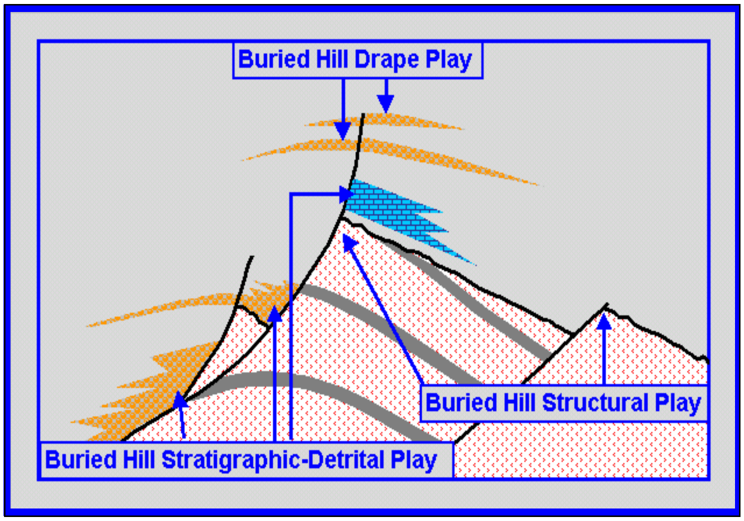

Figure 1. Diagrammatic cross-section model illustrating the Buried Hills plays, after Zhai and Zha (1982).

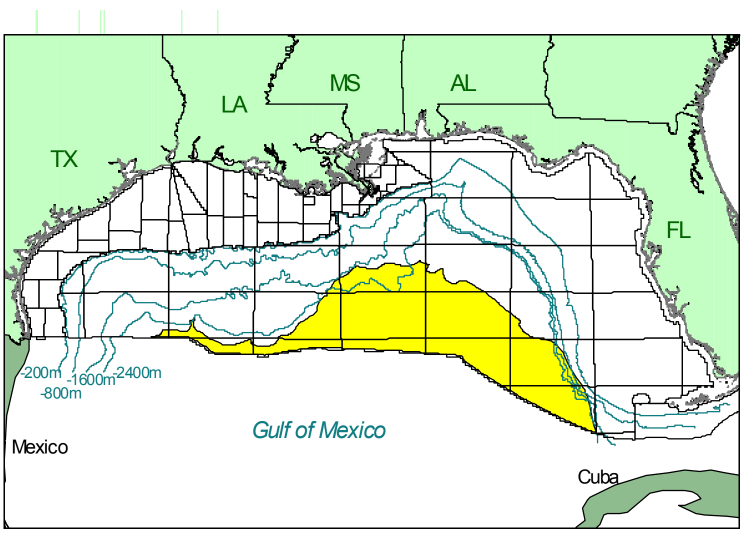

Figure 2. Play location.

Buried Hill Conceptual Plays	
Buried Hill Drape Plays	Lower Tertiary Buried Hill Drape (LE-LL BC1) Play
	Cretaceous Buried Hill Drape (UK5-LK3 BC2) Play
	Upper Jurassic Buried Hill Drape (UJ4-BC1) Play
Upper Cretaceous to Upper Jurassic Buried Hill Stratigraphic-Detrital (UK5-UJ4 BC3) Play	
Mesozoic Structural Buried Hill (UK5-LTR BC4) Play	

Figure 3. General stratigraphic relationships of the conceptual Buried Hill plays.

Play Description

The conceptual Mesozoic Structural Buried Hill (UK5-LTR BC4) play is defined by a series of footwall structural highs associated with the rifting event that formed the Gulf of Mexico (figure 1). The mostly pre-Jurassic rocks that comprise the buried hills are themselves reservoir targets. Although the play is recognized primarily in the Walker Ridge and Lund protraction areas, it appears to extend from Alaminos Canyon through Vernon, and southward through the Dry Tortugas protraction areas (figure 2). The play is bounded to the northwest and northeast by the depositional limit of the Louann Salt. To the south, the play continues into Mexican national waters.

The following discussion is from Post (2000), unless otherwise noted.

Play Characteristics

The buried hills formed primarily during the Late Middle Triassic (?) to Late Middle Jurassic rifting episode(s) that created the Gulf of Mexico. This break-up event formed a series of northeast-southwest trending rifts (Bartok, 1993). A system of northwest-southeast trending transfer faults/zones divide the rifted terrain into segments allowing the amount of extension and displacement on one structural element (rift) to be transferred to one or more different structural elements, linking the entire terrain and conserving the overall amount of extension or extensional strain (Nelson *et al.*, 1992). Where sharply defined, these are designated as transfer faults (Gibbs, 1984; Lister *et al.*, 1986). Where the transfer of displacement occurs over a broader area, these regions are referred to as transfer or accommodation zones (Gibbs, 1984; Bosworth, 1985; Rosendahl, 1987; Morley *et al.*, 1990). The footwall blocks located at

UK5-LTR BC4 Buried Hill Structural Marginal Probability = 0.29	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	13	1.223	2.140	1.603
5th percentile	–	5.914	12.197	8.514
Total Endowment				
95th percentile	–	0.000	0.000	0.000
Mean	13	1.223	2.140	1.603
5th percentile	–	5.914	12.197	8.514

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

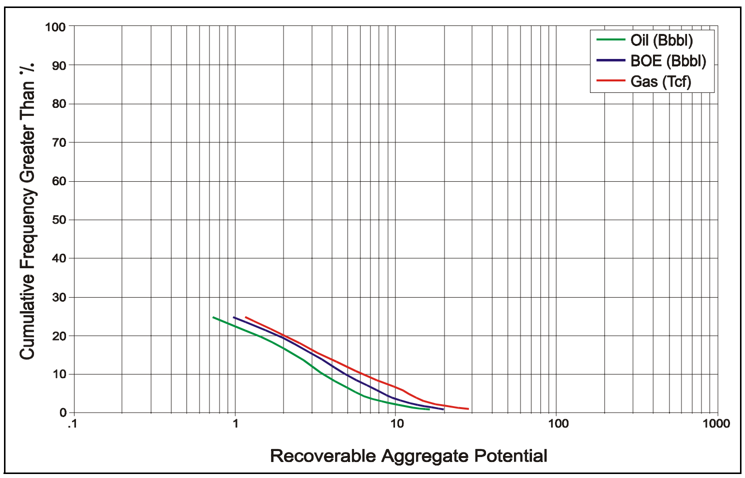

Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

rift margins or transfer zones are composed of older, pre-rift units. These blocks are typically uplifted relative to the more subsiding internal parts of the rift system and consequently they are often fractured and are usually exposed to weathering processes for long periods of geologic time. Reservoirs in buried hill plays are best characterized as topographic remnants of pre-rift rocks that have been exposed, weathered, fractured and, if carbonate, karstified.

Seismic character throughout the rifted terrain basinward of the Sigsbee Escarpment in the ultra-deepwater Gulf of Mexico OCS is similar to that observed in the ultra-deepwater region of the Congo basin of the Angolan continental margin. In that West African region, these reflectors are interpreted as sub-aerially erupted, late-rift to early-drift onset, mafic/volcanics that pre-date seafloor spreading (Danforth *et al.,* 2000). The comparable seismic character, structural setting, and configuration indicate that these ultra-deepwater Gulf of Mexico terrains may consist of similar mafic/volcanics.

However, since no wells penetrate the buried hills, several other models/interpretations are possible. One model suggests that Pre-Triassic units may form the buried hills in the Gulf of Mexico OCS. On the basis of regional analysis of the Gulf of Mexico, these rocks are expected to be either crystalline igneous and/or metamorphic, or Late Paleozoic (Early Pennsylvanian through Permian) clastics and carbonates (Woods *et al.,* 1991). A second model would be that extremely attenuated continental crust or possibly Callovian age oceanic crust emplaced late in the Gulf of Mexico rifting phase may also form the core of the buried hill. A third alternative is that Cretaceous age intrusives, using the transfer faults/zones, form a younger buried hill play. Although a reconnaissance seismic data grid of 2 miles by 2 miles was used, steeply dipping strata or significant structural disrup-

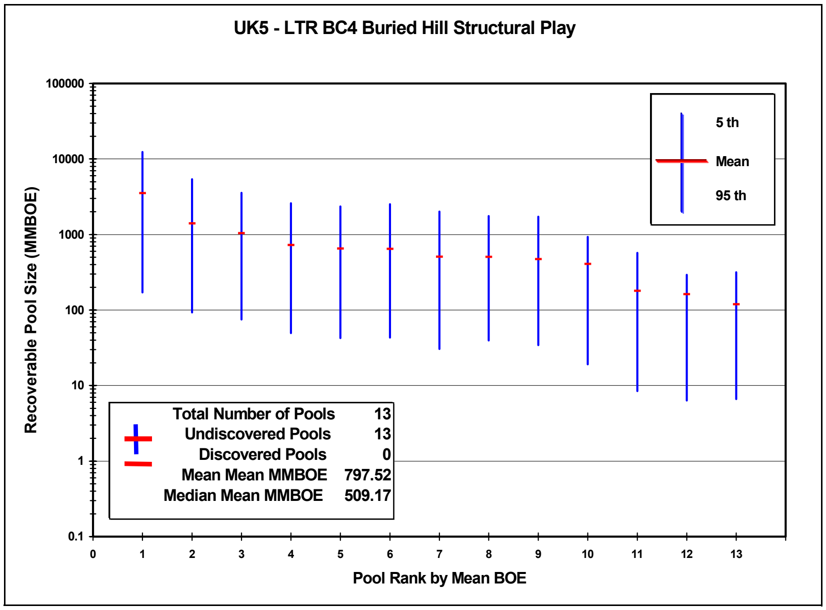

Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

tion of sedimentary section around the buried hills indicating late intrusive activity was not observed. Seismic indications of either of these would strongly support younger (Cretaceous) intrusives as the core rocks of the buried hills. Although Cretaceous intrusives are well documented in the Gulf Coast (Braunstein and McMichael, 1976; Hunter and Davies, 1979; Saunders and Harrelson, 1992), available interpretations indicate that many have significantly disrupted the sedimentary section through which they are emplaced. The absence of significant structural disruption on the flanks of most buried hills compared with the flanks of younger intrusive bodies appears to favor a model involving pre-existing structural features gradually buried by pelagic sediments, rather than younger intrusives emplaced through these sediments. Therefore, while Cretaceous age intrusives may occur in conjunction with transfer zones and form some buried hills, they do not appear to be the predominant core lithology for the buried hills.

Although matrix porosity in most fractured igneous and metamorphic reservoirs is generally quite low (typically 1-2%), significantly better reservoir porosity (up to 25%) has been often described. Matrix permeability is generally low (0.1 to 10 millidarcies), although it may exceed 1 darcy in fractured zones. The variability within these reservoirs is such that the upper parts of the reservoir may be ineffective, lacking porosity and permeability (making them effective reservoir top seals), whereas better reservoir quality may exist deeper in the section. As a result, many hydrocarbon accumulations may have been missed throughout Asia because drilling stopped when non-sedimentary rocks were encountered in the belief that these formations constituted “economic” basement and that no hydrocarbons could be reservoired in these rocks (Sladen, 1997).

Source rocks for buried hills are always younger than the buried hill and are either laterally adjacent to the buried hill reservoir or onlap and seal it. Source rocks for the UK5-LTR BC4 play are most likely to be Oxfordian, Kimmeridgian-Tithonian, Barremian-Hauterivian, Aptian, or Albian age, depending on the relief and final burial age of the buried hill. All of these are well-documented source units in the Gulf of Mexico OCS (Wenger et al., 1994). Where these overlie the buried hills, they may also provide the regional top seals for the features.

Because 2-D seismic data on a 2-mile by 2-mile grid was used to delineate the play, the seismic grid size did not usually permit full delineation of buried hill features. The areal extent of individual buried hill features may reach ~70,000 acres in size. Vertical relief of the buried hills may attain 2,000 feet.

Discoveries

No wells have been drilled in the UK5-LTR BC4 play prior to this study’s January 1, 1999, cutoff date.

Assessment Results

Buried hills represent a prolific play type that produces in Southeast and East Asia, North and South America, Africa, Europe, and Australasia. A number of references were used in developing the analogs used in this play. Among these are: Landes *et al.,* 1960; Chung-Hsiang P’An, 1982; Zhai and Zha, 1982; Zheng, 1988; Yu and Li, 1989; Horn, 1990; Tong and Huang, 1991; Areshev *et al.,* 1992; Tran Canh *et al.*, 1994; Blanche and Blanche, 1997; and Sladen, 1997. Buried hill fields in Vietnam and China were primarily used to develop reservoir parameters and to provide analogs.

The marginal probability of hydrocarbons for the UK5-LTR BC4 play is 0.29. The play contains a mean total endowment of 1.223 Bbo and 2.140

Tcfg (1.603 BBOE) (table 1).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000 to 5.914 Bbo and 0.000 to 12.197 Tcfg at the 95th and 5th percentiles, respectively (figure 4). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 13 pools. The largest undiscovered pool has a mean size of 3,538 MMBOE (figure 5). The mean mean size of the five largest undiscovered pools is 1,472 MMBOE.

Exploration Future

Developing and maintaining reservoir-quality porosity and permeability in the prospective mostly pre-Jurassic objectives is an important issue facing explorationists in this play. Using available seismic, gravity, and magnetic data to understand the geohistory of the buried hills and potential reservoirs will significantly advance the understanding, evolution, and evaluation of this play.

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Lower Cretaceous to Upper Jurassic Transition Zone (LK8-UJ4 BC5) Play

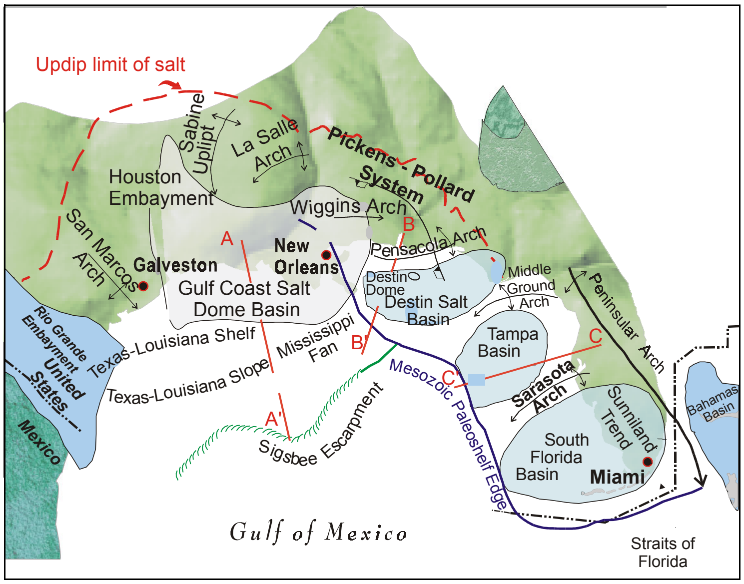

Figure 1. Physiographic map of the Gulf of Mexico Region.

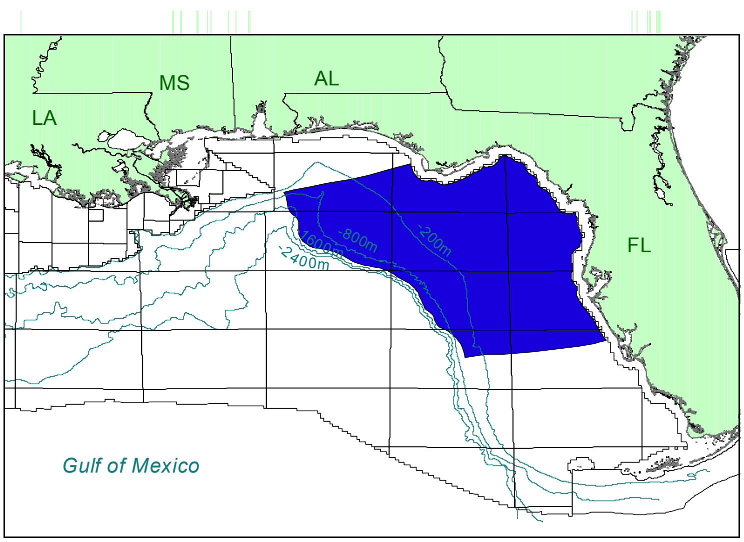

Figure 2. Play location.

Play Description

The conceptual and unassessed Lower Cretaceous to Upper Jurassic Transition Zone (LK8-UJ4 BC5) play is a stratigraphically inclusive play centered in the Tampa Basin area between clastics of the Pensacola Arch and Destin Salt Basin, and carbonates and upper Jurassic basal clastics of the Sarasota Arch (figure 1). The location of the play is shown in figure 2. Seismic data from the Tampa basin show mainly flat-lying units with little structural disruption. Potential reservoirs are inferred to be Lower Cretaceous to Upper Jurrasic interfingered, fine-grained clastics and carbonates. In the 1995 assessment (Lore *et al.*, 1999), this play was referred to as the Upper Jurassic to Lower Cretaceous Transition Zone (UU-LK TZ) play.

The LK8-UJ4 play was not assessed because the Tampa basin is thought to lack hydrocarbon source rocks.

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Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) Play

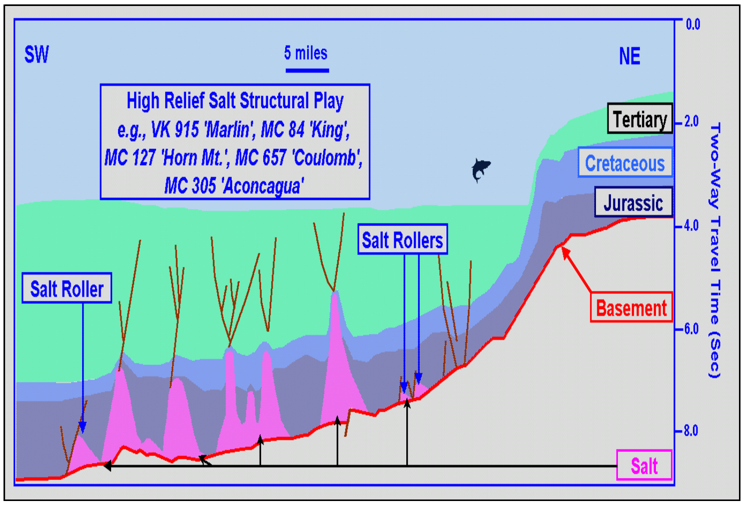

Figure 1. Diagrammatic cross-section illustrating salt rollers and high-relief salt structures in the northern Gulf of Mexico.

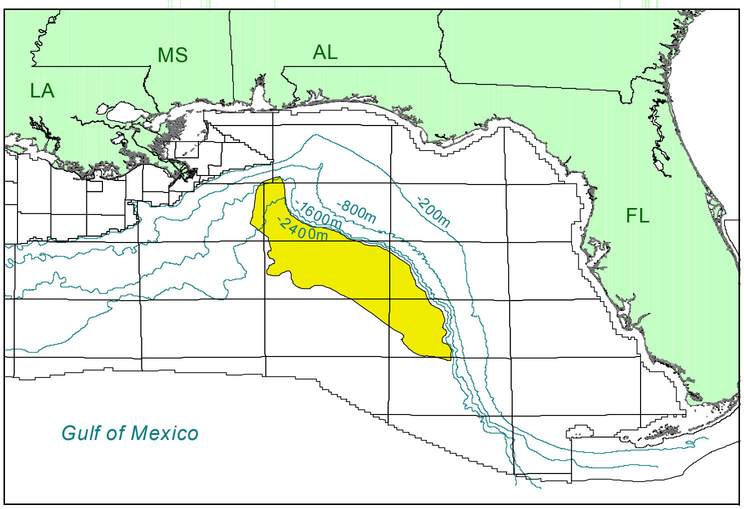

Figure 2. Play location.

Play Description

The Upper Cretaceous to Upper Jurassic Salt Roller/High-Relief Salt Structure (UK5-UJ4 S1) play is defined in the ultra-deepwater Gulf of Mexico Region by (1) the occurrence of Louann salt-cored salt rollers, salt swells, and vertical salt welds/pinnacle salt structures (figure 1), and (2) source, reservoir, and seal lithologies that comprise seismically correlated units of the upper Jurassic through the upper Cretaceous.

The play is located downdip and parallel to the Florida Escarpment in parts of the DeSoto Canyon, Lloyd, the Elbow, and Vernon Areas of the Eastern Planning Area of the northern Gulf of Mexico (figure 2). The play is bounded updip (north and northeast) by the Florida Escarpment. A variety of depositional and structural features defines its southern and western boundaries. To the west (at the boundary of the DeSoto Canyon and Mississippi Canyon Areas), salt canopies, salt domes, salt diapirs, salt-floored mini-basins, and the compressional folds of the Mississippi Fan Fold Belt (refer to the established Cenozoic Mississippi Fan Fold Belt (UPL-LL X2) play) delineate the play. The south and southwest play boundary (at the border of the Lloyd Ridge and Atwater Valley Areas and extending eastward across the middle of the Lloyd Ridge Area) coincides with the depositional limit of salt. Buried hills are the dominant structural features beyond this boundary (refer to the various Buried Hills conceptual plays).

The following discussion is from Post (2000), unless otherwise noted.

Play Characteristics

Salt rollers are low-amplitude, asymmetric salt structures comprising two flanks: one flank in conformable stratigraphic contact

UK5-UJ4 S1 Salt Roller-High Relief Salt Marginal Probability = 0.35	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	18	0.400	0.744	0.532
5th percentile	--	1.846	3.518	2.448
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	18	0.400	0.744	0.532
5th percentile	--	1.846	3.518	2.448

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

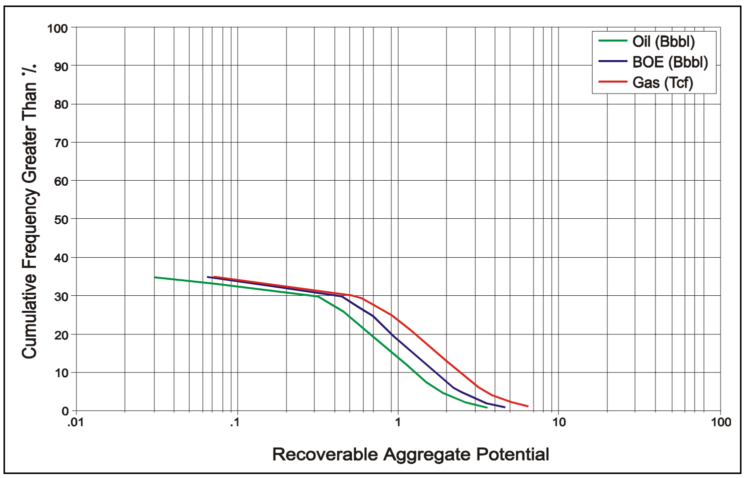

Figure 3. Cumulative probability distribution for undiscovered conventionally recoverable resources.

with the overburden, and the other in normal-faulted contact with the overburden (Bally, 1981; Jackson and Talbot, 1991; Duval *et al.,* 1992). Salt rollers in the play area formed because of updip extension as a result of post-rift subsidence and increased basinward dip to the southwest. Near the updip depositional limit of the Late Jurassic Louann Salt, the overlying Late Jurassic clastics and carbonates (possibly equivalent to the Norphlet and Smackover Formations) fracture and separate. Gravity gliding and spreading of this lithified 'beam unit' create regional extension (Rowan *et al.*, 1999). As the beam unit begins to slide downdip on the salt, buckling and breaking into smaller segments, a series of predominantly down-to-the-basin listric normal faults develop. Concurrently, the Louann Salt begins to flow, filling the space created along the fault planes. The areal extent of individual salt rollers ranges from ~1,700 to ~300,000 acres in size.

High relief salt structures include autochthonous salt swells, e.g., the Coulomb (MC 657) and Aconcagua (MC 305) discoveries, and vertical salt welds/pinnacle salt structures, e.g., the Fourier (MC 522) discovery. Although the reservoirs in these discoveries are Tertiary in age, these structures may provide traps for Jurassic and Cretaceous reservoirs. High-relief salt structures typically develop when the supply of salt is not exhausted in the formation of salt rollers, and where updip extension and associated gravity gliding continue into more recent geologic time.

Early formed salt rollers create a series of paleostructures, the crests of which remain near wavebase. These structures localize high-energy oolite and grainstone deposits that are the primary Jurassic carbonate reservoir objectives throughout the Gulf of Mexico basin. Jurassic clastics may also serve as reservoir objectives where they possess suffi-

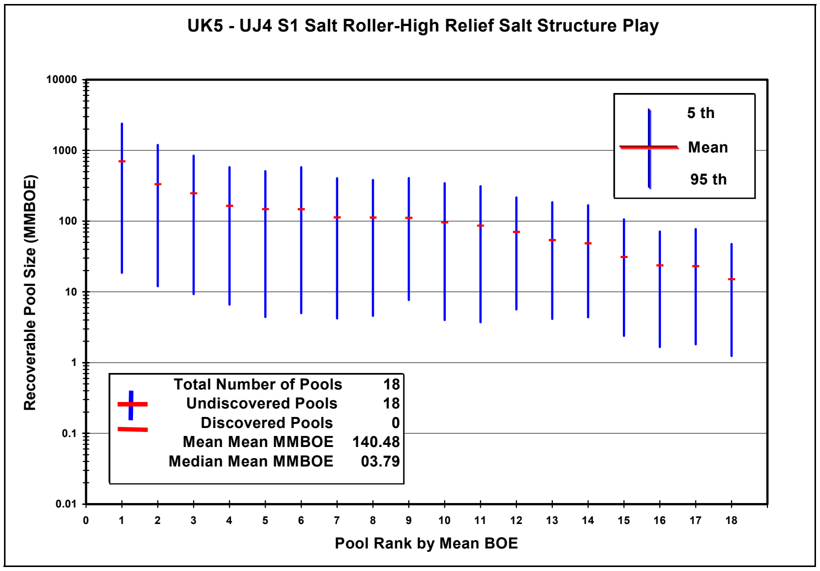

Figure 4. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

cient continuity, thickness, porosity and permeability, especially in areas where high-energy carbonates are not developed. Deeper-water, low-energy facies in the footwall of the salt rollers form fault-juxtaposed seals for hydrocarbon traps formed on, or by, the salt rollers. Late Jurassic through predominantly Early Cretaceous sediments onlap and thin onto the salt rollers. Depending on the water depth, the structural relief of the salt rollers, their continued development into high-relief salt swells, vertical salt welds/pinnacle salt structures, and their location in the basin, high-energy carbonates depositional environments may have been able to persist on these paleostructures into the Late Cretaceous.

Source rocks for the oldest reservoir objectives in the UK5-UJ4 S1 play, the Jurassic clastics and carbonates, are most likely to be Oxfordian or Kimmeridgian-Tithonian in age. These are documented source rocks for equivalent age reservoirs in onshore Gulf of Mexico basins, and marine hydrocarbon seeps in the play area have been geochemically typed as originating from these source beds (Wenger et al., 1994). These are also the most likely source rocks for Cretaceous carbonate objectives if cross-stratal migration paths can be located. Although other possible source rocks for Cretaceous objectives may include source rocks of Barremian-Hauterivian, Aptian, Albian, Turonian, Coniacian-Santonian, or Paleocene in age, seeps in the area have not been geochemically matched with any of these source rocks.

Porosities for carbonate and clastic reservoirs objectives may range from 7 to 20 percent using analogous productive reservoirs of the same age in salt rollers onshore and in shallower water depths. The relief of each salt roller/high-relief salt structure will determine the youngest reservoir objectives. Redeposited Late Cretaceous chalks may be reservoir objectives in the high-relief structures. These may also be fracture-enhanced, depending on the amount of faulting associated with the crestal part of the structure.

Regional top seals for the reservoirs are anticipated to be fine-grained, low-energy carbonates, marls, and chalks. Depending upon the water depth during the time of deposition, anhydrite or anhydrite-rich sediments may also provide a top seal.

Discoveries

No wells have been drilled in the UK5-UJ4 S1 play prior to this study's January 1, 1999, cutoff date.

Assessment Results

A number of producing fields serve as analogs for the UK5-UJ4 S1 play. Examples of productive salt rollers are well documented in the East Texas (Thomson, 1983), Mississippi (Hughes, 1968; Price *et al.,* 1979; Shew and Garner, 1986), DeSoto Canyon (MacRae and Watkins, 1993) and Campeche (Romero *et al.,* 1998) salt basins. They have also been described in most salt-bearing, extensional basins, e.g., the South American and African Atlantic-margin basins (Spencer *et al.,* 1998; Cobbold *et al.,* 1995; Mohriak *et al.,* 1995; Liro and Coen, 1995; and Duval *et al.,* 1992). Examples of the productive autochthonous salt swells, vertical salt welds/pinnacle salt structures found in the eastern part of the Mississippi Canyon Area are the Coulomb (MC 657) and Aconcagua (MC 305) discoveries. The Fourier (MC 522) discovery provides one of many productive analogs of a vertical salt weld/pinnacle salt structure.

The marginal probability of hydrocarbons for the UK5-UJ4 S1 play is 0.35. The play contains a mean total endowment of 0.400 Bbo and 0.744 Tcfg (0.532 BBOE) (table 1).

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) have a range of 0.000

to 1.846 Bbo and 0.000 to 3.518 Tcfg at the 95th and 5th percentiles, respectively (figure 3). Mean UCRR equal mean total endowment. These undiscovered resources might occur in as many as 18 pools. The largest undiscovered pool has a mean size of 703 MMBOE (figure 4). The mean mean size of the five largest undiscovered pools is 319 MMBOE.

Exploration Future

Although a variety of geotechnical factors influences the prospectivity of a play, one of the most significant for the UK5-UJ4 S1 play is the reservoir component. Reservoir quality, the depositional environment of postulated reservoirs, and the diagenetic history of those reservoirs are some of the most important areas to address in the future exploration of this play. Developing integrated geologic history models to best locate favorable reservoir facies in trapping configurations using 3-D seismic, available well log and core data will be necessary to reduce the reservoir uncertainty in the play.

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Atlantic Chronozone, Series, and System Aggregations

Region	Province	System	Series	Chronozone
	Mesozoic	Cretaceous	Upper	AUK
			Lower	ALK
		Jurassic	Upper	AUJ
			Middle	AMJ
			Lower	ALJ
		Triassic	Upper	AUTR
			Middle	AMTR
			Lower	ALTR

Figure 1. MMS chronostratigraphic chart for the Atlantic Region illustrating potential play aggregation levels.

Included in the **Summary Tables** of this report are assessment data aggregated to the chronozone, series, system, province, and region levels (figure 1). However, in the text, only the Mesozoic Province, the Jurassic System, and the Upper- and Middle Jurassic Chronozones contain written descriptions. This is because all other levels either contain no assessed plays or are adequately aggregated and discussed at the chronozone or play level (figure 2).

For example, the Atlantic Region does not have an aggregation write-up because the Cenozoic Province is not considered prospective and was not assessed. Thus, the Atlantic Region equals the Atlantic Mesozoic Province, which is discussed.

Atlantic Region	Equal to Mesozoic Province
Cenozoic Province	Not considered prospective
Mesozoic Province	Cretaceous and Jurassic Systems aggregated
Cretaceous System	Equal to Lower Cretaceous Series
Jurassic System	Upper Jurassic and Middle Jurassic Chronozones aggregated
Triassic System	No assessed plays
Plays that span Systems	Five conceptual plays not assessed
Upper Cretaceous Series	Equal to Upper Cretaceous Chronozone
Lower Cretaceous Series	Equal to Lower Cretaceous Chronozone
Upper Jurassic Series	Equal to Upper Jurassic Chronozone
Middle Jurassic Series	Equal to Middle Jurassic Chronozone
Lower Jurassic Series	No assessed plays
Upper Triassic Series	No assessed plays
Upper Cretaceous Chronozone	AUK C1 play not assessed
Lower Cretaceous Chronozone	Equal to **ALK C1** play
Upper Jurassic Chronozone	**AUJ B1** and **AUJ C1** plays aggregated
Middle Jurassic Chronozone	**AMJ B1** and **AMJ C1** plays aggregated
Lower Jurassic Chronozone	No assessed plays
Upper Triassic Chronozone	No assessed plays

Figure 2. Chart for the Atlantic Region illustrating data aggregation levels. Lettering in bold represents aggregation levels that are discussed in this report. All other levels are not discussed because they either contain no assessed plays or are adequately aggregated and discussed at the chronozone or play level.

Atlantic Region

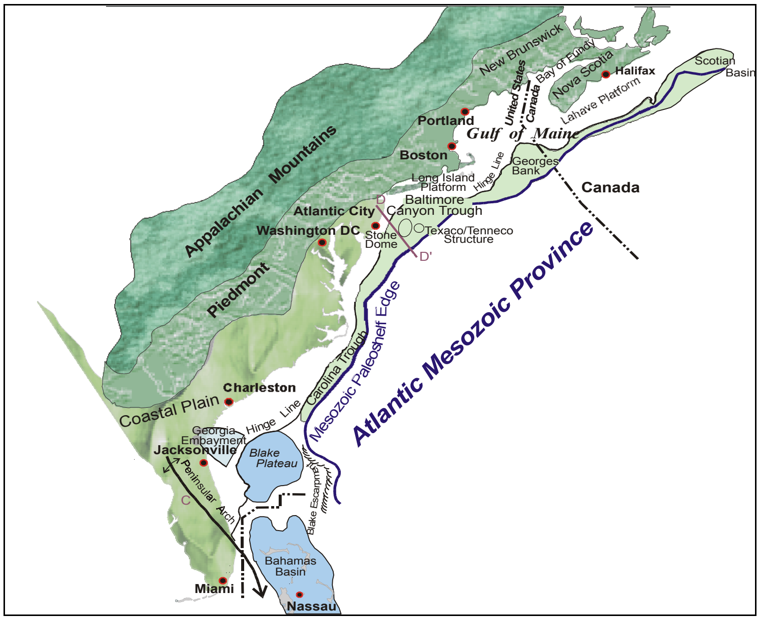


Figure 1. Physiographic map of the Atlantic Margin.

Region Description

The Atlantic Region contains two provinces. The Atlantic Mesozoic Province was assessed and is described on following pages. The Cenozoic Province has poor reservoir and source rock characteristics, and therefore was not assessed.

Atlantic Mesozoic Province

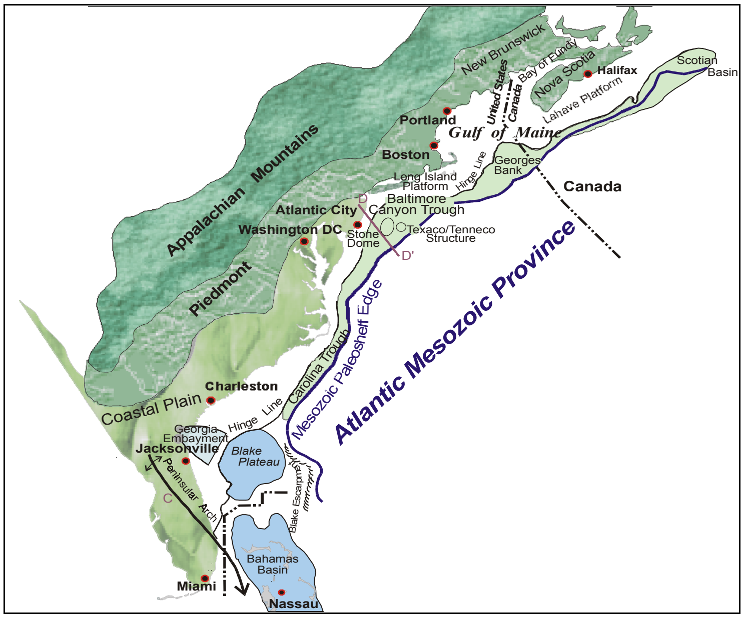


Figure 1. Physiographic map of the Atlantic Margin.

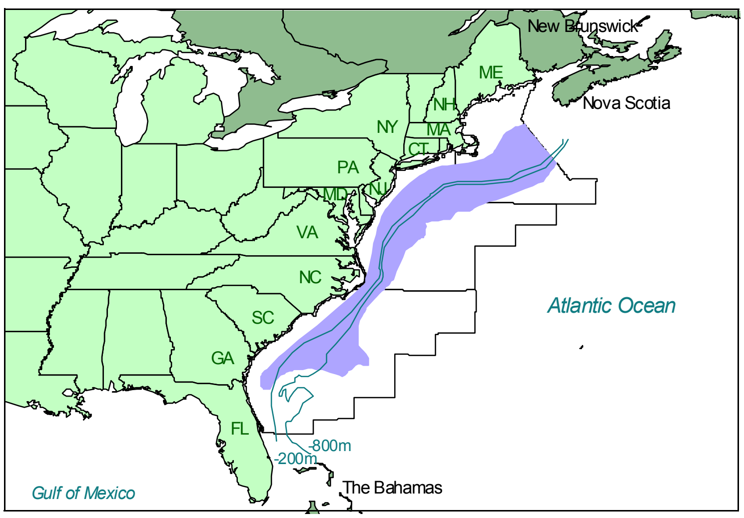


Figure 2. Extent of plays assessed in the Atlantic Mesozoic Province.

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). In the northern and central portions of the Province, sediments underlying the shelf are siliciclastic, derived from erosion of the Appalachian Mountains, with platform and reefal carbonates lying 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.

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 overlies the rift sedimentary sequence under the shelf. The post-rift unconformity represents a 20-million-year hiatus and is overlain by the middle Jurassic to recent sediments. 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.

Province	System	Series	Chronozone Name	Chronozone Number	Biozone
Mesozoic	Cretaceous	Upper	UK5	38	*Globotruncana mayaroensis* *Globotruncana fornicata* *Globotruncana concavata*
			UK2	41	*Planulina eaglefordnsis* *Rotalipora cushmani*
		Lower	LK8	43	*Lenticulina washitaensis* *Cythereis fredericksburgensis*
			LK6	45	*Eocytheropteron trinitiensis* *Orbitolina texana* *Rehacythereis? aff. R. glabrella*
			LK3	48	*Choffatella decipiens* *Schuleridea acuminata*
	Jurassic	Upper	UJ4	51	*Epistomina uhligi* *Epistomina mosquensis* *Pseudocyclammina jaccardi*
		Middle	MJ	55	
		Lower	LJ	56	
	Triassic	Upper	UTR	57	
		Middle	MTR	58	
		Lower	LTR	59	

Figure 3. Atlantic Mesozoic Province chronostratigraphic/biostratigraphic chart. Chronozones are after Reed et al. (1987).

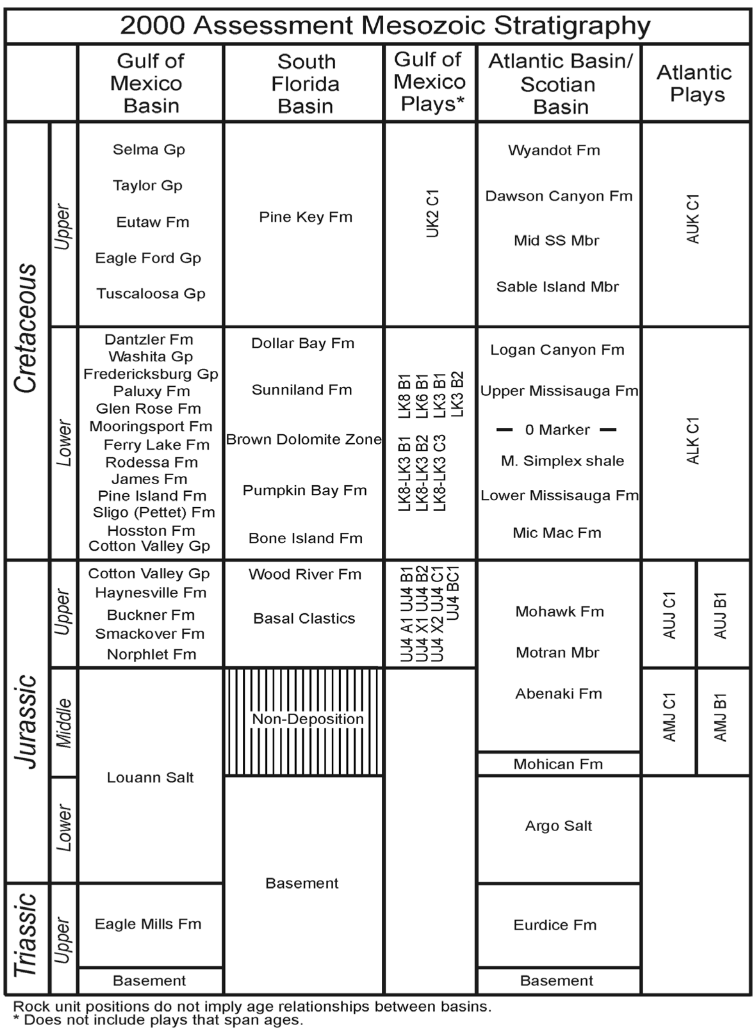


Figure 4. Mesozoic stratigraphy including a comparison of formations in the Atlantic and Scotian Basins to the Gulf of Mexico and South Florida Basins.

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 (AMJ), upper Jurassic (AUJ), and lower Cretaceous (ALK). Figures 4 and 5 illustrates the stratigraphic relationships of the Mesozoic sediments of the Atlantic OCS area.

Discoveries

In 1976, the first U.S. Atlantic offshore lease sale was held 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 (figure 1). The Stone Dome prospect was tested by seven exploration wells, all of which were dry. The Texaco/Tenneco prospect was tested by eight wells, five of which had subeconomic, mostly natural gas flows from lower Cretaceous siliciclastics.

Nine Atlantic OCS sales have been held 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 in 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; however, as of November 1, 2000, no oil and gas leases remain active in the Atlantic

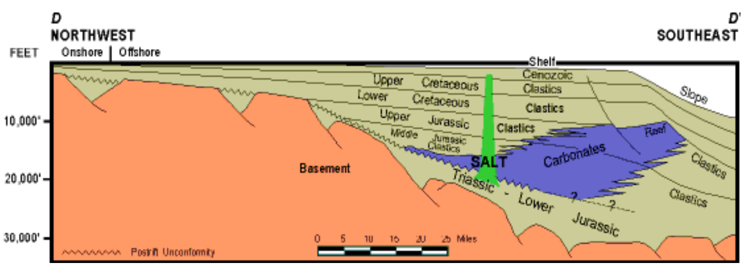


Figure 5. Cross section D-D' (refer to figure 1 for location) illustrating the stratigraphic and lithologic relationships of the formations overlying the basement from onshore to offshore along the Atlantic OCS.

Atlantic Mesozoic Province 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	–	1.297	16.117	4.558
Mean	502	2.307	27.712	7.238
5th percentile	–	3.706	43.499	10.739
Total Endowment				
95th percentile	–	1.297	16.117	4.558
Mean	502	2.307	27.712	7.238
5th percentile	–	3.706	43.499	10.739

Table 1. Assessment results for undiscovered conventionally recoverable hydrocarbons (equal to total endowment).

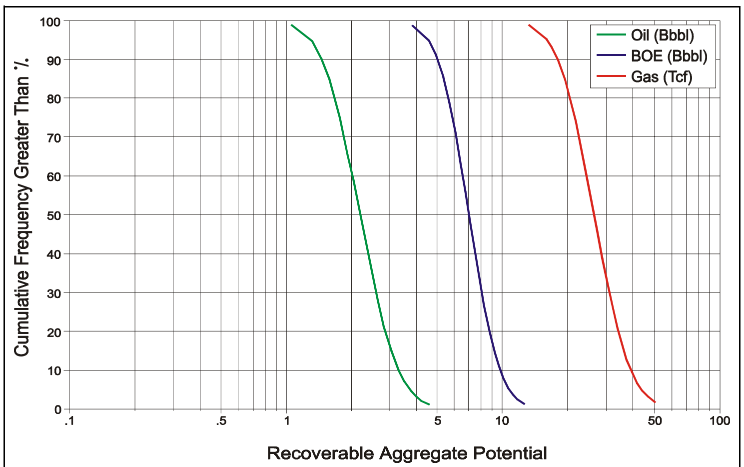


Figure 6. Cumulative probability distribution for undiscovered conventionally recoverable resources.

OCS.

Assessment Results

Eleven individual plays within the Atlantic Mesozoic Province have been identified, six of which were not assessed because of great burial depth, lack of source rocks, or high structural risk.

The mean total endowment, equal to mean undiscovered conventionally recoverable resources, for the Atlantic Mesozoic Province is forecast at 2.307 Bbo and 27.712 Tcfg (7.238 BBOE) (table 1). The total endowment ranges from 1.297 to 3.706 Bbo and 16.117 to 43.499 Tcfg at the 95th and 5th percentiles, respectively (figure 6). These undiscovered resources may occur in as many as 502 pools (figure 7).

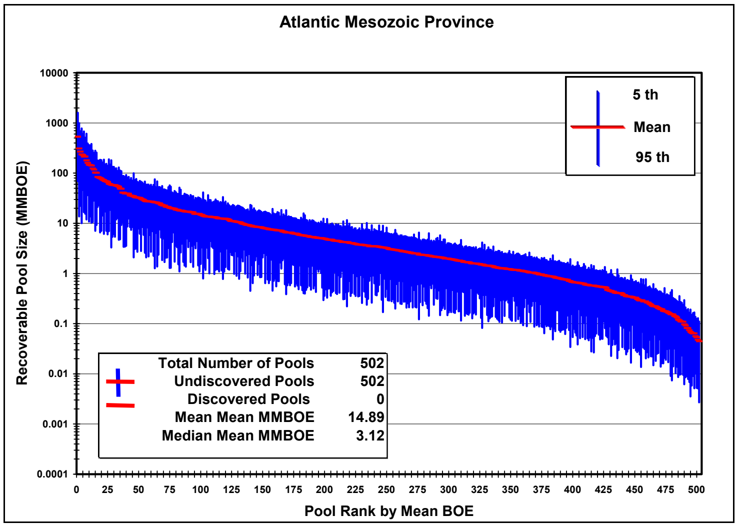


Figure 7. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars) in the Atlantic Mesozoic Province.

Atlantic Upper Cretaceous Clastic (AUK C1) Play

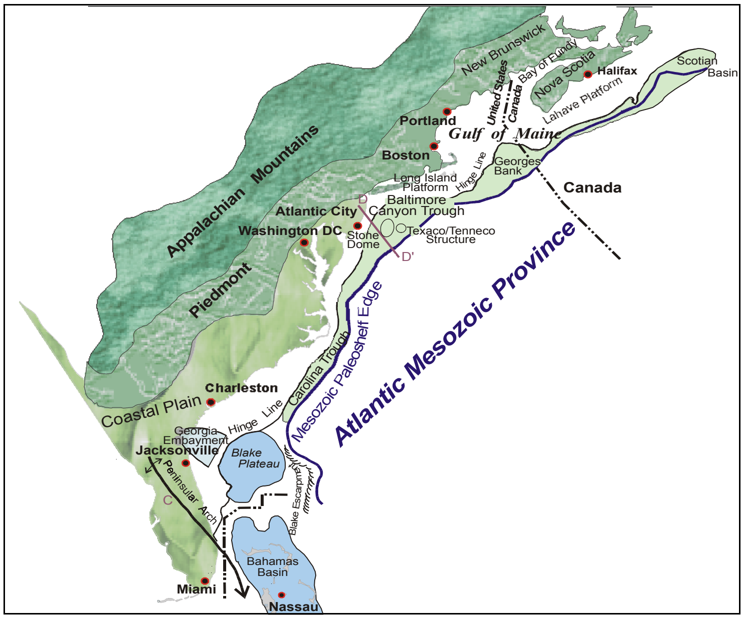


Figure 1. Physiographic map of the Atlantic Margin.

Play Description

The conceptual and unassessed Atlantic Upper Cretaceous Clastic (AUK C1) play is identified in the Georges Bank, Baltimore Canyon, and Georgia Embayment Areas of the Atlantic Margin (figure 1). During the Late Cretaceous, clastic sediments were eroded from the Appalachian Mountains and were deposited on the Atlantic Margin shelf. These sediments prograded seaward over the shelf and onto the slope. Potential reservoirs were deposited on the shelf in delta complexes and barrier bars, and on the slope as channel systems.

The AUK C1 play was not assessed because of shallow burial depth and lack of proximity to thermally mature source rocks.

Atlantic Lower Cretaceous Clastic (ALK C1) Play

Polycostella senaria through *Favusella washitaensis* biozones

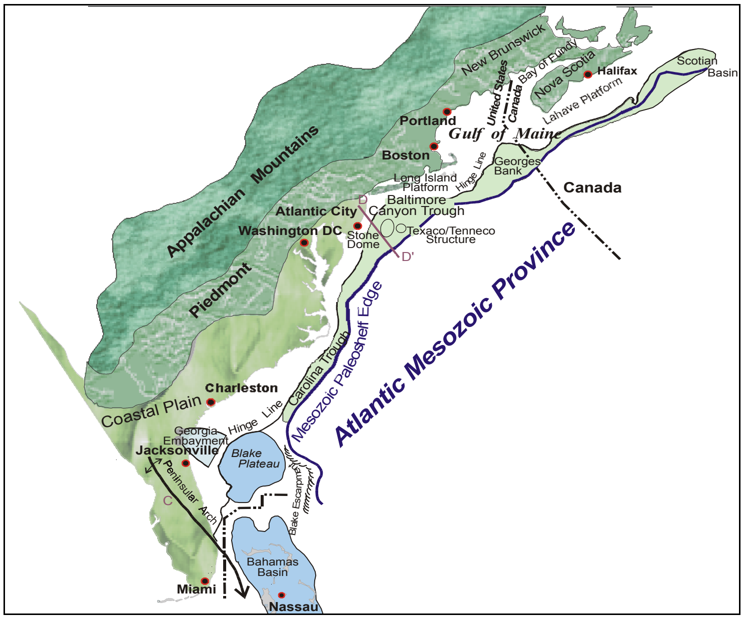


Figure 1. Physiographic map of the Atlantic Margin.

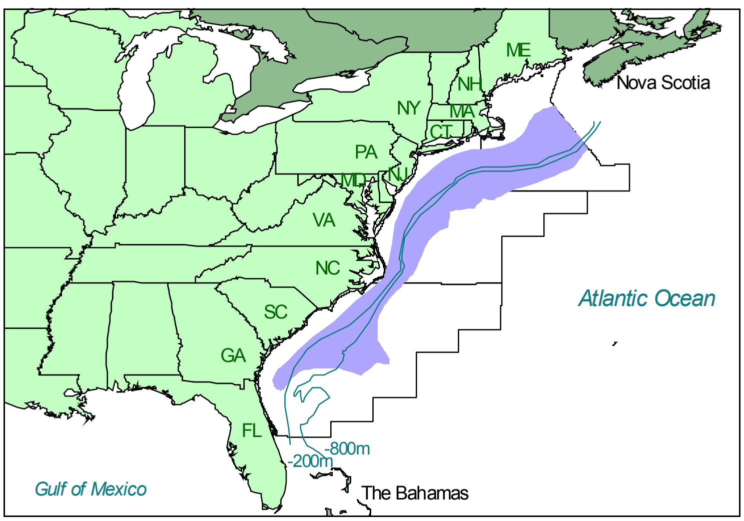


Figure 2. Play location.

Play Description

The frontier Atlantic Lower Cretaceous Clastic (ALK C1) play occurs within the *Polycostella senaria*, *Choffatella decipiens*, *Mud-erongia simplex,* and *Favusella washitaensis* biozones. This play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figures 1 and 2).

The updip limit for this play coincides with the updip limit of potential source rocks. The downdip limit is defined by lower Cretaceous clastic sediments that prograded over the upper Jurassic carbonate shelf and onto the slope.

The ALK C1 play is stratigraphically and structurally similar to the Atlantic Upper Jurassic Clastic (AUJ C1) and the Atlantic Middle Jurassic Clastic (AMJ C1) plays. However, the ALK C1 play does cover a larger geographic area than either the AUJ C1 or AMJ C1 plays.

Play Characteristics

During the lower Cretaceous, clastic sediments were eroded from the Appalachian Mountains and were deposited on the Atlantic Margin shelf. Delta complexes prograded across the shelf and, when clastic influx was great enough, fans were deposited on the slope. Potential lower Cretaceous reservoirs were deposited 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 occur in this play.

Potential trapping structures on the shelf include anticlines, normal faults, and growth faults. Potential trapping features on the slope include anticlines and sediment pinch-outs against diapirs. Potential source rocks include Jurassic shales and possibly Jurassic platform carbon-

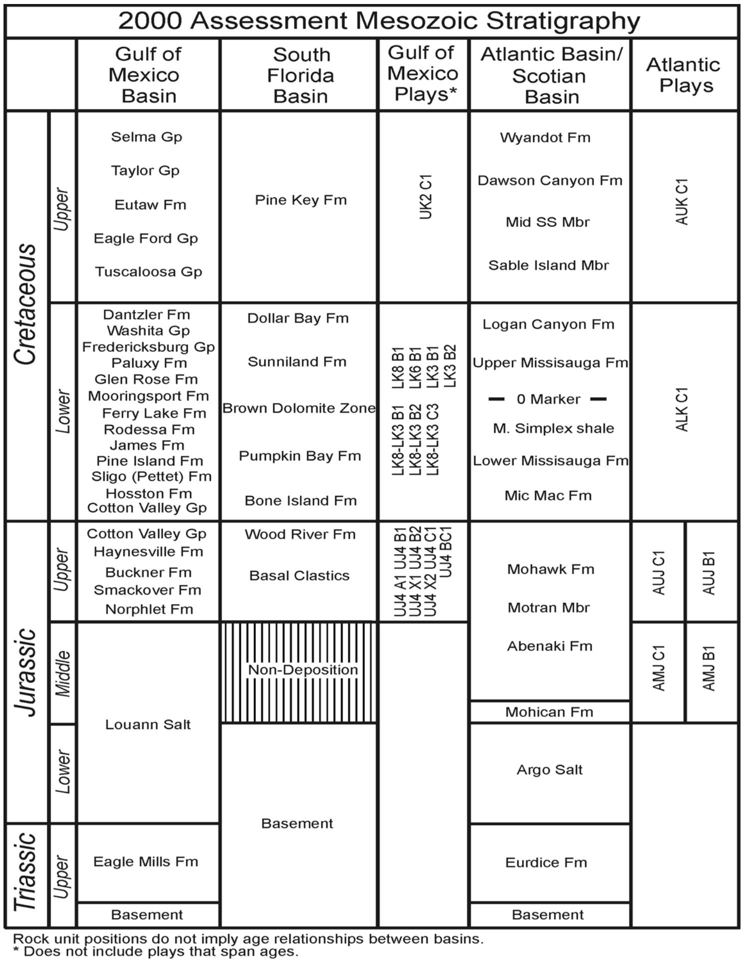


Figure 3. Mesozoic stratigraphy of the Gulf of Mexico and Atlantic Margins.

ALK C1 Play 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

—

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

ates. 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 extends from approximately 7,000 to 18,000 feet. Potential seals are provided by early to late Cretaceous limestones and overlying shales.

Discoveries

Exploration in the Atlantic Federal OCS area consists of 46 exploration and 5 COST wells. 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.

Analogs

Because the ALK C1 play contains no active Federal fields, productive lower Cretaceous clastic sediments of both the onshore Gulf of Mexico and the lower Cretaceous and upper Jurassic clastic sediments of the Canadian offshore Scotian Basin (figure 1) provide the analogs for input parameters used in this assessment.

The onshore Gulf of Mexico 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). The analog type field for the ALK C1 play is the Citronelle Field, Mobile County, Alabama. Production from the lower Cretaceous clastic section in this field is from the Rodessa Formation.

Exploration in the Gulf of Mexico analog area has a success rate of approximately 10 percent, and drilling is at a mature stage with about 75 percent of the analog area 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

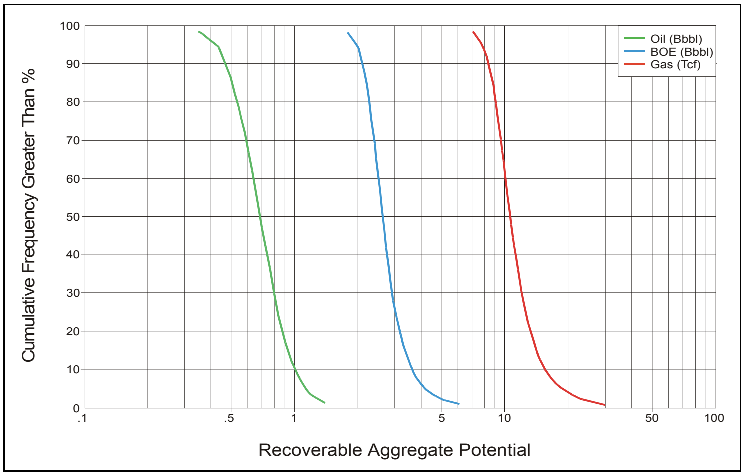


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

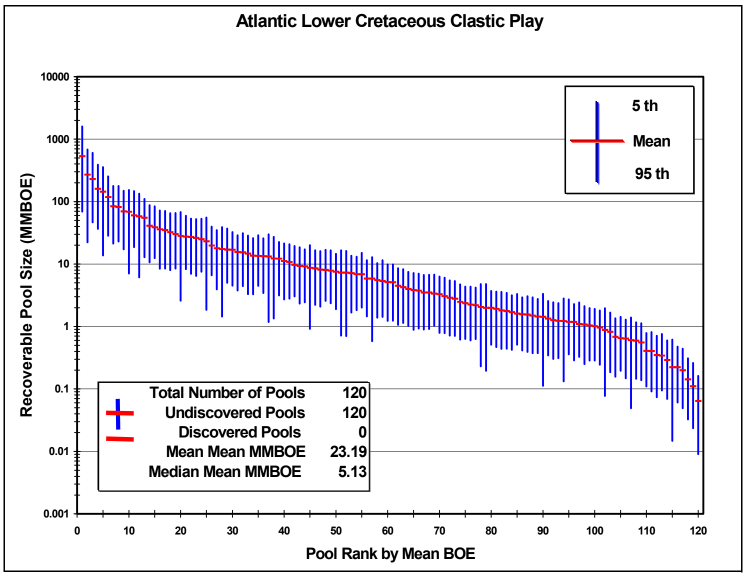


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

were not used as analogs in this assessment because they produce from eolian sands that are not analogous to the deltaic deposits in the ALK C1 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 area covers 35 million acres (54,700 square miles). Exploration has a success rate of approximately 30 percent, and drilling is at an immature stage with only about 30 percent of the analog area being explored. This analog was used primarily for field size distribution parameters because production data were not available.

Assessment Results

The marginal probability of hydrocarbons for the ALK C1 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) 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). Mean UCRR are forecast at 0.722 Bbo and 11.767 Tcfg (2.816 BBOE). These undiscovered resources might occur in as many as 120 pools. These pools have a mean size range of <1 to 535 MMBOE (figure 5) and a mean mean size of 23 MMBOE.

The ALK C1 play is projected to contain the largest amount of undiscovered gas resources (43%) and the second largest amount of undiscovered oil resources (32%) of all 11 Atlantic plays. Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

Atlantic Jurassic System

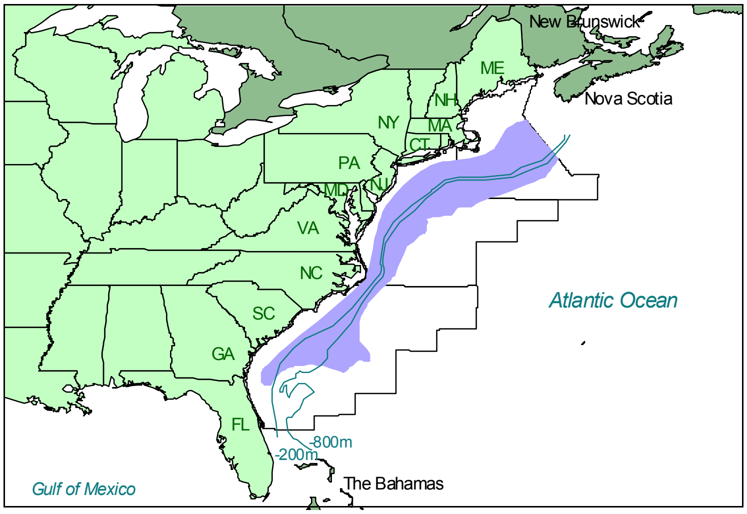


Figure 1. Extent of plays in the Jurassic System of the Atlantic Mesozoic Province.

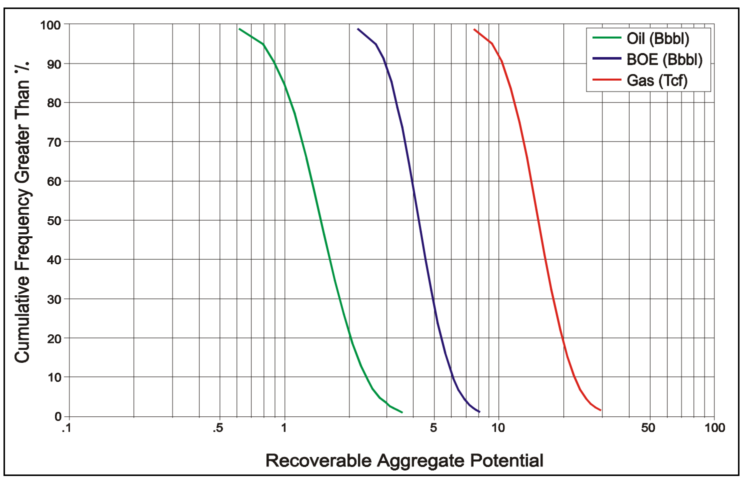


Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

System Description

The Atlantic Jurassic System contains the Middle and Upper Jurassic Series and four assessed plays. Figure 1 illustrates the overall extent of these plays in the Atlantic Jurassic System.

Discoveries

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

Assessment Results

Undiscovered conventionally recoverable resources (UCRR) for the Atlantic Jurassic System have a range of 0.790 to 2.754 Bbo and 9.311 to 24.847 Tcfg at the 95th and 5th percentiles, respectively (figure 2 and table 1). Mean UCRR are forecast at 1.549 Bbo and 15.712 Tcfg (4.345 BBOE). These undiscovered resources might occur in as many as 382 pools (figure 3).

Atlantic Jurassic System 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	--	0.790	9.311	2.667
Mean	382	1.585	15.944	4.422
5th percentile	--	2.754	24.957	6.768
Total Endowment				
95th percentile	--	0.790	9.311	2.667
Mean	382	1.585	15.944	4.422
5th percentile	--	2.754	24.957	6.768

Table 1. Assessment results for undiscovered conventionally recoverable resources and total endowment.

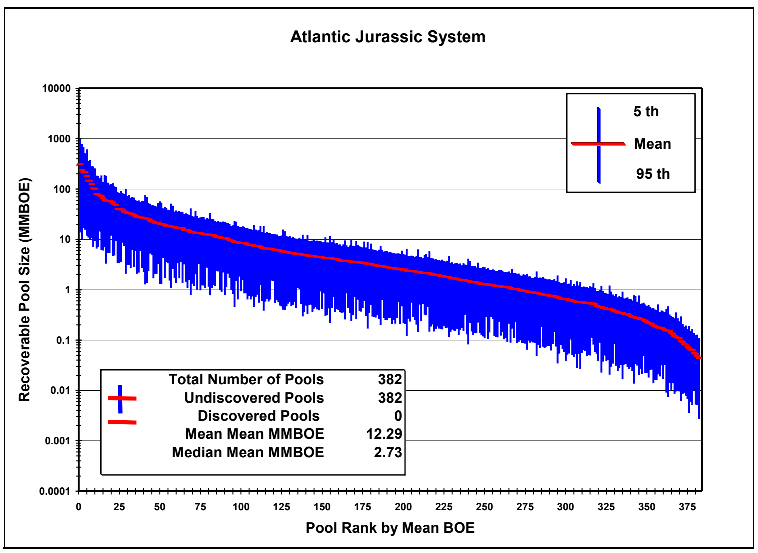


Figure 3. Pool rank plot showing the number of pools forecast to be discovered (blue bars).

Atlantic Upper Jurassic (AUJ) Chronzone

Pseudocyclammina jaccardi **through** ***Ctenedodinium penneum*** **biozones**

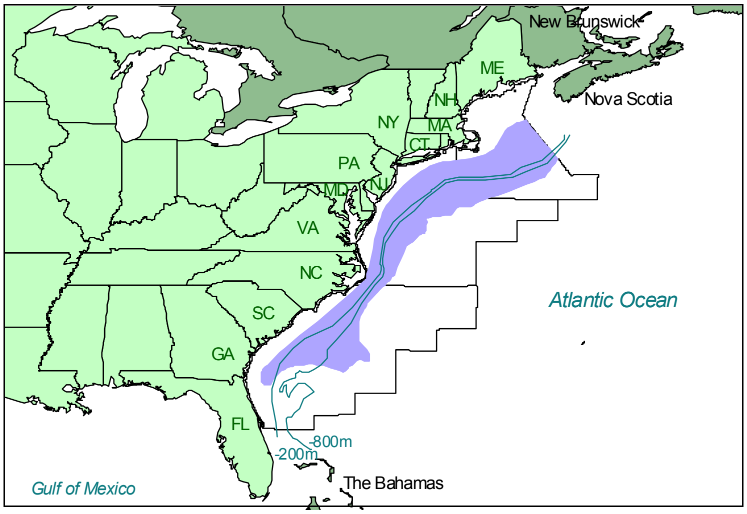


Figure 1. Extent of plays in the Upper Jurassic Chronozone of the Atlantic Mesozoic Province.

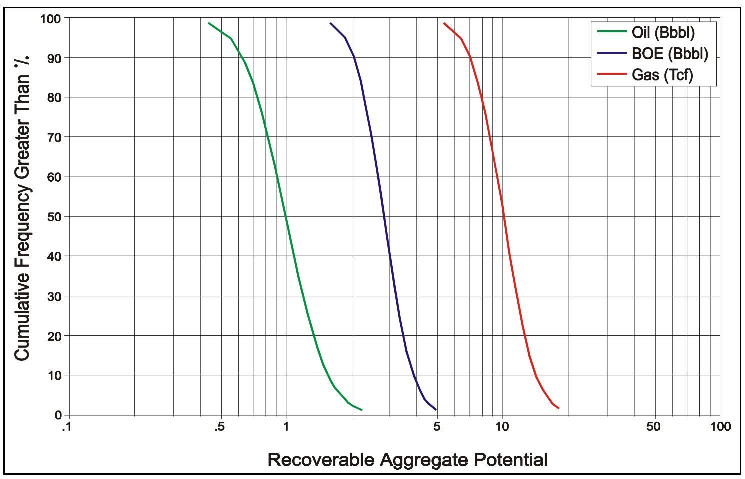


Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

Chronozone Description

The Atlantic Upper Jurassic (AUJ) chronozone corresponds to the *Pseudocyclammina jaccardi*, *Senoniasphaera jurassica*, *Epistomina uhligi*, and *Ctenedodinium penneum* biozones. The upper Jurassic section consists of clastics and carbonates, each of which defines a play: the Atlantic Upper Jurassic Clastic (AUJ C1) play and the Atlantic Upper Jurassic Carbonate (AUJ B1) play. Siliciclastics were deposited in retrogradational, aggradational, and progradational styles on the shelf, and in deep-water fans on the slope. Shallow-water limestone platforms and reef complexes developed where siliciclastic influx was minimal. In addition to upper Jurassic carbonates, thin lowermost Cretaceous carbonates might be discontinuously developed along the seaward-most edge of the carbonate complex. If present, these carbonates are also included in the AUJ B1 play.

Reservoir potential in the chronozone extends from the U.S.-Canadian border to offshore Georgia (figure 1). Updip reservoir potential is limited by the erosional limit of upper Jurassic clastics. Downdip reservoir potential is limited by the extent of slope fans.

Discoveries

No pools in the chronozone have yet been discovered in the Federal OCS.

Assessment Results

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) might occur in as many as 235 pools. These pools contain 0.555 to 1.774 Bbo and 6.422 to 15.760 Tcfg at the 95th and 5th percentiles, respectively (figure 2 and table 1). Mean UCRR are 1.056 Bbo and 10.444 Tcfg

AUJ Chronozone 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	–	0.555	6.422	1.879
Mean	235	1.056	10.444	2.914
5th percentile	–	1.774	15.760	4.250
Total Endowment				
95th percentile	–	0.555	6.422	1.879
Mean	235	1.056	10.444	2.914
5th percentile	–	1.774	15.760	4.250

Table 1. Assessment results for undiscovered conventionally recoverable resources (equal total endowment).

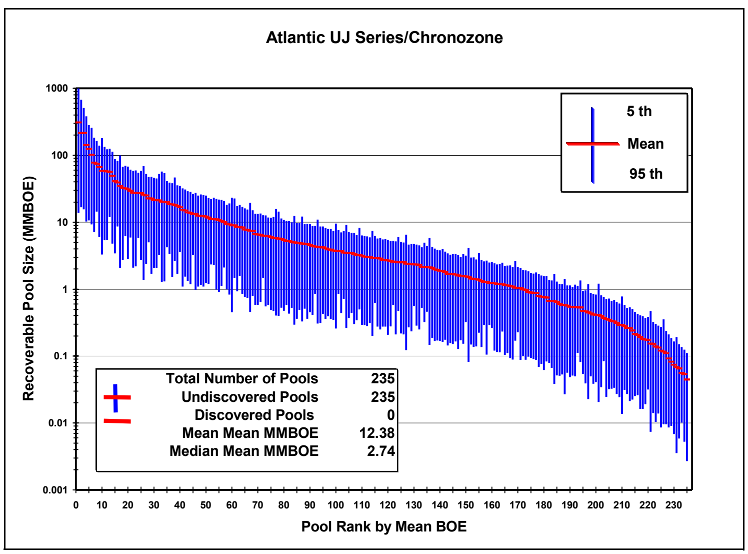


Figure 3. Pool rank plot showing the number of pools forecast to be discovered (blue bars).

(2.914 BBOE). These undiscovered pools have a mean mean size of 12.379 MMBOE (figure 3). Of the two plays in the chronozone, the AUJ C1 play is forecast to contain 83 percent of the BOE mean total endowment for the chronozone.

Atlantic Upper Jurassic Carbonate (AUJ B1) Play

***Pseudocyclammina jaccardi* through *Ctenidodinium penneum* biozones**

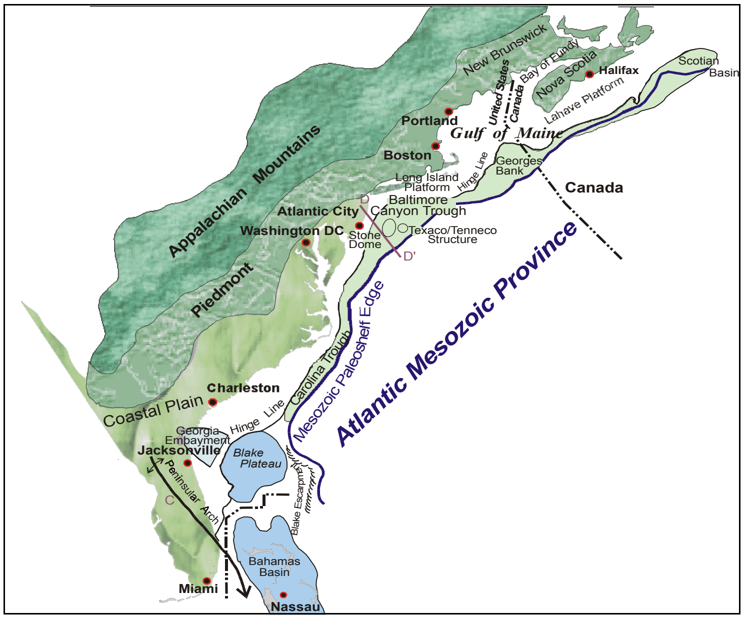


Figure 1. Physiographic map of the Atlantic Margin.

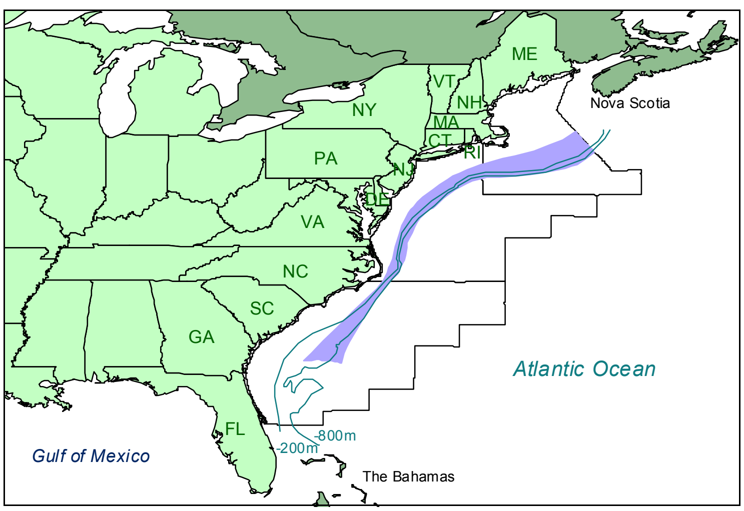


Figure 2. Play location.

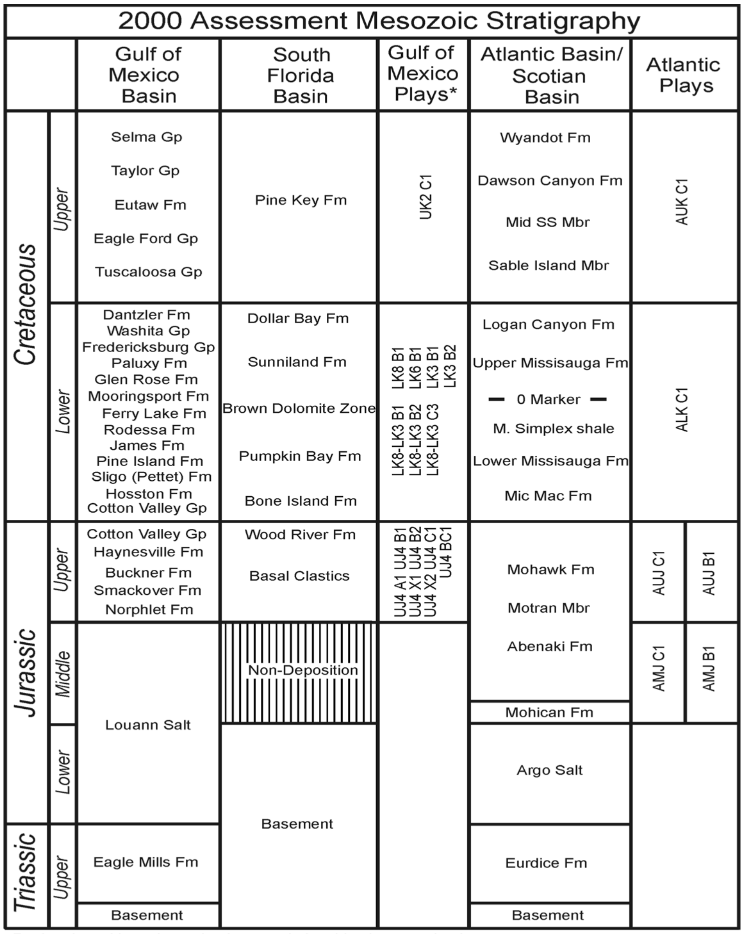
Play Description

The frontier Atlantic Upper Jurassic Carbonate (AUJ B1) 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 (figures 1 and 2).

The AUJ B1 carbonate platform and reef play is stratigraphically similar to the Atlantic Middle Jurassic Carbonate (AMJ B1) play; however, the carbonate platform became successively narrower during the Upper Jurassic because of 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 AUJ B1 play.

Play Characteristics

The AUJ B1 play consists of late Jurassic shelf-edge reef complexes with associated back-reef carbonate platforms and reef-face carbonate talus. These carbonate platforms and reef complexes developed where deltaic clastic influx was minimal. Potential reservoirs are located in the reef itself, in the fore-reef talus, and in the back-reef as oolitic, pelletal, or reef detritus grainstones. Reef and back-reef deposits have the best potential for enhanced porosity because of subaerial exposure. Traps are mainly stratigraphic on the carbonate platform. Combination stratigraphic and fault traps occur within the reef complex on the shelf edge and in reef talus on the slope. Potential source rocks include Juras-



Rock unit positions do not imply age relationships between basins.
* Does not include plays that span ages.

Figure 3. Mesozoic stratigraphy of the Gulf of Mexico and Atlantic Margins.

AUJ B1 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	–	0.087	0.718	0.232
Mean	35	0.234	1.488	0.499
5th percentile	–	0.520	3.371	1.060
Total Endowment				
95th percentile	–	0.087	0.718	0.232
Mean	35	0.234	1.488	0.499
5th percentile	–	0.520	3.371	1.060

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

sic shelf and slope shales, and possibly lagoonal and platform carbonates. 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 extends from approximately 7,000 to 18,000 feet. Seals are provided by upper Jurassic or lowermost Cretaceous carbonates, shales, and anhydrites.

Discoveries

Exploration in the Atlantic Federal OCS area consists of 46 exploration and 5 COST wells. Three exploration wells, Shell Offshore Inc.'s 372-1, 586-1, and 587-1, drilled in Wilmington Canyon penetrated the shelf-edge reef and back-reef facies of the AUJ B1 play. Good reservoir rock was encountered, but no hydrocarbons were detected.

Analogs

Because the AUJ B1 play contains no Federal fields, productive upper Jurassic platform carbonate reservoirs of the onshore eastern Gulf of Mexico and the onshore central Gulf of Mexico lower Cretaceous Sligo-Stuart City reef trend provide analogs for the input parameters used in this assessment (figure 3). The analog type field for the AUJ B1 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.

The onshore eastern Gulf of Mexico 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 area covers 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 area being explored. Fields in the analog area contain an average of 35 percent oil, 22 percent gas, and

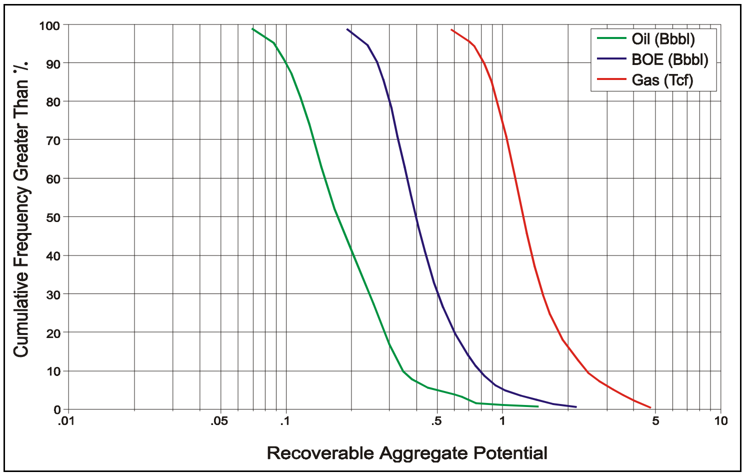


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

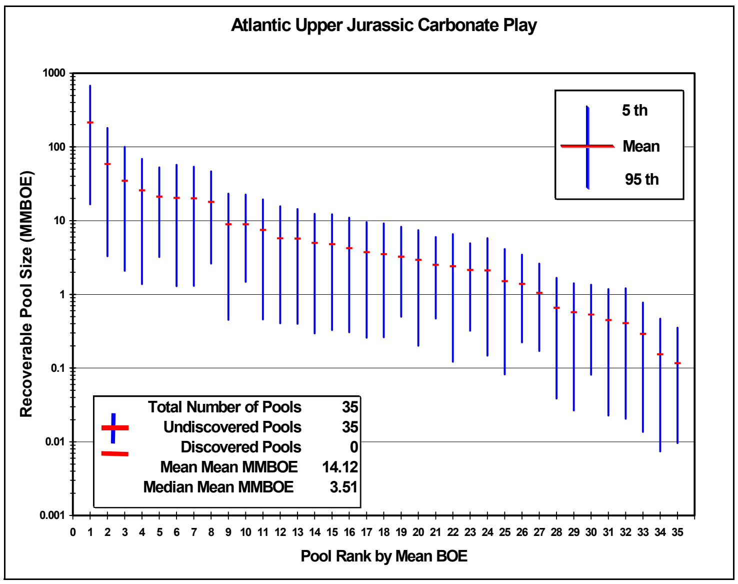


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

43 percent mixed hydrocarbons.

The central Gulf of Mexico 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). 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 area being explored. Analog fields in this area contain an average of 22 percent oil, 73 percent gas, and 5 percent mixed hydrocarbons.

Assessment Results

The marginal probability of hydrocarbons for the AUJ B1 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) are forecast to range from 0.087 to 0.520 Bbo and 0.718 to 3.371 Tcfg at the 5th and 95th percentiles, respectively (table 1; figure 4). Mean UCRR are forecast at 0.234 Bbo and 1.488 Tcfg (0.499 BBOE). These undiscovered resources might occur in as many as 35 pools. These pools have an unrisked mean size range of <1 to 215 MMBOE (figure 5) and an unrisked mean mean size of 14 MMBOE.

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

Atlantic Upper Jurassic Clastic (AUJ C1) Play

***Pseudocyclammina jaccardi* through *Ctenidodinium penneum* biozones**

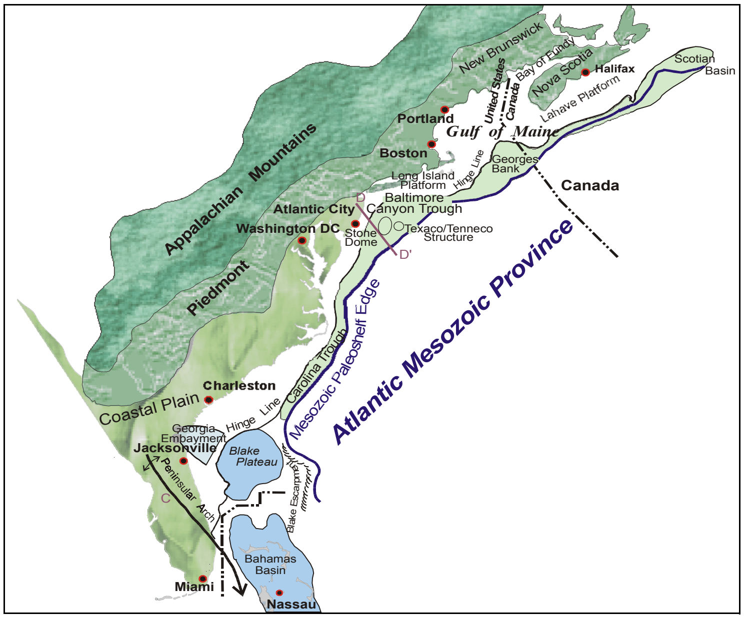


Figure 1. Physiographic map of the Atlantic Margin.

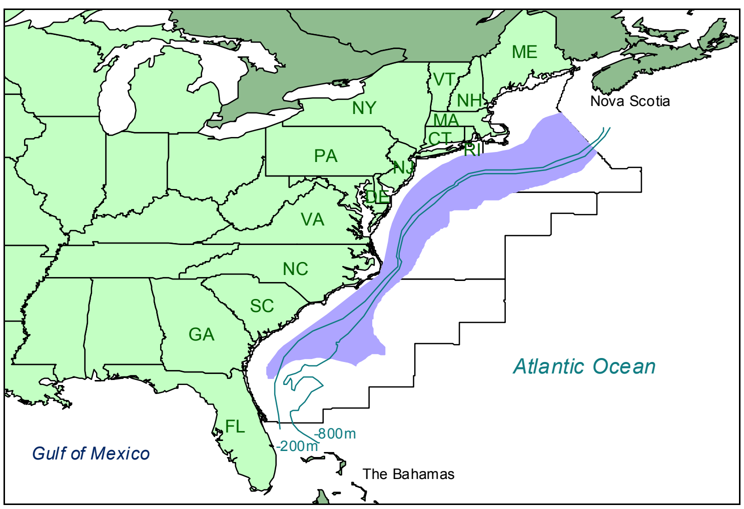


Figure 2. Play location.

Play Description

The frontier Atlantic Upper Jurassic Clastic (AUJ C1) 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 (figures 1 and 2).

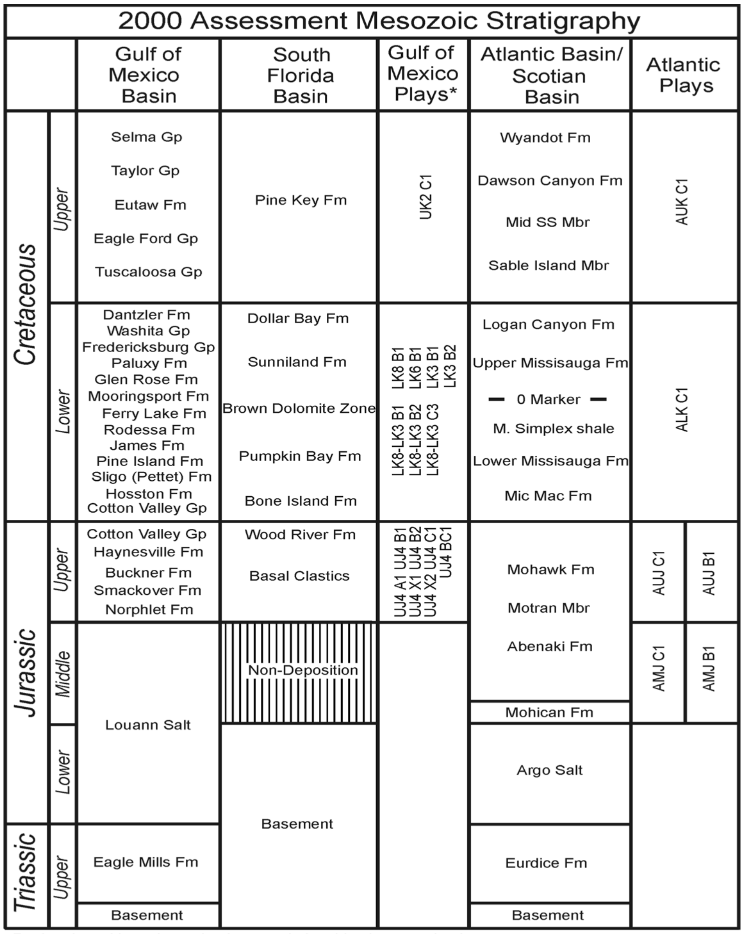
The updip assessment limit is the shoreward erosional limit of upper Jurassic sediments. Downdip, upper Jurassic sediments exhibit a facies change from nearshore clastic sediments to the platform carbonates and shelf-edge reef of the Atlantic Upper Jurassic Carbonate (AUJ B1) play. Where clastic sediment influx was great enough, deltas prograded across AUJ B1 carbonates, depositing fans on the slope. These slope fans define the downdip limit of the AUJ C1 play.

The AUJ C1 play is stratigraphically and structurally similar to the Atlantic Lower Cretaceous Clastic (ALK C1) and Atlantic Middle Jurassic Clastic (AMJ C1) plays.

Play Characteristics

During the upper Jurassic, clastic sediments were eroded from the Appalachian Mountains and were deposited on the Atlantic Margin shelf. Delta complexes prograded across the shelf and, where clastic sediment influx was great enough, fans were deposited on the slope. Potential upper Jurassic reservoirs were deposited in delta complexes, barrier bars, and channel systems on the shelf, and in fan complexes on the slope.

Potential trapping structures on the shelf include normal faults, growth faults, and anticlines. Potential trapping features on the slope include anticlines and sediment pinch-outs against diapirs. Potential source rocks are Jurassic shelf and



Rock unit positions do not imply age relationships between basins.
* Does not include plays that span ages.

Figure 3. Mesozoic stratigraphy of the Gulf of Mexico and Atlantic Margins.

AUJ C1 Play 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

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

slope shales, though Jurassic lagoonal and platform carbonates may also provide potential source rocks. 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 extends from approximately 7,000 to 18,000 feet. Seals are provided by upper Jurassic or lowermost Cretaceous limestones or overlying shales.

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. Five of the eight wells in the relinquished Hudson Canyon 598 field encountered hydrocarbons (95 MMcfd total) from upper Jurassic clastic intervals.

Analogs

Because the AUJ C1 play contains no active Federal fields, productive upper Jurassic clastic sediments from both the onshore eastern Gulf of Mexico and the Canadian offshore Scotian Basin provide the analogs for input parameters used in this assessment.

The onshore Gulf of Mexico upper Jurassic clastic analog comprises the Smackover Formation and Cotton Valley Group of Mississippi and Alabama (figure 3). The analog type field for the AUJ C1 play is the Thomasville Field, Rankin County, Mississippi. Production is from an upper Jurassic clastic section within the Smackover Formation (figure 3).

The Gulf of Mexico analog area covers 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 area explored. Fields in the analog area contain an average of 40 percent oil, 29 percent gas, and 31 percent mixed hydrocar-

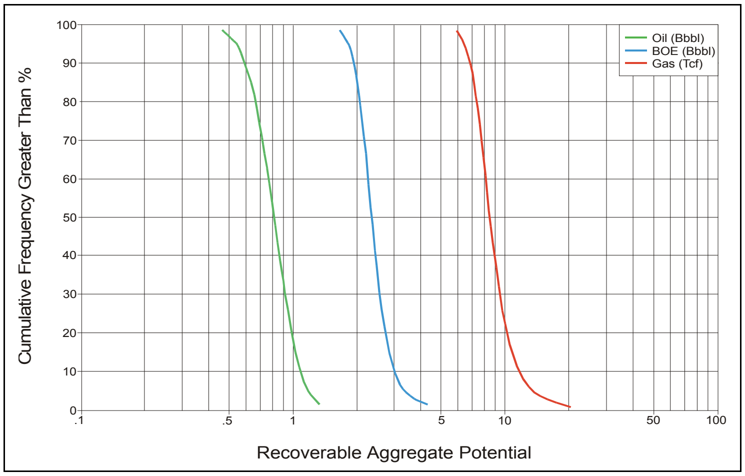


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

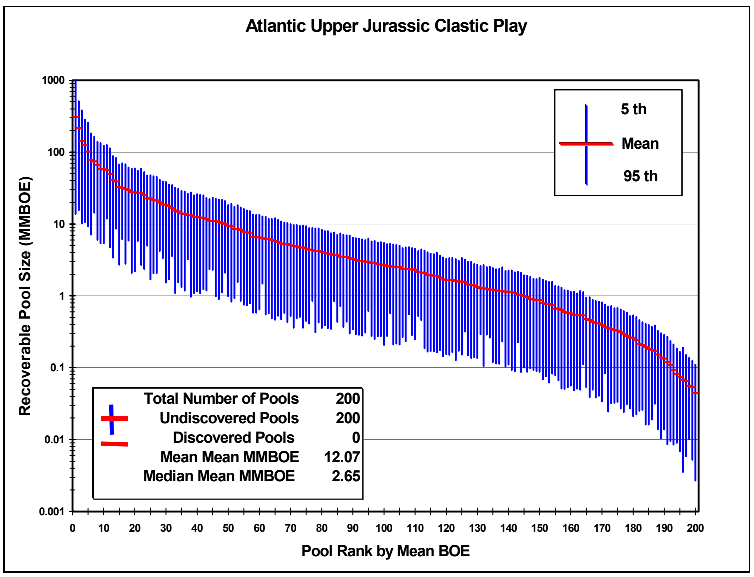


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

bons. Fields producing from the well-established Norphlet trend were not used as analogs in this assessment because they produce from eolian sands that are not comparable to the deltaic and fan deposits in the AUJ C1 play.

The Scotian Basin (figure 1) upper Jurassic clastic analog comprises the Mic Mac Formation (figure 3) and covers an area of 35 million acres (54,700 square miles). Exploration in this analog area has a success rate of approximately 30 percent, and drilling is at an immature stage with only about 30 percent of the analog area being explored. This analog was used primarily for field size distribution parameters because production data are not available.

Assessment Results

The marginal probability of hydrocarbons for the AUJ C1 play is 1.00. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) 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; figure 4). Mean UCRR are forecast at 0.822 Bbo and 8.953 Tcfg (2.415 BBOE). These undiscovered resources might occur in as many as 200 pools. These pools have a mean size range of <1 to 310 MMBOE (figure 5) and a mean mean size of 12 MMBOE.

Of the 11 Atlantic plays, the AUJ C1 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).

Atlantic Middle Jurassic (AMJ) Chronozone

Gonyaulacysta pachyderma and *Gonyaulacysta pectinigera* biozones

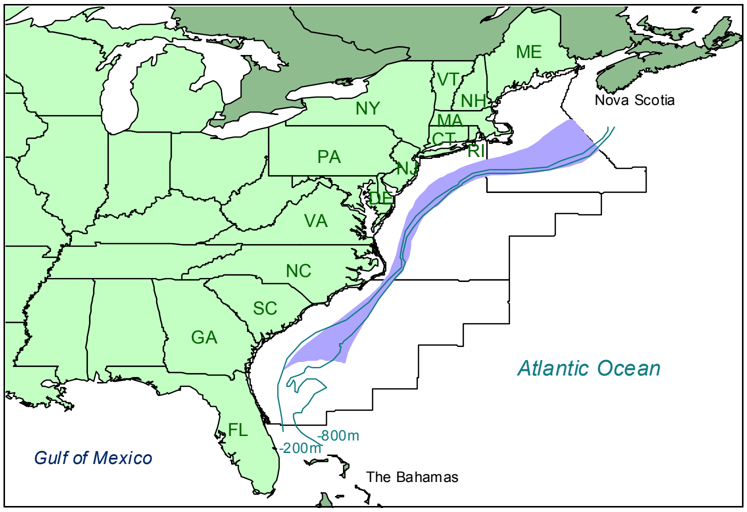


Figure 1. Extent of plays in the Middle Jurassic Chronozone of the Atlantic Mesozoic Province.

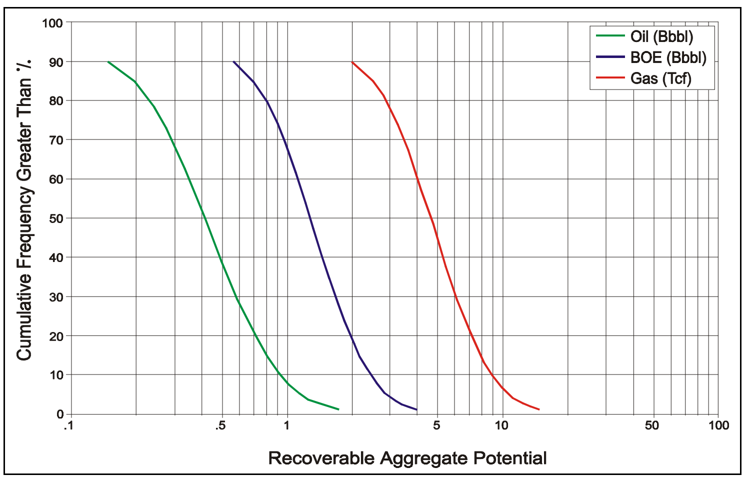


Figure 2. Cumulative probability distribution for undiscovered conventionally recoverable resources.

Chronozone Description

The Atlantic Middle Jurassic (AMJ) chronozone corresponds to the *Gonyaulacysta pachyderma* and *Gonyaulacysta pectinigera* biozones. The middle Jurassic section consists of clastics and carbonates, each of which defines a play: the Atlantic Middle Jurassic Clastic (AMJ C1) play and the Atlantic Middle Jurassic Carbonate (AMJ B1) play. Siliciclastics were deposited in retrogradational, aggradational, and progradational styles. Carbonates consist of shallow-water limestone platforms, ramps, and possible pinnacle and patch reefs where deltaic clastic influx was minimal.

Reservoir potential in the chronozone extends from the U.S.-Canadian border to offshore South Carolina (figure 1). Updip reservoir potential is the erosional limit of middle Jurassic clastics. Downdip reservoir potential is the extent of the carbonate ramp.

Discoveries

No pools in the chronozone have yet been discovered in the Federal OCS.

Assessment Results

Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) might 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). Mean UCRR are 0.529 Bbo and 5.502 Tcfg (1.508 BBOE). The 147 undiscovered pools have an unrisked mean mean size of 12.134 MMBOE (figure 3). Of the two plays in the chronozone, the AMJ C1 play is estimated to contain 84 percent of the BOE mean total endowment for the chronozone.

AMJ Chronozone 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

Table 1. Assessment results for undiscovered conventionally recoverable resources (equals total endowment).

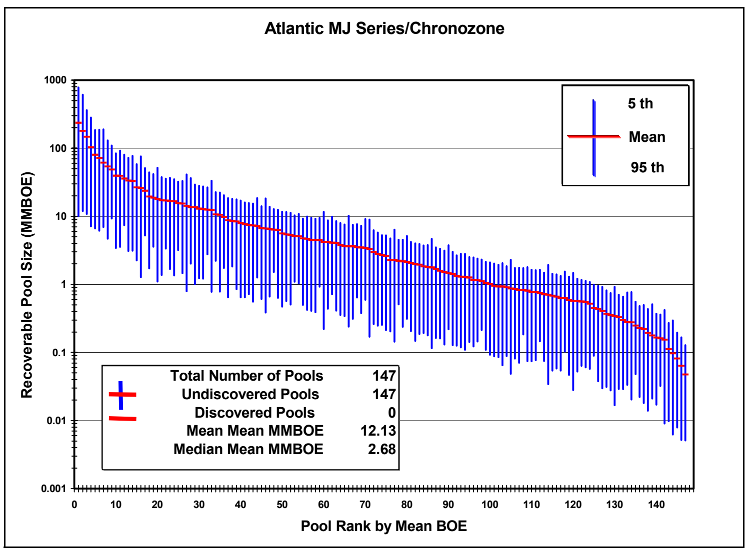


Figure 3. Pool rank plot showing the number of pools forecast to be discovered (blue bars).

Atlantic Middle Jurassic Carbonate (AMJ B1) Play

***Gonyaulacysta pachyderma* and *Gonyaulacysta pectinigera* biozones**

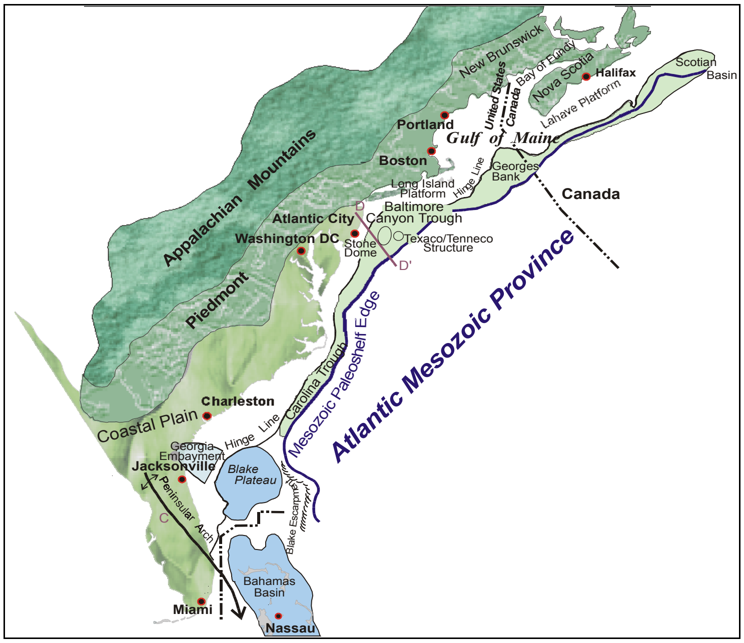


Figure 1. Physiographic map of the Atlantic Margin.

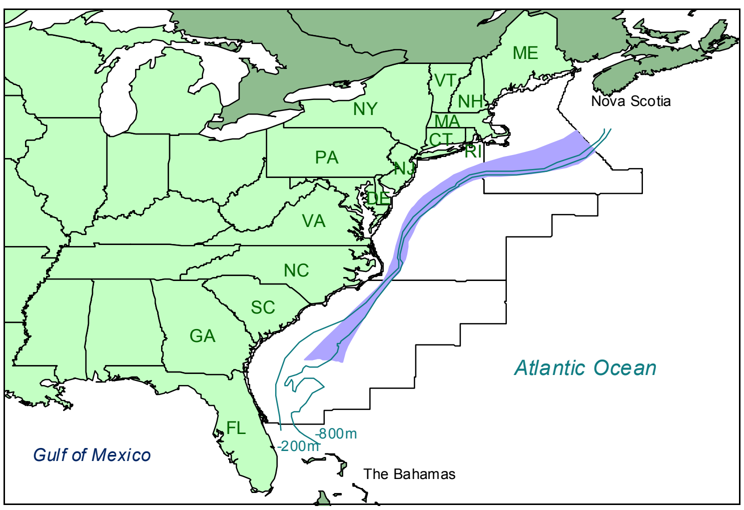


Figure 2. Play location.

Play Description

The frontier Atlantic Middle Jurassic Carbonate (AMJ B1) 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 (figures 1 and 2).

The AMJ B1 play is stratigraphically similar to the Atlantic Upper Jurassic Carbonate (AUJ B1) play. However, the middle Jurassic carbonate platform is much wider and extends farther shoreward because sediment influx was not as extensive during the Middle Jurassic.

Play Characteristics

The AMJ B1 play consists of shallow-water limestone platforms and ramps that merge with the slope. Potential reservoirs occur in porous bioclastic and pelletal carbonates that include pinnacle and patch reefs and associated reef talus. Structural closures over reefal buildups are possible, but potential 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 hydrocarbon evolution window extends from approximately 7,000 to 18,000 feet. Seals are provided by middle or lowermost upper Jurassic carbonates, shales, and anhydrites.

Discoveries

Exploration in the Atlantic Federal OCS area consists of 46 exploration and 5 COST wells. Of the 24 wells that may have penetrated this play, only one encountered hydrocarbons. Overpressured gas was encountered in Texaco's Hudson Canyon 642-1 well at almost 18,000 feet in probable middle Jurassic

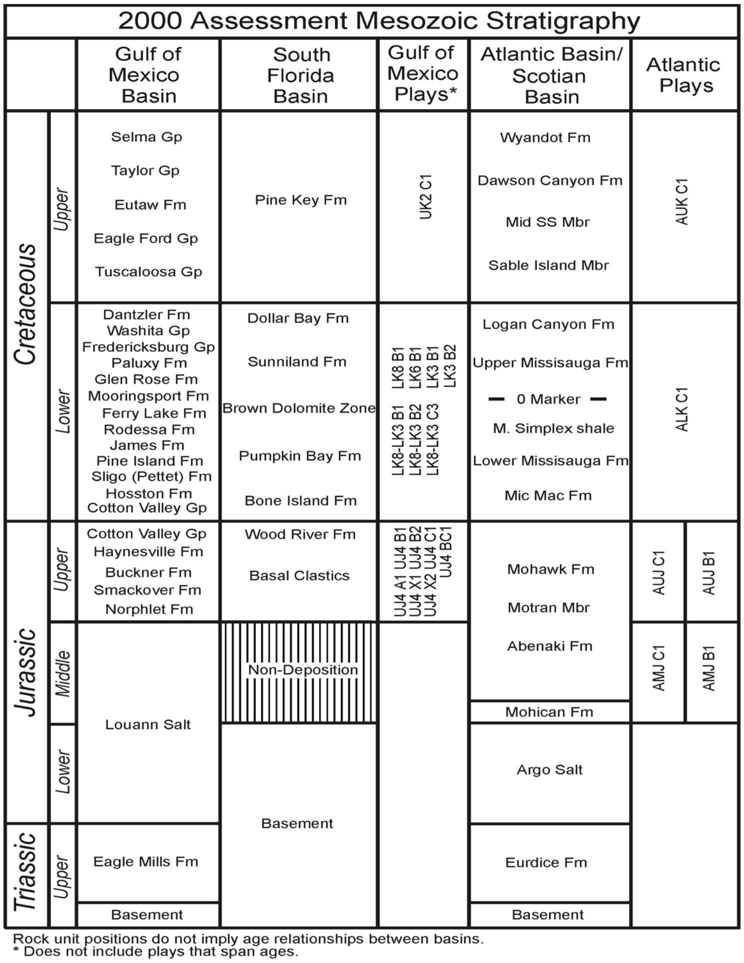


Figure 3. Mesozoic stratigraphy of the Gulf of Mexico and Atlantic Margins.

AMJ B1 Carbonate Play Marginal Probability = 0.64	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

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

rocks. The flow was not measured nor was the presence of reservoir-quality rock established.

Analogs

Since the AMJ B1 play contains no Federal fields, productive upper Jurassic platform carbonate reservoirs of the onshore Gulf of Mexico and the lower Cretaceous Sligo-Stuart City reef trend of the onshore Gulf of Mexico 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). The analog type field is the Chunchula Field, Mobile County, Alabama. This field's production is from the upper Jurassic Smackover Formation (figure 3).

The analog area covers 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 area being explored. Fields in the analog area 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 (figure 3) and Edwards Group (Fredericksburg Group equivalent) and covers an area of 104 million acres (162,435 square miles). 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 being explored. Fields in the analog area contain an average of 22 percent oil, 73 percent gas, and 5 percent mixed hydrocarbons.

Assessment Results

The marginal probability of hydrocarbons for the AMJ B1 play is 0.64. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) range

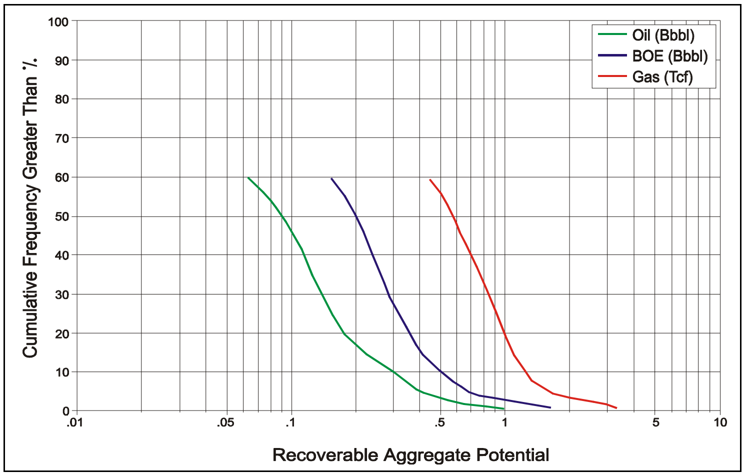


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

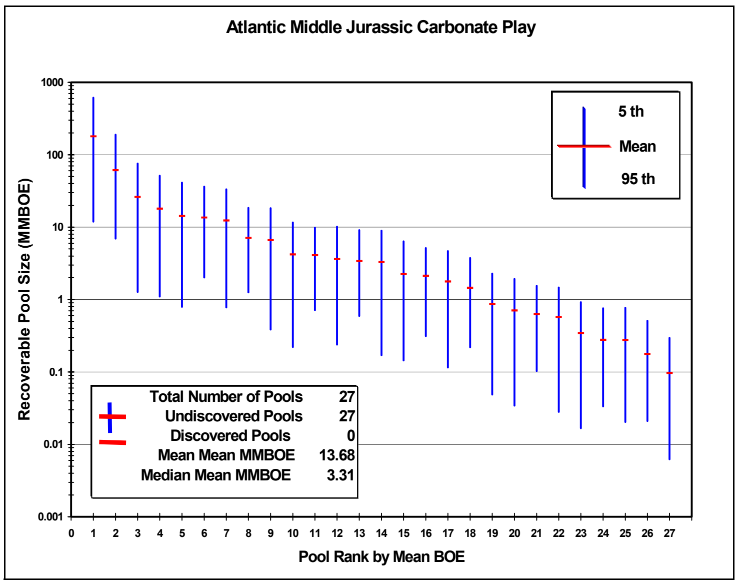


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

from zero at the 95th percentiles to 0.413 Bbo and 1.633 Tcfg at the 5th percentiles (table 1 and figure 4). Mean UCRR are estimated at 0.130 Bbo and 0.611 Tcfg (0.239 BBOE). These undiscovered resources might occur in as many as 27 pools. These pools have an unrisked mean size range of <1 to 179 MMBOE (figure 5) and an unrisked mean mean size of 14 MMBOE.

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

Atlantic Middle Jurassic Clastic (AMJ C1) Play

***Gonyaulacysta pachyderma* and *Gonyaulacysta pectinigera* biozones**

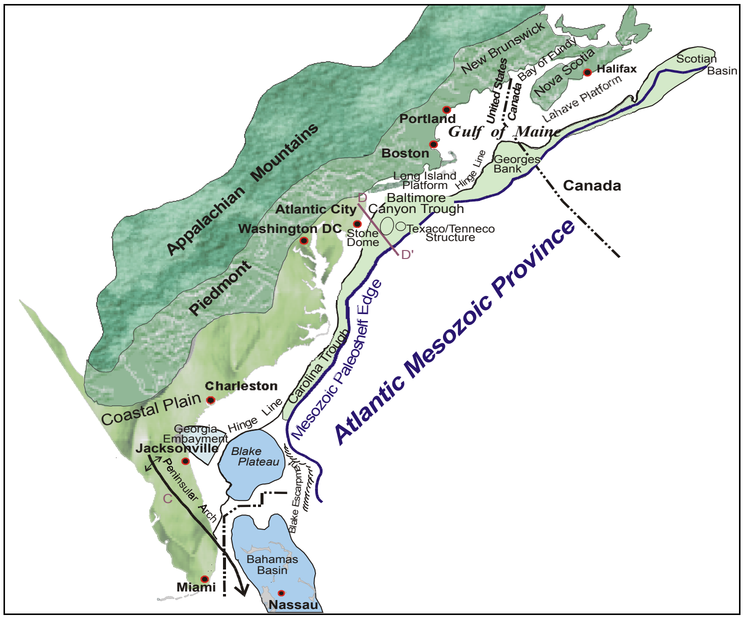


Figure 1. Physiographic map of the Atlantic Margin.

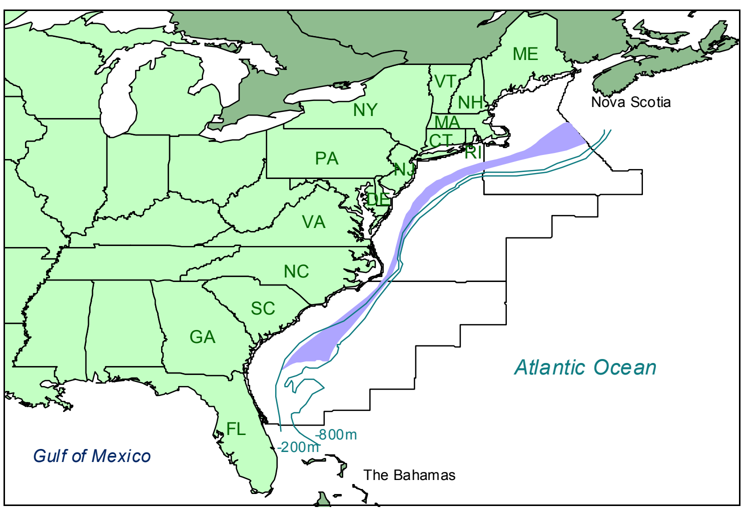


Figure 2. Play location.

Play Description

The frontier Atlantic Middle Jurassic Clastic (AMJ C1) 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 (figures 1 and 2).

The updip assessment limit is the shoreward erosional limit of middle Jurassic sediments. Downdip, middle Jurassic siliciclastics exhibit a facies change to platform carbonates of the Atlantic Middle Jurassic Carbonate (AMJ B1) play.

The AMJ C1 play is stratigraphically and structurally similar to the Atlantic Lower Cretaceous Clastic (ALK C1) and to the Atlantic Upper Jurassic Clastic (AUJ C1) plays.

Play Characteristics

During the middle Jurassic, clastic sediments were eroded from the Appalachian Mountains and were deposited on the Atlantic Margin shelf. Delta complexes prograded across the shelf and, where clastic sediment influx was great enough, fans were deposited on the slope. Potential upper Jurassic reservoirs were deposited in delta complexes, barrier bars, and channel systems on the shelf, and in fan complexes on the slope.

Trapping structures include mainly anticlines, growth faults, and normal faults. Potential source rocks include Jurassic shelf and slope shales, though Jurassic lagoonal and platform carbonates may also provide potential source rocks. 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 extends from approximately 7,000 to 18,000 feet. Seals are provided by middle or lowermost upper Jurassic limestones or by overlying

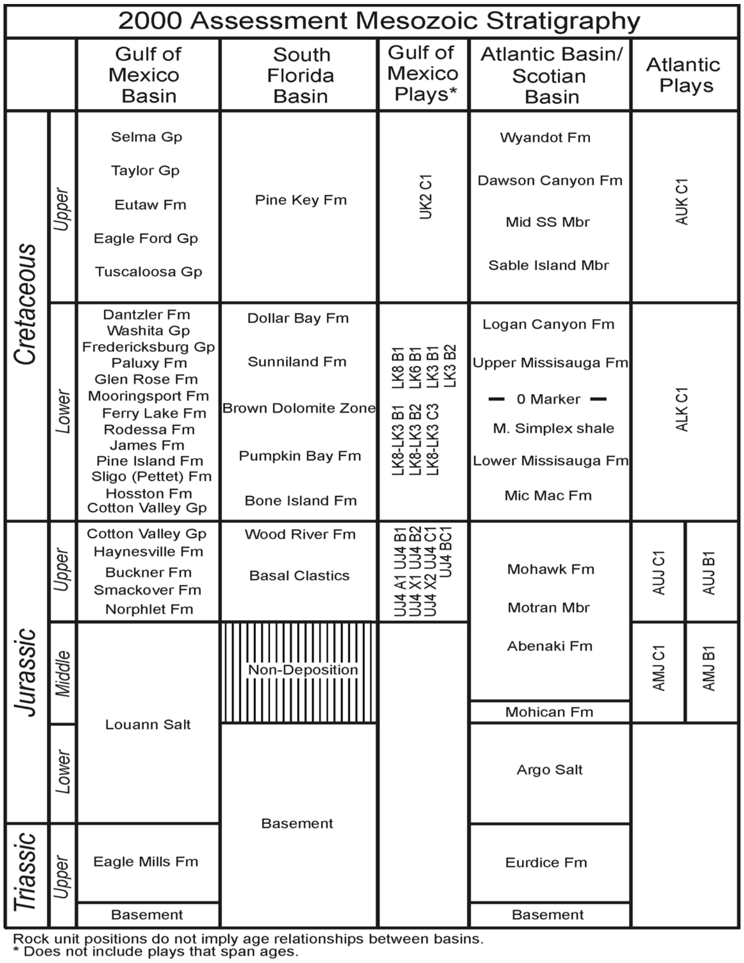


Figure 3. Mesozoic stratigraphy of the Gulf of Mexico and Atlantic Margins.

AMJ C1 Play 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

—

Table 1. Assessment results for reserves, undiscovered conventionally recoverable resources, and total endowment.

shales.

Discoveries

Exploration along the Atlantic Margin Federal OCS Area consists of 46 exploration and 5 COST wells. Of the two wells that may have penetrated the AMJ C1 play, no commercial quantities of hydrocarbons were found.

Analogs

Since the AMJ C1 play contains no Federal fields, productive upper Jurassic clastic sediments of the onshore eastern Gulf of Mexico and of the Canadian offshore Scotian Basin provide the analogs for input parameters used in this assessment (figure 2).

The eastern Gulf of Mexico and the Atlantic Continental Margin 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 area has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 60 to 90 percent of the analog being 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 that are not comparable to the deltaic and fan deposits in the AMJ C1 play.

The Scotian Basin upper Jurassic clastic analog comprises the Mic Mac Formation (figure 3) and covers an area of 35 million acres (54,700 square miles). Exploration in this analog area has a success rate of approximately 30 percent, and drilling is at an immature stage with approximately 30 percent of the ana-

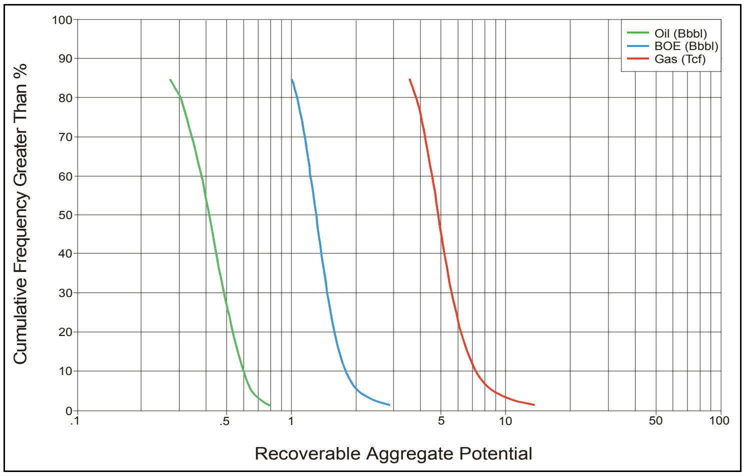


Figure 4. Cumulative probability distribution for undiscovered conventionally recoverable resources.

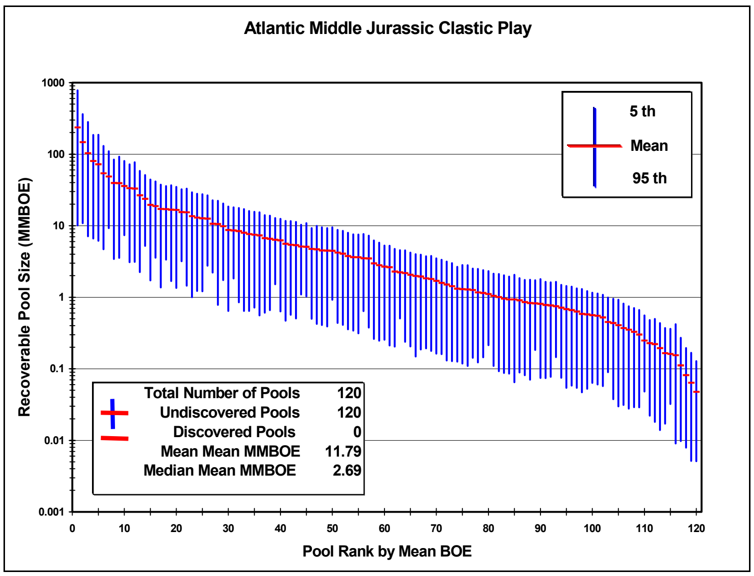


Figure 5. Pool rank plot showing the number of discovered pools (red lines) and the number of pools forecast as remaining to be discovered (blue bars).

log area being explored. This analog was used primarily for field size distribution parameters because production data are not available.

Assessment Results

The marginal probability of hydrocarbons for the AMJ C1 play is 0.90. Assessment results indicate that undiscovered conventionally recoverable resources (UCRR) range from zero at the 95th percentiles to 0.645 Bbo and 8.455 Tcfg at the 5th percentiles (table 1; figure 4). Mean UCRR are forecast to be 0.399 Bbo and 4.891 Tcfg (1.269 BBOE). These undiscovered resources might occur in as many as 120 pools. These pools have an unrisked mean size range of <1 to 237 MMBOE (figure 5) and an unrisked mean mean size of 12 MMBOE.

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

Atlantic Lower Jurassic to Triassic Carbonate Rift (ALJ-TR B1) Play

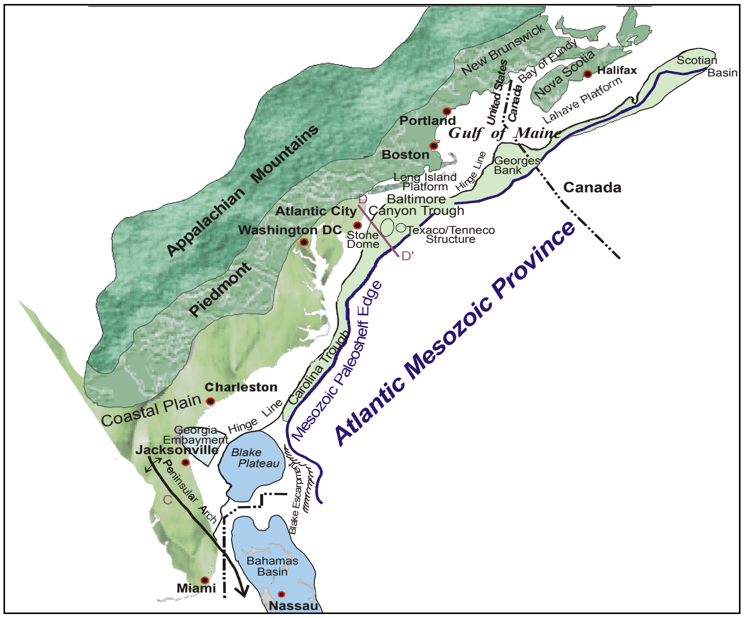


Figure 1. Physiographic map of the Atlantic Margin.

Play Description

The conceptual and unassessed Atlantic Lower Jurassic to Triassic Carbonate Rift (ALJ-TR B1) play is characterized by Triassic to Lower Jurassic-aged rift basins that extend from eastern Newfoundland to the Carolinas (figure 1). The play is identified seismically in the deep subsurface of the Georges Bank Area and in the eastern-most, lower Jurassic rift basins. Rift sediments of this play consist of mixed carbonates and evaporites. Prospective reservoir facies might include dolomites and platform limestones, as well as possible patch and pinnacle reefs.

The ALJ-TR B1 play was not assessed because of its great depth of burial and corresponding thermally over-mature source rocks.

Atlantic Lower Jurassic to Triassic Clastic Rift (ALJ-TR C1) Play

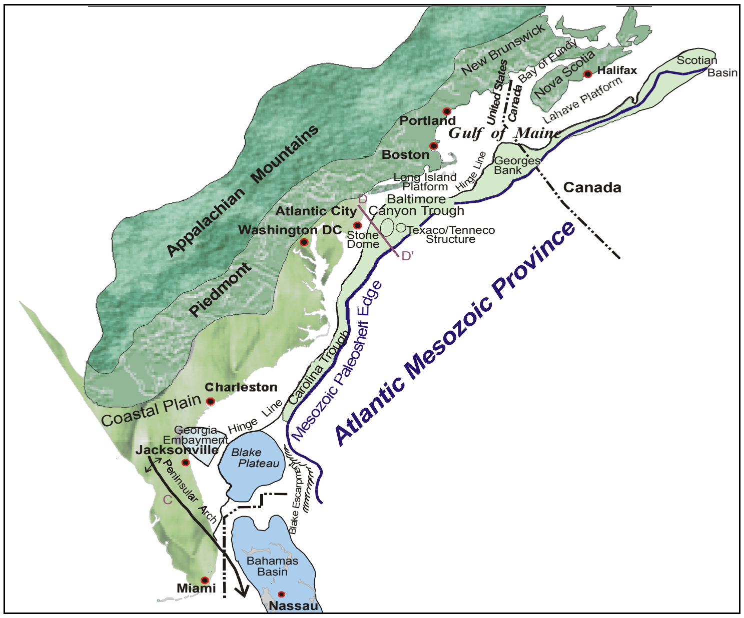


Figure 1. Physiographic map of the Atlantic Margin.

Play Description

The conceptual and unassessed Atlantic Lower Jurassic to Triassic Clastic Rift (ALJ-TR C1) play is characterized by Triassic to Lower Jurassic-aged rift basins that extend from eastern Newfoundland to the Carolinas (figure 1). The play includes both continental and marine rift basins. Red bed sediments were deposited in alluvial, lacustrine, fluvial, eolian, and deltaic depositional environments.

The ALJ-TR C1 play was not assessed because of its great depth of burial and corresponding thermally over-mature source rocks.

Atlantic Lower Cretaceous to Upper Jurassic Transition Zone (ALK-UJ BC1) Play

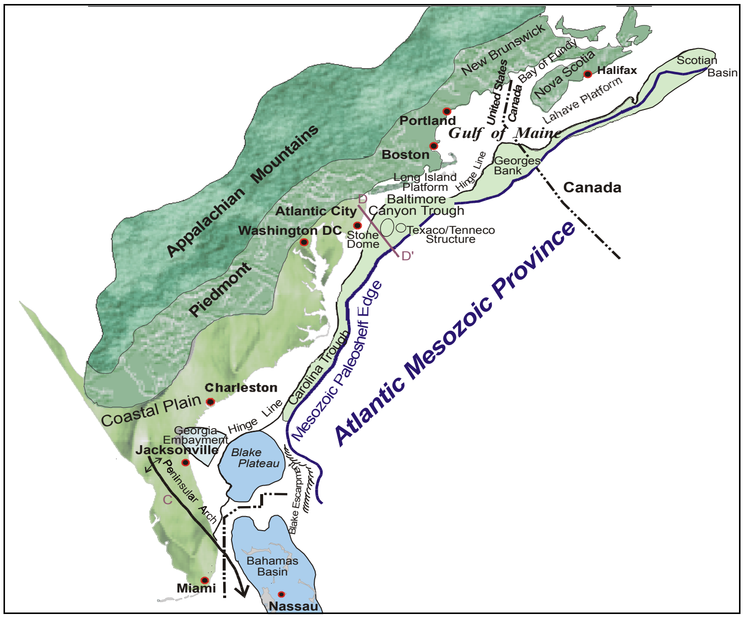


Figure 1. Physiographic map of the Atlantic Margin.

Play Description

The conceptual Atlantic Lower Cretaceous to Upper Jurassic Transition Zone (ALK-UJ BC1) play in the Blake Plateau Area represents a transition zone between a mixed siliciclastic/carbonate regime to the north and a purely carbonate regime in the Bahamas Basin to the south (figure 1). Potential reservoir rocks include both platform carbonates and shelf deltaic clastics.

The play is not assessed because of high structural risks.

Atlantic Cretaceous to Jurassic Diapir (AK-J S1) Play

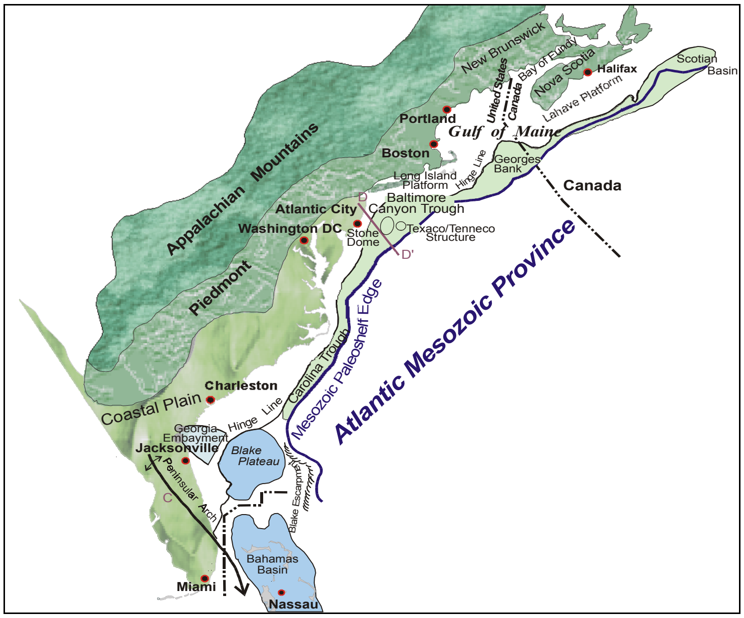


Figure 1. Physiographic map of the Atlantic Margin.

Play Description

Diapiric structures have been recognized on seismic data along the seaward edge of the Georges Bank Basin and Carolina Trough of the Atlantic Margin (figure 1). These diapirs may also extend seaward of the shelf edge from the Scotian Basin through the Carolina Trough. Potential reservoirs around these diapirs include either clastics or carbonates associated with crestal, flank, or sub-diapir structural traps.

The Atlantic Cretaceous to Jurassic Diapir (AK-J S1) play was not assessed because diapir structures in the adjacent Scotian Basin have not yielded hydrocarbons.

Atlantic Upper Cretaceous to Upper Jurassic Basin Floor Fan (AUK-UJ F1) Play

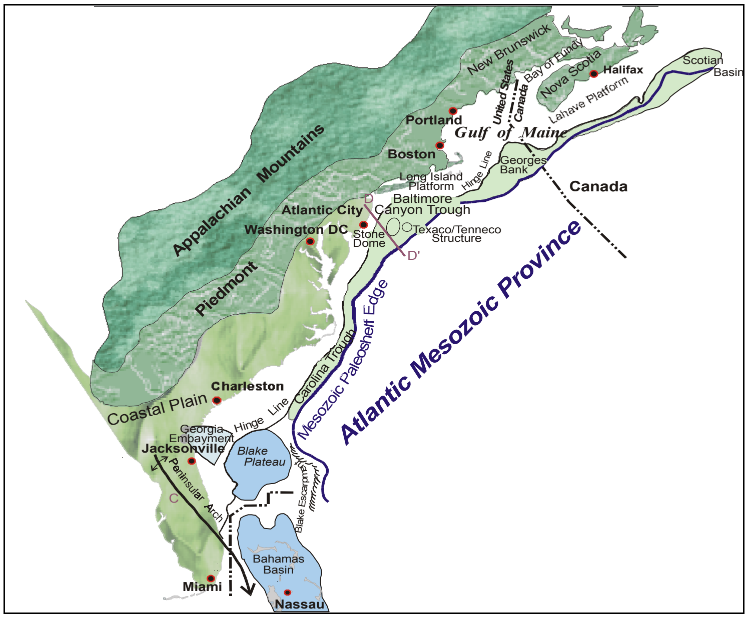


Figure 1. Physiographic map of the Atlantic Margin.

Play Description

The conceptual Atlantic Upper Cretaceous to upper Jurassic Basin Floor Fan (AUK-UJ F1) play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1). The play is located on the continental rise and consists of the distal portions of siliciclastic fan systems. The downdip limit of the play is the basinward extent of siliciclastic deposition during the Late Jurassic through Late Cretaceous. Potential basin floor fan reservoirs consist of thin-bedded sheet sands.

This play was not assessed because hydrocarbon source rocks in the relatively thin stratigraphic section are likely immature.

Summary Table 1. Play Classification and Total Endowment

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. Data at the chronozone, series, and system aggregation levels may be incomplete when comparing to previous assessments due to significant resources contained in the plays that span the ages.

	Play Classification (E=Established, F=Frontier, C=Conceptual, T=Total)												Total Endowment (Reserves + Resources) @ 12/31/98									
	Assessed				Non-assessed				Total				No.	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	E	F	C	T	E	F	C	T	E	F	C	T	Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
GOM/Atl Continental Margin	60	13	19	92	0	0	11	11	60	13	30	103	5825	47.517	62.430	82.044	401.497	455.248	518.845	120.486	143.435	171.591
Gulf of Mexico Region	60	8	19	87	0	0	5	5	60	8	24	92	5323	45.818	60.123	79.051	380.998	427.537	482.510	114.825	136.197	162.576
Cenozoic Province	58	3	7	68	0	0	1	1	58	3	8	69	4967	48.751	53.780	59.387	375.941	401.325	429.338	116.750	125.190	134.435
Quaternary System	14	0	0	14	0	0	0	0	14	0	0	14	1556	11.120	12.130	13.303	117.963	122.342	127.144	32.308	33.899	35.665
Pleistocene Series	14	0	0	14	0	0	0	0	14	0	0	14	1556	11.120	12.130	13.303	117.963	122.342	127.144	32.308	33.899	35.665
UPL Chronozone	5	0	0	5	0	0	0	0	5	0	0	5	463	1.751	1.983	2.250	33.861	36.233	38.996	7.861	8.697	9.709
UPL B1 Play	1	0	0	1	0	0	0	0	1	0	0	1	1	0.047	0.047	0.047	0.008	0.008	0.008	0.048	0.048	0.048
UPL A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	82	0.143	0.145	0.154	3.611	3.654	3.704	0.787	0.796	0.807
UPL P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	215	0.501	0.565	0.659	18.755	18.970	19.189	3.856	3.941	4.059
UPL F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	50	0.229	0.248	0.270	2.579	2.676	2.800	0.696	0.724	0.756
UPL F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	115	0.932	1.244	1.748	9.270	10.925	14.284	2.679	3.188	4.066
MPL Chronozone	5	0	0	5	0	0	0	0	5	0	0	5	411	1.570	1.665	1.778	23.851	24.974	26.281	5.863	6.109	6.389
MPL B1 Play	1	0	0	1	0	0	0	0	1	0	0	1	1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
MPL A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	69	0.017	0.020	0.022	1.035	1.060	1.083	0.203	0.208	0.213
MPL P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	198	1.034	1.064	1.102	17.229	17.451	17.677	4.114	4.169	4.229
MPL F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	53	0.146	0.166	0.196	1.911	2.197	2.694	0.494	0.557	0.656
MPL F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	90	0.359	0.415	0.493	3.512	4.265	5.161	1.016	1.174	1.360
LPL Chronozone	4	0	0	4	0	0	0	0	4	0	0	4	682	7.648	8.215	8.857	59.274	61.136	63.148	18.268	19.094	20.000
LPL A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	87	0.382	0.395	0.414	2.304	2.371	2.436	0.797	0.817	0.840
LPL P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	265	1.942	1.969	2.003	24.323	24.534	24.745	6.284	6.335	6.390
LPL F 1 Play	1	0	0	1	0	0	0	0	1	0	0	1	170	1.203	1.276	1.387	17.608	18.105	18.576	4.367	4.498	4.645
LPL F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	160	4.234	4.573	5.175	14.918	16.127	17.695	6.964	7.443	8.293
Tertiary System	43	2	7	52	0	0	0	0	43	2	7	52	3299	31.437	35.047	39.098	236.658	257.907	281.699	74.400	80.938	88.165
Pliocene Series	8	0	0	8	0	0	0	0	8	0	0	8	822	10.402	11.028	11.710	51.471	57.954	65.813	19.809	21.339	23.057
UP Chronozone	4	0	0	4	0	0	0	0	4	0	0	4	490	6.648	7.125	7.645	34.454	38.077	42.273	12.922	13.900	14.980
UP A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	43	0.152	0.155	0.158	1.143	1.162	1.181	0.356	0.362	0.367
UP P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	180	1.258	1.290	1.328	12.034	12.221	12.412	3.414	3.465	3.521
UP F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	117	0.720	0.802	0.895	9.002	10.077	10.811	2.420	2.595	2.778
UP F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	150	4.487	4.878	5.328	12.315	14.617	18.127	6.775	7.479	8.453
LP Chronozone	4	0	0	4	0	0	0	0	4	0	0	4	332	3.670	3.903	4.170	16.412	19.877	25.069	6.678	7.440	8.401
LP A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	40	0.554	0.562	0.572	1.512	1.545	1.578	0.826	0.837	0.848
LP P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	175	1.702	1.733	1.767	10.326	10.470	10.618	3.551	3.596	3.643
LP F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	57	0.105	0.122	0.146	1.892	2.136	2.400	0.448	0.503	0.566
LP F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	60	1.281	1.486	1.722	3.987	5.726	10.491	2.061	2.505	3.376
Miocene Series	35	1	4	40	0	0	0	0	35	1	4	40	2343	20.085	22.728	25.706	175.406	190.395	207.090	51.863	56.606	61.850
UM3 Chronozone	6	0	0	6	0	0	0	0	6	0	0	6	444	5.758	6.130	6.581	30.703	32.941	35.480	11.318	11.991	12.758
UM3 R1 Play	1	0	0	1	0	0	0	0	1	0	0	1	13	0.058	0.059	0.061	0.379	0.388	0.398	0.126	0.129	0.131
UM3 A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	12	0.019	0.019	0.019	0.099	0.110	0.122	0.037	0.039	0.041
UM3 AP1 Play	1	0	0	1	0	0	0	0	1	0	0	1	41	<0.001	<0.001	<0.001	0.597	0.634	0.674	0.106	0.113	0.120
UM3 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	209	2.774	2.799	2.827	15.460	15.611	15.772	5.536	5.577	5.622
UM3 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	84	0.311	0.410	0.596	4.006	4.990	6.554	1.042	1.298	1.734
UM3 F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	85	2.578	2.842	3.165	10.176	11.206	12.357	4.466	4.836	5.279
UM1 Chronozone	5	0	0	5	0	0	0	0	5	0	0	5	344	2.558	2.806	3.090	27.838	29.758	31.880	7.587	8.101	8.667
UM1 A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	2	<0.001	<0.001	<0.001	0.192	0.217	0.313	0.034	0.039	0.056
UM1 AP1 Play	1	0	0	1	0	0	0	0	1	0	0	1	38	<0.001	<0.001	<0.001	1.135	1.170	1.212	0.202	0.209	0.216
UM1 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	137	0.686	0.705	0.731	11.445	11.573	11.704	2.730	2.765	2.804
UM1 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	85	0.255	0.354	0.502	3.430	4.254	5.842	0.889	1.112	1.477
UM1 F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	82	1.580	1.745	1.919	11.835	12.543	13.400	3.733	3.977	4.240
MM9 Chronozone	6	0	0	6	0	0	0	0	6	0	0	6	291	2.340	2.647	2.987	23.624	28.112	33.559	6.709	7.649	8.721
MM9 A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	5	<0.001	<0.001	0.001	0.031	0.038	0.049	0.006	0.007	0.010
MM9 AP1 Play	1	0	0	1	0	0	0	0	1	0	0	1	8	<0.001	<0.001	<0.001	0.201	0.220	0.242	0.036	0.039	0.043
MM9 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	90	0.154	0.170	0.198	7.750	7.965	8.183	1.542	1.588	1.638
MM9 S1 Play	1	0	0	1	0	0	0	0	1	0	0	1	18	0.002	0.002	0.002	0.201	0.209	0.221	0.038	0.039	0.042
MM9 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	80	0.262	0.297	0.340	3.392	4.083	4.832	0.885	1.023	1.175
MM9 F2 Play	1	0	0	1	0	0	0	0	1	0	0	1	90	1.916	2.179	2.494	12.969	15.596	20.481	4.345	4.954	5.929
MM7 Chronozone	6	1	0	7	0	0	0	0	6	1	0	7	387	1.891	2.179	2.499	27.623	29.051	30.613	6.852	7.347	7.890
MM7 R1 Play	1	0	0	1	0	0	0	0	1	0	0	1	29	0.031	0.032	0.034	2.433	2.468	2.507	0.464	0.471	0.479
MM7 A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	20	0.001	0.003	0.007	0.176	0.206	0.247	0.033	0.040	0.049
MM7 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	110	0.187	0.194	0.206	10.774	10.929	11.088	2.108	2.139	2.171
MM7 S1 Play	1	0	0	1	0	0	0	0	1	0	0	1	37	0.014	0.014	0.015	4.136	4.259	4.397	0.750	0.772	0.797
MM7 S2 Play	1	0	0	1	0	0	0	0	0	1	0	1	11	0.001	0.002	0.003	0.463	0.510	0.561	0.084	0.093	0.103
MM7 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	85	0.250	0.287	0.338	3.221	3.597	4.130	0.830	0.927	1.059
MM7 F2 Play	0	1	0	1	0	0	0	0	1	0	0	1	95	1.438	1.646	1.919	6.253	7.080	8.230	2.592	2.905	3.348
MM4 Chronozone	4	0	1	5	0	0	0	0	4	0	1	5	334	1.272	1.480	1.714	22.376	24.626	27.228	5.356	5.862	6.426
MM4 R1 Play	1	0	0	1	0	0	0	0	1	0	0	1	56	0.045	0.050	0.058	1.768	1.821	1.889	0.363	0.375	0.391
MM4 A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	23	0.013	0.013	0.015	0.559	0.569	0.580	0.113	0.115	0.117
MM4 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	115	0.159	0.164	0.171	11.615	11.792	11.991	2.230	2.263	2.298
MM4 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	60	0.065	0.080	0.100	2.685	3.011	3.364	0.547	0.615	0.692
MM4 F2 Play	0	0	1	1	0	0	0	0	0	0	1	1	80	0.999	1.173	1.391	5.937	7.431	9.942	2.121	2.495	3.044

Table 1. continued, 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. Data at the chronozone, series, and system aggregation levels may be incomplete when comparing to previous assessments due to significant resources contained in the plays that span the ages.

	Play Classification (E=Established, F=Frontier, C=Conceptual, T=Total)												Total Endowment (Reserves + Resources) @ 12/31/98									
	Assessed				Non-assessed				Total				No.	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	E	F	C	T	E	F	C	T	E	F	C	T	Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
LM4 Chronozone	4	0	1	5	0	0	0	0	4	0	1	5	232	2.398	3.211	4.181	14.119	17.760	22.233	4.974	6.370	8.042
LM4 R1 Play	1	0	0	1	0	0	0	0	1	0	0	1	25	0.001	0.001	0.002	0.621	0.650	0.680	0.112	0.117	0.123
LM4 A1 Play	1	0	0	1	0	0	0	0	1	0	0	1	21	0.002	0.003	0.003	0.711	0.748	0.786	0.129	0.135	0.142
LM4 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	72	0.053	0.057	0.063	4.944	5.133	5.335	0.934	0.970	1.008
LM4 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	29	0.015	0.036	0.067	0.947	1.276	1.725	0.190	0.263	0.360
LM4 F2 Play	0	0	1	1	0	0	0	0	0	0	1	1	85	2.408	3.114	4.113	7.688	9.952	14.393	3.842	4.885	6.489
LM2 Chronozone	2	0	1	3	0	0	0	0	2	0	1	3	176	2.115	3.215	4.625	14.609	17.652	21.259	4.780	6.355	8.291
LM2 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	44	0.040	0.047	0.059	3.975	4.270	4.612	0.750	0.806	0.872
LM2 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	47	0.034	0.059	0.104	3.028	3.403	3.790	0.582	0.665	0.757
LM2 F2 Play	0	0	1	1	0	0	0	0	0	0	1	1	85	2.312	3.109	4.513	7.903	9.979	13.343	3.769	4.885	6.784
LM1 Chronozone	2	0	1	3	0	0	0	0	2	0	1	3	135	0.870	1.062	1.280	8.555	10.499	12.918	2.473	2.930	3.458
LM1 P1 Play	1	0	0	1	0	0	0	0	1	0	0	1	10	0.001	0.002	0.003	0.124	0.133	0.142	0.024	0.026	0.028
LM1 F1 Play	1	0	0	1	0	0	0	0	1	0	0	1	55	0.048	0.060	0.077	5.963	6.700	7.564	1.112	1.252	1.415
LM1 F2 Play	0	0	1	1	0	0	0	0	0	0	1	1	70	0.835	1.001	1.217	2.644	3.666	5.598	1.346	1.653	2.137
Oligocene Series	0	1	0	1	0	0	0	0	0	1	0	1	31	0.012	0.025	0.043	0.683	0.851	1.039	0.138	0.177	0.222
UO - MO Chronozone	0	1	0	1	0	0	0	0	0	1	0	1	31	0.012	0.025	0.043	0.683	0.851	1.039	0.138	0.177	0.222
UO MO F1 F2 Play	0	1	0	1	0	0	0	0	0	1	0	1	31	0.012	0.025	0.043	0.683	0.851	1.039	0.138	0.177	0.222
Plays that span Series	0	0	3	3	0	0	0	0	0	0	3	3	103	0.495	1.265	2.528	5.362	8.707	13.129	1.521	2.814	4.641
LE-LL BC1(Lwr TertiaryBuriedHillDrape)	0	0	1	1	0	0	0	0	0	0	1	1	6	0.000	0.006	0.000	0.000	0.008	0.000	0.000	0.007	0.000
LO-LL C1 (Lwr Tertiary Clastic Gas)	0	0	1	1	0	0	0	0	0	0	1	1	42	0.004	0.022	0.052	3.065	4.821	8.037	0.567	0.880	1.451
LO-LL C2 (Lwr Tertiary Clastic G & O)	0	0	1	1	0	0	0	0	0	0	1	1	55	0.687	1.237	2.339	2.830	3.878	5.498	1.256	1.927	3.231
Plays that span Systems	1	1	0	2	0	0	1	1	1	1	1	3	112	5.273	6.604	8.183	18.234	21.076	24.343	8.685	10.354	12.283
UPL-LL (Cenozoic Fan 3 Play)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UPL-LL X1 (Cenozoic Perdido FB Play)	0	1	0	1	0	0	0	0	0	1	0	1	27	0.523	0.989	2.025	1.290	2.220	3.983	0.796	1.384	2.568
UPL-LL X2 (Cenozoic Miss Fan FB Play)	1	0	0	1	0	0	0	0	1	0	0	1	85	4.927	5.615	6.435	16.875	18.856	21.104	8.066	8.970	10.000
Mesozoic Province	2	5	12	19	0	0	4	4	2	5	16	23	356	0.728	6.342	20.023	9.255	26.211	62.333	2.430	11.006	30.639
Cretaceous System	1	4	5	10	0	0	1	1	1	4	6	11	200	0.552	3.449	9.952	1.384	10.404	32.380	0.811	5.300	15.606
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
UK2 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
UK2 C1 (Tuscaloosa)	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	3	2	6	0	0	1	1	1	3	3	6	139	0.553	1.107	1.918	0.473	0.869	1.515	0.660	1.262	2.137
LK8 Chronozone	0	1	0	1	0	0	0	0	0	1	0	1	6	0.005	0.030	0.074	0.021	0.046	0.085	0.010	0.038	0.089
LK8 B1 (Andrew)	0	1	0	1	0	0	0	0	0	1	0	1	6	0.005	0.030	0.074	0.021	0.046	0.085	0.010	0.038	0.089
LK 6 Chronozone	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LK6 B1 (Mooringsport)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LK3 Chronozone	1	0	1	2	0	0	0	0	1	0	1	2	22	0.004	0.036	0.116	0.351	0.637	1.140	0.066	0.149	0.312
LK3 B1 (James)	1	0	0	1	0	0	0	0	1	0	0	1	18	0.008	0.019	0.036	0.339	0.427	0.526	0.074	0.096	0.121
LK3 B2 (Sligo)	0	0	1	1	0	0	0	0	0	0	1	1	4	<.001	0.016	0.077	0.042	0.210	0.562	0.009	0.054	0.168
Plays that span Chronozones	0	2	1	3	0	0	0	0	0	2	1	3	111	0.536	1.041	1.773	0.066	0.186	0.392	0.553	1.075	1.830
LK8-LK3 B1 (Sunniland)	0	1	0	1	0	0	0	0	0	1	0	1	33	0.236	0.421	0.782	0.017	0.030	0.056	0.239	0.426	0.792
LK8-LK3 B2 (S Florida Basin)	0	0	1	1	0	0	0	0	0	0	1	1	58	0.375	0.583	0.964	0.027	0.046	0.089	0.380	0.591	0.981
LK8-LK3 C3 (Lwr Cretaceous Clastic)	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
Plays that span Series	0	0	3	3	0	0	0	0	0	0	3	3	56	0.000	2.297	8.705	0.000	9.464	34.475	0.000	3.981	14.688
UK5-LK3 BC2(Cretaceous Buried Hill Drape)	0	0	1	1	0	0	0	0	0	0	1	1	14	0.000	0.028	0.169	0.000	0.109	0.601	0.000	0.048	0.290
UK5-LK3 X4 (Cretaceous Perdido FB)	0	0	1	1	0	0	0	0	0	0	1	1	20	0.000	1.012	4.426	0.000	4.280	18.769	0.000	1.773	7.498
UK5-LK3 X5 (Cretaceous Miss Fan FB)	0	0	1	1	0	0	0	0	0	0	1	1	22	0.000	1.257	5.298	0.000	5.075	21.421	0.000	2.160	8.902
Jurassic System	1	1	4	6	0	0	2	2	1	1	6	8	115	0.379	1.132	2.452	10.255	12.690	15.738	2.172	3.391	5.161
Upper Jurassic Series	1	1	4	6	0	0	1	1	1	1	5	7	115	0.379	1.132	2.452	10.255	12.690	15.738	2.172	3.391	5.161
UJ4 Chronozone	1	1	4	6	0	0	1	1	1	1	5	7	115	0.379	1.132	2.452	10.255	12.690	15.738	2.172	3.391	5.161
UJ4 B1 (Smackover)	0	1	0	1	0	0	0	0	0	1	0	1	5	0.004	0.059	0.205	0.013	0.104	0.309	0.008	0.078	0.265
UJ4 B2 (Oolitic)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UJ4 C1 (Cotton Valley CL)	0	0	1	1	0	0	0	0	0	0	1	1	13	0.004	0.015	0.032	0.064	0.296	0.785	0.021	0.067	0.155
UJ4 BC1(Jurassic BuriedHill Drape)	0	0	1	1	0	0	0	0	0	0	1	1	14	0.000	0.009	0.045	0.000	0.016	0.090	0.000	0.012	0.065
UJ4 A1 (Norphlet)	1	0	0	1	0	0	0	0	1	0	0	1	43	0.444	0.713	1.016	10.777	11.512	12.269	2.428	2.762	3.135
UJ4 X1 (Jurassic Perdido FB)	0	0	1	1	0	0	0	0	0	0	1	1	19	0.000	0.148	0.635	0.000	0.368	1.837	0.000	0.213	0.940
UJ4 X2 (Jurassic Miss Fan FB)	0	0	1	1	0	0	0	0	0	0	1	1	21	0.000	0.189	0.804	0.000	0.395	1.730	0.000	0.259	1.093
Play that span Series	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UJ4 - MJ C4 (Florida Basal Clastic)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Plays that span Systems	0	0	3	3	0	0	1	1	0	0	4	4	41	0.000	1.762	8.019	0.000	3.117	14.166	0.000	2.316	10.541
UK5-UJ4 BC3 (UK to UJ Buried Hill Strat)	0	0	1	1	0	0	0	0	0	0	1	1	10	0.000	0.140	0.398	0.000	0.233	0.933	0.000	0.181	0.610
UK5-LTR BC4(Mesozoic Buried Hill Struct)	0	0	1	1	0	0	0	0	0	0	1	1	13	0.000	1.223	5.914	0.000	2.140	12.197	0.000	1.603	8.514
LK8-UJ4 BC5 (LK to UJ Transition zone)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UK5-UJ4 S1 (Salt Roller/Hi Relief Salt)	0	0	1	1	0	0	0	0	0	0	1	1	18	0.000	0.400	1.846	0.000	0.744	3.518	0.000	0.532	2.448

Table 1. continued, 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. Data at the chronozone, series, and system aggregation levels may be incomplete when comparing to previous assessments due to significant resources contained in the plays that span the ages.

	Play Classification													Total Endowment								
	(E=Established, F=Frontier, C=Conceptual, T=Total)													(Reserves + Resources) @ 12/31/98								
	Assessed				Non-assessed				Total				No.	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	E	F	C	T	E	F	C	T	E	F	C	T	Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
Atlantic Region	0	5	0	5	0	0	6	6	0	5	6	11	502	1.297	2.307	3.706	16.117	27.712	43.499	4.558	7.238	10.739
Mesozoic Province	0	5	0	5	0	0	1	1	0	5	1	6	502	1.297	2.307	3.706	16.117	27.712	43.499	4.558	7.238	10.739
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 C1 Play (Clastic)	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 C1 Play (Clastic)	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	0	0	0	4	0	4	382	0.790	1.585	2.754	9.311	15.944	24.957	2.667	4.422	6.768
Upper Jurassic Series	0	2	0	2	0	0	0	0	0	2	0	2	235	0.555	1.056	1.774	6.422	10.444	15.760	1.879	2.914	4.250
AUJ Chronozone	0	2	0	2	0	0	0	0	0	2	0	2	235	0.555	1.056	1.774	6.422	10.444	15.760	1.879	2.914	4.250
AUJ B1 Play (Carbonate)	0	1	0	1	0	0	0	0	0	1	0	1	35	0.087	0.234	0.520	0.718	1.488	3.371	0.232	0.499	1.060
AUJ C1 Play (Clastic)	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
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
AMJ 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
AMJ B1 Play (Carbonate)	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
AMJ C1 Play (Clastic)	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
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
ALJ 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
AUTR Chronozone	0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Plays that span Systems	0	0	0	0	0	0	5	5	0	0	5	5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ-TR B1 Play (Carbonate Rift)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ-TR C1 Play (Clastic Rift)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALK-UJ BC1 Play (Transition Zone)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AK-J S1 Play (Structural Diapir)	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK-UJ F1 Play (Basin Floor Fan)	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 by Play

Table 2. Reserves by play.

	Total Reserves @ 12/31/98				Proved @ 12/31/98				Cumulative Production			Remaining Proved			Unproved				Appreciation (P&U)		
	No. Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	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/Atl Continental Margin	2453	22.997	235.910	64.974	2369	14.266	162.711	43.218	10.908	132.677	34.515	3.358	30.034	8.703	84	0.995	5.102	1.903	7.736	68.096	19.853
Gulf of Mexico Region	2453	22.997	235.910	64.974	2369	14.266	162.711	43.218	10.908	132.677	34.515	3.358	30.034	8.703	84	0.995	5.102	1.903	7.736	68.096	19.853
Cenozoic Province	2435	22.997	230.677	64.042	2354	14.266	160.457	42.817	10.907	131.946	34.385	3.358	28.510	8.431	81	0.995	4.477	1.792	7.736	65.743	19.434
Quaternary System	953	7.571	90.953	23.755	924	5.045	64.805	16.576	3.892	53.970	13.496	1.152	10.834	3.080	29	0.202	1.091	0.396	2.325	25.057	6.783
Pleistocene Series	953	7.571	90.953	23.755	924	5.045	64.805	16.576	3.892	53.970	13.496	1.152	10.834	3.080	29	0.202	1.091	0.396	2.325	25.057	6.783
UPL Chronozone	268	1.111	25.673	5.679	262	0.709	17.743	3.866	0.518	14.985	3.184	0.191	2.757	0.682	6	0.020	0.399	0.091	0.382	7.532	1.722
UPL B1 Play	1	0.047	0.008	0.048	1	0.040	0.006	0.041	0.035	0.005	0.036	0.005	0.002	0.005	0	0.000	0.000	0.000	0.007	0.001	0.007
UPL A1 Play	71	0.142	3.521	0.769	71	0.109	2.659	0.582	0.088	2.277	0.493	0.021	0.382	0.089	0	0.000	0.000	0.000	0.033	0.862	0.187
UPL P1 Play	149	0.449	17.097	3.492	149	0.333	12.686	2.590	0.253	11.105	2.229	0.079	1.581	0.361	0	0.000	0.000	0.000	0.117	4.411	0.902
UPL F1 Play	30	0.199	1.912	0.539	28	0.130	1.256	0.353	0.090	0.874	0.246	0.039	0.382	0.107	2	0.000	0.011	0.002	0.069	0.645	0.184
UPL F2 Play	17	0.273	3.135	0.831	13	0.098	1.134	0.300	0.051	0.724	0.180	0.047	0.410	0.120	4	0.020	0.388	0.089	0.155	1.612	0.442
MPL Chronozone	254	1.303	19.979	4.858	245	0.925	14.421	3.491	0.789	12.197	2.960	0.136	2.224	0.532	9	0.029	0.198	0.064	0.348	5.360	1.302
MPL B1 Play	1	0.000	0.000	0.000	1	0.000	0.000	0.000	<0.001	<0.001	<0.001	0.000	0.000	0.000	0	0.000	0.000	0.000	<0.001	<0.001	<0.001
MPL A1 Play	49	0.017	0.959	0.188	49	0.017	0.730	0.147	0.015	0.636	0.128	0.002	0.094	0.018	0	0.000	0.000	0.000	<0.001	0.229	0.041
MPL P1 Play	150	0.986	15.665	3.773	148	0.750	11.865	2.862	0.670	10.504	2.539	0.080	1.362	0.322	2	0.000	0.022	0.004	0.235	3.778	0.907
MPL F1 Play	31	0.120	1.348	0.360	29	0.071	0.856	0.223	0.054	0.561	0.153	0.017	0.295	0.070	2	0.008	0.016	0.010	0.042	0.476	0.127
MPL F2 Play	23	0.179	2.006	0.536	18	0.087	0.969	0.259	0.050	0.496	0.139	0.037	0.473	0.121	5	0.022	0.160	0.050	0.071	0.877	0.227
LPL Chronozone	431	5.157	45.301	13.218	417	3.411	32.641	9.219	2.585	26.788	7.352	0.825	5.853	1.867	14	0.152	0.495	0.240	1.595	12.165	3.759
LPL A1 Play	71	0.378	2.123	0.756	70	0.365	1.738	0.675	0.319	1.475	0.582	0.046	0.263	0.093	1	0.000	0.001	0.000	0.013	0.384	0.081
LPL P1 Play	210	1.893	23.065	5.997	209	1.551	18.139	4.778	1.397	16.086	4.259	0.154	2.053	0.520	1	0.000	0.008	0.002	0.342	4.919	1.217
LPL F 1 Play	118	1.011	14.233	3.544	115	0.703	10.087	2.498	0.561	8.176	2.016	0.142	1.910	0.482	3	0.000	0.018	0.003	0.308	4.129	1.043
LPL F2 Play	32	1.874	5.880	2.921	23	0.791	2.678	1.268	0.308	1.051	0.495	0.483	1.627	0.773	9	0.152	0.469	0.235	0.931	2.733	1.418
Tertiary System	1478	14.174	132.480	37.747	1430	9.221	95.652	26.241	7.015	77.976	20.890	2.206	17.676	5.351	48	0.493	1.753	0.804	4.460	35.075	10.701
Pliocene Series	466	6.324	34.547	12.471	454	4.334	26.281	9.010	3.354	21.428	7.166	0.980	4.853	1.843	12	0.104	0.185	0.137	1.887	8.082	3.325
UP Chronozone	254	3.573	21.315	7.366	245	2.226	15.842	5.045	1.575	12.664	3.829	0.651	3.178	1.216	9	0.081	0.138	0.105	1.266	5.335	2.215
UP A1 Play	36	0.149	1.106	0.346	36	0.140	0.992	0.317	0.129	0.900	0.289	0.011	0.092	0.027	0	0.000	0.000	0.000	0.009	0.113	0.029
UP P1 Play	144	1.207	11.213	3.202	143	1.000	8.979	2.598	0.868	7.864	2.267	0.132	1.115	0.330	1	0.000	0.005	0.001	0.207	2.229	0.603
UP F1 Play	51	0.467	5.227	1.397	51	0.336	3.946	1.038	0.257	2.928	0.778	0.079	1.017	0.260	0	0.000	0.000	0.000	0.131	1.281	0.359
UP F2 Play	23	1.750	3.769	2.421	15	0.750	1.925	1.092	0.321	0.971	0.494	0.429	0.953	0.599	8	0.081	0.132	0.104	0.919	1.713	1.224
LP Chronozone	212	2.751	13.232	5.106	209	2.107	10.439	3.965	1.778	8.764	3.338	0.329	1.675	0.627	3	0.023	0.047	0.031	0.621	2.746	1.109
LP A1 Play	32	0.548	1.401	0.797	32	0.488	1.222	0.706	0.461	1.110	0.658	0.028	0.112	0.048	0	0.000	0.000	0.000	0.060	0.179	0.092
LP P1 Play	145	1.638	9.639	3.353	145	1.354	7.929	2.765	1.233	6.880	2.457	0.121	1.049	0.307	0	0.000	0.000	0.000	0.284	1.710	0.588
LP F1 Play	26	0.071	1.286	0.300	26	0.051	0.928	0.217	0.043	0.719	0.170	0.009	0.209	0.046	0	0.000	0.000	0.000	0.019	0.358	0.083
LP F2 Play	9	0.494	0.906	0.655	6	0.214	0.359	0.278	0.042	0.055	0.052	0.172	0.304	0.226	3	0.023	0.047	0.031	0.257	0.499	0.346
Miocene Series	1010	7.848	97.867	25.262	974	4.886	69.328	17.222	3.661	56.540	13.722	1.225	12.788	3.501	36	0.389	1.568	0.668	2.573	26.972	7.372
UM3 Chronozone	259	4.779	21.082	8.530	245	3.293	14.731	5.915	2.415	11.729	4.502	0.879	3.002	1.413	14	0.158	0.744	0.290	1.327	5.607	2.325
UM3 R1 Play	10	0.057	0.367	0.123	10	0.051	0.319	0.108	0.045	0.286	0.096	0.005	0.033	0.011	0	0.000	0.000	0.000	0.006	0.049	0.015
UM3 A1 Play	9	0.019	0.092	0.036	9	0.019	0.074	0.032	0.016	0.057	0.027	0.002	0.017	0.005	0	0.000	0.000	0.000	<0.001	0.019	0.004
UM3 AP1 Play	22	0.000	0.398	0.071	21	0.000	0.211	0.038	<0.001	0.095	0.017	<0.001	0.116	0.021	1	0.000	0.007	0.001	<0.001	0.179	0.032
UM3 P1 Play	174	2.720	14.726	5.341	172	2.421	12.207	4.593	2.183	10.525	4.056	0.238	1.682	0.537	2	0.000	0.002	0.000	0.299	2.517	0.747
UM3 F1 Play	29	0.181	1.952	0.528	27	0.110	0.867	0.264	0.089	0.674	0.209	0.021	0.193	0.055	2	0.007	0.135	0.031	0.064	0.950	0.233
UM3 F2 Play	15	1.801	3.546	2.432	6	0.692	1.052	0.880	0.081	0.091	0.097	0.612	0.961	0.783	9	0.152	0.599	0.258	0.957	1.894	1.294
UM1 Chronozone	166	1.535	17.064	4.571	159	0.633	12.054	2.778	0.558	9.853	2.311	0.075	2.202	0.467	7	0.193	0.412	0.267	0.709	4.598	1.527
UM1 A1 Play	1	0.000	0.192	0.034	1	0.000	0.135	0.024	<0.001	0.121	0.021	<0.001	0.014	0.002	0	0.000	0.000	0.000	<0.001	0.057	0.010
UM1 AP1 Play	24	0.000	1.004	0.179	24	0.000	0.597	0.106	<0.001	0.491	0.087	<0.001	0.106	0.019	0	0.000	0.000	0.000	<0.001	0.407	0.072
UM1 P1 Play	111	0.650	10.818	2.575	110	0.566	9.167	2.198	0.512	8.304	1.989	0.055	0.862	0.208	1	0.001	0.001	0.001	0.083	1.651	0.377
UM1 F1 Play	23	0.077	1.661	0.373	22	0.046	0.899	0.206	0.042	0.763	0.178	0.003	0.136	0.028	1	0.005	0.093	0.021	0.027	0.669	0.146
UM1 F2 Play	7	0.807	3.389	1.410	2	0.021	1.257	0.244	0.004	0.174	0.034	0.017	1.083	0.210	5	0.188	0.318	0.245	0.598	1.813	0.921
MM9 Chronozone	117	0.689	11.999	2.824	107	0.415	7.983	1.835	0.273	6.194	1.375	0.142	1.788	0.460	10	0.027	0.344	0.088	0.247	3.672	0.901
MM9 A1 Play	2	0.000	0.028	0.005	2	0.000	0.020	0.003	<0.001	0.019	0.003	<0.001	<0.001	<0.001	0	0.000	0.000	0.000	<0.001	0.008	0.001
MM9 AP1 Play	4	0.000	0.159	0.028	4	0.000	0.100	0.018	<0.001	0.045	0.008	<0.001	0.055	0.010	0	0.000	0.000	0.000	<0.001	0.059	0.010
MM9 P1 Play	61	0.142	6.887	1.368	61	0.105	5.749	1.128	0.096	5.300	1.040	0.009	0.449	0.089	0	0.000	0.000	0.000	0.037	1.138	0.239
MM9 S1 Play	13	0.002	0.191	0.036	13	0.001	0.134	0.025	0.001	0.114	0.021	<0.001	0.019	0.003	0	0.000	0.000	0.000	<0.001	0.058	0.011
MM9 F1 Play	27	0.205	1.472	0.467	23	0.161	0.873	0.317	0.148	0.620	0.258	0.013	0.253	0.058	4	0.000	0.003	0.001	0.043	0.597	0.149
MM9 F2 Play	10	0.341	3.262	0.921	4	0.147	1.108	0.344	0.028	0.095	0.045	0.119	1.013	0.300	6	0.027	0.340	0.087	0.167	1.813	0.489
MM7 Chronozone	150	0.459	18.629	3.773	146	0.245	14.012	2.738	0.166	12.074	2.315	0.078	1.938	0.423	4	0.010	0.062	0.021	0.204	4.555	1.014
MM7 R1 Play	22	0.030	2.353	0.449	22	0.023	1.831	0.348	0.019	1.716	0.324	0.004	0.115	0.024	0	0.000	0.000	0.000	0.008	0.522	0.101
MM7 A1 Play	10	0.001	0.134	0.025	10	0.001	0.092	0.017	<0.001	0.070	0.013	<0.001	0.021	0.004	0	0.000	0.000	0.000	<0.001	0.043	0.008
MM7 P1 Play	70	0.178	10.058	1.968	69	0.143	8.520	1.659	0.129	7.681	1.496	0.014	0.839	0.163	1	0.000	0.003	0.001	0.035	1.535	0.309
MM7 S1 Play	23	0.013	3.810	0.691	23	0.009	2.760	0.500	0.006	2.171	0.393	0.003	0.589	0.107	0	0.000	0.000	0.000	0.004	1.050	0.190
MM7 S2 Play	7	0.001	0.423	0.077	7	0.001	0.183	0.033	<0.001	0.133	0.024	<0.001	0.050	0.009	0	0.000	0.000	0.000	0.001	0.240	0.043
MM7 F1 Play	17	0.075	1.293	0.305	14	0.016	0.444	0.095	0.010	0.303	0.064	0.006	0.141	0.031	3	0.010	0.059	0.021	0.049	0.790	0.189
MM7 F2 Play	1	0.160	0.557	0.259	1	0.052	0.183	0.085	0.000	0.000	0.000	0.052	0.183	0.085	0	0.000	0.000	0.000	0.107	0.375	0.174
MM4 Chronozone	161	0.253	14.131	2.767	160	0.199	10.258	2.024	0.168	8.665	1.710	0.031	1.592	0.314	1	0.000	0.006	0.001	0.054	3.867	0.742
MM4 R1 Play	45	0.042	1.620	0.331	45	0.036	1.192	0.248	0.030	0.967	0.202	0.006	0.225	0.046	0	0.000	0.000	0.000	0.007	0.428	0.083
MM4 A1 Play	19	0.013	0.551	0.111	19	0.011	0.424	0.087	0.010	0.360	0.074	0.001	0.064	0.013	0	0.000	0.000	0.000	0.001	0.127	0.024
MM4 P1 Play	85	0.156	10.542	2.032	84	0.120	7.530	1.460	0.101	6.344	1.230	0.020	1.186	0.231	1	0.000	0.006	0.001	0.035	3.006	0.570
MM4 F1 Play	12	0.042	1.417	0.294	12	0.031	1.112	0.229	0.027	0.994	0.204	0.004	0.119	0.025	0	0.000	0.000	0.000	0.010	0.305	0.065
MM4 F2 Play	0	0.000	0.000	0.000	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

Table 2. continued, reserves by play.

	Total Reserves @ 12/31/98				Proved @ 12/31/98				Cumulative Production			Remaining Proved			Unproved				Appreciation (P&U)		
	No. Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	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)
LM4 Chronozone	84	0.050	5.391	1.009	84	0.039	3.604	0.680	0.033	2.833	0.537	0.006	0.770	0.143	0	0.000	0.000	0.000	0.012	1.787	0.330
LM4 R1 Play	16	0.001	0.538	0.097	16	0.001	0.324	0.058	0.001	0.189	0.034	<0.001	0.135	0.024	0	0.000	0.000	0.000	<0.001	0.214	0.039
LM4 A1 Play	13	0.002	0.587	0.106	13	0.001	0.345	0.062	0.001	0.196	0.035	0.001	0.149	0.027	0	0.000	0.000	0.000	0.001	0.242	0.044
LM4 P1 Play	51	0.047	4.213	0.796	51	0.037	2.914	0.555	0.032	2.438	0.465	0.005	0.476	0.090	0	0.000	0.000	0.000	0.010	1.298	0.241
LM4 F1 Play	4	0.000	0.053	0.010	4	0.000	0.020	0.004	<0.001	0.010	0.002	<0.001	0.010	0.002	0	0.000	0.000	0.000	<0.001	0.033	0.006
LM4 F2 Play	0	0.000	0.000	0.000	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
LM2 Chronozone	50	0.052	5.334	1.001	50	0.041	3.782	0.714	0.033	2.912	0.551	0.009	0.870	0.164	0	0.000	0.000	0.000	0.011	1.552	0.287
LM2 P1 Play	33	0.035	3.428	0.644	33	0.027	2.298	0.436	0.021	1.734	0.330	0.006	0.564	0.107	0	0.000	0.000	0.000	0.007	1.130	0.208
LM2 F1 Play	17	0.018	1.906	0.357	17	0.014	1.484	0.278	0.012	1.177	0.221	0.003	0.306	0.057	0	0.000	0.000	0.000	0.003	0.423	0.079
LM2 F2 Play	0	0.000	0.000	0.000	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
LM1 Chronozone	23	0.032	4.239	0.786	23	0.022	2.905	0.539	0.016	2.279	0.422	0.006	0.626	0.117	0	0.000	0.000	0.000	0.010	1.333	0.247
LM1 P1 Play	5	0.001	0.089	0.017	5	0.001	0.074	0.014	0.001	0.039	0.007	<0.001	0.036	0.007	0	0.000	0.000	0.000	<0.001	0.015	0.003
LM1 F1 Play	18	0.031	4.150	0.769	18	0.021	2.831	0.525	0.016	2.241	0.414	0.005	0.590	0.110	0	0.000	0.000	0.000	0.010	1.319	0.244
LM1 F2 Play	0	0.000	0.000	0.000	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
Oligocene Series	2	0.001	0.066	0.013	2	0.001	0.044	0.009	<0.001	0.008	0.002	0.001	0.035	0.007	0	0.000	0.000	0.000	<0.001	0.022	0.004
UO - MO Chronozone	2	0.001	0.066	0.013	2	0.001	0.044	0.009	<0.001	0.008	0.002	0.001	0.035	0.007	0	0.000	0.000	0.000	<0.001	0.022	0.004
UO MO F1 F2 Play	2	0.001	0.066	0.013	2	0.001	0.044	0.009	<0.001	0.008	0.002	0.001	0.035	0.007	0	0.000	0.000	0.000	<0.001	0.022	0.004
Plays that span Series	0	0.000	0.000	0.000	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
LE-LL BC1(Lwr TertiaryBuriedHillDrape)	0	0.000	0.000	0.000	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
LO-LL C1 (Lwr Tertiary Clastic Gas)	0	0.000	0.000	0.000	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
LO-LL C2 (Lwr Tertiary Clastic G & O)	0	0.000	0.000	0.000	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
Plays that span Systems	4	1.252	7.244	2.541	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4	0.301	1.633	0.592	0.951	5.611	1.949
UPL-LL (Cenozoic Fan 3 Play)	NA	NA	NA	NA	NA	NA	NA	0.000	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.000	NA	NA	NA
UPL-LL X1 (Cenozoic Perdido FB Play)	1	0.000	0.016	0.003	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1	0.000	0.005	0.001	<0.001	0.011	0.002
UPL-LL X2 (Cenozoic Miss Fan FB Play)	3	1.252	7.228	2.538	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3	0.301	1.629	0.591	0.951	5.600	1.947
Mesozoic Province	18	0.000	5.232	0.931	15	0.000	2.254	0.401	<0.001	0.730	0.130	<0.001	1.524	0.271	3	0.000	0.625	0.111	<0.001	2.353	0.419
Cretaceous System	5	0.000	0.212	0.038	3	0.000	0.023	0.004	<0.001	0.004	0.001	<0.001	0.018	0.003	2	0.000	0.055	0.010	<0.001	0.134	0.024
Upper Cretaceous Series	0	0.000	0.000	0.000	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
UK2 Chronozone	0	0.000	0.000	0.000	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
UK2 C1 (Tuscaloosa)	0	0.000	0.000	0.000	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
Lower Cretaceous Series	5	0.000	0.212	0.038	3	0.000	0.023	0.004	<0.001	0.004	0.001	<0.001	0.018	0.003	2	0.000	0.055	0.010	<0.001	0.134	0.024
LK8 Chronozone	1	0.000	0.000	0.000	1	0.000	0.000	0.000	<0.001	<0.001	<0.001	0.000	0.000	0.000	0	0.000	0.000	0.000	<0.001	<0.001	<0.001
LK8 B1 (Andrew)	1	0.000	0.000	0.000	1	0.000	0.000	0.000	<0.001	<0.001	<0.001	0.000	0.000	0.000	0	0.000	0.000	0.000	<0.001	<0.001	<0.001
LK 6 Chronozone	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LK6 B1 (Mooringsport)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LK3 Chronozone	4	0.000	0.211	0.038	2	0.000	0.022	0.004	0.000	0.004	0.001	0.000	0.018	0.003	2	0.000	0.055	0.010	0.000	0.134	0.024
LK3 B1 (James)	4	0.000	0.211	0.038	2	0.000	0.022	0.004	0.000	0.004	0.001	<0.001	0.018	0.003	2	0.000	0.055	0.010	<0.001	0.134	0.024
LK3 B2 (Sligo)	0	0.000	0.000	0.000	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
Plays that span Chronozones	0	0.000	0.000	0.000	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
LK8-LK3 B1 (Sunniland)	0	0.000	0.000	0.000	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
LK8-LK3 B2 (S Florida Basin)	0	0.000	0.000	0.000	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
LK8-LK3 C3 (Lwr Cretaceous Clastic)	0	0.000	0.000	0.000	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
Plays that span Series	0	0.000	0.000	0.000	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
UK5-LK3 BC2(Cretaceous Buried Hill Drape)	0	0.000	0.000	0.000	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
UK5-LK3 X4 (Cretaceous Perdido FB)	0	0.000	0.000	0.000	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
UK5-LK3 X5 (Cretaceous Miss Fan FB)	0	0.000	0.000	0.000	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
Jurassic System	13	0.000	5.020	0.894	12	0.000	2.232	0.397	<0.001	0.726	0.129	<0.001	1.506	0.268	1	0.000	0.569	0.101	<0.001	2.220	0.395
Upper Jurassic Series	13	0.000	5.020	0.894	12	0.000	2.232	0.397	<0.001	0.726	0.129	<0.001	1.506	0.268	1	0.000	0.569	0.101	<0.001	2.220	0.395
UJ4 Chronozone	13	0.000	5.020	0.894	12	0.000	2.232	0.397	<0.001	0.726	0.129	<0.001	1.506	0.268	1	0.000	0.569	0.101	<0.001	2.220	0.395
UJ4 B1 (Smackover)	0	0.000	0.000	0.000	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
UJ4 B2 (Oolitic)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UJ4 C1 (Cotton Valley CL)	0	0.000	0.000	0.000	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
UJ4 BC1(Jurassic BuriedHill Drape)	0	0.000	0.000	0.000	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
UJ4 A1 (Norphlet)	13	0.000	5.020	0.894	12	0.000	2.232	0.397	<0.001	0.726	0.129	<0.001	1.506	0.268	1	0.000	0.569	0.101	<0.001	2.220	0.395
UJ4 X1 (Jurassic Perdido FB)	0	0.000	0.000	0.000	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
UJ4 X2 (Jurassic Miss Fan FB)	0	0.000	0.000	0.000	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
Play that span Series	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UJ4 - MJ C4 (Florida Basal Clastic)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Plays that span Systems	0	0.000	0.000	0.000	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
UK5-UJ4 BC3 (UK to UJ Buried Hill Strat)	0	0.000	0.000	0.000	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
UK5-LTR BC4(Mesozoic Buried Hill Struct)	0	0.000	0.000	0.000	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
LK8-UJ4 BC5 (LK to UJ Transition zone)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UK5-UJ4 S1 (Salt Roller/Hi Relief Salt)	0	0.000	0.000	0.000	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

Table 2. continued, reserves by play.

	Total Reserves @ 12/31/98				Proved @ 12/31/98				Cumulative Production			Remaining Proved			Unproved				Appreciation (P&U)		
	No. Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	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)
Atlantic Region	0	0.000	0.000	0.000	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	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
Cretaceous System	0	0.000	0.000	0.000	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
Upper Cretaceous Series	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
AUK C1 Play (Clastic)	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	0.000	0.000	0.000	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
ALK Chronozone	0	0.000	0.000	0.000	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
ALK C1 Play (Clastic)	0	0.000	0.000	0.000	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
Jurassic System	0	0.000	0.000	0.000	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
Upper Jurassic Series	0	0.000	0.000	0.000	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
AUJ Chronozone	0	0.000	0.000	0.000	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
AUJ B1 Play (Carbonate)	0	0.000	0.000	0.000	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
AUJ C1 Play (Clastic)	0	0.000	0.000	0.000	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
Middle Jurassic Series	0	0.000	0.000	0.000	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
AMJ Chronozone	0	0.000	0.000	0.000	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
AMJ B1 Play (Carbonate)	0	0.000	0.000	0.000	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
AMJ C1 Play (Clastic)	0	0.000	0.000	0.000	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
Lower Jurassic Series	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ Chronozone	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
Upper Triassic Series	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
Plays that span Systems	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ-TR B1 Play (Carbonate Rift)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ-TR C1 Play (Clastic Rift)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALK-UJ BC1 Play (Transition Zone)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AK-J S1 Play (Structural Diapir)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK-UJ F1 Play (Basin Floor Fan)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Summary Table 3. UCRR by play

Table 3. Undiscovered Conventionally Recoverable Resources (UCRR) by play.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. Data at the chronozone, series, and system aggregation levels may be incomplete when comparing to previous assessments due to significant resources contained in the plays that span the ages.

		Risked Undiscovered Conventionally Recoverable Resources (UCRR)"GRASP DATA"									
		No.	UCRR Oil			UCRR Gas			UCRR BOE		
	MPhc	Undisc.		(Bbbl)			(Tcf)			(Bbbl)	
		Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
GOM/Atl Continental Margin	1	3372	24.520	39.433	59.047	165.587	219.338	282.935	55.512	78.461	106.617
Gulf of Mexico Region	1	2870	22.821	37.126	56.054	145.088	191.627	246.600	49.851	71.223	97.602
Cenozoic Province	1	2532	25.754	30.783	36.390	145.264	170.648	198.661	52.708	61.148	70.393
Quaternary System	1	603	3.549	4.559	5.732	27.010	31.389	36.191	8.553	10.144	11.910
Pleistocene Series	1	603	3.549	4.559	5.732	27.010	31.389	36.191	8.553	10.144	11.910
UPL Chronozone	1	195	0.640	0.872	1.139	8.188	10.560	13.323	2.182	3.018	4.030
UPL B1 Play	1	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
UPL A1 Play	1	11	0.001	0.003	0.012	0.090	0.133	0.183	0.018	0.027	0.038
UPL P1 Play	1	66	0.052	0.116	0.210	1.658	1.873	2.092	0.364	0.449	0.567
UPL F1 Play	1	20	0.030	0.049	0.071	0.667	0.764	0.888	0.157	0.185	0.217
UPL F2 Play	1	98	0.659	0.971	1.475	6.135	7.790	11.149	1.848	2.357	3.235
MPL Chronozone	1	157	0.267	0.362	0.475	3.872	4.995	6.302	1.005	1.251	1.531
MPL B1 Play	1	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MPL A1 Play	1	20	<0.001	0.002	0.004	0.075	0.100	0.124	0.015	0.020	0.025
MPL P1 Play	1	48	0.049	0.078	0.116	1.564	1.786	2.012	0.341	0.396	0.456
MPL F1 Play	1	22	0.026	0.046	0.076	0.563	0.849	1.346	0.134	0.197	0.296
MPL F2 Play	1	67	0.179	0.236	0.314	1.506	2.259	3.155	0.480	0.638	0.824
LPL Chronozone	1	251	2.491	3.058	3.700	13.973	15.835	17.847	5.050	5.876	6.782
LPL A1 Play	1	16	0.004	0.017	0.036	0.181	0.248	0.313	0.041	0.061	0.084
LPL P1 Play	1	55	0.049	0.076	0.110	1.258	1.469	1.680	0.287	0.338	0.393
LPL F 1 Play	1	52	0.192	0.265	0.376	3.375	3.872	4.343	0.823	0.954	1.101
LPL F2 Play	1	128	2.360	2.699	3.301	9.038	10.247	11.815	4.043	4.522	5.372
Tertiary System	1	1821	17.263	20.873	24.924	104.178	125.427	149.219	36.653	43.191	50.418
Pliocene Series	1	356	4.078	4.704	5.386	16.924	23.407	31.266	7.338	8.868	10.586
UP Chronozone	1	236	3.075	3.552	4.072	13.139	16.762	20.958	5.556	6.534	7.614
UP A1 Play	1	7	0.003	0.006	0.009	0.037	0.056	0.075	0.010	0.016	0.022
UP P1 Play	1	36	0.051	0.083	0.121	0.821	1.008	1.199	0.212	0.263	0.319
UP F1 Play	1	66	0.253	0.335	0.428	3.775	4.850	5.584	1.023	1.198	1.381
UP F2 Play	1	127	2.737	3.128	3.578	8.546	10.848	14.358	4.354	5.058	6.032
LP Chronozone	1	120	0.919	1.152	1.419	3.180	6.645	11.837	1.572	2.334	3.295
LP A1 Play	1	8	0.006	0.014	0.024	0.111	0.144	0.177	0.029	0.039	0.051
LP P1 Play	1	30	0.064	0.095	0.129	0.687	0.831	0.979	0.198	0.243	0.290
LP F1 Play	1	31	0.034	0.052	0.075	0.606	0.850	1.114	0.148	0.203	0.266
LP F2 Play	1	51	0.787	0.992	1.228	3.081	4.820	9.585	1.406	1.850	2.721
Miocene Series	1	1333	12.237	14.880	17.858	77.539	92.528	109.223	26.601	31.344	36.588
UM3 Chronozone	1	185	0.979	1.351	1.802	9.621	11.859	14.398	2.788	3.461	4.228
UM3 R1 Play	1	3	0.001	0.002	0.004	0.012	0.021	0.031	0.003	0.006	0.008
UM3 A1 Play	1	3	<0.001	<0.001	<0.001	0.007	0.018	0.030	0.001	0.003	0.006
UM3 AP1 Play	1	19	<0.001	<0.001	<0.001	0.199	0.236	0.276	0.035	0.042	0.049
UM3 P1 Play	1	35	0.054	0.079	0.107	0.734	0.885	1.046	0.195	0.236	0.281
UM3 F1 Play	1	55	0.130	0.229	0.415	2.054	3.038	4.602	0.514	0.769	1.206
UM3 F2 Play	1	70	0.777	1.041	1.364	6.630	7.660	8.811	2.034	2.404	2.847
UM1 Chronozone	1	178	1.023	1.271	1.555	10.774	12.694	14.816	3.016	3.530	4.096
UM1 A1 Play	1	1	<0.001	<0.001	<0.001	<0.001	0.025	0.121	<0.001	0.005	0.022
UM1 AP1 Play	1	14	<0.001	<0.001	<0.001	0.131	0.166	0.208	0.023	0.030	0.037
UM1 P1 Play	1	26	0.036	0.055	0.081	0.627	0.755	0.886	0.155	0.190	0.229
UM1 F1 Play	1	62	0.178	0.277	0.425	1.769	2.593	4.181	0.516	0.739	1.104
UM1 F2 Play	1	75	0.773	0.938	1.112	8.446	9.154	10.011	2.323	2.567	2.830
MM9 Chronozone	1	174	1.651	1.958	2.298	11.625	16.113	21.560	3.885	4.825	5.897
MM9 A1 Play	1	3	<0.001	<0.001	0.001	0.003	0.011	0.021	0.001	0.002	0.005
MM9 AP1 Play	1	4	<0.001	<0.001	<0.001	0.042	0.061	0.083	0.008	0.011	0.015
MM9 P1 Play	1	29	0.012	0.028	0.056	0.863	1.078	1.296	0.174	0.220	0.270
MM9 S1 Play	1	5	<.001	<.001	<.001	0.010	0.018	0.030	0.002	0.003	0.006
MM9 F1 Play	1	53	0.057	0.092	0.135	1.920	2.611	3.360	0.418	0.556	0.708
MM9 F2 Play	1	80	1.575	1.838	2.153	9.707	12.334	17.219	3.424	4.033	5.008
MM7 Chronozone	1	237	1.432	1.720	2.040	8.994	10.422	11.984	3.079	3.574	4.117
MM7 R1 Play	1	7	0.001	0.002	0.004	0.080	0.115	0.154	0.015	0.022	0.030
MM7 A1 Play	1	10	<0.001	0.002	0.006	0.042	0.072	0.113	0.008	0.015	0.024
MM7 P1 Play	1	40	0.009	0.016	0.028	0.716	0.871	1.030	0.140	0.171	0.203
MM7 S1 Play	1	14	0.001	0.001	0.002	0.326	0.449	0.587	0.059	0.081	0.106
MM7 S2 Play	1	4	<.001	0.001	0.002	0.040	0.087	0.138	0.007	0.016	0.026
MM7 F1 Play	1	68	0.175	0.212	0.263	1.928	2.304	2.837	0.525	0.622	0.754
MM7 F2 Play	1	94	1.278	1.486	1.759	5.696	6.523	7.673	2.333	2.646	3.089
MM4 Chronozone	1	173	1.019	1.227	1.461	8.245	10.495	13.097	2.589	3.095	3.659
MM4 R1 Play	1	11	0.003	0.008	0.016	0.148	0.201	0.269	0.032	0.044	0.060
MM4 A1 Play	1	4	<0.001	<0.001	0.002	0.008	0.018	0.029	0.002	0.004	0.006
MM4 P1 Play	1	30	0.003	0.008	0.015	1.073	1.250	1.449	0.198	0.231	0.266
MM4 F1 Play	1	48	0.023	0.038	0.058	1.268	1.594	1.947	0.253	0.321	0.398
MM4 F2 Play	1	80	0.999	1.173	1.391	5.937	7.431	9.942	2.121	2.495	3.044

Table 3. continued, Undiscovered Conventionally Recoverable Resources (UCRR) by play.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. Data at the chronozone, series, and system aggregation levels may be incomplete when comparing to previous assessments due to significant resources contained in the plays that span the ages.

		Risked Undiscovered Conventionally Recoverable Resources (UCRR)"GRASP DATA"									
		No.	UCRR Oil			UCRR Gas			UCRR BOE		
	MPhc	Undisc.		(Bbbl)			(Tcf)			(Bbbl)	
		Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
LM4 Chronozone	1	148	2.348	3.161	4.131	8.728	12.369	16.842	3.965	5.361	7.033
LM4 R1 Play	1	9	<0.001	<0.001	0.001	0.083	0.112	0.142	0.015	0.020	0.026
LM4 A1 Play	1	8	<0.001	0.001	0.001	0.124	0.161	0.199	0.023	0.029	0.036
LM4 P1 Play	1	21	0.006	0.010	0.016	0.731	0.920	1.122	0.138	0.174	0.212
LM4 F1 Play	1	25	0.015	0.036	0.067	0.894	1.223	1.672	0.180	0.253	0.350
LM4 F2 Play	1	85	2.408	3.114	4.113	7.688	9.952	14.393	3.842	4.885	6.489
LM2 Chronozone	1	126	2.063	3.163	4.573	9.275	12.318	15.925	3.779	5.354	7.290
LM2 P1 Play	1	11	0.005	0.012	0.024	0.547	0.842	1.184	0.106	0.162	0.228
LM2 F1 Play	1	30	0.016	0.041	0.086	1.122	1.497	1.884	0.225	0.308	0.400
LM2 F2 Play	1	85	2.312	3.109	4.513	7.903	9.979	13.343	3.769	4.885	6.784
LM1 Chronozone	1	112	0.838	1.030	1.248	4.316	6.260	8.679	1.687	2.144	2.672
LM1 P1 Play	1	5	<0.001	0.001	0.002	0.035	0.044	0.053	0.007	0.009	0.011
LM1 F1 Play	1	37	0.017	0.029	0.046	1.813	2.550	3.415	0.343	0.483	0.646
LM1 F2 Play	1	70	0.835	1.001	1.217	2.644	3.666	5.598	1.346	1.653	2.137
Oligocene Series	1	29	0.011	0.024	0.042	0.617	0.785	0.973	0.125	0.164	0.209
UO - MO Chronozone	1	29	0.011	0.024	0.042	0.617	0.785	0.973	0.125	0.164	0.209
UO MO F1 F2 Play	1	29	0.011	0.024	0.042	0.617	0.785	0.973	0.125	0.164	0.209
Plays that span Series	1	103	0.495	1.265	2.528	5.362	8.707	13.129	1.521	2.814	4.641
LE-LL BC1(Lwr TertiaryBuriedHillDrape)	0.05	6	0.000	0.006	0.000	0.000	0.008	0.000	0.000	0.007	0.000
LO-LL C1 (Lwr Tertiary Clastic Gas)	1	42	0.004	0.022	0.052	3.065	4.821	8.037	0.567	0.880	1.451
LO-LL C2 (Lwr Tertiary Clastic G & O)	1	55	0.687	1.237	2.339	2.830	3.878	5.498	1.256	1.927	3.231
Plays that span Systems	1	108	4.021	5.352	6.931	10.990	13.832	17.099	6.144	7.813	9.742
UPL-LL (Cenozoic Fan 3 Play)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UPL-LL X1 (Cenozoic Perdido FB Play)	1	26	0.523	0.989	2.025	1.274	2.204	3.967	0.793	1.381	2.565
UPL-LL X2 (Cenozoic Miss Fan FB Play)	1	82	3.675	4.363	5.183	9.647	11.628	13.876	5.528	6.432	7.462
Mesozoic Province	1	338	0.728	6.342	20.023	4.023	20.979	57.101	1.499	10.075	29.708
Cretaceous System	1	195	0.552	3.449	9.952	1.172	10.192	32.168	0.773	5.262	15.568
Upper Cretaceous Series	0.56	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
UK2 Chronozone	0.56	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
UK2 C1 (Tuscaloosa)	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	134	0.553	1.107	1.918	0.261	0.657	1.303	0.622	1.224	2.099
LK8 Chronozone	1	5	0.005	0.030	0.074	0.021	0.046	0.085	0.010	0.038	0.089
LK8 B1 (Andrew)	1	5	0.005	0.030	0.074	0.021	0.046	0.085	0.010	0.038	0.089
LK 6 Chronozone	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LK6 B1 (Mooringsport)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LK3 Chronozone	1	18	0.004	0.036	0.116	0.140	0.426	0.929	0.028	0.111	0.274
LK3 B1 (James)	1	14	0.008	0.019	0.036	0.128	0.216	0.315	0.036	0.058	0.083
LK3 B2 (Sligo)	1	4	<.001	0.016	0.077	0.042	0.210	0.562	0.009	0.054	0.168
Plays that span Chronozones	1	111	0.536	1.041	1.773	0.066	0.186	0.392	0.553	1.075	1.830
LK8-LK3 B1 (Sunniland)	1	33	0.236	0.421	0.782	0.017	0.030	0.056	0.239	0.426	0.792
LK8-LK3 B2 (S Florida Basin)	1	58	0.375	0.583	0.964	0.027	0.046	0.089	0.380	0.591	0.981
LK8-LK3 C3 (Lwr Cretaceous Clastic)	0.64	20	0.000	0.037	0.093	0.000	0.110	0.244	0.000	0.057	0.133
Plays that span Series	0.54	56	0.000	2.297	8.705	0.000	9.464	34.475	0.000	3.981	14.688
UK5-LK3 BC2(Cretaceous Buried Hill Drape)	0.08	14	0.000	0.028	0.169	0.000	0.109	0.601	0.000	0.048	0.290
UK5-LK3 X4 (Cretaceous Perdido FB)	0.4	20	0.000	1.012	4.426	0.000	4.280	18.769	0.000	1.773	7.498
UK5-LK3 X5 (Cretaceous Miss Fan FB)	0.4	22	0.000	1.257	5.298	0.000	5.075	21.421	0.000	2.160	8.902
Jurassic System	1	102	0.379	1.132	2.452	5.235	7.670	10.718	1.278	2.497	4.267
Upper Jurassic Series	1	102	0.379	1.132	2.452	5.235	7.670	10.718	1.278	2.497	4.267
UJ4 Chronozone	1	102	0.379	1.132	2.452	5.235	7.670	10.718	1.278	2.497	4.267
UJ4 B1 (Smackover)	1	5	0.004	0.059	0.205	0.013	0.104	0.309	0.008	0.078	0.265
UJ4 B2 (Oolitic)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UJ4 C1 (Cotton Valley CL)	1	13	0.004	0.015	0.032	0.064	0.296	0.785	0.021	0.067	0.155
UJ4 BC1(Jurassic BuriedHill Drape)	0.08	14	0.000	0.009	0.045	0.000	0.016	0.090	0.000	0.012	0.065
UJ4 A1 (Norphlet)	1	30	0.444	0.713	1.016	5.757	6.492	7.249	1.534	1.868	2.241
UJ4 X1 (Jurassic Perdido FB)	0.4	19	0.000	0.148	0.635	0.000	0.368	1.837	0.000	0.213	0.940
UJ4 X2 (Jurassic Miss Fan FB)	0.4	21	0.000	0.189	0.804	0.000	0.395	1.730	0.000	0.259	1.093
Play that span Series	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UJ4 - MJ C4 (Florida Basal Clastic)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Plays that span Systems	0.5	41	0.000	1.762	8.019	0.000	3.117	14.166	0.000	2.316	10.541
UK5-UJ4 BC3 (UK to UJ Buried Hill Strat)	0.24	10	0.000	0.140	0.398	0.000	0.233	0.933	0.000	0.181	0.610
UK5-LTR BC4(Mesozoic Buried Hill Struct)	0.29	13	0.000	1.223	5.914	0.000	2.140	12.197	0.000	1.603	8.514
LK8-UJ4 BC5 (LK to UJ Transition zone)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UK5-UJ4 S1 (Salt Roller/Hi Relief Salt)	0.35	18	0.000	0.400	1.846	0.000	0.744	3.518	0.000	0.532	2.448

Table 3. continued, Undiscovered Conventionally Recoverable Resources (UCRR) by play.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. Data at the chronozone, series, and system aggregation levels may be incomplete when comparing to previous assessments due to significant resources contained in the plays that span the ages.

		Risked Undiscovered Conventionally Recoverable Resources (UCRR)"GRASP DATA"									
		No.	UCRR Oil			UCRR Gas			UCRR BOE		
	MPhc	Undisc.		(Bbbl)			(Tcf)			(Bbbl)	
		Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
Atlantic Region	1	502	1.297	2.307	3.706	16.117	27.712	43.499	4.558	7.238	10.739
Mesozoic Province	1	502	1.297	2.307	3.706	16.117	27.712	43.499	4.558	7.238	10.739
Cretaceous System	1	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
AUK Chronozone	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK C1 Play (Clastic)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lower Cretaceous Series	1	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
ALK Chronozone	1	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
ALK C1 Play (Clastic)	1	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
Jurassic System	1	382	0.790	1.585	2.754	9.311	15.944	24.957	2.667	4.422	6.768
Upper Jurassic Series	1	235	0.555	1.056	1.774	6.422	10.444	15.760	1.879	2.914	4.250
AUJ Chronozone	1	235	0.555	1.056	1.774	6.422	10.444	15.760	1.879	2.914	4.250
AUJ B1 Play (Carbonate)	1	35	0.087	0.234	0.520	0.718	1.488	3.371	0.232	0.499	1.060
AUJ C1 Play (Clastic)	1	200	0.545	0.822	1.153	6.401	8.953	13.270	1.832	2.415	3.273
Middle Jurassic Series	0.93	147	0.000	0.529	1.163	0.000	5.502	10.426	0.000	1.508	2.830
AMJ Chronozone	0.93	147	0.000	0.529	1.163	0.000	5.502	10.426	0.000	1.508	2.830
AMJ B1 Play (Carbonate)	0.64	27	0.000	0.130	0.413	0.000	0.611	1.633	0.000	0.239	0.688
AMJ C1 Play (Clastic)	0.9	120	0.000	0.399	0.645	0.000	4.891	8.455	0.000	1.269	2.020
Lower Jurassic Series	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ Chronozone	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Triassic System	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
AUTR Chronozone	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Plays that span Systems	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ-TR B1 Play (Carbonate Rift)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALJ-TR C1 Play (Clastic Rift)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALK-UJ BC1 Play (Transition Zone)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AK-J S1 Play (Structural Diapir)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK-UJ F1 Play (Basin Floor Fan)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Summary Table 4. Reserves by Area and Water Depth

Table 4. Reserve listing of the Gulf of Mexico (GOM)and Atlantic Continental Margin by planning area and water depth ranges.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding.

Water Depth	Reserves @ 12 / 31 / 98																				
	Total Reserves				Proved				Cumulative Production			Remaining Proved			Unproved				Appreciation (P&U)		
Range	No.	Oil	Gas	BOE	No.	Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE	No.	Oil	Gas	BOE	Oil	Gas	BOE
meters (m)	Pools	(Bbbl)	(Tcf)	(Bbbl)	Pools	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	Pools	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)
GOM/Atlantic	2,453	22.997	235.909	64.974	2,369	14.266	162.711	43.218	10.908	132.677	34.515	3.358	30.034	8.703	84	0.995	5.102	1.903	7.736	68.096	19.852
0 - 200m	2,300	14.027	201.580	49.895	2,269	11.386	151.624	38.366	10.006	128.736	32.912	1.381	22.888	5.453	31	0.031	1.014	0.211	2.610	48.942	11.318
200 - 800m	97	2.766	12.349	4.964	83	1.470	6.872	2.692	0.674	3.389	1.277	0.796	3.483	1.416	14	0.088	0.369	0.154	1.208	5.108	2.117
> 800 m	56	6.203	21.981	10.115	17	1.410	4.215	2.160	0.228	0.551	0.326	1.182	3.664	1.834	39	0.876	3.719	1.538	3.917	14.046	6.417
GOM Region	2,453	22.997	235.909	64.974	2,369	14.266	162.711	43.218	10.908	132.677	34.515	3.358	30.034	8.703	84	0.995	5.102	1.903	7.736	68.096	19.852
0 - 200m	2,300	14.027	201.580	49.895	2,269	11.386	151.624	38.366	10.006	128.736	32.912	1.381	22.888	5.453	31	0.031	1.014	0.211	2.610	48.942	11.318
200 - 800m	97	2.766	12.349	4.964	83	1.470	6.872	2.692	0.674	3.389	1.277	0.796	3.483	1.416	14	0.088	0.369	0.154	1.208	5.108	2.117
800 - 1600m	39	4.697	12.099	6.850	16	1.409	3.432	2.020	0.228	0.490	0.315	1.181	2.942	1.704	23	0.455	1.540	0.729	2.833	7.127	4.101
1600 - 2400m	17	1.507	9.881	3.265	1	0.001	0.783	0.140	<0.001	0.061	0.011	0.001	0.722	0.129	16	0.421	2.179	0.809	1.085	6.920	2.316
> 2400m	0	0.000	0.000	0.000	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
Western GOM	569	2.212	49.673	11.051	555	1.054	31.189	6.603	0.559	23.795	4.793	0.495	7.393	1.810	14	0.067	0.603	0.174	1.091	17.881	4.273
0 - 200m	528	0.730	42.346	8.265	524	0.508	28.289	5.541	0.378	22.518	4.385	0.130	5.771	1.157	4	<0.001	0.015	0.003	0.222	14.042	2.720
200 - 800m	29	0.329	3.356	0.926	26	0.163	1.773	0.479	0.071	0.986	0.247	0.092	0.787	0.232	3	0.006	0.069	0.018	0.160	1.515	0.429
800 - 1600m	11	1.154	3.955	1.857	5	0.383	1.127	0.583	0.110	0.291	0.162	0.273	0.836	0.421	6	0.061	0.515	0.153	0.710	2.313	1.121
1600 - 2400m	1	<0.001	0.016	0.003	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1	<0.001	0.005	0.001	<0.001	0.011	0.002
> 2400m	0	0.000	0.000	0.000	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
Central GOM	1,880	20.785	184.895	53.684	1,813	13.212	131.518	36.614	10.348	108.882	29.722	2.864	22.636	6.891	67	0.929	3.821	1.608	6.644	49.556	15.462
0 - 200m	1,769	13.297	158.147	41.437	1,744	10.879	123.330	32.823	9.628	106.218	28.528	1.251	17.111	4.296	25	0.031	0.423	0.106	2.388	34.394	8.508
200 - 800m	68	2.438	8.992	4.038	57	1.307	5.099	2.214	0.603	2.403	1.030	0.704	2.696	1.184	11	0.083	0.300	0.136	1.049	3.593	1.688
800 - 1600m	28	3.543	8.145	4.992	11	1.026	2.306	1.436	0.118	0.199	0.153	0.908	2.106	1.283	17	0.394	1.025	0.577	2.123	4.813	2.980
1600 - 2400m	15	1.507	9.611	3.217	1	0.001	0.783	0.140	<0.001	0.061	0.011	0.001	0.722	0.129	14	0.421	2.073	0.790	1.085	6.755	2.287
> 2400m	0	0.000	0.000	0.000	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
Eastern GOM	4	<0.001	1.342	0.239	1	0.000	0.005	0.001	0.000	0.000	0.000	0.000	0.005	0.001	3	<0.001	0.678	0.121	<0.001	0.659	0.117
0 - 200m	3	<0.001	1.087	0.193	1	0.000	0.005	0.001	0.000	0.000	0.000	0.000	0.005	0.001	2	<0.001	0.576	0.103	<0.001	0.506	0.090
200 - 800m	0	0.000	0.000	0.000	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
800 - 1600m	0	0.000	0.000	0.000	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
1600 - 2400m	1	<0.001	0.255	0.045	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1	<0.001	0.101	0.018	<0.001	0.153	0.027
> 2400m	0	0.000	0.000	0.000	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
Straits of FL	0	0.000	0.000	0.000	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	0	0.000	0.000	0.000	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 - 800m	0	0.000	0.000	0.000	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
> 800m	0	0.000	0.000	0.000	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	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	0	0.000	0.000	0.000	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 - 800m	0	0.000	0.000	0.000	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
> 800m	0	0.000	0.000	0.000	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	0	0.000	0.000	0.000	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	0	0.000	0.000	0.000	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 - 800m	0	0.000	0.000	0.000	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
> 800m	0	0.000	0.000	0.000	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	0	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000	0.000	0.000
0 - 200m	0	0.000	0.000	0.000	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 - 800m	0	0.000	0.000	0.000	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
> 800m	0	0.000	0.000	0.000	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	0	0.000	0.000	0.000	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	0	0.000	0.000	0.000	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 - 800m	0	0.000	0.000	0.000	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
> 800m	0	0.000	0.000	0.000	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 5. Total endowment & UCRR listing by area and water

Table 5. Total endowment and Undiscovered Conventionally Recoverable Resources (UCRR) of the GOM and Atlantic Continental Margin by planning area and water depth ranges.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding.

	Total Endowment										Risked UCRR "Presto" data except GOM , Atlantic, & GOM/Atl totals are "Grasp" data								
Water Depth	(Reserves + Resources) @ 12 / 31 / 98										Oil			Gas			BOE		
Range	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)			MPhc	(Bbbl)			(Tcf)			(Bbbl)		
meters (m)	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5		F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
GOM/Atlantic	47.517	62.430	82.044	401.496	455.247	518.844	120.486	143.435	171.591	1.00	24.520	39.433	59.047	165.587	219.338	282.935	55.512	78.461	106.617
0 - 200m	18.874	19.515	20.065	262.579	266.278	273.611	65.596	66.895	68.750	1.00	4.847	5.488	6.038	60.999	64.698	72.031	15.701	17.000	18.855
200 - 800m	6.858	7.541	8.338	38.094	40.752	43.233	13.637	14.792	16.031	1.00	4.092	4.775	5.572	25.745	28.403	30.884	8.673	9.828	11.067
> 800 m	31.904	35.325	42.539	138.630	149.811	167.182	56.572	61.982	72.288	1.00	25.701	29.122	36.336	116.649	127.830	145.201	46.457	51.867	62.173
GOM Region	45.818	60.123	79.051	380.998	427.537	482.510	114.825	136.197	162.576	1.00	22.821	37.126	56.054	145.088	191.627	246.600	49.851	71.223	97.602
0 - 200m	18.410	18.939	19.815	255.626	258.305	261.538	63.895	64.901	66.352	1.00	4.383	4.912	5.788	54.045	56.724	59.958	13.999	15.005	16.457
200 - 800m	6.283	6.911	7.574	31.163	33.394	35.787	11.828	12.853	13.942	1.00	3.517	4.144	4.807	18.814	21.046	23.438	6.864	7.889	8.978
800 - 1600m	14.626	15.578	16.563	57.546	62.196	71.658	24.865	26.645	29.314	1.00	9.929	10.882	11.867	45.446	50.096	59.558	18.016	19.796	22.464
1600 - 2400m	12.123	13.491	15.733	53.221	58.029	65.401	21.593	23.816	27.370	1.00	10.616	11.984	14.226	43.340	48.148	55.520	18.328	20.551	24.105
> 2400m	3.315	5.147	10.763	12.594	16.967	29.031	5.556	8.166	15.928	1.00	3.315	5.147	10.763	12.594	16.967	29.031	5.556	8.166	15.928
Western GOM	14.319	15.198	16.432	119.863	124.393	130.032	35.647	37.332	39.569	1.00	12.107	12.986	14.220	70.191	74.721	80.360	24.597	26.281	28.518
0 - 200m	1.578	1.709	1.850	61.827	63.723	66.545	12.579	13.047	13.690	1.00	0.848	0.979	1.120	19.481	21.377	24.199	4.315	4.783	5.426
200 - 800m	2.089	2.399	2.766	12.409	13.568	14.765	4.297	4.813	5.393	1.00	1.760	2.071	2.437	9.053	10.212	11.409	3.371	3.888	4.467
800 - 1600m	5.350	5.738	6.136	22.882	24.916	28.908	9.422	10.171	11.280	1.00	4.197	4.584	4.982	18.927	20.962	24.953	7.565	8.314	9.422
1600 - 2400m	3.750	4.167	4.806	15.723	17.472	20.109	6.547	7.276	8.385	1.00	3.750	4.167	4.806	15.707	17.456	20.093	6.544	7.273	8.382
> 2400m	0.989	1.180	1.615	4.151	4.733	5.814	1.727	2.022	2.649	1.00	0.989	1.180	1.615	4.151	4.733	5.814	1.727	2.022	2.649
Central GOM	39.250	41.189	44.552	284.250	290.414	299.072	89.829	92.864	97.767	1.00	18.466	20.404	23.767	99.355	105.519	114.177	36.145	39.180	44.083
0 - 200m	15.200	15.525	16.081	186.170	187.411	188.613	48.326	48.872	49.642	1.00	1.903	2.227	2.783	28.022	29.264	30.466	6.889	7.434	8.205
200 - 800m	4.082	4.368	4.667	17.876	19.131	20.397	7.263	7.772	8.296	1.00	1.644	1.930	2.229	8.884	10.138	11.404	3.225	3.734	4.258
800 - 1600m	9.256	9.749	10.286	33.962	36.830	42.390	15.299	16.302	17.829	1.00	5.713	6.206	6.743	25.817	28.686	34.246	10.307	11.310	12.836
1600 - 2400m	8.112	9.028	10.499	35.830	38.950	43.791	14.488	15.959	18.291	1.00	6.606	7.522	8.992	26.219	29.339	34.180	11.271	12.742	15.074
> 2400m	1.826	2.554	4.740	6.596	8.218	12.803	2.999	4.017	7.018	1.00	1.826	2.554	4.740	6.596	8.218	12.803	2.999	4.017	7.018
Eastern GOM	2.351	3.576	6.614	11.366	13.648	20.276	4.373	6.004	10.222	1.00	2.351	3.576	6.614	10.024	12.306	18.934	4.134	5.766	9.983
0 - 200m	1.287	1.700	2.348	6.856	7.157	7.435	2.507	2.973	3.671	1.00	1.287	1.700	2.348	5.769	6.070	6.348	2.314	2.780	3.477
200 - 800m	0.093	0.133	0.213	0.500	0.673	1.033	0.181	0.253	0.397	1.00	0.093	0.133	0.213	0.500	0.673	1.033	0.181	0.253	0.397
800 - 1600m	0.085	0.092	0.099	0.401	0.452	0.550	0.156	0.172	0.197	1.00	0.085	0.092	0.099	0.401	0.452	0.550	0.156	0.172	0.197
1600 - 2400m	0.253	0.294	0.367	1.429	1.609	1.975	0.507	0.580	0.719	1.00	0.253	0.294	0.367	1.175	1.354	1.721	0.462	0.535	0.673
> 2400m	0.458	1.433	4.780	1.767	3.987	11.014	0.772	2.143	6.740	1.00	0.458	1.433	4.780	1.767	3.987	11.014	0.772	2.143	6.740
Straits of FL	0.015	0.025	0.045	0.019	0.026	0.030	0.018	0.030	0.051	1.00	0.015	0.025	0.045	0.019	0.026	0.030	0.018	0.030	0.051
0 - 200m	0.007	0.013	0.025	0.001	0.001	0.002	0.007	0.013	0.025	1.00	0.007	0.013	0.025	0.001	0.001	0.002	0.007	0.013	0.025
200 - 800m	0.007	0.012	0.021	0.017	0.025	0.041	0.010	0.016	0.028	1.00	0.007	0.012	0.021	0.017	0.025	0.041	0.010	0.016	0.028
> 800m	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Atlantic Region	1.297	2.307	3.706	16.117	27.712	43.499	4.558	7.238	10.739	1.00	1.297	2.307	3.706	16.117	27.712	43.499	4.558	7.238	10.739
0 - 200m	0.420	0.576	0.669	4.784	8.003	14.557	1.271	2.000	3.259	1.00	0.420	0.576	0.669	4.784	8.003	14.557	1.271	2.000	3.259
200 - 800m	0.447	0.637	0.973	5.957	7.363	9.173	1.507	1.947	2.605	1.00	0.447	0.637	0.973	5.957	7.363	9.173	1.507	1.947	2.605
> 800m	0.855	1.109	1.537	10.812	12.748	15.190	2.779	3.378	4.240	1.00	0.855	1.109	1.537	10.812	12.748	15.190	2.779	3.378	4.240
North Atlantic	0.622	0.726	0.832	7.664	9.036	11.125	1.986	2.334	2.811	1.00	0.622	0.726	0.832	7.664	9.036	11.125	1.986	2.334	2.811
0 - 200m	0.139	0.190	0.221	1.579	2.641	4.804	0.419	0.660	1.076	1.00	0.139	0.190	0.221	1.579	2.641	4.804	0.419	0.660	1.076
200 - 800m	0.140	0.192	0.268	1.891	2.322	2.844	0.477	0.605	0.774	1.00	0.140	0.192	0.268	1.891	2.322	2.844	0.477	0.605	0.774
> 800m	0.276	0.347	0.452	3.473	4.098	4.901	0.894	1.077	1.324	1.00	0.276	0.347	0.452	3.473	4.098	4.901	0.894	1.077	1.324
Mid-Atlantic	0.678	0.813	1.014	8.200	9.718	11.933	2.138	2.543	3.137	1.00	0.678	0.813	1.014	8.200	9.718	11.933	2.138	2.543	3.137
0 - 200m	0.143	0.196	0.227	1.627	2.721	4.950	0.432	0.680	1.108	1.00	0.143	0.196	0.227	1.627	2.721	4.950	0.432	0.680	1.108
200 - 800m	0.144	0.198	0.273	1.956	2.399	2.949	0.492	0.625	0.797	1.00	0.144	0.198	0.273	1.956	2.399	2.949	0.492	0.625	0.797
> 800m	0.312	0.426	0.663	3.889	4.624	5.603	1.004	1.249	1.660	1.00	0.312	0.426	0.663	3.889	4.624	5.603	1.004	1.249	1.660
South Atlantic	0.645	0.770	0.924	7.870	9.286	11.667	2.046	2.422	3.000	1.00	0.645	0.770	0.924	7.870	9.286	11.667	2.046	2.422	3.000
0 - 200m	0.139	0.190	0.221	1.579	2.641	4.804	0.419	0.660	1.076	1.00	0.139	0.190	0.221	1.579	2.641	4.804	0.419	0.660	1.076
200 - 800m	0.162	0.247	0.437	2.090	2.642	3.503	0.533	0.717	1.060	1.00	0.162	0.247	0.437	2.090	2.642	3.503	0.533	0.717	1.060
> 800m	0.270	0.336	0.429	3.419	4.027	4.779	0.878	1.052	1.279	1.00	0.270	0.336	0.429	3.419	4.027	4.779	0.878	1.052	1.279

Summary Table 6. $18/bbl scenario UERR listing by area and water depth

Table 6. $18/bbl scenario Undiscovered Economically Recoverable Resources (UERR) of the GOM and Atlantic Continental Margin by planning area and water depth ranges.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding.

Water Depth Range meters (m)	Risked Undiscovered Economically Recoverable Resources Full-Cycle @ $18.00/bbl and $2.11/Mcf										Risked Undiscovered Economically Recoverable Resources Half-Cycle @ $18.00/bbl and $2.11/Mcf without exploratory costs									
	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	1.00	14.264	17.936	22.030	91.944	106.756	123.673	30.624	36.932	44.036	1.00	15.447	19.134	23.574	97.187	112.203	127.304	32.740	39.099	46.226
0 - 200m	1.00	2.609	3.108	3.662	42.203	46.232	51.949	10.118	11.335	12.906	1.00	2.864	3.297	3.758	43.962	48.149	54.024	10.687	11.864	13.370
200 - 800m	1.00	2.732	3.456	4.143	13.850	16.541	19.637	5.196	6.399	7.637	1.00	2.811	3.509	4.175	14.065	16.892	20.152	5.313	6.515	7.761
> 800 m	1.00	7.958	11.417	15.591	29.854	44.057	56.645	13.270	19.256	25.670	1.00	8.917	12.376	16.310	32.876	47.338	62.103	14.767	20.799	27.361
GOM Region	1.00	13.968	17.467	21.851	84.530	100.260	114.075	29.009	35.307	42.149	1.00	14.905	18.569	23.073	90.434	105.167	118.912	30.996	37.282	44.232
0 - 200m	1.00	2.205	2.726	3.400	38.544	40.236	41.756	9.063	9.885	10.830	1.00	2.332	2.879	3.521	40.398	41.816	43.354	9.520	10.320	11.235
200 - 800m	1.00	2.700	3.392	4.028	13.485	16.211	18.821	5.100	6.276	7.376	1.00	2.764	3.432	4.056	13.863	16.497	19.122	5.230	6.368	7.459
800 - 1600m	1.00	5.394	6.453	7.543	21.351	28.714	38.979	9.194	11.562	14.479	1.00	5.730	6.726	7.795	22.418	29.895	39.679	9.719	12.045	14.855
1600 - 2400m	0.98	0.744	3.536	5.879	1.188	11.308	20.451	0.956	5.548	9.518	0.99	1.267	3.966	6.199	2.025	12.836	21.498	1.627	6.250	10.024
> 2400m	0.98	0.366	1.485	3.709	0.624	3.895	7.403	0.477	2.178	5.026	0.99	0.518	1.698	4.443	1.140	4.419	8.995	0.721	2.484	6.044
Western GOM	1.00	5.115	6.461	7.671	33.006	38.494	44.425	10.989	13.311	15.576	1.00	5.552	6.806	7.944	34.476	40.365	46.460	11.687	13.989	16.211
0 - 200m	1.00	0.535	0.679	0.842	12.507	13.744	14.960	2.761	3.124	3.504	1.00	0.541	0.696	0.879	13.174	14.318	15.461	2.885	3.243	3.630
200 - 800m	1.00	1.273	1.583	1.878	6.306	7.647	8.876	2.395	2.943	3.458	1.00	1.290	1.601	1.894	6.497	7.767	8.981	2.446	2.983	3.492
800 - 1600m	1.00	2.226	2.656	3.114	8.763	11.827	16.003	3.785	4.761	5.961	1.00	2.359	2.768	3.208	9.233	12.313	16.343	4.001	4.959	6.116
1600 - 2400m	0.98	0.207	1.238	2.017	0.313	4.225	7.807	0.262	1.989	3.406	0.99	0.349	1.395	2.126	0.556	4.818	8.302	0.447	2.252	3.603
> 2400m	0.97	0.057	0.335	0.565	0.094	1.138	2.202	0.074	0.538	0.957	0.99	0.102	0.383	0.646	0.162	1.289	2.315	0.131	0.612	1.058
Central GOM	1.00	7.366	9.508	11.780	46.606	54.726	62.514	15.659	19.246	22.903	1.00	7.907	10.091	12.479	49.453	57.549	65.404	16.707	20.331	24.117
0 - 200m	1.00	1.093	1.282	1.483	20.194	21.605	22.849	4.686	5.126	5.549	1.00	1.144	1.325	1.535	20.994	22.479	23.675	4.879	5.324	5.747
200 - 800m	1.00	1.390	1.741	2.046	6.995	8.406	9.871	2.635	3.236	3.803	1.00	1.414	1.760	2.085	7.164	8.544	9.881	2.689	3.280	3.843
800 - 1600m	1.00	3.125	3.737	4.332	12.235	16.633	22.633	5.302	6.697	8.359	1.00	3.303	3.902	4.485	12.848	17.295	23.267	5.589	6.979	8.625
1600 - 2400m	0.98	0.520	2.176	3.686	0.861	6.676	12.182	0.674	3.364	5.853	0.99	0.881	2.446	3.903	1.462	7.579	12.723	1.141	3.794	6.166
> 2400m	0.97	0.154	0.618	1.414	0.424	1.554	3.169	0.230	0.894	1.978	0.99	0.204	0.727	1.706	0.681	1.804	3.891	0.326	1.048	2.398
Eastern GOM	1.00	0.530	1.572	3.832	5.716	6.946	10.698	1.547	2.808	5.735	1.00	0.728	1.748	4.154	5.863	7.341	11.786	1.771	3.054	6.252
0 - 200m	1.00	0.140	0.740	1.395	4.733	4.854	5.065	0.983	1.604	2.296	1.00	0.347	0.846	1.480	4.754	5.010	5.255	1.192	1.737	2.415
200 - 800m	1.00	0.027	0.061	0.152	0.132	0.165	0.241	0.050	0.090	0.194	1.00	0.027	0.063	0.158	0.136	0.169	0.261	0.052	0.094	0.204
800 - 1600m	1.00	0.050	0.061	0.070	0.207	0.282	0.385	0.087	0.111	0.139	1.00	0.054	0.063	0.073	0.218	0.293	0.399	0.092	0.116	0.143
1600 - 2400m	0.90	0.000	0.103	0.186	0.000	0.384	0.801	0.000	0.171	0.328	0.93	0.000	0.114	0.201	0.000	0.434	0.829	0.000	0.192	0.348
> 2400m	0.98	0.047	0.506	2.154	0.078	1.166	4.089	0.061	0.714	2.881	0.99	0.071	0.571	2.441	0.154	1.296	4.617	0.098	0.801	3.263
Straits of FL	0.65	0.000	0.013	0.037	0.000	0.002	0.005	0.000	0.013	0.037	0.72	0.000	0.014	0.037	0.000	0.002	0.006	0.000	0.015	0.038
0 - 200m	0.62	0.000	0.008	0.021	0.000	0.001	0.002	0.000	0.008	0.021	0.68	0.000	0.008	0.022	0.000	0.001	0.002	0.000	0.008	0.022
200 - 800m	0.65	0.000	0.006	0.015	0.000	0.001	0.008	0.000	0.006	0.017	0.72	0.000	0.006	0.016	0.000	0.001	0.008	0.000	0.006	0.017
> 800m	0.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Atlantic Region	1.00	0.216	0.530	1.067	2.325	6.649	12.546	0.630	1.713	3.300	1.00	0.280	0.602	1.178	3.059	7.310	13.280	0.824	1.903	3.541
0 - 200m	0.99	0.160	0.386	0.516	1.924	6.021	12.796	0.503	1.458	2.793	0.99	0.188	0.419	0.549	2.340	6.391	13.015	0.605	1.556	2.865
200 - 800m	0.25	0.000	0.076	0.462	0.000	0.339	2.038	0.000	0.137	0.825	0.34	0.000	0.091	0.462	0.000	0.465	2.830	0.000	0.174	0.965
> 800m	0.18	0.000	0.087	0.560	0.000	0.351	2.781	0.000	0.149	1.054	0.26	0.000	0.109	0.659	0.000	0.499	3.203	0.000	0.198	1.229
North Atlantic	1.00	0.066	0.161	0.269	0.754	2.135	4.148	0.200	0.541	1.007	1.00	0.089	0.182	0.314	0.966	2.343	4.349	0.260	0.599	1.088
0 - 200m	0.99	0.053	0.127	0.170	0.635	1.987	4.223	0.166	0.481	0.922	0.99	0.062	0.138	0.181	0.772	2.109	4.295	0.199	0.513	0.945
200 - 800m	0.25	0.000	0.016	0.103	0.000	0.076	0.449	0.000	0.030	0.183	0.34	0.000	0.020	0.118	0.000	0.112	0.747	0.000	0.040	0.251
> 800m	0.18	0.000	0.022	0.145	0.000	0.094	0.771	0.000	0.039	0.283	0.26	0.000	0.029	0.175	0.000	0.136	0.921	0.000	0.053	0.339
Mid-Atlantic	1.00	0.070	0.184	0.411	0.784	2.283	4.332	0.210	0.590	1.182	1.00	0.089	0.210	0.483	1.037	2.514	4.579	0.274	0.658	1.297
0 - 200m	0.99	0.055	0.131	0.176	0.654	2.047	4.351	0.171	0.496	0.950	0.99	0.064	0.142	0.187	0.796	2.173	4.425	0.206	0.529	0.974
200 - 800m	0.25	0.000	0.016	0.105	0.000	0.077	0.448	0.000	0.030	0.185	0.34	0.000	0.020	0.120	0.000	0.113	0.762	0.000	0.040	0.255
> 800m	0.18	0.000	0.046	0.291	0.000	0.177	1.278	0.000	0.078	0.519	0.26	0.000	0.057	0.322	0.000	0.244	1.444	0.000	0.100	0.579
South Atlantic	1.00	0.066	0.185	0.370	0.807	2.231	4.481	0.210	0.582	1.167	1.00	0.089	0.209	0.401	1.050	2.453	4.689	0.275	0.646	1.236
0 - 200m	0.99	0.053	0.127	0.170	0.635	1.987	4.223	0.166	0.481	0.922	0.99	0.062	0.138	0.181	0.772	2.109	4.295	0.199	0.513	0.945
200 - 800m	0.25	0.000	0.044	0.248	0.000	0.186	1.079	0.000	0.077	0.440	0.34	0.000	0.051	0.251	0.000	0.240	1.255	0.000	0.094	0.475
> 800m	0.18	0.000	0.018	0.133	0.000	0.080	0.577	0.000	0.033	0.235	0.26	0.000	0.024	0.154	0.000	0.119	0.790	0.000	0.045	0.294

Summary Table 7. $30/bbl scenario UERR listing by area and water depth

Table 7. $30/bbl scenario Undiscovered Economically Recoverable Resources (UERR) of the GOM and Atlantic Continental Margin by planning area and water depth ranges.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding.

Water Depth Range meters (m)	Risked Undiscovered Economically Recoverable Resources Full-Cycle @ $30.00/bbl and $3.52/Mcf										Risked Undiscovered Economically Recoverable Resources Half-Cycle @ $30.00/bbl and $3.52/Mcf without exploratoy costs									
	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	1.00	25.822	29.331	34.807	141.839	153.598	168.857	51.061	56.661	64.853	1.00	26.680	30.236	36.210	146.738	158.999	173.879	52.790	58.527	67.150
0 - 200m	1.00	3.621	4.133	4.569	49.972	53.575	59.344	12.513	13.666	15.129	1.00	3.732	4.218	4.636	51.087	54.793	60.751	12.822	13.967	15.446
200 - 800m	1.00	3.382	4.082	4.858	18.203	21.494	24.495	6.621	7.907	9.216	1.00	3.522	4.156	4.889	19.214	22.297	25.160	6.941	8.124	9.366
> 800 m	1.00	17.745	21.205	27.282	67.978	78.829	93.263	29.841	35.231	43.877	1.00	18.732	21.928	28.047	70.280	82.091	97.687	31.237	36.535	45.429
GOM Region	1.00	24.749	28.134	34.749	129.389	140.731	151.929	47.772	53.175	61.783	1.00	25.171	28.811	35.643	133.790	143.986	155.311	48.977	54.431	63.278
0 - 200m	1.00	3.102	3.615	4.266	44.936	46.534	48.176	11.098	11.896	12.838	1.00	3.217	3.689	4.306	45.648	47.641	49.742	11.339	12.166	13.157
200 - 800m	1.00	3.070	3.686	4.319	15.859	18.295	20.614	5.892	6.941	7.987	1.00	3.090	3.703	4.325	16.166	18.440	20.790	5.967	6.984	8.024
800 - 1600m	1.00	8.317	9.229	10.017	34.304	40.094	50.645	14.421	16.363	19.028	1.00	8.415	9.361	10.250	35.163	40.701	50.876	14.671	16.603	19.303
1600 - 2400m	1.00	6.553	8.121	10.174	21.442	27.108	35.640	10.368	12.944	16.516	1.00	6.878	8.389	10.402	22.357	28.175	36.706	10.857	13.403	16.934
> 2400m	1.00	1.985	3.618	8.849	5.823	9.140	16.502	3.021	5.244	11.785	1.00	2.076	3.735	9.039	6.097	9.483	16.971	3.160	5.423	12.058
Western GOM	1.00	9.019	9.872	10.886	49.986	54.104	59.227	17.913	19.499	21.424	1.00	9.117	10.065	11.065	51.686	55.584	60.833	18.314	19.955	21.890
0 - 200m	1.00	0.623	0.755	0.895	14.788	16.125	17.784	3.254	3.625	4.060	1.00	0.647	0.759	0.898	15.201	16.756	18.619	3.352	3.741	4.211
200 - 800m	1.00	1.428	1.710	1.999	7.467	8.592	9.705	2.757	3.239	3.726	1.00	1.436	1.716	2.003	7.533	8.652	9.774	2.776	3.255	3.742
800 - 1600m	1.00	3.417	3.796	4.120	14.152	16.509	20.856	5.935	6.734	7.831	1.00	3.464	3.851	4.213	14.466	16.760	20.967	6.038	6.833	7.944
1600 - 2400m	1.00	2.360	2.849	3.486	7.862	10.154	12.716	3.759	4.656	5.749	1.00	2.427	2.945	3.605	8.474	10.548	13.043	3.935	4.822	5.926
> 2400m	1.00	0.607	0.801	1.129	2.181	2.738	3.673	0.995	1.288	1.782	1.00	0.643	0.828	1.156	2.252	2.841	3.761	1.043	1.333	1.825
Central GOM	1.00	13.369	15.369	18.148	71.337	77.467	85.500	26.062	29.154	33.362	1.00	13.648	15.719	18.653	73.260	79.091	86.373	26.683	29.792	34.022
0 - 200m	1.00	1.371	1.548	1.726	23.706	25.010	26.267	5.589	5.998	6.400	1.00	1.378	1.563	1.739	24.171	25.395	26.630	5.679	6.082	6.478
200 - 800m	1.00	1.565	1.880	2.193	8.221	9.446	10.717	3.028	3.560	4.100	1.00	1.581	1.887	2.196	8.251	9.513	10.781	3.049	3.579	4.114
800 - 1600m	1.00	4.833	5.362	5.858	19.977	23.226	28.873	8.387	9.495	10.996	1.00	4.939	5.437	5.917	20.168	23.573	29.317	8.528	9.632	11.134
1600 - 2400m	1.00	3.983	5.054	6.338	12.803	16.063	21.441	6.261	7.912	10.153	1.00	4.195	5.224	6.510	13.257	16.700	22.018	6.533	8.196	10.427
> 2400m	1.00	0.992	1.639	3.300	2.702	3.919	6.781	1.473	2.337	4.506	1.00	1.047	1.700	3.388	2.864	4.069	6.680	1.557	2.424	4.576
Eastern GOM	1.00	1.641	2.776	5.603	7.461	9.222	14.448	2.969	4.417	8.174	1.00	1.736	2.887	5.839	7.588	9.431	14.682	3.087	4.565	8.451
0 - 200m	1.00	0.873	1.301	1.916	5.082	5.438	5.685	1.777	2.269	2.927	1.00	0.894	1.353	1.985	5.204	5.498	5.721	1.820	2.331	3.003
200 - 800m	1.00	0.049	0.089	0.170	0.154	0.255	0.633	0.077	0.134	0.282	1.00	0.050	0.091	0.174	0.158	0.264	0.634	0.078	0.138	0.287
800 - 1600m	1.00	0.076	0.083	0.091	0.327	0.387	0.489	0.134	0.152	0.177	1.00	0.077	0.084	0.092	0.332	0.392	0.489	0.136	0.154	0.179
1600 - 2400m	1.00	0.166	0.215	0.293	0.685	0.884	1.225	0.288	0.372	0.511	1.00	0.174	0.221	0.299	0.707	0.914	1.263	0.300	0.384	0.523
> 2400m	1.00	0.276	1.115	4.138	0.842	2.385	7.069	0.426	1.540	5.396	1.00	0.288	1.145	4.217	0.889	2.457	7.328	0.447	1.582	5.520
Straits of FL	1.00	0.010	0.020	0.041	0.002	0.006	0.013	0.010	0.022	0.043	1.00	0.010	0.021	0.041	0.002	0.006	0.013	0.011	0.022	0.043
0 - 200m	1.00	0.005	0.011	0.023	<0.001	0.001	0.002	0.005	0.012	0.023	1.00	0.006	0.011	0.023	<0.001	0.001	0.002	0.006	0.012	0.024
200 - 800m	1.00	0.004	0.009	0.018	<0.001	0.005	0.024	0.004	0.010	0.022	1.00	0.004	0.009	0.018	<0.001	0.006	0.025	0.004	0.010	0.023
> 800m	0.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Atlantic Region	1.00	0.823	1.338	1.920	7.939	12.780	19.205	2.235	3.612	5.338	1.00	1.044	1.570	2.011	10.100	14.875	21.847	2.842	4.216	5.898
0 - 200m	1.00	0.355	0.523	0.612	3.881	7.066	13.622	1.045	1.780	3.036	1.00	0.376	0.531	0.621	3.952	7.199	13.749	1.079	1.812	3.068
200 - 800m	0.97	0.082	0.411	0.787	0.442	3.219	5.264	0.000	0.984	1.724	0.99	0.256	0.467	0.799	2.287	3.870	5.894	0.663	1.155	1.848
> 800m	0.98	0.041	0.422	0.957	0.386	2.568	5.787	0.109	0.879	1.987	1.00	0.065	0.581	1.074	0.605	3.851	6.718	0.173	1.266	2.270
North Atlantic	1.00	0.265	0.418	0.574	2.531	4.113	6.171	0.715	1.150	1.672	1.00	0.331	0.493	0.624	3.257	4.791	6.947	0.911	1.345	1.860
0 - 200m	1.00	0.117	0.173	0.202	1.281	2.332	4.495	0.345	0.587	1.002	1.00	0.124	0.175	0.205	1.304	2.376	4.537	0.356	0.598	1.012
200 - 800m	0.97	0.018	0.122	0.213	0.089	1.000	1.578	0.000	0.300	0.493	0.99	0.082	0.140	0.221	0.735	1.207	1.760	0.213	0.354	0.534
> 800m	0.98	0.014	0.128	0.282	0.127	0.805	1.793	0.036	0.272	0.601	1.00	0.022	0.180	0.315	0.199	1.223	2.136	0.058	0.398	0.695
Mid-Atlantic	1.00	0.275	0.467	0.720	2.672	4.394	6.580	0.750	1.248	1.890	1.00	0.359	0.547	0.762	3.412	5.115	7.354	0.966	1.457	2.070
0 - 200m	1.00	0.121	0.178	0.208	1.320	2.403	4.631	0.355	0.605	1.032	1.00	0.128	0.181	0.211	1.344	2.448	4.675	0.367	0.616	1.043
200 - 800m	0.97	0.018	0.126	0.213	0.089	1.033	1.653	0.000	0.309	0.507	0.99	0.085	0.144	0.224	0.760	1.246	1.831	0.220	0.366	0.549
> 800m	0.98	0.014	0.172	0.426	0.129	0.985	2.307	0.036	0.347	0.836	1.00	0.022	0.229	0.463	0.202	1.437	2.665	0.058	0.484	0.938
South Atlantic	1.00	0.272	0.454	0.672	2.705	4.273	6.569	0.753	1.214	1.841	1.00	0.355	0.530	0.724	3.316	4.969	7.262	0.945	1.414	2.016
0 - 200m	1.00	0.117	0.173	0.202	1.281	2.332	4.495	0.345	0.587	1.002	1.00	0.124	0.175	0.205	1.304	2.376	4.537	0.356	0.598	1.012
200 - 800m	0.97	0.040	0.164	0.361	0.246	1.186	2.162	0.000	0.374	0.746	0.99	0.091	0.183	0.386	0.758	1.416	2.296	0.226	0.435	0.794
> 800m	0.98	0.013	0.122	0.257	0.126	0.778	1.758	0.036	0.260	0.570	1.00	0.022	0.172	0.292	0.195	1.192	2.077	0.057	0.384	0.662

Glossary

Selected terms relevant to this report are defined here. They are intended to be generally explanatory rather than strictly technical.

Abyssal plain: A flat region of the ocean floor, usually at the base of the continental rise, where the slope is less than 1:1000. It is formed by the deposition of sediments that obscure the preexisting topography.

Aggradational: See "*depositional style.*"

Allochthonous: 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*."

API Gravity: An arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the fluid.

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

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

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

Barrel: A volumetric unit of measure for crude oil, equivalent to 42 U.S. gallons.

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.

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

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.

Biozone: Biostratigraphic unit including all strata deposited during the existence of a particular kind of fossil.

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.

Lower slope: That portion of the continental slope that is under 1,642-6,562 ft of water.

Upper slope: That portion of the continental slope that is under 656-1,641 ft of water.

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 (F_{95}), a high estimate having a 5-percent probability (1 in 20 chance) of at least that amount (F_5), 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 determine more accurately 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 used 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 deepwater ecozones and 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 semisubmersible that 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.

Floating Production, Storage, and Offloading System (FPSO): An offshore facility consisting of a large tanker type vessel moored to the seafloor. An FPSO is designed to process and stow production from nearby subsea wells and to periodically transfer the stored oil to a smaller shuttle tanker. The shuttle tanker then transports the oil to an onshore facility for further processing. An FPSO may be suited for marginally economic fields located in remote deepwater areas where a pipeline infrastructure does not exist. FPSO's are projected to be economically feasible for installation in water depths up to 10,000 feet. Currently, there are no FPSO's approved for use in the Gulf of Mexico.

Mini-tension leg platform (Mini-TLP): An offshore facility consisting of a floating tension leg platform of relatively low cost developed for production of smaller deepwater reserves that 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. Mini-tension leg 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 seafloor. SPAR's are used at present 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 seafloor 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 7,000 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 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 representing the ratio of the size of a field of a specific age as estimated in a subsequent year.

Cumulative growth factor (CGF): The function representing 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. As used in this report the term is synonymous with *petroleum*.

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. In the GRASP model μ is one of the two standard descriptive parameters defining a lognormal distribution; it represents the mean of the log-transformed data.

Mini-tension leg platform: See "development systems."

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 pseudorandom processes.

Mudstone: A detrital sedimentary rock composed of clay-sized particles.

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.

Petroleum: A collective term for

oil, gas, and condensate.

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 hypothesized by the analysts on the basis of 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.

Immature play: For this report, an established play in which UCRR are greater than 75 percent of the total endowment, many of the largest pools are forecast as yet to be discovered, and the average undiscovered pool size is greater than or equal to the average discovered pool size.

Mature play: For this report, an established play in which UCRR are between 10 and 75 percent of the total endowment, most of the largest pools are forecast to have been discovered, and the average undiscovered pool size is less than the average discovered pool size.

Super-mature play: For this report, an established play in which UCRR are less than 10 percent of the total endowment, all of the large pools are forecast to have been discovered, and the average undiscovered pool size is much less than the average discovered pool size.

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 (are) 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 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 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.

Remaining total reserves: Total reserves minus cumulative production. May be loosely referred to as "reserves still in the ground."

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: Quantities of hydrocarbon reserves that are assessed on the basis of 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.

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

Sandstone: A clastic rock composed of particles that range in diameter from 1/16 millimeter to 2 millimeters in diameter.

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, on the basis of a clearly designated stratigraphic interval.

Shale: A sedimentary rock composed of detrital sediment particles less than 0.004 millimeters in diameter.

Shelf: See "continental shelf."

Shelf edge: The demarcation between the continental shelf and the continental slope.

Slope: See "continental slope."

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 worldwide 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. In the GRASP model σ^2 is one of the two standard descriptive parameters defining a lognormal distribution; it represents the variance of the log-transformed data.

Abbreviations

Units

B billion
Bbbl billion barrels
bbl barrel(s)
Bbo billion barrels of oil
BBOE billion barrels of oil equivalent
Bcfg billion cubic feet of gas
bcpd barrels of condensate per day
BOE barrels of oil equivalent
bopd barrels of oil per day
cf cubic feet
ft feet
m meter(s)
Mbo thousand barrels of oil
MBOE thousand barrels of oil equivalent
Mcf thousand cubic feet
mi mile(s)
M thousand
MM million
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
MMcfgd million cubic feet of gas per day
scf standard cubic feet
stb stock tank barrels
T trillion
Tcf trillion cubic feet
Tcfg trillion cubic feet of gas

Chronozones

E Eocene
L Paleocene
LK Lower Cretaceous
LM1 Lower Lower Miocene
LM2 Middle Lower Miocene
LM4 Upper Lower Miocene
LP Lower Pliocene
LPL Lower Pleistocene
LJ Lower Jurassic
MM4 Lower Middle Miocene
MM7 Middle Middle Miocene
MM9 Upper Middle Miocene
MPL Middle Pleistocene
MJ Middle Jurassic
O Oligocene
UK Upper Cretaceous
UM1 Lower Upper Miocene
UM3 Upper Upper Miocene
UP Upper Pliocene
UPL Upper Pleistocene
UTR Upper Triassic
UJ Upper Jurassic

Depositional Style/ Facies

A Aggradational
AP Aggradational/Progradational
B Biologic (Carbonate)
BC Biologic/Clastic
C Clastic
F Fan
P Progradational
R Retrogradational
S Structural
X Fold Belt

Offshore Areas

AC Alaminos Canyon
AP Apalachicola
AT Atwater Valley
BA Brazos
BM Bay Marchand
BS Breton Sound
CA Chandeleur
CC Corpus Christi
CH Charlotte Harbor
CP Coon Point
DC DeSoto Canyon
DD Destin Dome
DT Dry Tortugas
EB East Breaks
EC East Cameron
EI Eugene Island
EL The Elbow
EW Ewing Bank
FM Florida Middle Ground
GA Galveston
GB Garden Banks
GC Green Canyon
GI Grand Isle
GV Gainesville
HE Henderson
HH Howell Hook
HI High Island
KC Keathley Canyon
KW Key West
LL Lloyd
LP Lighthouse Point
LU Lund
328
MA Miami
MC Mississippi Canyon
MI Matagorda Island
MO Mobile
MP Main Pass
MU Mustang Island
PB St. Petersburg
PE Pensacola
PI Port Isabel
PL South Pelto
PN North Padre Island
PR Pulley Ridge
PS South Padre Island
RK Rankin
SA Sabine Pass, Louisiana
SM South Marsh Island
SP South Pass
SS Ship Shoal
ST South Timbalier
SX Sabine Pass, Texas
TP Tarpon Springs
TS Tiger Shoal
VK Viosca Knoll
VN Vernon
VR Vermilion
WC West Cameron
WD West Delta
WR Walker Ridge

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
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
PVT	pressure, volume, and temperature
RECG	recoverable gas
RECO	recoverable oil
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

Table Column Header Definitions

AGE = Paleo Age
API = Oil API gravity (API units) - weighted average of all reservoirs in pool/field
ASSESSED = Assessed Yes (Y) or No (N)
BGI = Initial gas formation volume factor (scf/cf)
BLAT = Latitude of pool or field
BLON = Longitude of pool or field
BOI = Initial oil formation volume factor (bbl/stb)
CHRONOZONE = Chronozone name
CUMBOE = Cumulative BOE produced (bbl)
CUMGAS = Cumulative gas produced (mcf)
CUMOIL = Cumulative oil produced (bbl)
DRIVE = Dominant reservoir drive type according to bulk volume
ECO = Eco zone
EIAID = Energy Information Administration identification number
FCLASS = MMS field classification
FDDATE = Discovery date (field)
FDDATEH = Discovery date of last reservoir discovered
FDYEAR = Discovery year (field)
FDYEARH = Discovery year of last reservoir discovered
FSTAT = Field status (active, expired)
FSTRU = See field structure and trap codes following these definitions
FTRAP1 = See field structure and trap codes following these definitions
FTRAP2 = See field structure and trap codes following these definitions
GAREA = Total gas acreage (acres)
GIP = Technically recoverable gas in place (mcf) based on available data
GOR = Gas-oil ratio (mcf/bbl)
GR_TAREA = TAREA multiplied by growth factor
GR_TVOL = TVOL multiplied by growth factor
GRECG = Gas reservoir recoverable gas (mcf)
GRECO = Gas reservoir recoverable oil (bbl)
GRF = Gas recovery factor (decimal)
GROWTH_F = Growth factor
GRP = Produced GOR for gas reservoirs (mcf/stb)
GTHK = Average net gas thickness (ft)
GVOL = Gas volume (acre-feet)
MMS_FIELD = MMS Field Name
NCNT = Nonassociated reservoir count
OAREA = Total oil acreage (acres)
OIP = Technically recoverable oil in place (bbl) based on available data
ORECG = Oil reservoir recoverable gas (mcf)
ORECO = Oil reservoir recoverable oil (bbl)
ORF = Oil recovery factor (decimal)
ORP = Produced GOR for oil reservoirs (mcf/stb)
OTHK = Average net oil thickness (ft)
OVOL = Oil volume (acre-feet)
P_U = Proved (P), Unproved (U), or Non-assessed (N)
PDDATE = Discovery date of first reservoir discovered
PDDATEH = Discovery date of last reservoir discovered
PDYEAR = Discovery year of first reservoir discovered
PDYEARH = Discovery year of last reservoir discovered
PI = Initial pressure (psi) - weighted average of all reservoirs in pool/field
PLAREA = Offshore planning area
PLAY_NAME = Play name
PLAY_NUM = Play number
PLAY_TYPE = Type of play
POOL_NAME = Field Name
POROSITY = Average Porosity (percent)
PROP = Proportion oil (decimal)
RECBOE = Total original recoverable BOE (stb)
RECG_AF = Recoverable gas per acre-foot (mcf/acre-foot)
RECGAS = Total original recoverable gas (mcf)
RECO_AF = Recoverable oil per acre-foot (bbl/acre-foot)
RECOIL = Total original recoverable oil (stb)
REMBOE = Remaining proved BOE (stb)
REMGAS = Remaining gas (mcf)
REMOIL = Remaining oil (stb)
RESTYP = Dominant reservoir type
RSI = Initial solution gas-oil ratio (scf/stb)
SCNT = Saturated reservoir count
SDCOUNT = Sand count
SDPG = Sand pressure gradient (psi/ft)
SDTG = Sand temperature gradient (f/100ft)
SPGR = Gas specific gravity (decimal at 60 degrees F and 15.025 psia) - weighted average of all reservoirs in pool/field
SS = Subsea depth (feet) - weighted average of all reservoirs in pool/field
SW = Water saturation (decimal) - weighted average of all reservoirs in pool/field
TAREA = Total acreage (acres)
THK = Average sand thickness (ft)
TI = Initial temperature (degrees F) - weighted average of all reservoirs in pool/field
TOT_BOE = RECBOE multiplied by growth factor
TOT_GAS = RECGAS multiplied by growth factor

TOT_OIL = RECOIL multiplied by growth factor
TRCNT = Total reservoir count
TREND - Trend
TVOL = Total volume (acre-feet) - weighted average of all reservoirs in pool/field
TYPE = (O)Oil, (G)Gas or (B)Both
UCNT = Undersaturated reservoir count
WDEP = Water depth (feet) - weighted average of all reservoirs in pool/field
WELLAPI = Discovery well API
YIELD = Yield (stb/mmcf) - gas reservoirs' recoverable condensate divided by recoverable gas, weighted average of all gas reservoirs in pool/field

Field Structure and Trap Codes

FSTRU = The overall structural style of a field as designated by the following single digit code.

A = Anticline
B = Fault
C = Shallow Salt diapir: 0-4,000 ft subsea
D = Intermediate salt diapir: 4,000-10,000 ft subsea
E = Deep salt dome: >10,000 ft subsea
F = Salt ridge
G = Shale diapir
H = Unconformity
I = Stratigraphic
J = Reef
K = Rollover into growth fault
L = Rotational slump block
M = Non diapiric Louann Salt
N = Thrust Fault
U = Unknown/Other

FTRAP1 = The primary or major trap component of a reservoir as designated by the single digit code, below.

FTRAP2 = The secondary or minor trap component of reservoir as designated by the following single digit code (FTRAP1 and FTRAP2 use the same letter code).

A = Anticline
B = Faulted anticline
C = Rollover anticline into growth fault
D = Normal fault
E = Reverse fault
F = Turtle structure
G = Flank traps associated with salt or shale diapirs
H = Sediments overlying diapirs
I = Caprock
J = Updip facies change
K = Updip pinch out
L = Permeability trap
M = Onlap sands
N = Angular unconformity
O = Barrier Reef
P = Patch reef
Q = Subsalt trap
U = Unknown/Other

Data Files Information

Tabular Data

Tabular data for this report can be found in the Data Files directory on the CD. Tabular data files are formatted in Excel 97 (.xls) and tab delimited ASCII (.txt). For those without any spreadsheet software, we have included the Excel 97 Viewer in the Software directory on the CD (Software/Microsoft Excel Viewer/xlViewer.exe). This free software from Microsoft will enable the user to view the .xls files, but not to edit, query, or sort them.

Eight tabular data files are included on the CD:

GrownReserves = reserves growth database by pool as of 1/1/99 (.xls and .txt formats),

Summary Sheets 2000 Resource Assessment.xls = endowment and reserves summary by play and summary by water depth,

99naTBLS.xls = pool characteristics, economic results, and miscellaneous tables,

fldna99 = field level data as of 1/1/99 (.xls and .txt formats),

pool99 = pool level data as of 1/1/99 for assessed pools (.xls and .txt formats),

Reserves_by_Play.xls = tables of individual reserves and resources by play,

cumgrpoolplot.xls = plots of cumulative grown reserves by discovery order,

Field-PoolData.xls = discovered and undiscovered field and pool BOE total endowment (mean, 95th, and 5th percentile).

Separate pool and field data files include the same source data that have been variously grouped, summed, and averaged for the convenience of the user. ***All pools are weighted by bulk volume of individual reservoirs.*** This averaging emphasizes the attribute values of reservoirs having the most original oil or gas in place. If the reservoir contains both oil and gas, then gas is converted to barrels of oil.

PowerPoint Graphics

Price-supply curves and exploration history graphs are also provided in the Data Files directory as Microsoft PowerPoint presentations (.ppt). For those without PowerPoint software, we have included a PowerPoint viewer in the Software directory (Software/Microsoft PowerPoint Viewer/ppview97.exe). This free software from Microsoft will enable the user to view the graphs, but not to manipulate or extract data from them.

Three PowerPoint files are included on the CD:

Gulf of Mexico Price Supply Plots.ppt = price-supply plots for the GOM that appear in the Economic Results section of the report,

Atlantic Price Supply Plots.ppt = price-supply plots for the Atlantic Region that appear in the Economic Results section of the report,

Pool ExpHistpptPlots.ppt = exploration history plots that appear in established play write-ups.

GIS Data

Map outlines of plays, cultural map data, and field and pool polygons are provided as geographic system (GIS) shapefiles (.shp). Field and pool shapefiles are linked to their respective data tables. The shapefiles are located in the GIS Data directory and are formatted for use in ArcView 3.2a. For those without ArcView software, we have included ArcExplorer, a GIS data viewer. This free software from ESRI is located in the Software directory (Software/ESRI ArcExplorer/ae2setup.exe).

Three folders are located in the GIS Data directory. The first, General Data, contains cultural map shapefiles such as OCS block boundaries, coastlines, and shipping fairways. Other shapefiles include contour lines at intervals used in the report's play and economic area maps.

The second folder, Play Outlines, contains the play boundary shapefiles that were used in the report's play maps. Each play boundary encloses the prospective area for a play, and contains "hydrocarbon limit" polygons. Hydrocarbon limits are those areas within a play that have discovered resources.

The third folder, Field and Pool Data, contains outlines (polygons) for pools in each play and field outlines that are linked to the **pool99** and **fldna99** tabular data files. A "pool" is a discovered or undiscovered hydrocarbon accumulation, typically within a single stratigraphic interval. Because both the pool and field polygons are linked to their respective data tables, tabular data can be displayed on screen, and both the tabular data and accompanying graphic data (polygons) can be queried. Attribute definitions are the same as those presented in the "Table Column Header Definitions" on page 631.

Pool polygons were aggregated to make the field polygons. A field may contain more than one pool and may consist of more than one polygon. When graphically querying a field consisting of several separate polygons, each polygon will yield the same data for the field; therefore, it is not necessary to sum data from each polygon.

All GIS data are presented here in latitude and longitude decimal degrees, NAD 27. It is inappropriate to use this projection of data for volume or area analysis. Volumetric measurements of pools and fields are presented in the tabular data files. To use the GIS files for accurate measurement, the graphics files would first need to be converted to a true cartographic projection. Note that map data have certain tolerances for accuracy (scale, degree of generalization) or other specific limitations. Play boundaries are drawn on the basis of well data available as of January 1, 1999.

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Who We Are

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 MMS 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 Minerals Revenue 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.

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Minerals Management Service
Gulf of Mexico OCS Region
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1201 Elmwood Park Blvd.
New Orleans, LA 70123-2394
(504) 736-2519 or 1-800-200-GULF
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