GULF OF AMERICA, OUTER CONTINENTAL SHELF

2025 ESTIMATED OIL AND GAS RESERVES REPORT

BOEM
BUREAU OF OCEAN ENERGY MANAGEMENT

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UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF OCEAN ENERGY MANAGEMENT

GULF OF AMERICA REGION

NEW ORLEANS, LOUISIANA

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ON COVER - The Thunder Horse field, located in Mississippi Canyon, was discovered in 1999. Production operations, led by BP Exploration & Production Inc. (BP), commenced in June 2008.

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ACRONYMS

API	American Petroleum Institute
bbl	Barrel(s)
Bbbl	Billion barrels
BBO	Billion barrels of oil
BBOE	Billion barrels of oil equivalent
Bcf	Billion cubic feet
BOE	Barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management
CDF	Cumulative Distribution Function
CGA	Central Gulf of America
e.g.	For example
EGA	Eastern Gulf of America
EOGR	Estimated Oil and Gas Reserves
GOA	Gulf of America
GOAR	Gulf of America Region
GOR	Gas-to-Oil Ratio
MBOE	Thousand Barrels of Oil Equivalent
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MMbbl	Million barrels
MMBOE	Million barrels of oil equivalent
MMcf	Million cubic feet
MS	Mail stop
OCS	Outer Continental Shelf
P0	Corresponds to the minimum possible reserves volume, reflecting the most conservative estimate.
P10	A low-case estimate. There is a 90% probability that the actual quantity recovered will exceed this reserves volume. Represents a conservative scenario.

P50	The best estimate or median case. There is a 50% probability that the actual quantity recovered will be greater than or less than this reserves' volume.
P90	A high-case estimate. There is a 10% probability that the actual quantity recovered will exceed this reserves' volume. Represents an optimistic scenario.
P100	Corresponds to the maximum possible reserves volume, reflecting the most optimistic estimate.
PRMS	Petroleum Resources Management System
psia	Pounds per square inch absolute
RE	Resource Evaluation
scf	Standard cubic feet
SPE	Society of Petroleum Engineers
stb	Stock tank barrel
Tcf	Trillion cubic feet
USGS	United States Geological Survey
WGA	Western Gulf of America

ABSTRACT

This publication presents the Bureau of Ocean Energy Management's (BOEM) probabilistic estimates of oil and gas reserves in the Gulf of America (GOA) Outer Continental Shelf (OCS). As of December 31, 2023, the mean Original Reserves are estimated at 30.43 billion barrels of oil (BBO), 201.17 trillion cubic feet (Tcf) of gas, or 66.22 billion barrels of oil equivalent (BBOE) from 1,336 fields, including 912 fields that have produced and expired. Fields are defined as areas containing single or multiple reservoirs associated with the same geological structure and/or stratigraphic trapping condition. Original Reserves consist of the total cumulative production and remaining reserves. Cumulative production accounts for 24.66 BBO, 194.02 Tcf of gas, or 59.18 BBOE. Additionally, total mean Contingent Resources on the GOA slope are estimated to be 2.49 BBO and 3.88 Tcf of gas, or 3.19 BBOE.

Mean remaining reserves are estimated at 5.77 BBO, 7.15 Tcf of gas, or 7.04 BBOE. These remaining reserves are recoverable from 424 active fields. Mean reserves for the 2025 Estimated Oil and Gas Reserves (EOGR) Report are derived starting at the reservoir level. Reservoir level estimates account for the full range of uncertainty from P0 to P100. Once finalized, reservoir estimates are aggregated to the field level to obtain mean reserve estimates for each field. Mean reserves for each field are then summed to get Original Reserves (production + reserves) estimates. BOEM then subtracts produced volumes to calculate remaining reserves. Reserves must be discovered, recoverable, and commercially viable.

Estimates of reserves for this report represent the collaborative efforts of engineers, geoscientists, paleontologists, petrophysicists, and other personnel of the BOEM GOA Region (GOAR), Office of Resource Evaluation, in New Orleans, Louisiana. Reserves estimates are derived for individual reservoirs from geologic and engineering calculations using a probabilistic methodology. For any field spanning state and federal waters, reserves are estimated for the federal portion only.

1.0 INTRODUCTION

This report supersedes the "Estimated Oil and Gas Reserves Report, Gulf of America OCS Region, December 31, 2019 (Burgess et al., 2021)." It presents estimated Original Reserves, cumulative production, remaining reserves, as of December 31, 2023. The 2025 EOGR marks the first inclusion of slope Contingent Resources in the reporting framework.

As of December 31, 2023, the 1,336 oil and gas fields in the federally regulated portion of the GOA OCS contained a mean Original Reserves estimate of 30.43 BBO, 201.17 Tcf of gas, or 66.22 BBOE. Cumulative production from the fields accounts for 24.66 BBO, 194.02 Tcf of gas, or 59.18 BBOE. Remaining reserves are estimated to be 5.77 BBO and 7.15 Tcf of gas, or 7.04 BBOE for the 424 active fields. Oil remaining reserves have increased 24.1 percent, and the gas reserves have increased 17.2 percent since the 2019 report. These increases are the result of new fields added and field revisions from January 1, 2020, through December 31, 2023. Figure 1 outlines GOA cumulative production along with BOEM remaining reserves estimates.

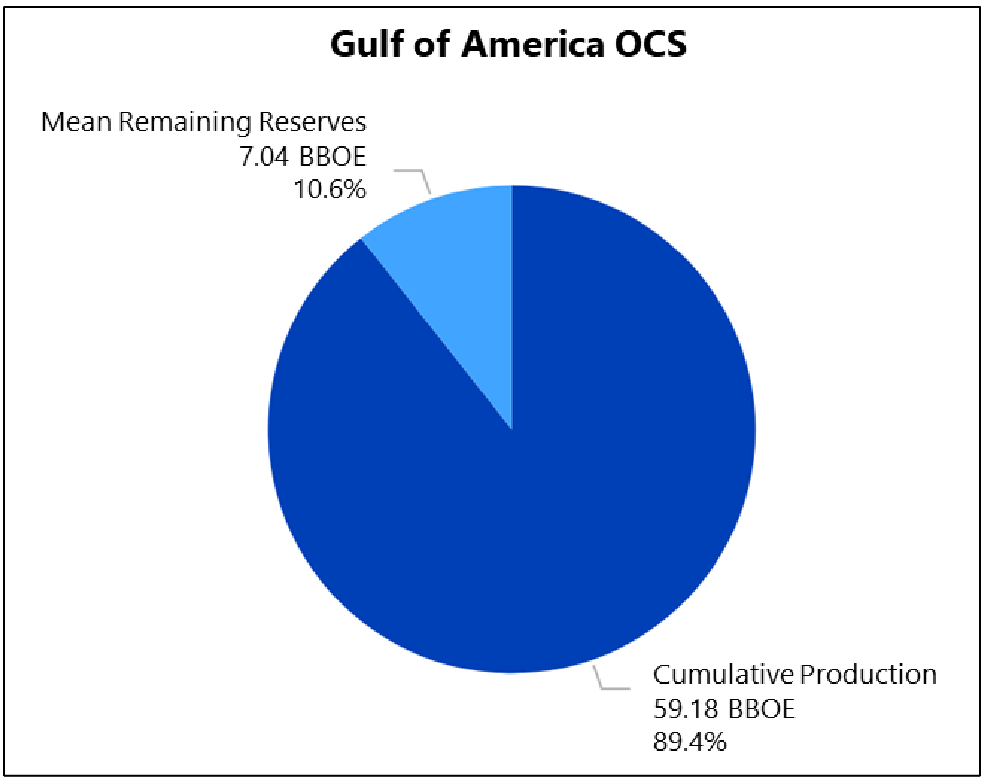

Figure 1. GOA Cumulative Production and BOEM Mean Remaining Reserves Estimates

2.0 BACKGROUND

The Reserves Inventory component of the Resource Evaluation (RE) Program incorporates new producible leases into fields and develops independent estimates of recoverable amounts of oil and gas contained within discovered fields. The RE Program also develops independent estimates of natural gas and oil in previously discovered OCS fields by conducting field reserve studies and reviews of fields, sands, and reservoirs. The Program periodically revises the estimates of natural gas and oil volumes to reflect new discoveries, development, and annual production. RE publishes an Estimated Oil and Gas Reserves Report based on field studies completed at the reservoir and sand levels. All the reservoir level data have been linked to the sand, pool, play, chronozone, and series level to support the Offshore Atlas Project. Current Atlas data associated with all Estimated Oil and Gas Reserves Reports are available at Atlas of Gulf of America Gas and Oil Sands Data. BOEM publishes the National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf every 5 years. This report summarizes the results of the BOEM assessment of the undiscovered oil and gas resources for the U.S. OCS. For more information visit BOEM's web site at https://www.boem.gov/oil-gas-energy/resource-evaluation/undiscovered-resources.

3.0 CLASSIFICATION OF RESOURCES AND RESERVES

BOEM's Reserves Classification Framework allows for accurate and understandable reporting of oil and gas volumes (Figure 2). BOEM classifies accumulations based on specific definitions, which are presented in Appendix A. This classification system closely aligns with guidelines set forth by the Society of Petroleum Engineer's Petroleum Resources Management System (SPE-PRMS). BOEM has adjusted the terminology for some categories and sub-classes to better align with its program requirements.

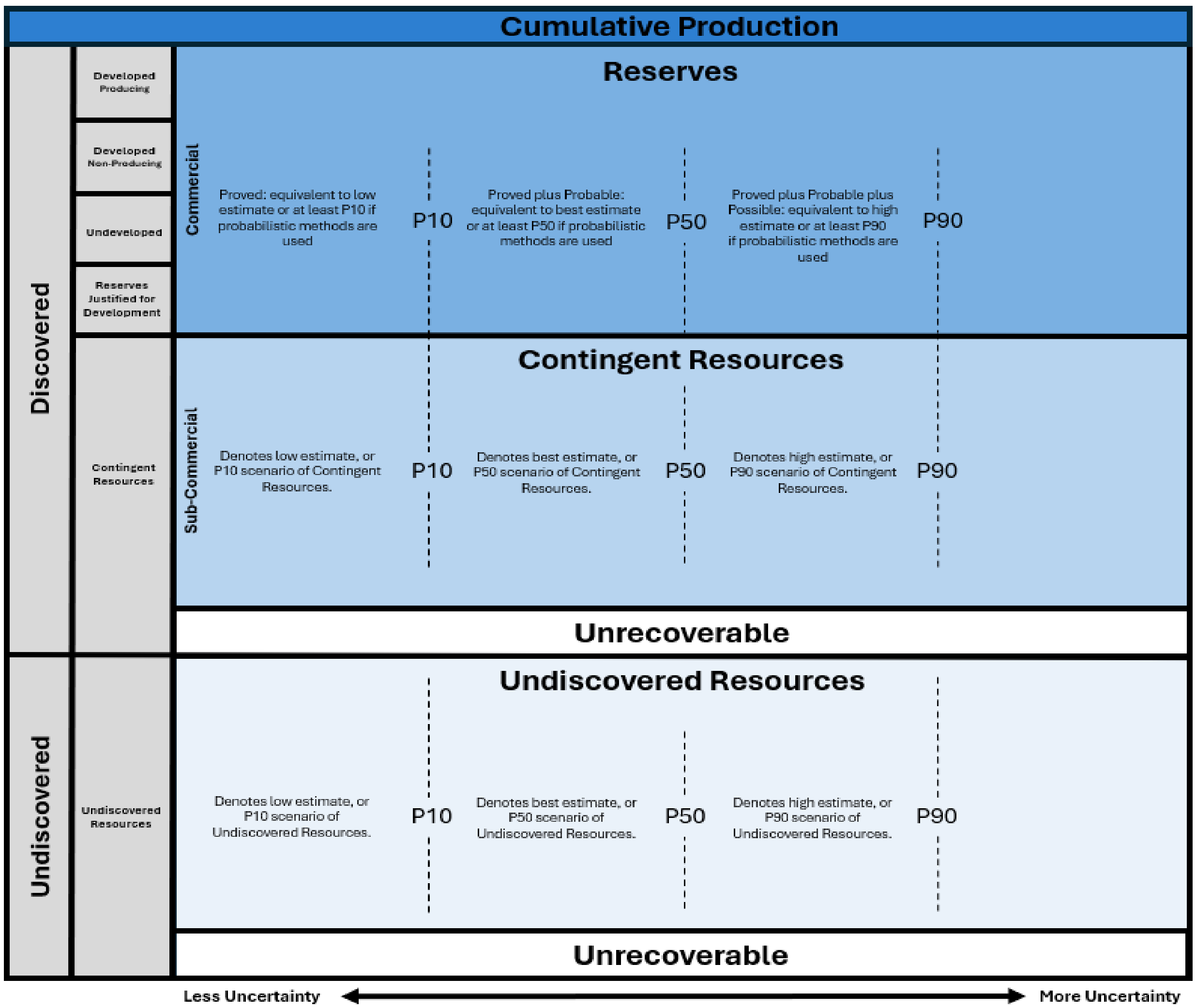

Figure 2: BOEM Reserves Classification Framework

The framework incorporates elements of uncertainty. One component of uncertainty depends on the amount of reliable geological and petroleum engineering data available at the time of the estimate and the interpretation of these data. The second component is the technical and economic factors that impact the likelihood of the commercial development of a project. Oil and natural gas deposits believed to exist based on play-based geologic knowledge and theory but have not yet been discovered are categorized as Undiscovered Resources. These resources are located outside of known fields or accumulations on the GOA OCS and are considered technically and economically recoverable. Undiscovered Resource estimates are not presented in this report, however they can be found in the report titled "2021 Assessment of Technically and Economically Recoverable Oil and Natural Gas Resources of the Gulf of Mexico Outer Continental Shelf (OCS Report BOEM 2021-082)." Upon initial discovery, an identified hydrocarbon accumulation is classified as a Contingent Resource. In this category, reservoir boundaries and resource estimates are determined using geophysical mapping along with rock and fluid data from both the target reservoir and analogous reservoirs of similar age and depositional environment. Once a development project is identified, sanctioned, and approved, Contingent Resources may be moved into the Reserves category. In alignment with SPE-PRMS, BOEM defines Reserves as those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given evaluation date) based on the development project(s) applied. At the time a lessee makes a formal commitment to develop and produce the accumulation, it is classified as Reserves Justified for Development. During the period when infrastructure is being constructed and installed, the accumulation is classified as Undeveloped Reserves. After all necessary production equipment is in place and production of the accumulation has begun, the status becomes Developed Producing Reserves.

As a field is depleted and/or abandoned, the Original Reserves of productive reservoirs are assigned a value equal to the amount produced and any unrecovered reserve volumes may be converted back to a Contingent Resource. Currently, there are 912 expired and depleted fields.

4.0 METHODS USED FOR ESTIMATING RESERVES

Methods for estimating reserves can be classified into three categories: analog, volumetric, and performance. Reserve estimates presented in this report primarily rely on volumetric and performance methodologies. Volumetric reservoir analysis employs a geological model derived from subsurface data interpretation and petrophysical well log analysis to define the vertical and lateral boundaries of a hydrocarbon-bearing reservoir to calculate bulk volume. A total of 22 variables is considered in the reserves evaluation process. To estimate a range of recoverable reserves, a Monte Carlo simulation is performed using probability distributions for all applicable variables. These variables may include pressure, temperature, porosity, water saturation, depth to the top of the structure, datum depth, contact depth, API gravity, gas gravity, reservoir volume, recovery factor, and gas-oil ratio, among others. For each variable, a cumulative distribution function (CDF) is constructed, with the distribution type selected based on the shape, quality, and quantity of the available data.

Once calculated, individual reservoir reserve estimates are aggregated to the field level and reported at the P10, P50, P90, and mean statistical percentiles, reflecting different probabilities of recoverable reserves. Within BOEM, the P10 value represents a 90% probability that this reserve estimate will be achieved. Conversely, the P90 estimate has only 10% chance of being attained. Once aggregated to the field level, mean reserves for each field are summed to get Original Reserves estimates. BOEM then subtracts produced volumes to calculate remaining reserves. The total volume of oil and oil-equivalent gas is referred to as barrels of oil equivalent (BOE) and is reported in barrels at standard conditions.

Reserve estimates are formulated for reservoirs at various life cycle stages. Upon discovery, the uncertainty of the reserves estimate is high. As additional wells are drilled, the reservoir becomes better defined and characterized leading to a substantial reduction in volumetric uncertainty (Figure 3). Once a reservoir begins producing and a production trend is observed, decline curve analysis is utilized to forecast future reservoir performance.

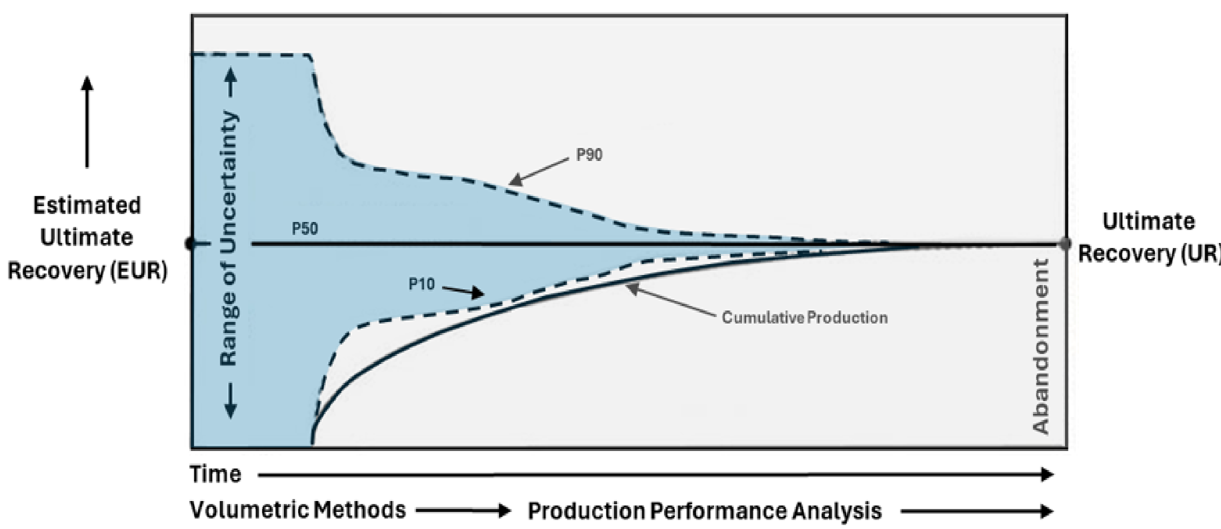

Figure 3. Change in Uncertainty & Examples of Assessment Methods Over a Reservoir's Life Cycle

As additional data becomes available, ongoing reservoir evaluation, including the analysis of production performance, allows for the refinement of reserves estimates. This continuous improvement ensures that the estimates remain up-to-date and accurate.

Production data is the metered volumes of raw liquids and gas reported to the Office of Natural Resources Revenue by Federal OCS unit and lease operators. Metered volumes from production platforms and/or leases are allocated to individual wells and reservoirs based on periodic well test gauges. These procedures introduce approximations in both production and remaining reserves volumes.

Oil and gas volume measurements and reserves are corrected to reference standard conditions of 60 °F and one atmosphere (14.73 pounds per square inch absolute [psia]). Prior to September 1998, gas was reported at 15.025 psia. BOEM has converted all historical gas production volumes to the 14.73 pressure base.

5.0 RESERVES DATA BY PLANNING AREA

The GOA OCS is divided into three administrative planning areas: the Western Gulf of America (WGA), Central Gulf of America (CGA), and Eastern Gulf of America (EGA). Figure 4 illustrates the geographic boundaries of these areas and includes reserve estimates for the WGA and CGA. The EGA is currently under a leasing moratorium and has no reserves. Each planning area is subdivided into protractions, which in turn are divided into numbered blocks. Fields are identified by the protraction area name and block number of the discovery – for example, East Cameron Block 271 (EC 271) Field. As the field is developed, the limits may expand into adjacent blocks and planning areas. These adjacent blocks are then identified as part of the original field and are added to that field. Reserve estimates in this report are presented as protraction area totals associated with each field name. For example, EC 271 Field reserve estimates are included in the East Cameron totals, although part of the field extends into the adjacent area of Vermilion. There are 4 exceptions: data from Tiger Shoal and Lighthouse Point are included in the South Marsh Island reserve totals; data from Coon Point is included in the Ship Shoal reserve totals; and data from Bay Marchand is included in the South Timbalier reserve totals.

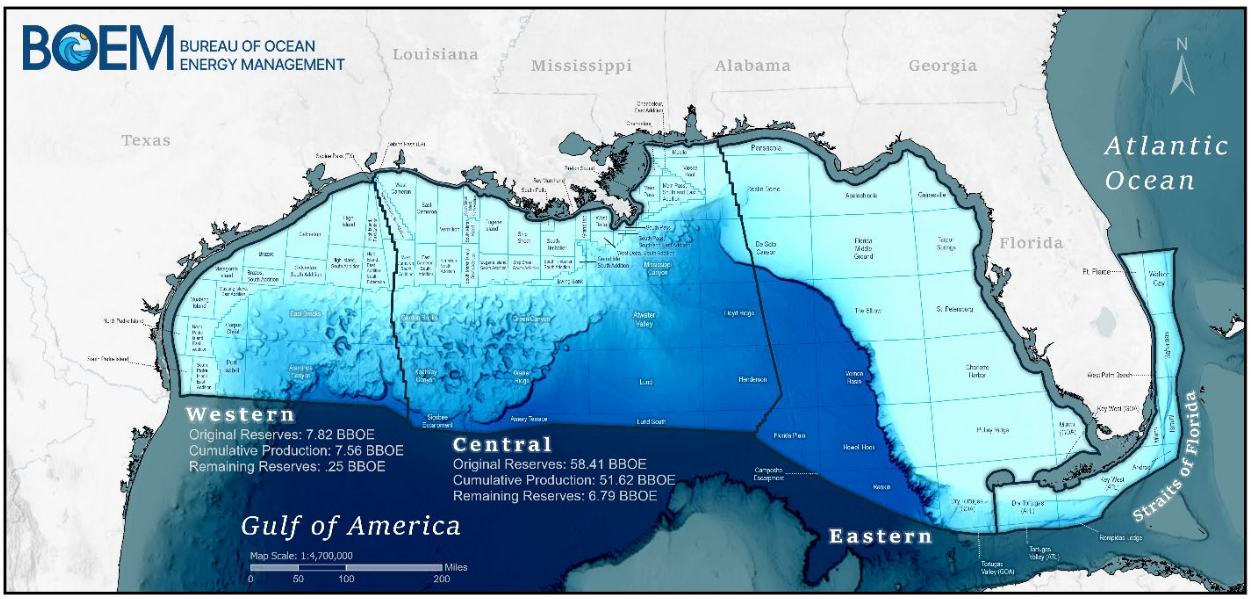

Figure 4. GOA U.S. Outer Continental Shelf

As of December 31, 2023, there were 424 active fields located in the federally regulated portion of the GOA. A list of active and expired fields is maintained and updated quarterly in the OCS Operations Field Directory. Additionally, there are 912 expired, depleted and/or abandoned fields that produced 26.9 percent of the total cumulative GOA oil and gas production. One hundred eighteen fields expired, relinquished, or terminated without production. Table 1 presents the mean estimated oil and gas reserves for each protraction area. Mean estimates for each field are summed to the protraction area level. Protraction area estimates are then aggregated to determine the mean reserves for each planning area, ultimately resulting in the total reserves for the GOA.

Table 1. Estimated Oil and Gas Reserves by Planning and Protraction Areas, December 31, 2023

	Number of Fields				Original Reserves			Cumulative Production			Remaining Reserves		
	Active prod	Active nonprod	Expired depleted	Expired nonprod	Oil (MMbbl)	Gas (Bcf)	BOE (MMBOE)	Oil (MMbbl)	Gas (Bcf)	BOE (MMBOE)	Oil (MMbbl)	Gas (Bcf)	BOE (MMBOE)
Western Planning Area													
Alaminos Canyon	4	0	1	3	571.5	841.4	721.3	407.0	645.0	521.8	164.6	196.4	199.5
Brazos	3	0	35	3	10.3	3,775.9	682.2	10.3	3,755.6	678.5	0.0	20.3	3.7
East Breaks	9	0	12	3	281.9	2,225.3	677.9	272.1	2,181.6	660.3	9.8	43.7	17.6
Galveston	2	0	48	2	74.0	2,256.0	475.4	69.3	2,228.9	466.0	4.7	27.0	9.5
Garden Banks	1	0	6	2	37.7	330.0	96.5	37.6	328.9	96.1	0.1	1.1	0.3
High Island and Sabine Pass	20	0	111	9	438.0	16,108.4	3,304.3	430.1	16,046.8	3,285.4	7.9	61.7	18.8
Keathley Canyon	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Matagorda Island	0	0	28	2	23.9	5,261.4	960.1	23.9	5,261.4	960.1	0.0	0.0	0.0
Mustang Island	1	0	27	5	8.2	1,786.9	326.2	8.2	1,786.9	326.2	0.0	0.0	0.0
N.& S.Padre Island	0	0	19	0	0.4	625.3	111.6	0.4	625.3	111.6	0.0	0.0	0.0
Port Isabel	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Cameron and Sabine Pass	2	0	22	1	33.2	2,415.0	462.9	31.4	2,407.7	459.9	1.7	7.3	3.0
Western Planning Area Subtotal	***42***	***0***	***309***	***32***	***1,479.2***	***35,625.7***	***7,818.3***	***1,290.4***	***35,268.1***	***7,565.9***	***188.8***	***357.6***	***252.4***
Central Planning Area													
Atwater Valley	1	0	5	5	61.5	610.2	170.1	47.8	597.5	154.1	13.7	12.7	16.0
Chandeleur	1	0	13	0	0.2	393.7	70.3	0.2	386.5	69.0	0.0	7.2	1.3
Desoto Canyon	2	0	4	1	33.3	537.0	128.9	22.5	524.9	115.9	10.8	12.1	13.0
Destin Dome	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East Cameron	10	0	57	0	374.2	11,032.5	2,337.3	363.8	10,974.0	2,316.5	10.4	58.5	20.8
Eugene Island	32	0	57	4	1,831.3	20,759.3	5,525.2	1,762.7	20,524.1	5,414.7	68.6	235.2	110.5
Ewing Bank	13	0	5	2	511.3	945.3	679.5	444.6	842.2	594.5	66.7	103.1	85.0
Garden Banks	14	0	18	4	1,019.1	4,994.6	1,907.8	926.0	4,642.2	1,752.0	93.1	352.4	155.8
Grand Isle	6	0	17	1	1,075.5	5,245.9	2,008.9	1,014.6	5,066.2	1,916.0	61.0	179.7	92.9
Green Canyon	38	0	14	25	5,450.5	5,935.0	6,506.6	3,532.6	4,333.0	4,303.6	1,917.9	1,601.9	2,203.0
Keathley Canyon	2	0	1	2	656.6	717.7	784.3	190.5	416.7	264.7	466.1	301.0	519.6
Lloyd Ridge	0	0	4	0	0.1	330.5	58.9	0.1	330.5	58.9	0.0	0.0	0.0
Main Pass and Breton Sound	30	0	62	4	1,348.8	7,316.9	2,650.8	1,224.6	7,116.6	2,490.9	124.2	200.3	159.9
Mississippi Canyon	48	2	24	14	6,864.6	13,419.6	9,252.5	4,903.6	11,466.3	6,943.9	1,961.0	1,953.4	2,308.6
Mobile	8	0	26	2	0.4	2,614.1	465.5	0.3	2,481.0	441.8	0.1	133.0	23.7
Pensacola	0	0	1	0	0.0	7.7	1.4	0.0	7.7	1.4	0.0	0.0	0.0
Ship Shoal	35	0	34	3	1,572.9	13,125.2	3,908.3	1,504.4	12,792.9	3,780.7	68.5	332.3	127.6
Sigsbee Escarpment	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Marsh Island	30	0	21	0	1,040.6	15,293.3	3,761.8	995.3	14,949.8	3,655.4	45.3	343.5	106.4
South Pass	8	0	5	1	1,145.9	4,600.4	1,964.5	1,117.9	4,539.6	1,925.7	28.0	60.8	38.9
South Pelto	3	0	6	0	160.6	1,181.0	370.7	159.4	1,175.8	368.6	1.1	5.3	2.1
South Timbalier	21	0	42	2	1,723.2	10,753.1	3,636.6	1,645.1	10,564.0	3,524.8	78.1	189.1	111.8
Vermilion	26	0	59	0	612.0	16,879.0	3,615.4	593.7	16,748.6	3,573.9	18.3	130.4	41.5
Viosca Knoll	17	0	38	8	736.3	3,997.2	1,447.6	670.4	3,781.1	1,343.2	66.0	216.1	104.4
Walker Ridge	7	0	0	2	1,017.9	222.1	1,057.4	613.3	126.2	635.8	404.6	95.9	421.6
West Cameron and Sabine Pass	16	0	78	0	200.3	18,722.8	3,531.8	195.9	18,570.8	3,500.4	4.4	152.1	31.5
West Delta	12	0	12	3	1,509.5	5,912.7	2,561.5	1,441.2	5,791.8	2,471.7	68.3	120.8	89.8
Central Planning Area Subtotal	***380***	***2***	***603***	***85***	***28,946.8***	***165,546.8***	***58,403.5***	***23,370.5***	***158,750.0***	***51,617.8***	***5,576.3***	***6,796.8***	***6,785.7***
Eastern Planning Area													
Destin Dome	0	0	0	1	0	0	0	0	0	0	0	0	0
Eastern Planning Area Subtotal	***0***	***0***	***0***	***1***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***
GOA Total:	***422***	***2***	***912***	***118***	***30,426.0***	***201,172.5***	***66,221.8***	***24,660.9***	***194,018.1***	***59,183.7***	***5,765.1***	***7,154.4***	***7,038.1***
		1,336											

Figure 5 shows the spatial distribution of all oil and gas fields in the GOA, while Figure 6 displays the distribution of active oil and gas fields, categorized by water depth: shelf areas (less than 656 feet or 200 meters) and slope areas (greater than or equal to 656 feet or 200 meters).

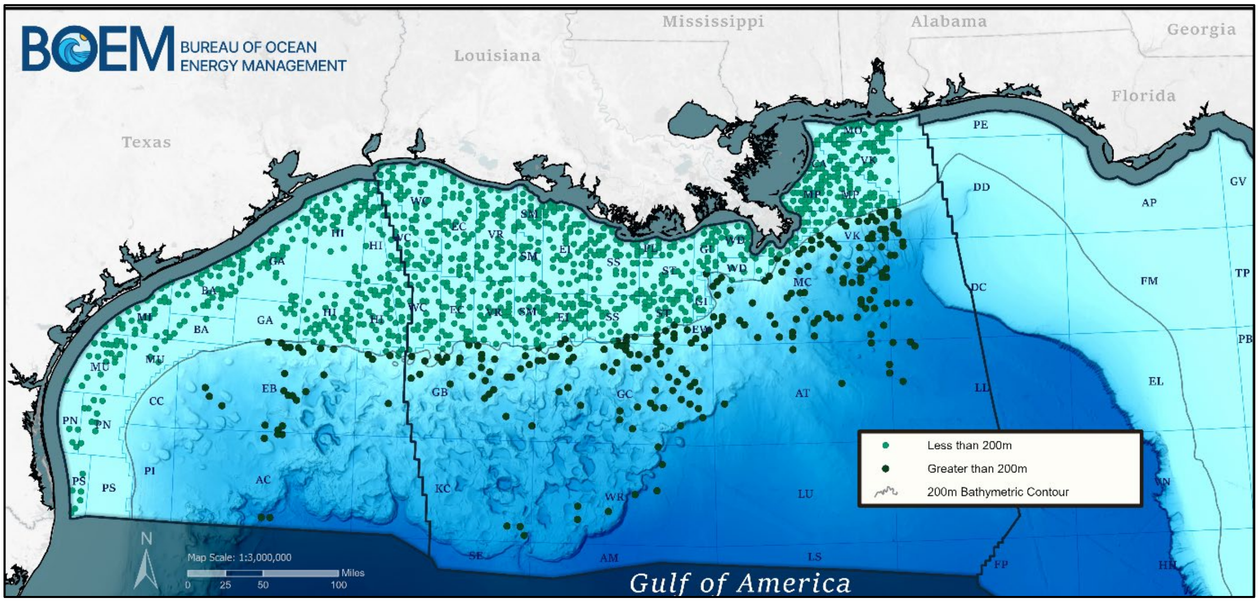

Figure 5. Oil and Gas Fields by Water Depth

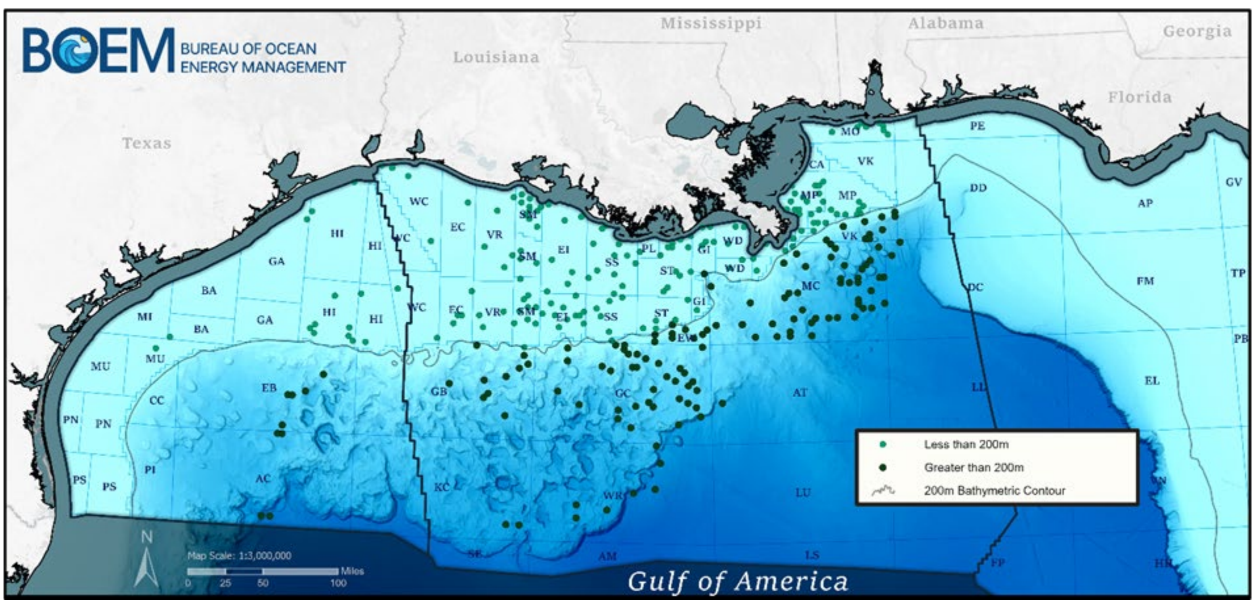

Figure 6. Active Oil and Gas Fields by Water Depth

6.0 FIELD SIZE DISTRIBUTION

Field size distributions are presented as Original Reserves in millions of barrels of oil equivalent (MMBOE). Fields are categorized as either oil or gas, with each field classified individually based on an analysis of its reservoirs and fluid distributions. However, some fields produce both, complicating the classification process. For ease of comparison, gas reserves are converted to MMBOE and combined with liquid reserves. The conversion factor used is 5,620 standard cubic feet of gas per 1 BOE, reflecting the average heating values of domestic hydrocarbons.

A geometric progression, developed by the United States Geological Survey (USGS) (Attanasi, 1998), was selected for field-size (deposit-size) distribution ranges (Table 2). This model, along with its associated ranges, helps in understanding the distribution and frequency of various field sizes for oil and gas deposits.

Table 2. Description of Deposit-Size Classes

Class	Deposit-size range*	Class	Deposit-size range*	Class	Deposit-size range*
1	0.031 - 0.062	10	16 - 32	18	4,096 - 8,192
2	0.062 - 0.125	11	32 -64	19	8,192 - 16,384
3	0.125 - 0.25	12	64 - 128	20	16,384 - 32,768
4	0.25 - 0.50	13	128 - 256	21	32,768 - 65,536
5	0.50 - 1.00	14	256 - 512	22	65,536 - 131,072
6	1 - 2	15	512 - 1,024	23	131,072 - 262,144
7	2 - 4	16	1,024 - 2,048	24	262,144 - 524,288
8	4 - 8	17	2,048 - 4,096	25	524,288 - 1,048,576
9	8 - 16	*Million Barrels of Oil Equivalent (MMBOE)			

The field-size distribution based on Original Reserves in MMBOE for 1,336 fields is shown in Figure 7, along with the CGA and WGA planning area distributions. Of the 1,336 oil and gas fields, there are 302 oil fields represented in Figure 8 and 1,034 gas fields shown in Figure 9. These figures also display the planning area distributions.

Analysis of 1,336 oil and gas fields shows that the GOA has transitioned from being predominantly gas-prone to increasingly oil-focused, driven by the expansion of slope resources. This shift highlights distinct regional differences shaped by the contrasting geology of the shelf and slope. In the WGA, gas production once dominated due to prolific shelf fields. However, as these fields declined, new slope developments have shifted the region's output toward oil. The CGA is now the most oil-prone area, with deepwater slope reservoirs making it the heart of U.S. offshore crude production; gas here plays a secondary role. Supporting this regional characterization, the Gas-Oil Ratio (GOR), based on Original Reserves of the 302 oil fields, is 2,496 standard cubic feet/standard tank barrel (scf/stb). The yield (condensate divided by gas), based on Original Reserves for the 1,034 gas fields, is 23.3 stb/MMcf (million cubic feet).

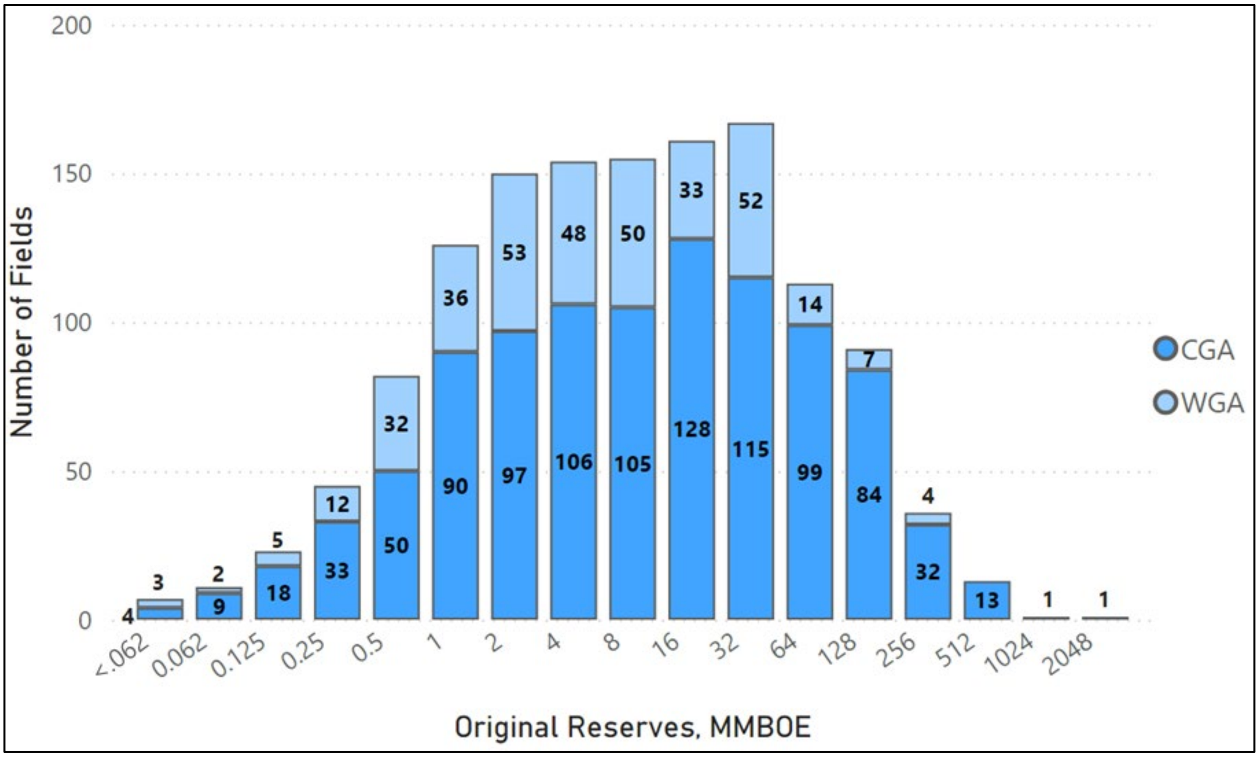

Figure 7. Field Size Distribution of GOA Fields by Planning Area

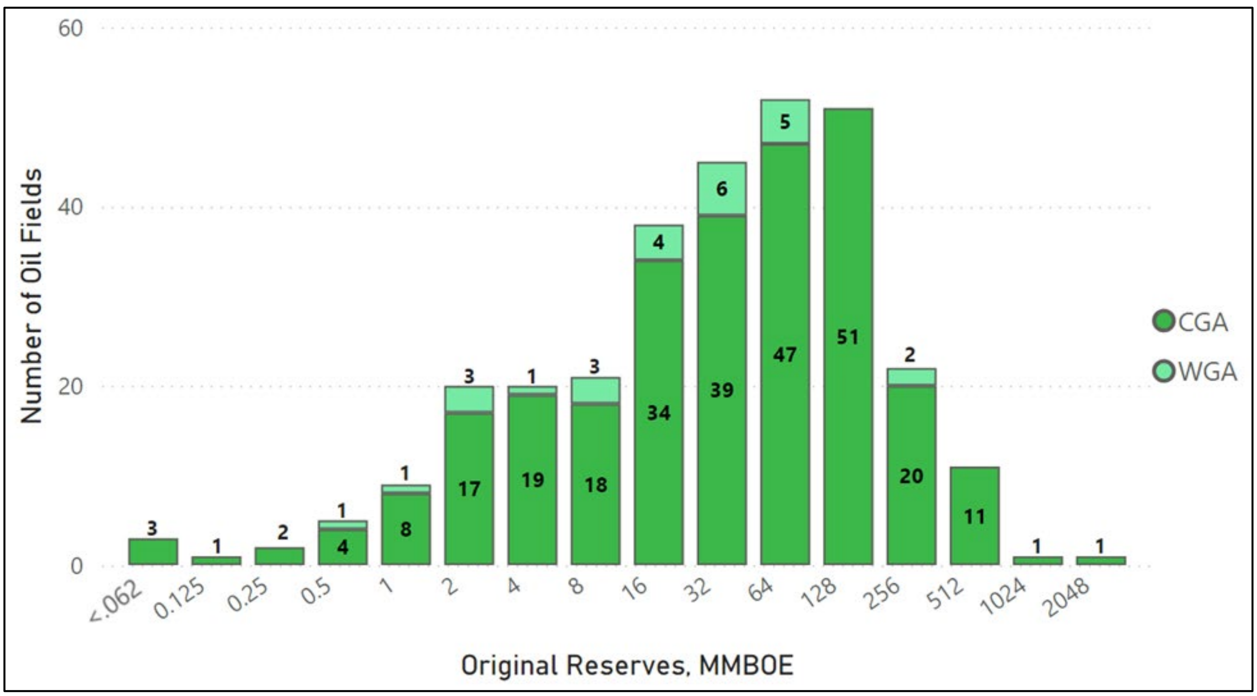

Figure 8. Field Size Distribution of GOA Oil Fields by Planning Area

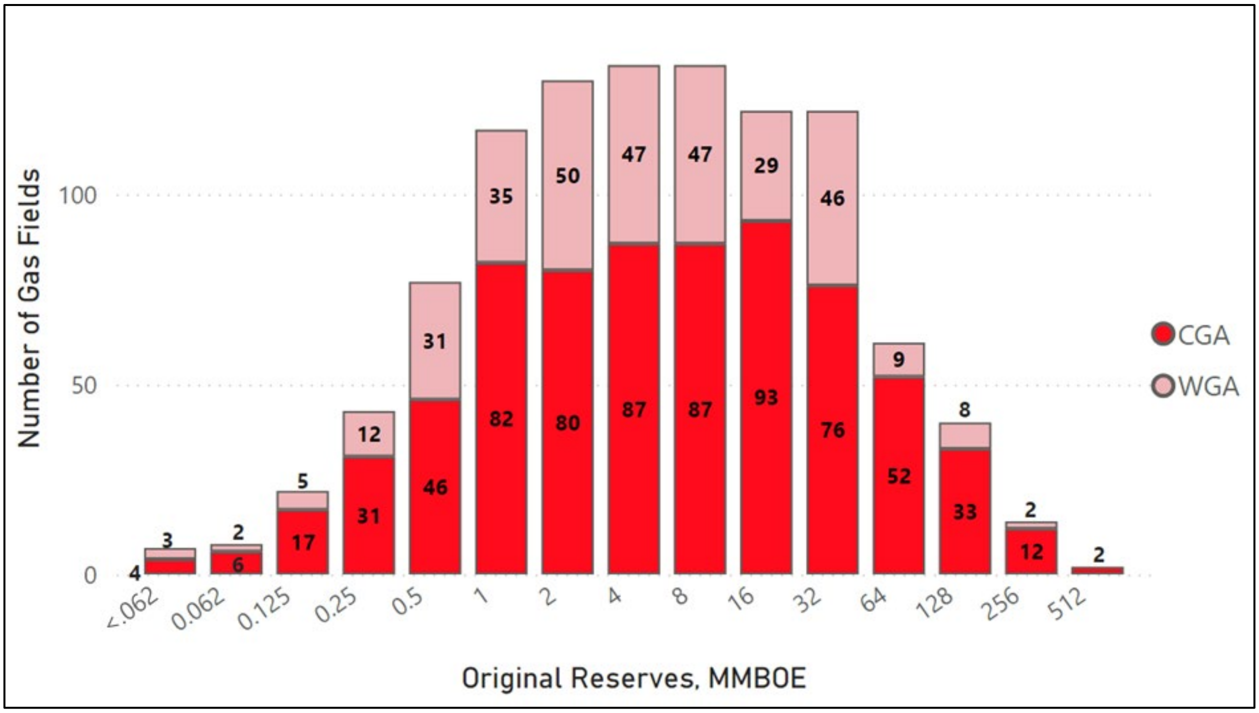

Figure 9. Field Size Distribution of GOA Gas Fields by Planning Area

Figure 10 shows the cumulative percent distribution of Original Reserves (BBOE), by field size rank. All 1,336 fields in the GOA OCS are included in this figure. A phenomenon often observed in hydrocarbon-producing basins is a rapid drop-off in size from that of largest known field to smallest. Twenty-five percent of the Original Reserves are contained in the 24 largest fields. Fifty percent of the Original Reserves are contained in the 87 largest fields. Ninety percent of the Original Reserves are contained in the 434 largest fields.

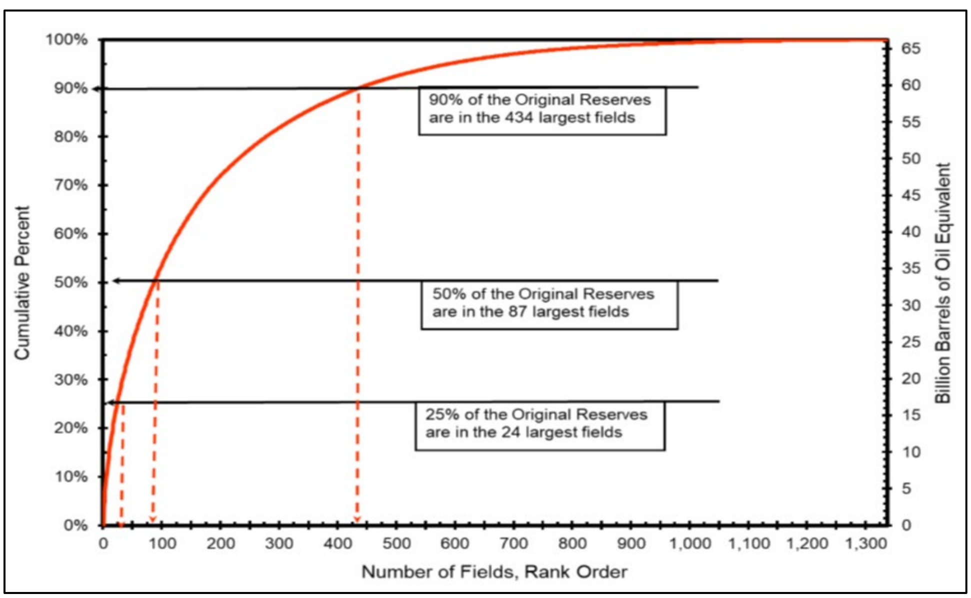

Figure 10. Cumulative Percent Original Reserves versus Rank Order of Field Size

Table 3 shows the distribution of the number of fields and reserves by water depth. A field's water depth is determined by averaging the water depth where the wells are drilled in the field. Reserves and production, reported in MMBOE, are associated with the 1,336 fields. Eighty-five percent of the remaining reserves are found in water depths greater than 656 ft. Of the 235 fields at these depths, 142 are producing, 92 are depleted or expired, and one has yet to produce.

Table 3. Number of Fields, Cumulative Production, and Remaining Reserves by Water Depth

Water Depth Range (Feet)	Number of Fields	Number of Active Fields	Cumulative Production (MMBOE)	Remaining Reserves (MMBOE)
< 656	1,101	281	42,432	1,025
656 - 999	33	9	1,010	56
1,000 - 1,499	29	15	1,602	238
1,500 - 4,999	110	75	9,006	3,379
5,000 - 7,499	45	38	4,224	2,069
>= 7,500	18	6	910	271
Totals:	1,336	424	59,184	7,038

Table 4 ranks the 50 largest fields by mean Original Reserves, measured in MMBOE. It includes details such as rank, field name, field nickname, discovery year, water depth, field classification, field type, distribution of Original Reserves, cumulative production through 2023, and distribution of remaining reserves. Figure 11 highlights the 20 largest fields based on Original Reserves, while Figure 12 provides a spatial overview of the location of all 50 fields. A complete listing of all 1,336 fields is available on the BOEM Web site at https://www.data.boem.gov/Main/HtmlPage.aspx?page=estimated2023.

Table 4. Top 50 GOA Fields by Rank Order, Based on Mean Original Reserves, MMBOE

Rank	Field name	Field nickname	Disc year	Water depth (feet)	Field type	Original Reserves (MMBOE)				Cumulative Production through 2023 (MMBOE)	Remaining Reserves (MMBOE)			
						P10	P50	P90	MEAN		P10	P50	P90	MEAN
1	MC807	MARS-URSA	1989	3341	O	2,306.4	2,570.1	2,845.2	2,575.8	2,133.8	172.6	436.3	711.4	442.0
2	GC826	MAD DOG	1998	4843	O	783.9	1,107.5	1,455.7	1,119.8	346.2	437.7	761.3	1,109.5	773.6
3	GC640	TAHITI/CAE/TONG	2002	4350	O	802.7	1,007.6	1,196.1	999.4	701.3	101.4	306.3	494.8	298.1
4	EI330		1971	248	O	826.8	854.2	883.0	854.9	808.9	17.9	45.3	74.1	46.0
5	WD030		1949	48	O	784.2	824.8	837.4	810.8	770.4	13.8	54.4	67.0	40.4
6	GC743	ATLANTIS	1998	6362	O	652.5	790.5	933.5	793.0	568.7	83.8	221.8	364.8	224.3
7	GI043		1956	140	O	699.4	755.1	758.4	728.9	680.1	19.3	75.0	78.3	48.8
8	TS000		1958	13	G	707.8	735.3	742.5	725.1	698.0	9.8	37.3	44.5	27.1
9	BM002		1949	50	O	674.7	709.2	738.3	706.5	654.7	20.0	54.5	83.6	51.8
10	VR014		1956	26	G	604.2	604.2	604.2	604.2	604.2	0.0	0.0	0.0	0.0
11	MC940	VITO	2010	4007	O	513.5	603.2	966.6	604.1	20.6	492.9	582.6	946.0	583.5
12	MP041		1956	43	O	566.0	581.9	597.0	581.5	557.0	9.0	24.9	40.0	24.5
13	MC778	THUNDER HORSE	1999	6143	O	431.9	548.4	673.7	552.8	362.4	69.5	186.0	311.3	190.4
14	GC654	SHENZI	2002	4299	O	472.7	528.1	762.8	530.7	412.9	59.8	115.2	349.9	117.8
15	GB426	AUGER	1987	2843	O	503.9	527.4	556.9	530.4	490.3	13.6	37.1	66.6	40.1
16	MC776	N.THUNDER HORSE	2000	5671	O	447.5	499.1	552.1	499.8	413.1	34.4	86.0	139.0	86.7
17	SS208		1960	102	O	487.6	499.4	511.6	499.6	480.1	7.5	19.3	31.5	19.5
18	VR039		1948	38	G	496.1	505.2	508.4	496.1	495.6	0.5	9.6	12.8	0.5
19	MC084	KING/HORN MT.	1993	5151	O	427.7	482.0	540.1	483.9	396.7	31.0	85.3	143.4	87.2
20	KC872	BUCKSKIN	2008	6632	O	388.1	457.0	730.6	456.6	51.0	337.1	406.0	679.6	405.6
21	AC857	GREAT WHITE	2002	7934	O	398.1	445.3	642.5	447.0	346.1	52.0	99.2	296.4	100.9
22	WD073		1962	177	O	413.7	427.2	441.7	427.7	406.6	7.1	20.6	35.1	21.1
23	GI016		1948	54	O	385.0	395.2	402.0	393.5	379.7	5.3	15.5	22.3	13.8
24	EI238		1964	147	G	384.8	388.1	397.0	390.9	380.9	3.9	7.2	16.1	10.0
25	SP061		1967	220	O	369.7	373.8	377.4	373.3	367.8	1.9	6.0	9.6	5.5
26	WR678	SAINT MALO	2003	6939	O	283.2	363.0	441.8	362.5	238.2	45.0	124.8	203.6	124.3
27	SP089		1969	421	O	355.0	357.6	362.4	358.1	353.2	1.8	4.4	9.2	4.9
28	GB171	SALSA/CONGER	1984	1330	O	332.2	356.2	460.6	357.9	304.9	27.3	51.3	155.7	53.0
29	ST172		1962	98	G	349.9	349.9	349.9	349.9	349.9	0.0	0.0	0.0	0.0
30	WC180		1961	48	G	341.7	341.7	341.7	341.7	341.7	0.0	0.0	0.0	0.0
31	SS169		1960	63	O	335.1	340.7	342.1	338.1	333.4	1.7	7.3	8.7	4.7
32	ST021		1957	46	O	335.7	337.9	344.3	335.7	335.6	0.1	2.3	8.6	0.1
33	MC194	COGNAC	1975	1022	O	325.5	331.3	335.9	330.7	322.6	2.9	8.7	13.3	8.1
34	EI292		1964	214	G	323.8	329.2	332.2	328.0	321.2	2.6	8.0	11.0	6.8
35	ST176		1963	127	G	321.3	324.1	327.9	323.9	319.6	1.7	4.5	8.3	4.3
36	EC271		1971	172	G	315.9	317.8	322.5	318.2	314.3	1.6	3.5	8.2	3.9
37	EC064		1957	50	G	313.4	313.4	313.4	313.4	313.4	0.0	0.0	0.0	0.0
38	SS176		1956	101	G	308.6	313.4	317.4	313.0	306.0	2.6	7.4	11.4	7.0
39	SM048		1961	100	G	308.2	308.2	315.2	308.2	307.3	0.9	0.9	7.9	0.9
40	SP027	EAST BAY	1954	64	O	294.5	298.6	302.1	298.3	292.2	2.3	6.4	9.9	6.1
41	WC587		1971	210	G	294.7	294.7	294.7	294.7	294.7	0.0	0.0	0.0	0.0
42	ST135		1956	129	O	286.9	290.3	304.3	290.4	282.7	4.2	7.6	21.6	7.7
43	WD079		1966	123	O	283.3	289.9	295.7	289.5	279.7	3.6	10.2	16.0	9.8
44	GC244	TROIKA	1994	2750	O	271.1	286.3	354.7	287.8	251.0	20.1	35.3	103.7	36.8
45	VK956	RAM-POWELL	1985	3209	O	276.6	290.4	295.4	286.0	271.0	5.6	19.4	24.4	15.0
46	EI296		1971	214	G	281.1	281.1	281.1	281.1	281.1	0.0	0.0	0.0	0.0
47	KC875	LUCIUS	2010	7079	O	205.1	280.8	356.9	281.0	166.9	38.2	113.9	190.0	114.1
48	GI047		1955	88	O	269.3	281.2	292.1	280.7	262.7	6.6	18.5	29.4	18.0
49	WC192		1954	57	G	277.4	280.9	283.8	280.6	275.4	2.0	5.5	8.4	5.2
50	HI573A		1973	341	O	274.6	274.9	280.8	274.7	273.7	0.9	1.2	7.1	1.0

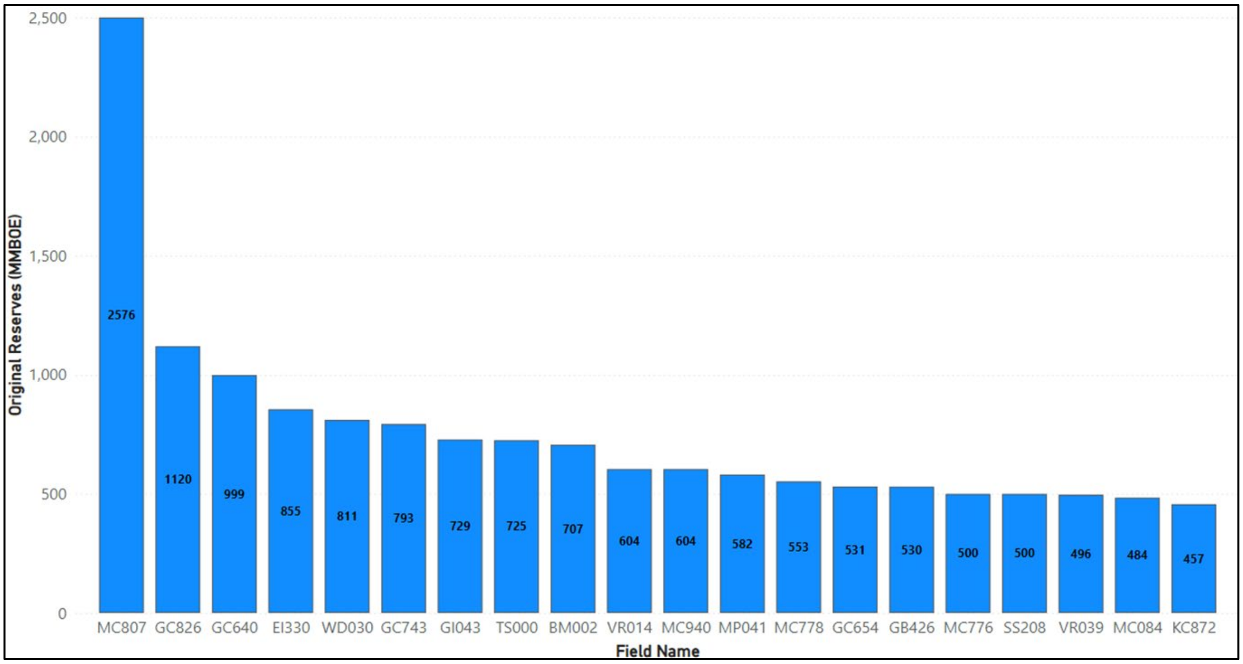

Figure 11. Largest 20 Fields by Original Reserves

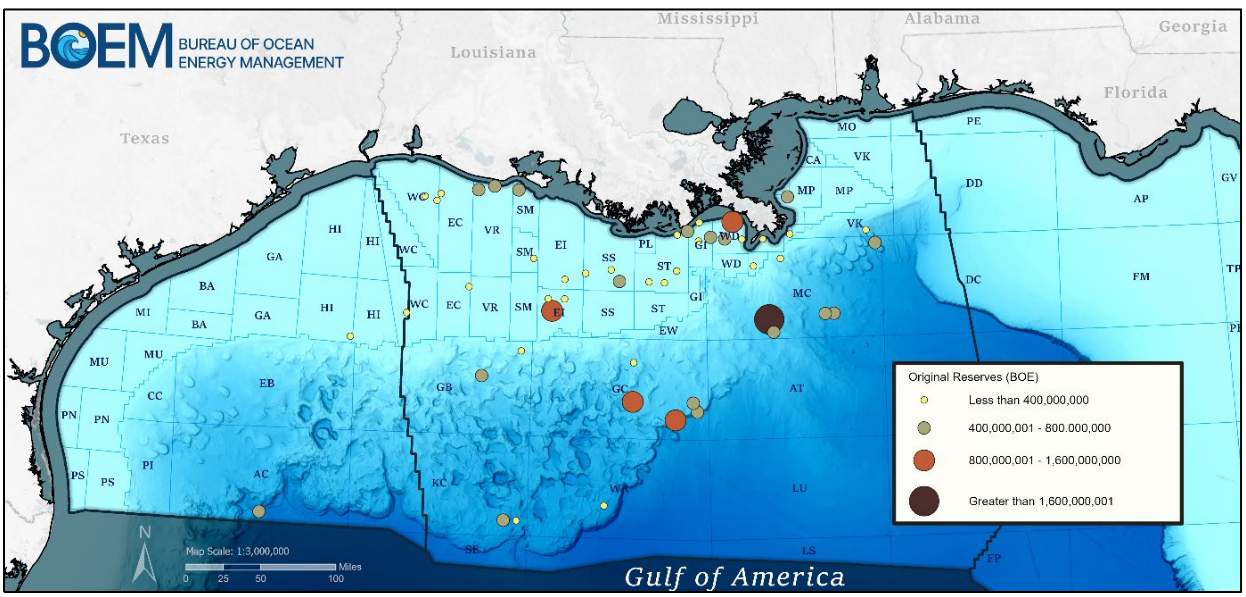

Figure 12. Largest 50 Fields by Original Reserves (BOE)

Table 5 ranks the 50 largest fields by mean remaining reserves, measured in MMBOE. It includes details such as rank, field name, field nickname, discovery year, water depth, field classification, field type, distribution of Original Reserves, cumulative production through 2023, and distribution of remaining reserves.

Table 5. Top 50 GOA Fields by Rank Order, Based on Mean Remaining Reserves, MMBOE

Rank	Field name	Field nickname	Disc year	Water depth (feet)	Field type	Original Reserves (MMBOE)				Cumulative Production through 2023 (MMBOE)	Remaining Reserves (MMBOE)			
						P10	P50	P90	MEAN		P10	P50	P90	MEAN
1	GC826	MAD DOG	1998	4843	O	783.9	1,107.5	1,455.7	1,119.8	346.2	437.7	761.3	1,109.5	773.6
2	MC940	VITO	2010	4007	O	513.5	603.2	966.6	604.1	20.6	492.9	582.6	946.0	583.5
3	MC807	MARS-URSA	1989	3341	O	2,306.4	2,570.1	2,845.2	2,575.8	2,133.8	172.6	436.3	711.4	442.0
4	KC872	BUCKSKIN	2008	6632	O	388.1	457.0	730.6	456.6	51.0	337.1	406.0	679.6	405.6
5	GC640	TAHITI/CAE/TONG	2002	4350	O	802.7	1,007.6	1,196.1	999.4	701.3	101.4	306.3	494.8	298.1
6	GC743	ATLANTIS	1998	6362	O	652.5	790.5	933.5	793.0	568.7	83.8	221.8	364.8	224.3
7	MC778	THUNDER HORSE	1999	6143	O	431.9	548.4	673.7	552.8	362.4	69.5	186.0	311.3	190.4
8	WR029	BIG FOOT	2005	5387	O	150.4	182.0	283.0	176.9	51.1	99.3	130.9	231.9	125.8
9	WR678	SAINT MALO	2003	6939	O	283.2	363.0	441.8	362.5	238.2	45.0	124.8	203.6	124.3
10	GC468	STAMPEDE	2006	3518	O	128.2	179.5	238.2	183.2	62.5	65.7	117.0	175.7	120.7
11	MC393	VICKSBURG A	2013	7410	O	108.2	152.4	177.8	154.6	35.0	73.2	117.4	142.8	119.6
12	GC654	SHENZI	2002	4299	O	472.7	528.1	762.8	530.7	412.9	59.8	115.2	349.9	117.8
13	KC875	LUCIUS	2010	7079	O	205.1	280.8	356.9	281.0	166.9	38.2	113.9	190.0	114.1
14	AC857	GREAT WHITE	2002	7934	O	398.1	445.3	642.5	447.0	346.1	52.0	99.2	296.4	100.9
15	GC562	K2	1999	4042	O	185.7	229.4	254.0	231.2	135.5	50.2	93.9	118.5	95.7
16	MC084	KING/HORN MT.	1993	5151	O	427.7	482.0	540.1	483.9	396.7	31.0	85.3	143.4	87.2
17	MC776	N.THUNDER HORSE	2000	5671	O	447.5	499.1	552.1	499.8	413.1	34.4	86.0	139.0	86.7
18	AC859	TOBAGO	2004	9359	O	88.1	124.5	144.7	125.8	48.9	39.2	75.6	95.8	76.9
19	MC525		2014	7460	O	60.3	70.0	113.4	70.9	0.0	60.3	70.0	113.4	70.9
20	MC392	APPOMATTOX	2009	7223	O	161.8	193.9	304.6	190.4	124.2	37.6	69.7	180.4	66.2
21	MC109	AMBERJACK	1983	1044	O	143.0	169.7	269.1	168.2	107.0	36.0	62.7	162.1	61.2
22	GC432	SAMURAI	2009	3448	O	48.8	68.7	80.2	69.7	11.5	37.3	57.2	68.7	58.2
23	MC768	KAIKIAS	2014	4479	O	97.3	135.3	169.3	133.3	75.4	21.9	59.9	93.9	57.9
24	GC039		1984	1971	O	60.9	70.3	114.6	71.6	14.6	46.3	55.7	100.0	57.0
25	WR759	JACK	2004	6967	O	162.7	183.3	289.7	188.1	131.7	31.0	51.6	158.0	56.4
26	MC773	DEVILS TOWER	1999	5345	O	167.6	206.0	239.8	203.7	149.0	18.6	57.0	90.8	54.7
27	MC943	POWER NAP	2014	4209	O	43.8	62.1	81.3	62.5	8.1	35.7	54.0	73.2	54.4
28	WR627	JULIA	2007	7135	O	108.5	126.9	204.2	127.6	73.4	35.1	53.5	130.8	54.2
29	GB171	SALSA/CONGER	1984	1330	O	332.2	356.2	460.6	357.9	304.9	27.3	51.3	155.7	53.0
30	BM002		1949	50	O	674.7	709.2	738.3	706.5	654.7	20.0	54.5	83.6	51.8
31	WR508	STONES	2005	9317	O	103.1	130.1	140.9	128.3	77.5	25.6	52.6	63.4	50.8
32	MC546	LONGHORN	1986	2542	O	206.0	238.8	267.0	236.5	185.9	20.1	52.9	81.1	50.6
33	GI043		1956	140	O	699.4	755.1	758.4	728.9	680.1	19.3	75.0	78.3	48.8
34	EI330		1971	248	O	826.8	854.2	883.0	854.9	808.9	17.9	45.3	74.1	46.0
35	GC236	PHOENIX	1984	2205	O	134.5	162.2	192.4	163.4	119.7	14.8	42.5	72.7	43.7
36	WD030		1949	48	O	784.2	824.8	837.4	810.8	770.4	13.8	54.4	67.0	40.4
37	GB426	AUGER	1987	2843	O	503.9	527.4	556.9	530.4	490.3	13.6	37.1	66.6	40.1
38	GC627	HOPKINS	2014	4385	O	42.8	60.8	70.3	61.1	21.7	21.1	39.1	48.6	39.4
39	VK990	POMPANO	1981	1447	O	222.8	248.9	269.2	246.0	208.3	14.5	40.6	60.9	37.7
40	GC644	HOLSTEIN	1999	4342	O	164.2	190.8	212.8	188.5	151.0	13.2	39.8	61.8	37.5
41	GC244	TROIKA	1994	2750	O	271.1	286.3	354.7	287.8	251.0	20.1	35.3	103.7	36.8
42	MC429	ARIEL	1995	6143	O	118.5	143.1	163.5	141.0	106.2	12.3	36.9	57.3	34.8
43	GC389	KHALEESI	2017	3576	O	51.6	59.8	97.1	60.7	27.9	23.7	31.9	69.2	32.8
44	MC657	COULOMB	1987	7540	G	119.7	136.1	193.2	134.4	102.1	17.6	34.0	91.1	32.3
45	GC019	BOXER	1980	758	O	151.6	173.3	191.4	171.5	139.8	11.8	33.5	51.6	31.7
46	MP299		1962	210	O	210.2	224.1	249.2	229.7	199.5	10.7	24.6	49.7	30.2
47	SS230		1962	119	O	229.7	245.2	267.7	248.7	219.3	10.4	25.9	48.4	29.4
48	MP144		1967	213	O	170.9	185.7	206.5	188.7	159.3	11.6	26.4	47.2	29.4
49	GC478	MORMONT	2017	3770	O	39.5	47.0	74.4	46.5	19.3	20.2	27.7	55.1	27.2
50	TS000		1958	13	G	707.8	735.3	742.5	725.1	698.0	9.8	37.3	44.5	27.1

Figure 13 highlights the 20 largest fields based on remaining reserves, while Figure 14 provides a spatial overview of the location of all 50 fields.

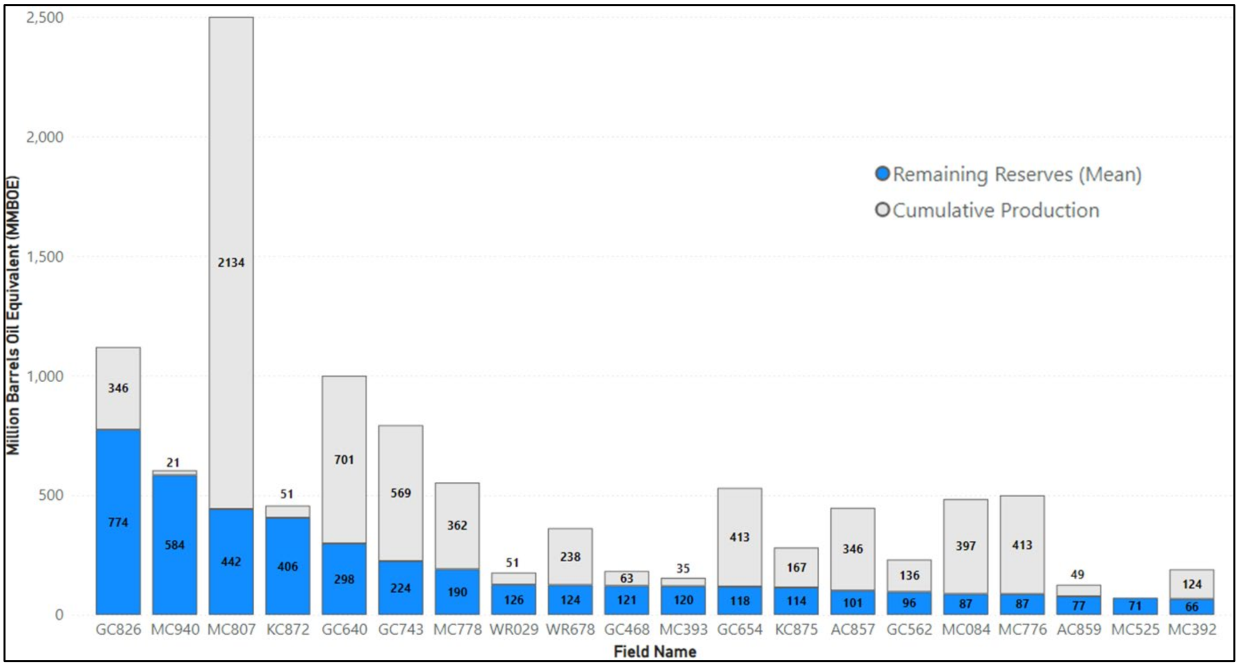

Figure 13. Largest 20 Fields by Remaining Reserves

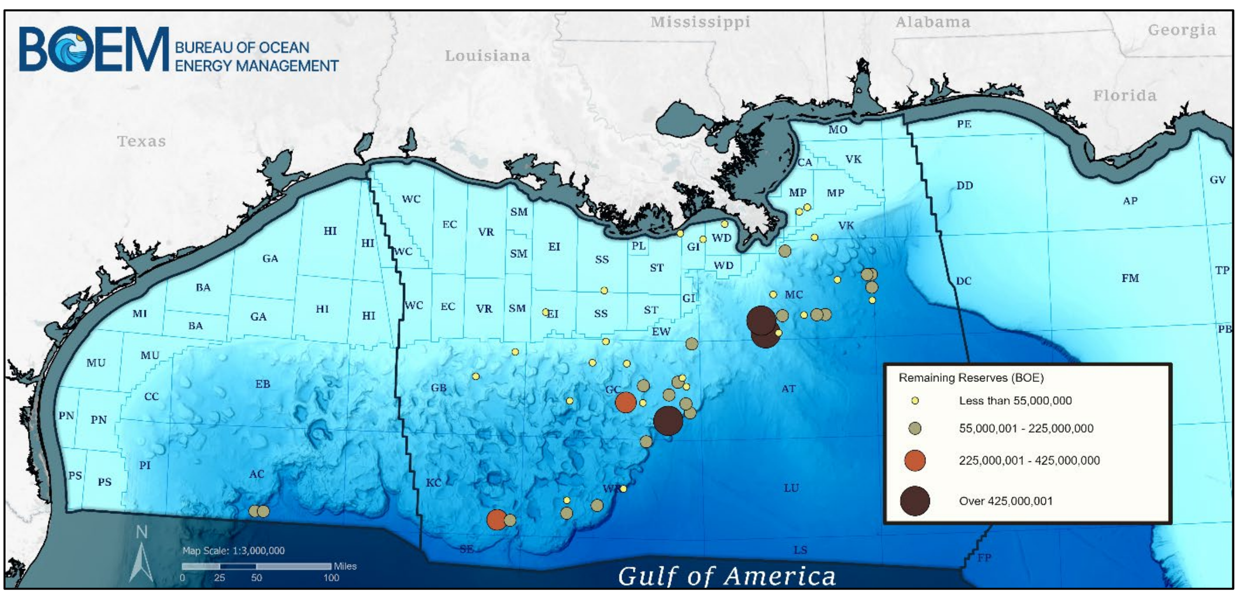

Figure 14. Largest 50 Fields by Remaining Reserves

7.0 RESERVOIR SIZE (ORIGINAL RESERVES) DISTRIBUTION

The size distributions of reservoirs are shown in Figure 15, Figure 16, and Figure 17. The size ranges are based on Original Reserves and are presented on a geometrically progressing horizontal scale. These sizes correspond with the USGS deposit-size ranges shown in Table 2, with a modification to subdivide small reservoirs into finer distributions. In Figure 15, the Original Reserves are presented in thousands of barrels of oil equivalent (MBOE). For combination reservoirs (saturated oil rims with associated gas caps), gas is converted to BOE and added to the liquid reserves. Figure 16 and Figure 17 are presented in thousand barrels of Oil (Mbbl) and thousand cubic feet (Mcf), respectively. The number of reservoirs in each size grouping, shown as percentages of the total, is presented on a linear vertical scale. Figure 15 shows the reservoir-size distribution of Original Reserves for 1,222 combination reservoirs. The median is 1,100 MBOE and the mean is 3,600 MBOE. The GOR for the oil portion of the reservoirs is 1,215 scf/stb, and the yield for the gas cap is 48.6 barrels (bbl) of condensate per Mcf of gas.

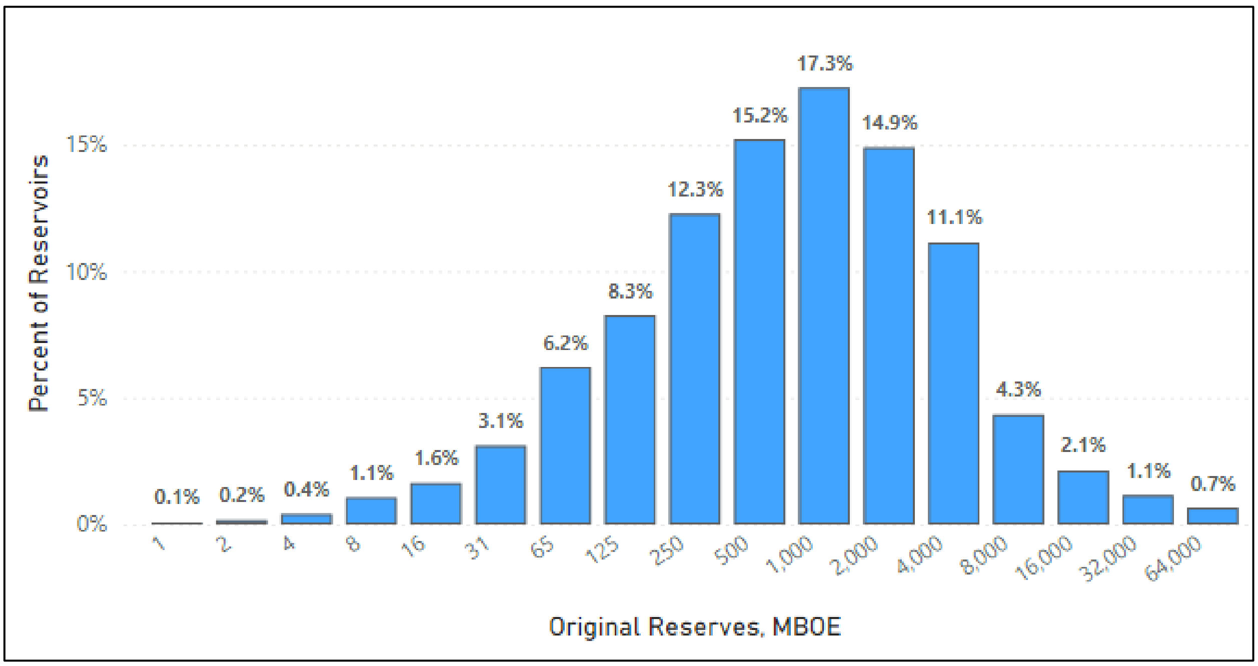

Figure 15. Reservoir-size Distribution, Combination Reservoirs

Figure 16 shows the reservoir-size distribution of original oil reserves for 9,883 undersaturated oil reservoirs. The median is 400 Mbbl, the mean is 2,600 Mbbl, and the GOR, is 1,177 scf/stb.

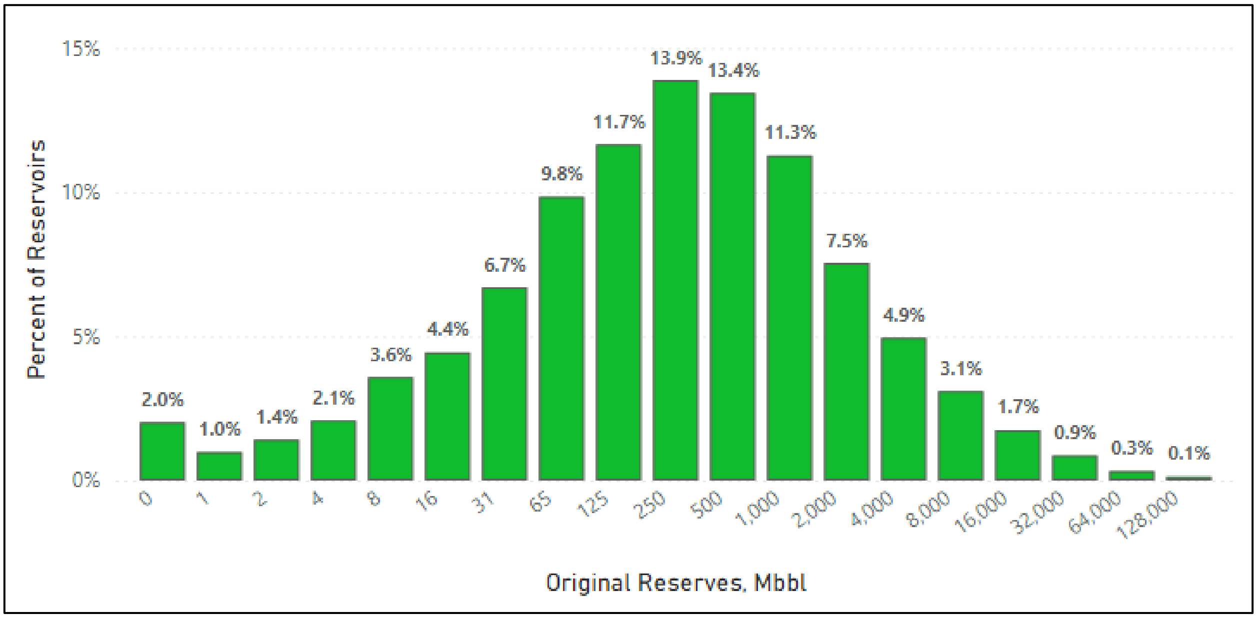

Figure 16. Reservoir-size Distribution, Oil Reservoirs

Figure 17 shows the reservoir-size distribution, for 18,829 gas reservoirs on the basis of Original Gas Reserves. The median is 2,000 Mcf of gas, the mean is 8,500 Mcf, and the yield, based on Original Reserves, is 12.8 bbl of condensate per Mcf of gas.

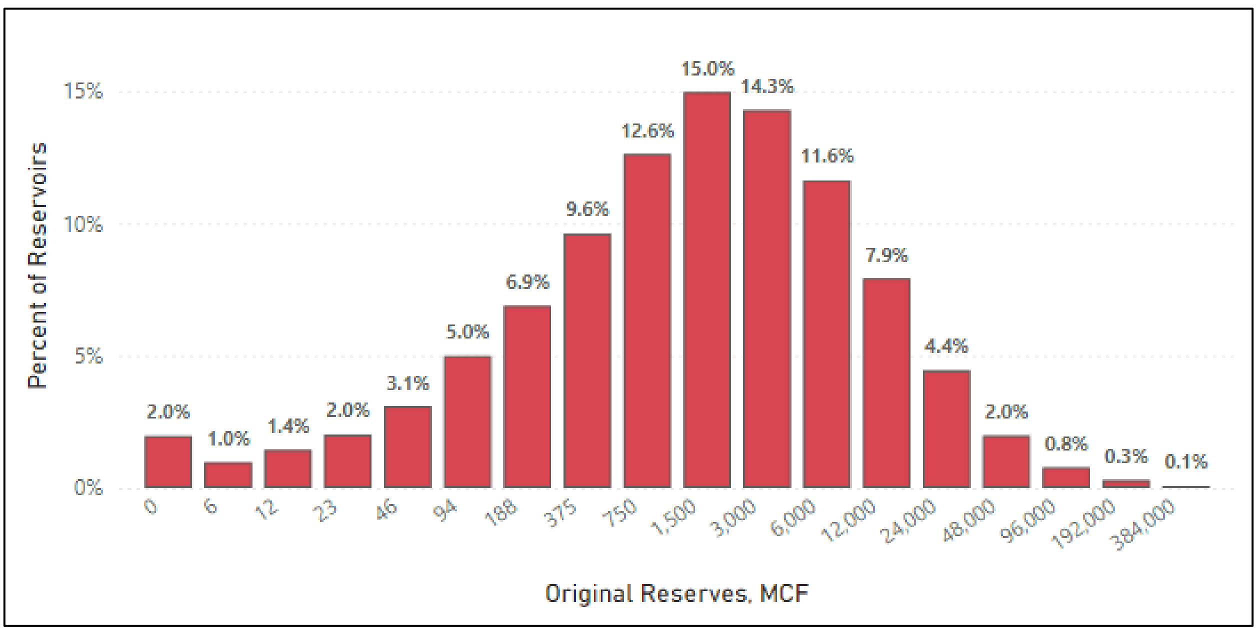

Figure 17. Reservoir-size Distribution, Gas Reservoirs

8.0 DRILLING AND PRODUCTION TRENDS

Exploration and development drilling in the GOA has steadily advanced into deeper waters over time. The first well drilled in water depths exceeding 1,000 feet reached total depth in 1975 at the Cognac Field (Mississippi Canyon 194). Since then, maximum drilling depths along the GOA slope have continued to increase, with true vertical subsea depths now surpassing 35,000 feet. This progression reflects significant improvements in rig capabilities, the pursuit of deeper exploration targets, and ongoing technological advancements across the industry.

8.1 EXPLORATORY WELLS DRILLED BY WATER DEPTH OVER TIME

Figure 18 and Figure 19 show the number of exploratory wells drilled over time by water depth category. Shelf exploratory drilling peaked in the 1980s and 1990s and has declined ever since, with roughly 14 shelf exploratory wells drilled annually since 2015. Exploratory wells drilled on the slope began increasing in the late 1990s, surpassing shelf exploratory wells in 2009. Since 2015, an average of 65 exploration wells has been drilled annually. The total footage of exploratory wells drilled in 2023 was 1.31 million feet, compared to 1.72 million feet in 2019. Figure 20 through Figure 28 provide a spatial overview of exploratory wells drilled by decade, showing how oil and gas activity has progressively moved into deeper waters over time.

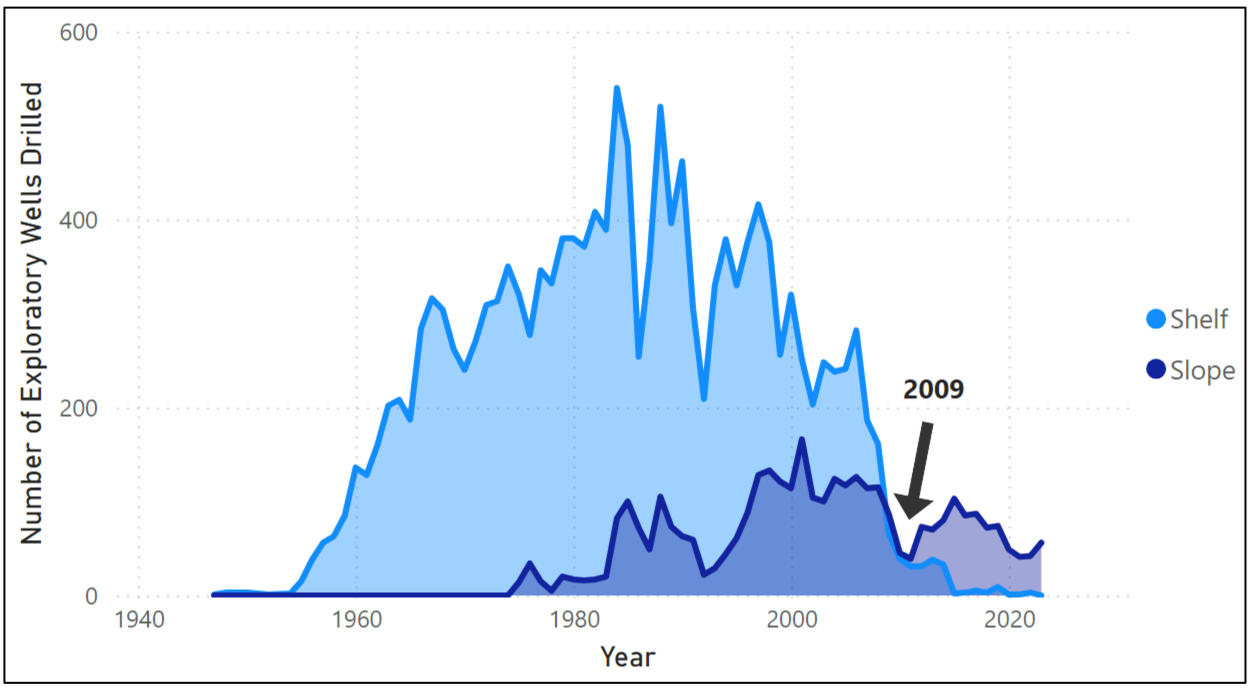

Figure 18. Exploratory Wells Drilled by Water Depth Over Time

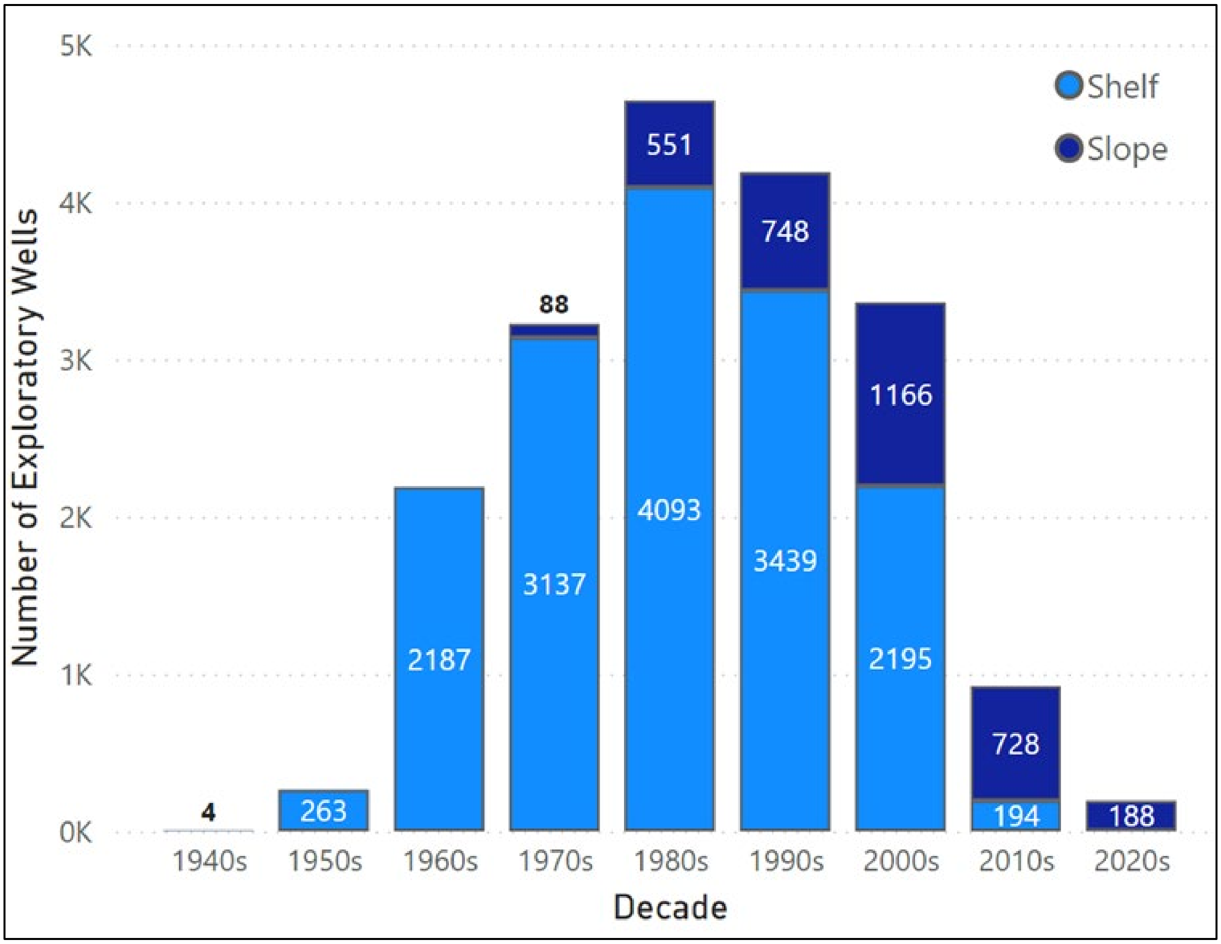

Figure 19. Number of Exploratory Wells Drilled by Water Depth Over Time

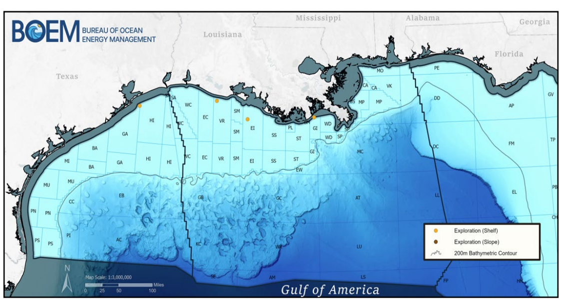

Figure 20. Exploratory Wells Drilled Over Time, 1940s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

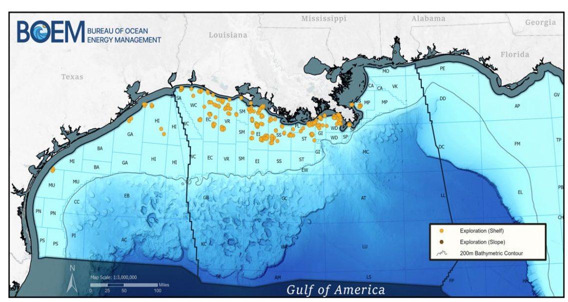

Figure 21. Exploratory Wells Drilled Over Time, 1950s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

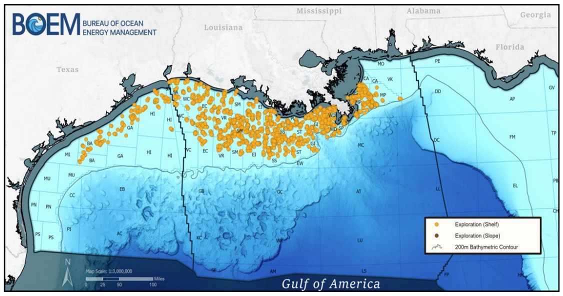

Figure 22. Exploratory Wells Drilled Over Time, 1960s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

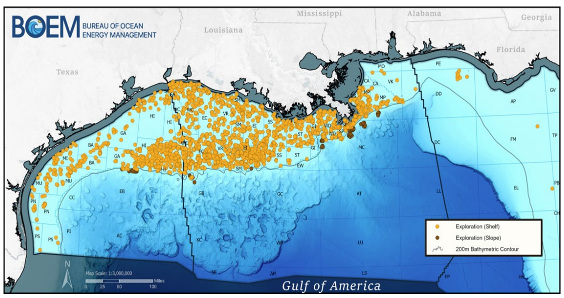

Figure 23. Exploratory Wells Drilled Over Time, 1970s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

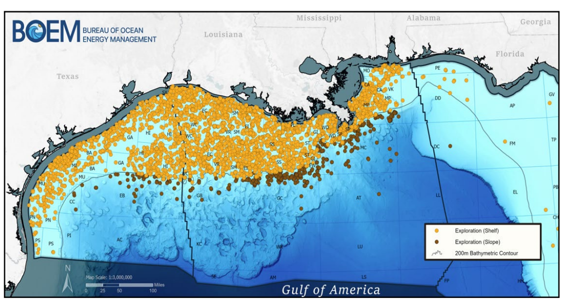

Figure 24. Exploratory Wells Drilled Over Time, 1980s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

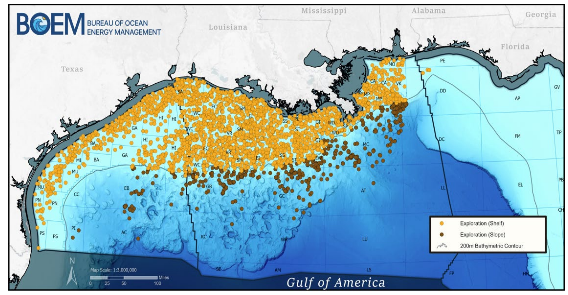

Figure 25. Exploratory Wells Drilled Over Time, 1990s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

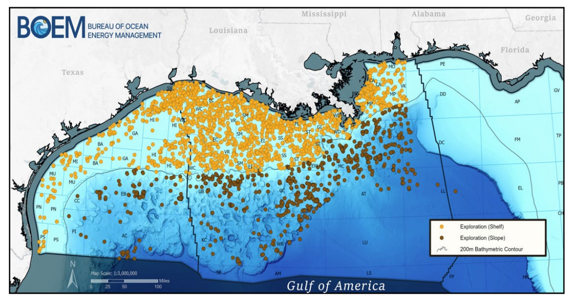

Figure 26. Exploratory Wells Drilled Over Time, 2000s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

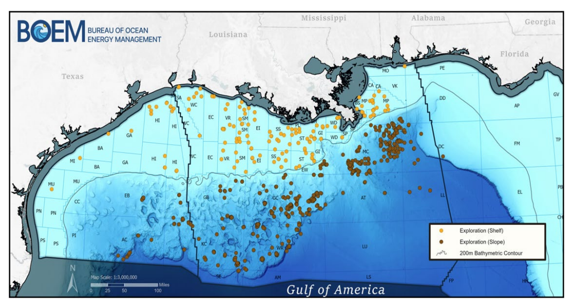

Figure 27. Exploratory Wells Drilled Over Time, 2010s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

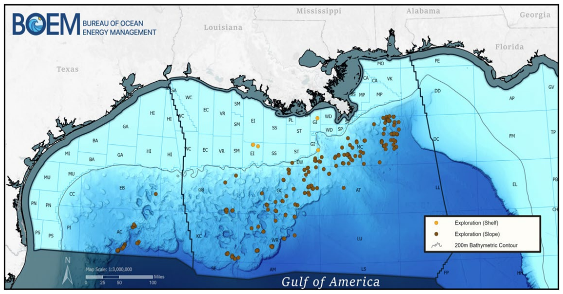

Figure 28. Exploratory Wells Drilled Over Time, 2020s. (Legend: The orange dots represent exploration wells drilled on the shelf and the brown dots represent exploration wells drilled on the slope).

8.2 DEVELOPMENT WELLS DRILLED BY WATER DEPTH OVER TIME

Historically, the GOA shelf was the center of offshore oil and gas production due to accessible reserves and simpler technology. As these mature shelf reserves declined, the industry began targeting deeper, less accessible resources. Today, technological advances have enabled the exploitation of high-volume reservoirs on the GOA slope. This shift makes the slope the leading source of production, despite requiring fewer, but more complex and expensive development wells.

Figure 29 and Figure 30 present the number of development wells drilled over time by water depth category. Shelf development drilling began to decline in the early 2000s but has stabilized over the past decade, with around 38 development wells drilled annually since 2015. Slope development drilling has held steady at about 44 wells per year since 2015, surpassing shelf development activity in 2018. The total footage of development wells drilled in 2023 was 1.43 million feet, compared to 1.63 million feet in 2019. Figure 31 through Figure 39 provide a spatial overview of development wells drilled by decade, showing a clear trend of oil and gas operations expanding into progressively deeper waters over time.

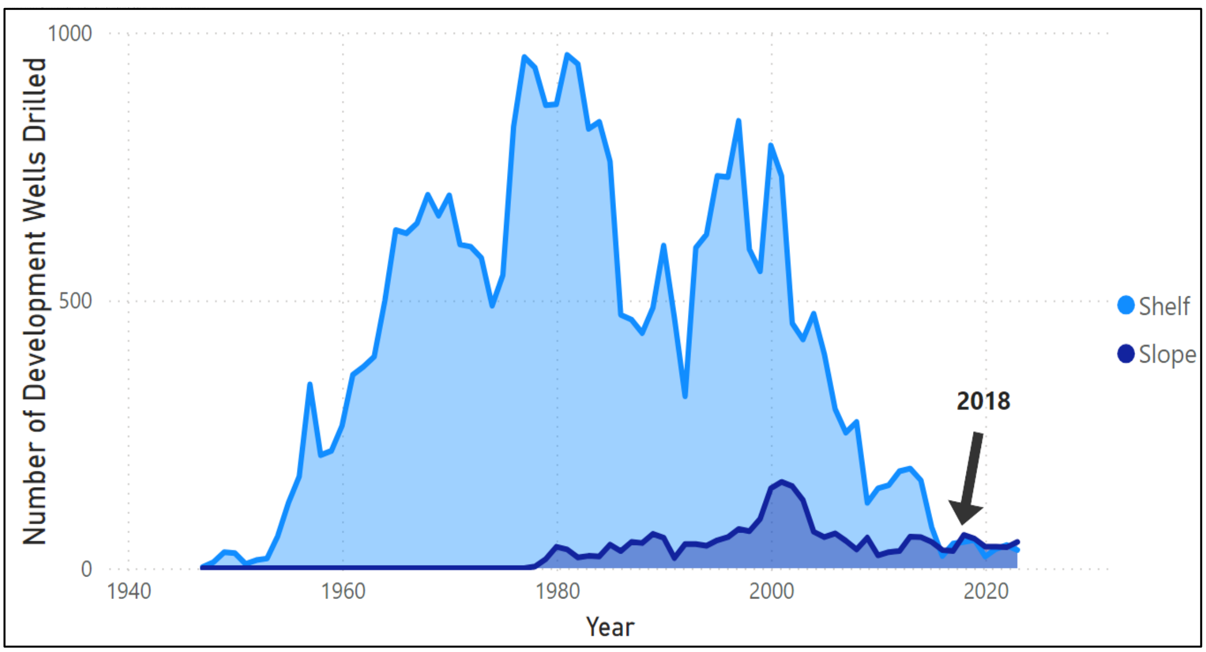

Figure 29. Development Wells Drilled by Water Depth Over Time

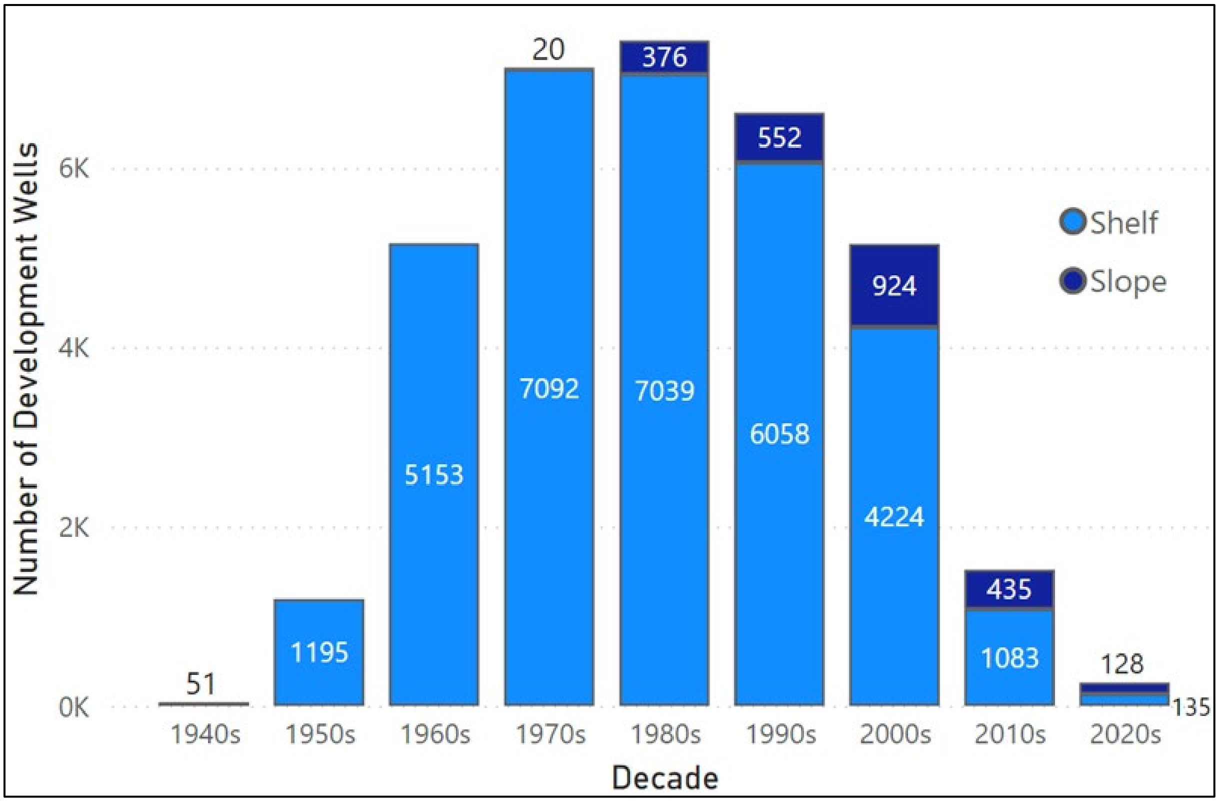

Figure 30. Number of Development Wells Drilled by Water Depth Over Time

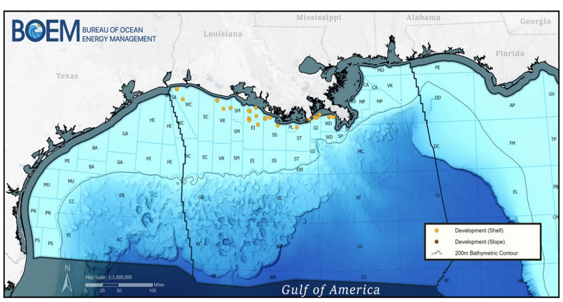

Figure 31. Development Wells Drilled Over Time, 1940s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

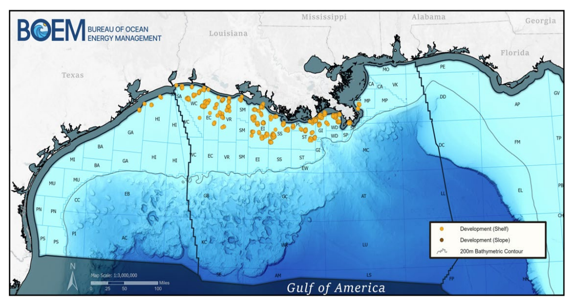

Figure 32. Development Wells Drilled Over Time, 1950s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

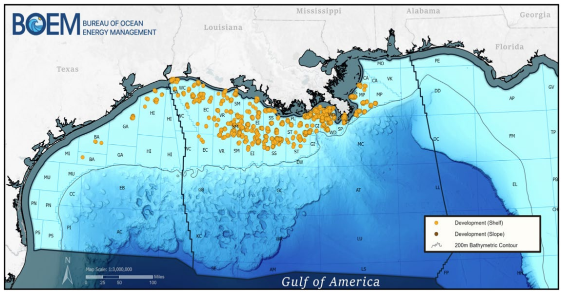

Figure 33. Development Wells Drilled Over Time, 1960s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

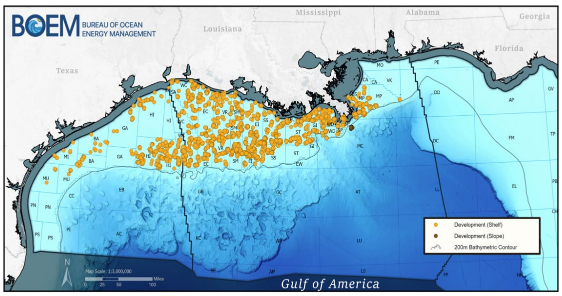

Figure 34. Development Wells Drilled Over Time, 1970s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

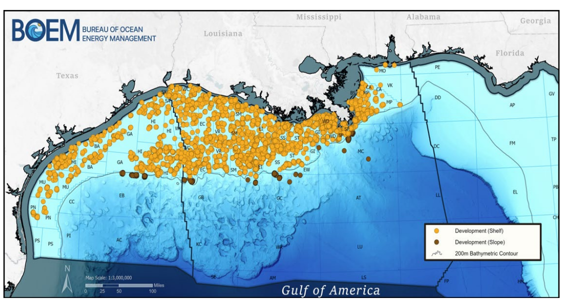

Figure 35. Development Wells Drilled Over Time, 1980s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

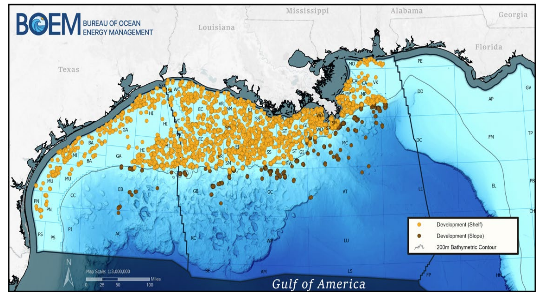

Figure 36. Development Wells Drilled Over Time, 1990s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

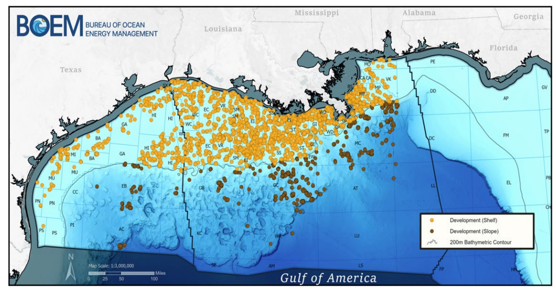

Figure 37. Development Wells Drilled Over Time, 2000s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

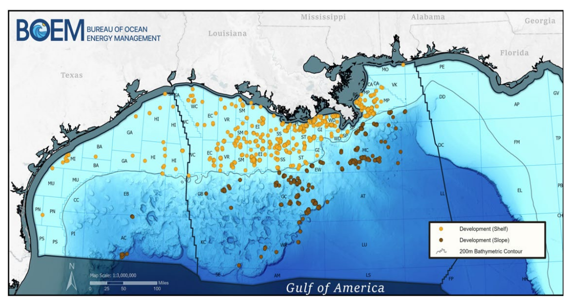

Figure 38. Development Wells Drilled Over Time, 2010s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

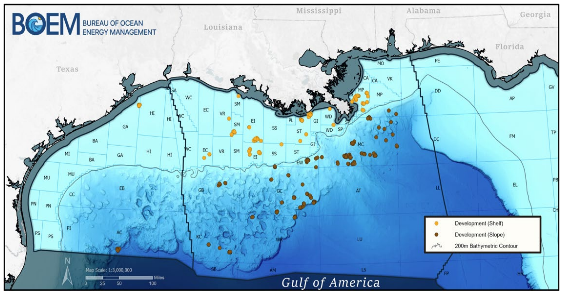

Figure 39. Development Wells Drilled Over Time, 2020s. (Legend: The orange dots represent development wells drilled on the shelf and the brown dots represent development wells drilled on the slope).

9.0 ORIGINAL RESERVES BY WATER DEPTH OVER TIME

Figure 40 presents annual discoveries of Original Reserves in BBOE on the GOA shelf and slope from 1947 to 2023. This figure highlights a distinct spatial shift in exploration and discovery activity. In the early years of offshore development, most discoveries were concentrated on the shelf. However, over time, the data clearly shows a migration of exploration efforts toward the deeper waters of the GOA slope. This trend underscores the industry's response to maturing shelf plays, advancements in deepwater technology, and the pursuit of untapped hydrocarbon potential in more geologically complex and technically challenging environments.

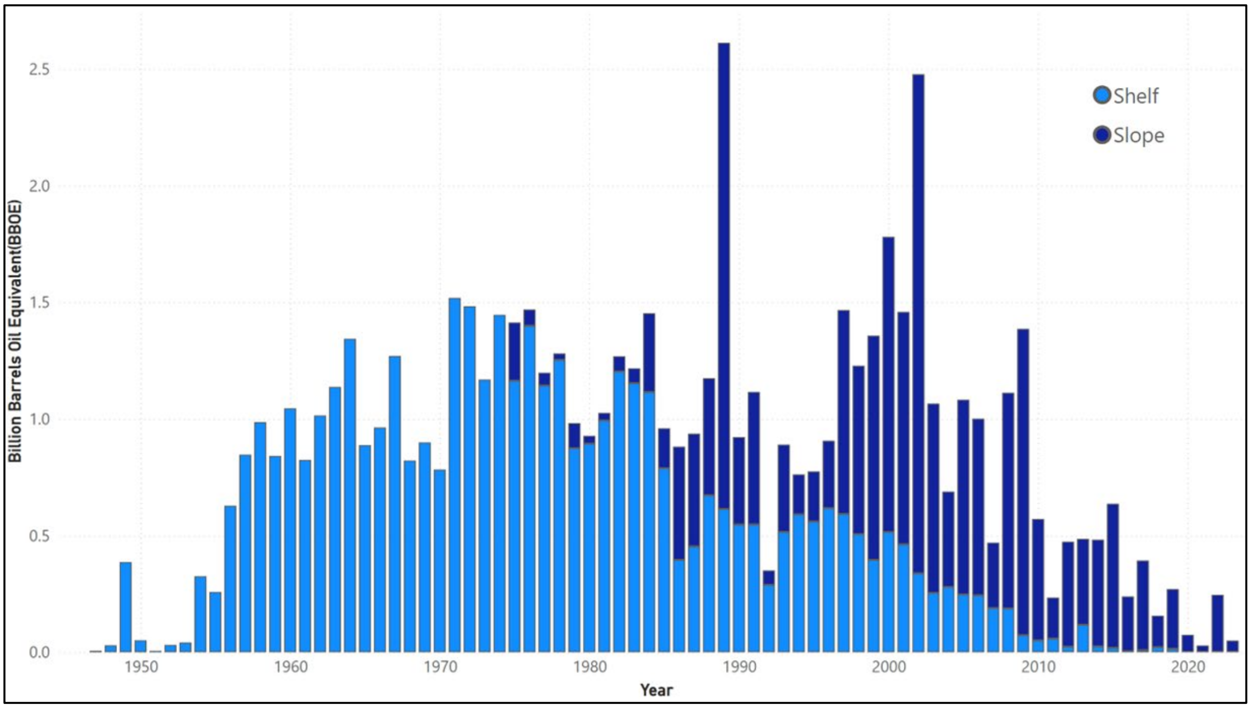

Figure 40. Original Reserves Discovered by Year on the Shelf vs Slope

10.0 ANNUAL OIL AND GAS PRODUCTION

Annual production in the GOA is shown on Figure 41 through Figure 43. The oil plot includes condensate, and the gas plot includes casinghead gas. From a peak of 693 million barrels (MMbbl) in 2019, annual oil production showed an overall decrease of 1.7% to 681 MMbbl in 2023. Annual gas production also decreased by 28% from 2019 to 2023, with 0.75 Tcf produced in 2023. The mean daily production during 2023 was 1.82 MMbbl of crude oil, 0.05 MMbbl of gas condensate, 1.64 billion cubic feet (Bcf) of casinghead gas, and 0.42 Bcf of gas-well gas. The mean GOR of oil wells was 900 scf/stb, and the mean yield from gas wells was 111 bbl of condensate per MMcf of gas. These figures further illustrate a shift in oil and gas activity toward the deeper waters of the GOA slope, with slope oil production overtaking shelf production in 2000, and slope gas production surpassing shelf gas production in 2014.

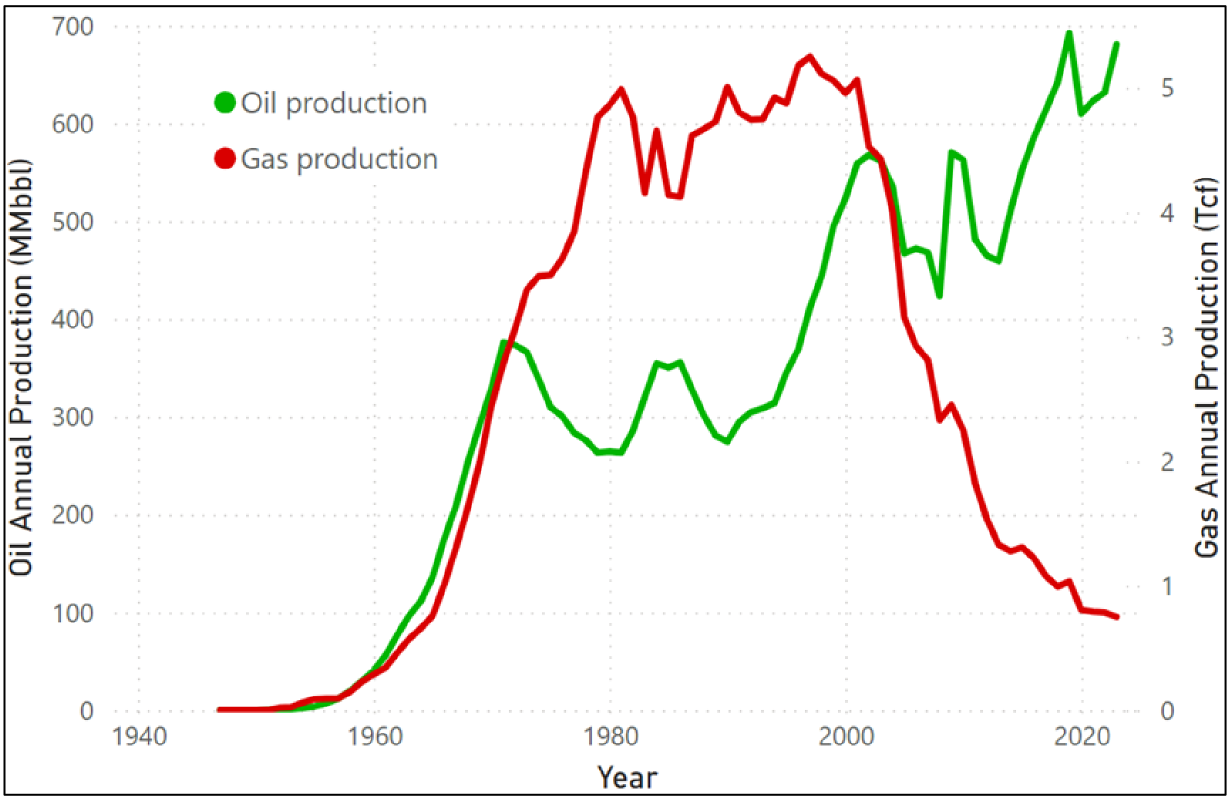

Figure 41. Annual Oil and Gas Production in the GOA

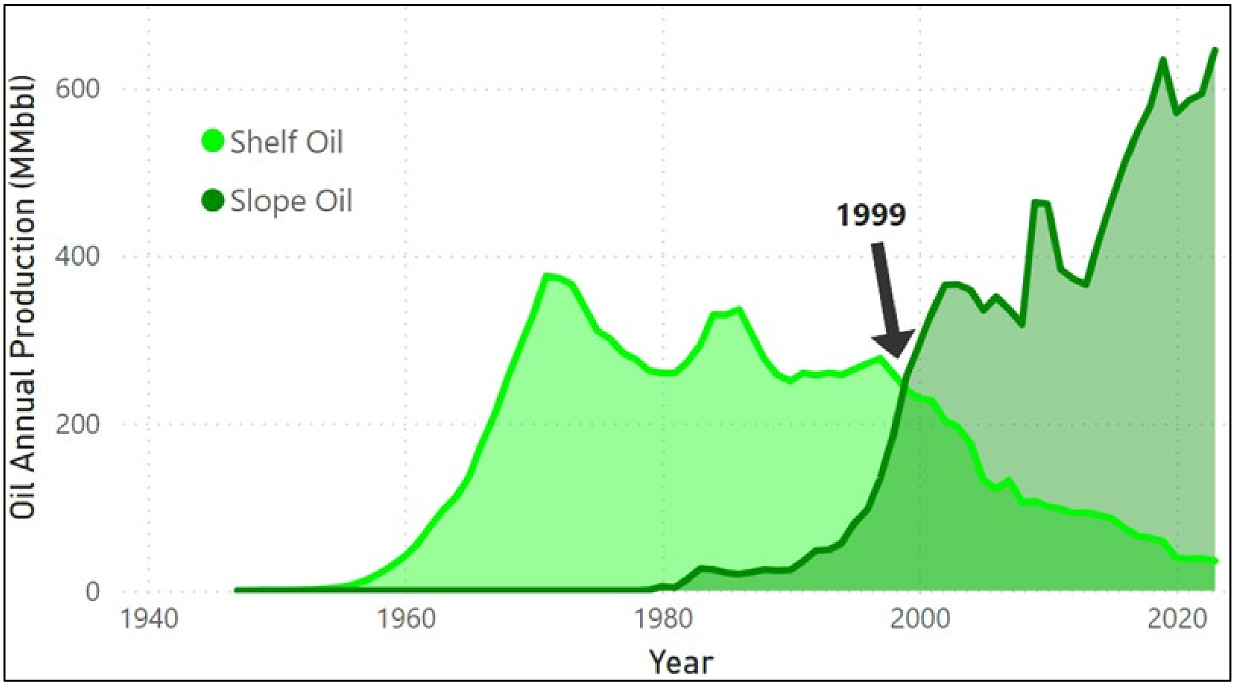

Figure 42. Shelf versus Slope Oil Production Over Time (denoted on the chart is the shelf/slope intersect)

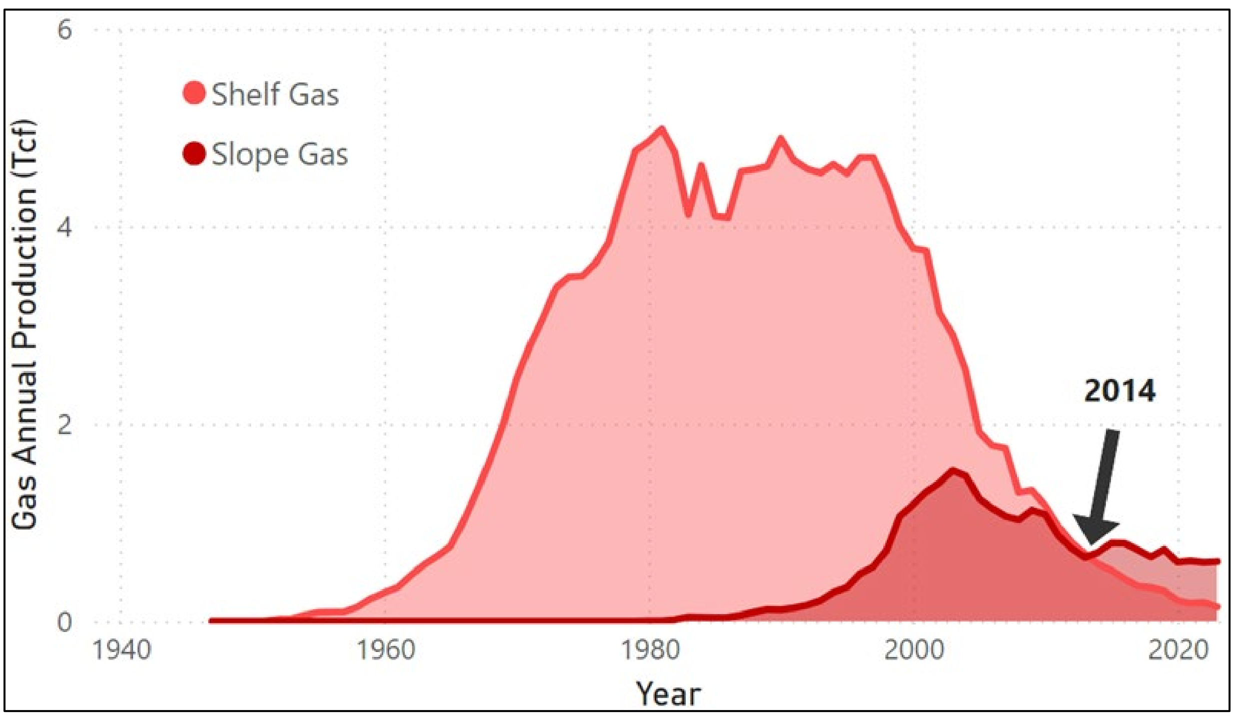

Figure 43. Shelf versus Slope Gas Production Over Time (denoted on the chart is the shelf/slope intersect)

11.0 DEVELOPMENT BY ASSESSMENT UNIT

This section provides graphical representations of reservoir and production data for 11 Cenozoic assessment units, as well as 2 Mesozoic plays. Assessment units consist of groups of geologically related hydrocarbon accumulations, with the term “Assessment Unit” referring to classifications based on chronozones and/or geological plays. The means from each reservoir within an assessment unit or play were aggregated to create graphs that illustrate the total reserves volume discovered each year (2023 reserves are represented by total mean reserves), the number of reservoirs identified within the unit, the production from these reservoirs, and the average size of each reservoir in the unit.

Assessment units are delineated based on water depth distinctions between the shelf and slope (Figure 39), as well as the geological age of Cenozoic sediments within the GOA OCS. Using these criteria, the Cenozoic section is subdivided into 12 assessment units, as detailed in Table 6. However, only 11 of these units are accompanied by figures, since the Lower Tertiary Shelf unit lacks reserves or production data.

Table 6. Twelve Cenozoic Assessment Units

Pleistocene Shelf	Pleistocene Slope
Pliocene Shelf	Pliocene Slope
Upper Miocene Shelf	Upper Miocene Slope
Middle Miocene Shelf	Middle Miocene Slope
Lower Miocene Shelf	Lower Miocene Slope
Lower Tertiary Shelf	Lower Tertiary Slope

In contrast to the aggregated assessment units of Cenozoic sediments, the Mesozoic sediments of the GOA OCS are classified by specific rock units or plays. This report specifically highlights two Mesozoic plays: the James Play and the Norphlet Play. These plays are included due to their associated reserves and production.

The data presented in this section reveals the lag time between reserves discovery and production, highlighting a shift in exploration and development from shelf to slope areas. While shelf Cenozoic data shows significant production decline, the development of discoveries in slope Cenozoic sediments has helped to mitigate these declines. Reserves and production data are available for the two assessment units within Mesozoic-aged sediments. This data indicates that the James play has matured with few additional opportunities anticipated. The Norphlet Play, however, has future opportunities. The expected range of undiscovered resources are described in the report titled “2021 Assessment of Technically and Economically Recoverable Oil and Natural Gas Resources of the Gulf of Mexico Outer Continental Shelf (OCS Report BOEM 2021-082).”

Pleistocene

Figure 44 and Figure 45 show the decline in volume of reserves discovered, number of reservoirs discovered, and production for the shelf and slope Pleistocene assessment units. The largest total Pleistocene shelf reserves discovered in a single year occurred in 1971, which included 2 large shelf reservoirs, one in the Eugene Island 296 Field and two in the Eugene Island 330 Field, containing 203 million barrels of oil equivalent (MMBOE). All three reservoirs are now depleted. A peak in the volume of Pleistocene reserves on the slope occurs in 1997. This is associated with discoveries in the Troika (Green Canyon 244) and Hoover (Alaminos Canyon 25) Fields and is also reflected in the average reservoir size. Production on the slope peaked in 2001 and, overall, have declined since. The data indicates this is associated with a significant decrease in reserves discovered on the slope.

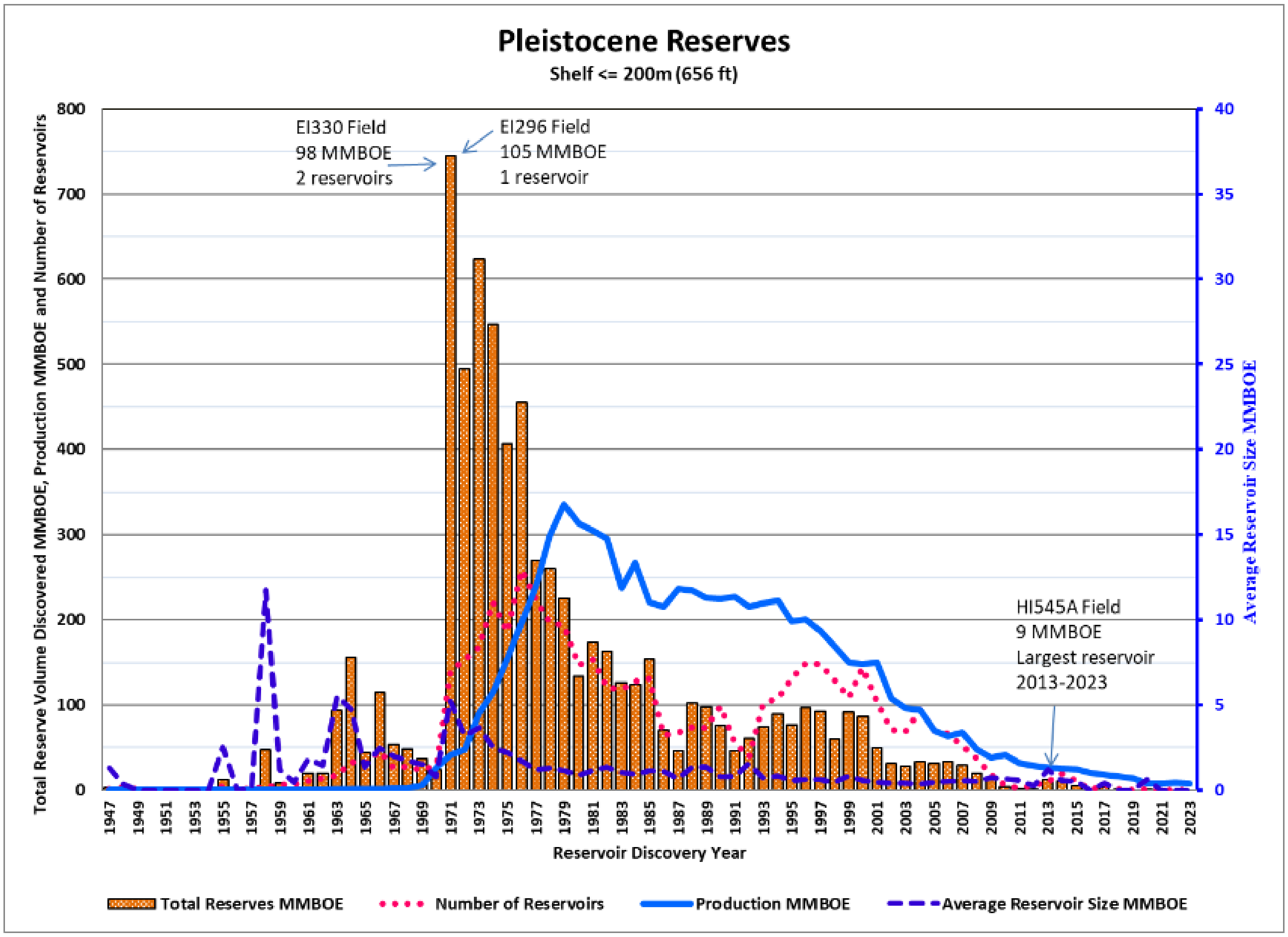

Figure 44. Pleistocene Shelf Development

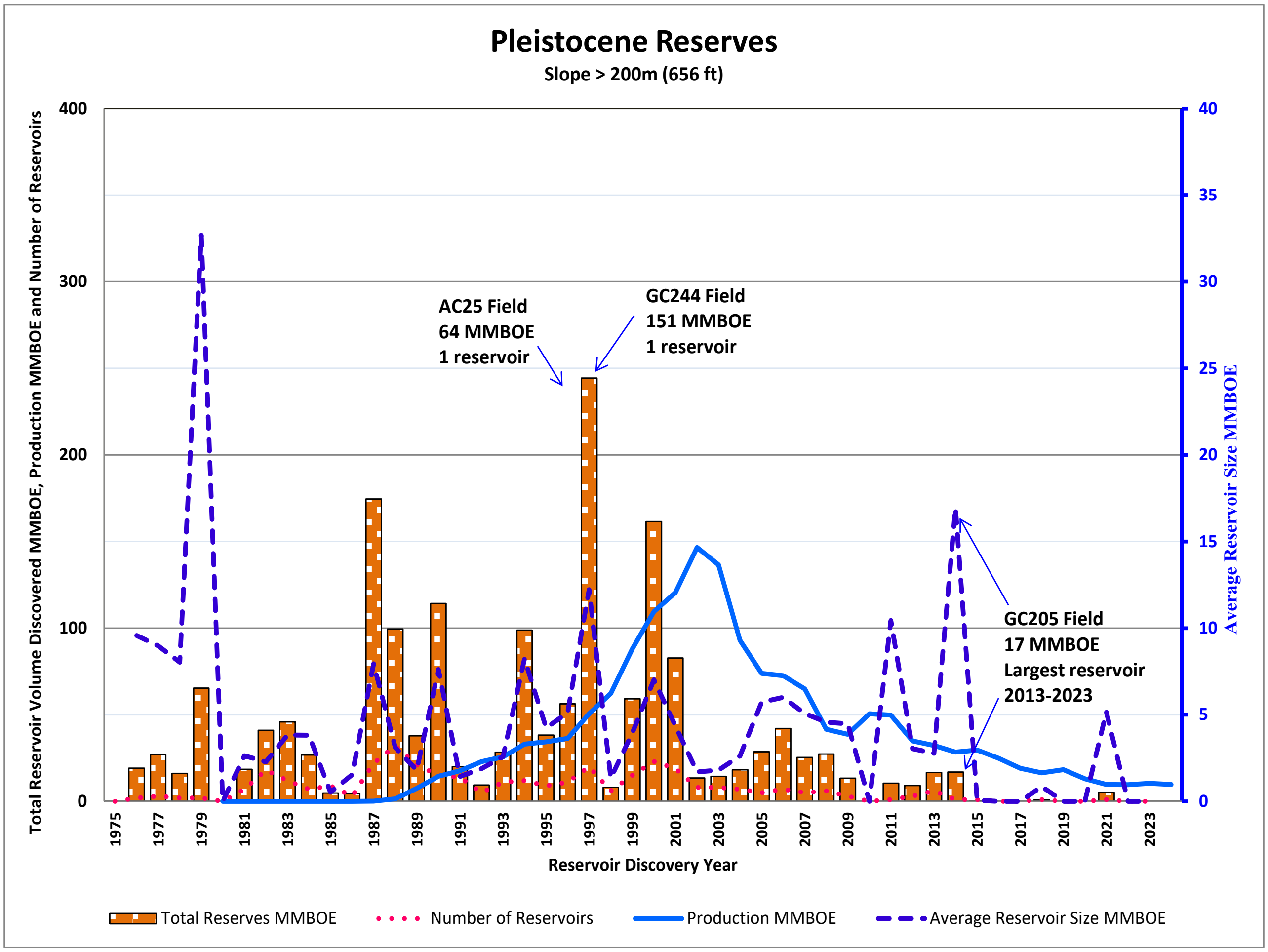

Figure 45. Pleistocene Slope Development

Pliocene

Both the production and number of reservoirs discovered have decreased consistently since 1997 in Pliocene shelf fields. Total reserves discovered during 2023 continued this trend, with a 78.5% decrease since 2019. On the slope, Pliocene production rates have been considerably higher than on the shelf for the last 15 years (Figure 46). Slope production rates have remained between 70-125 MMBOE since 2013 (Figure 47).

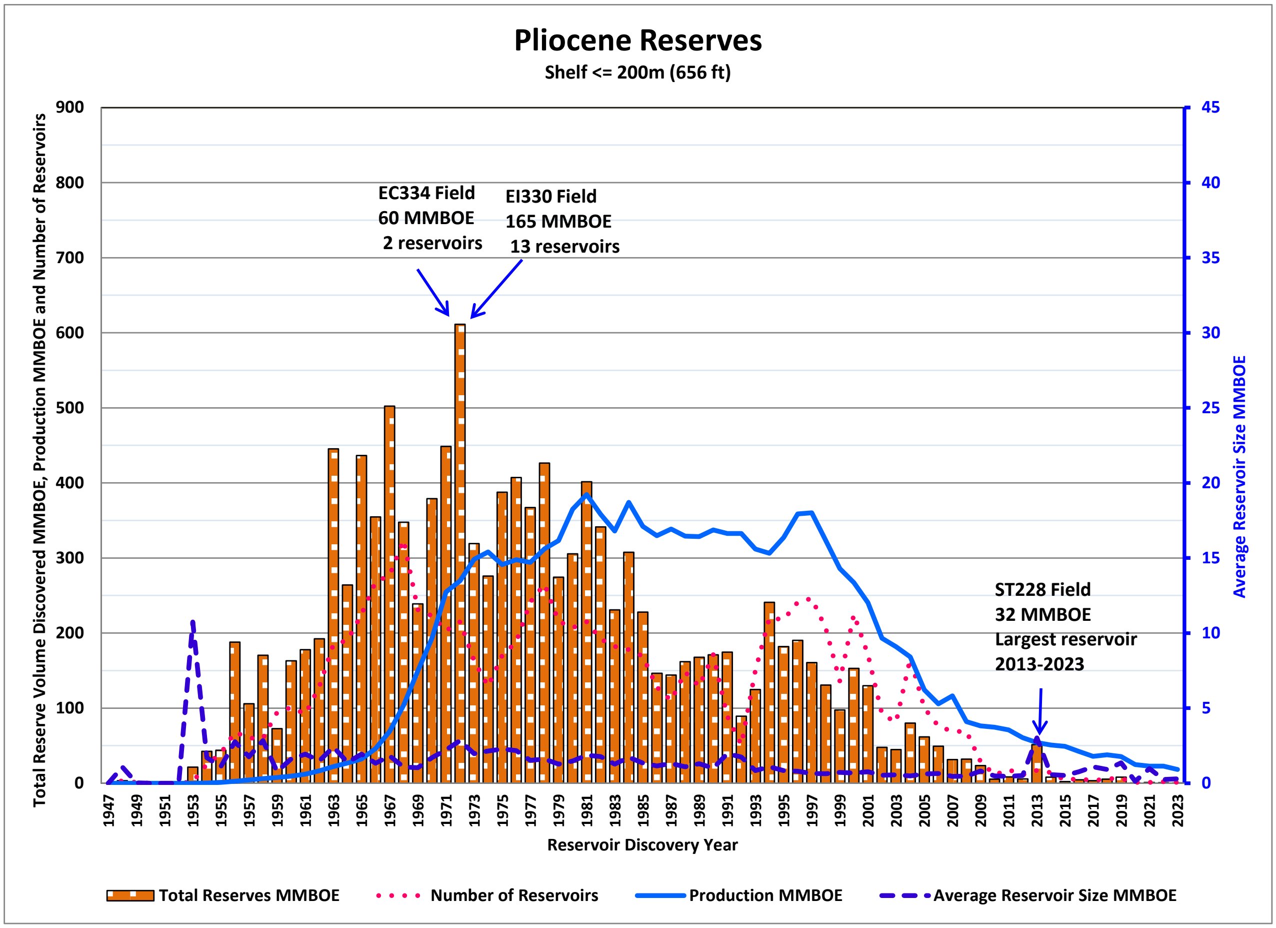

Figure 46. Pliocene Shelf Development

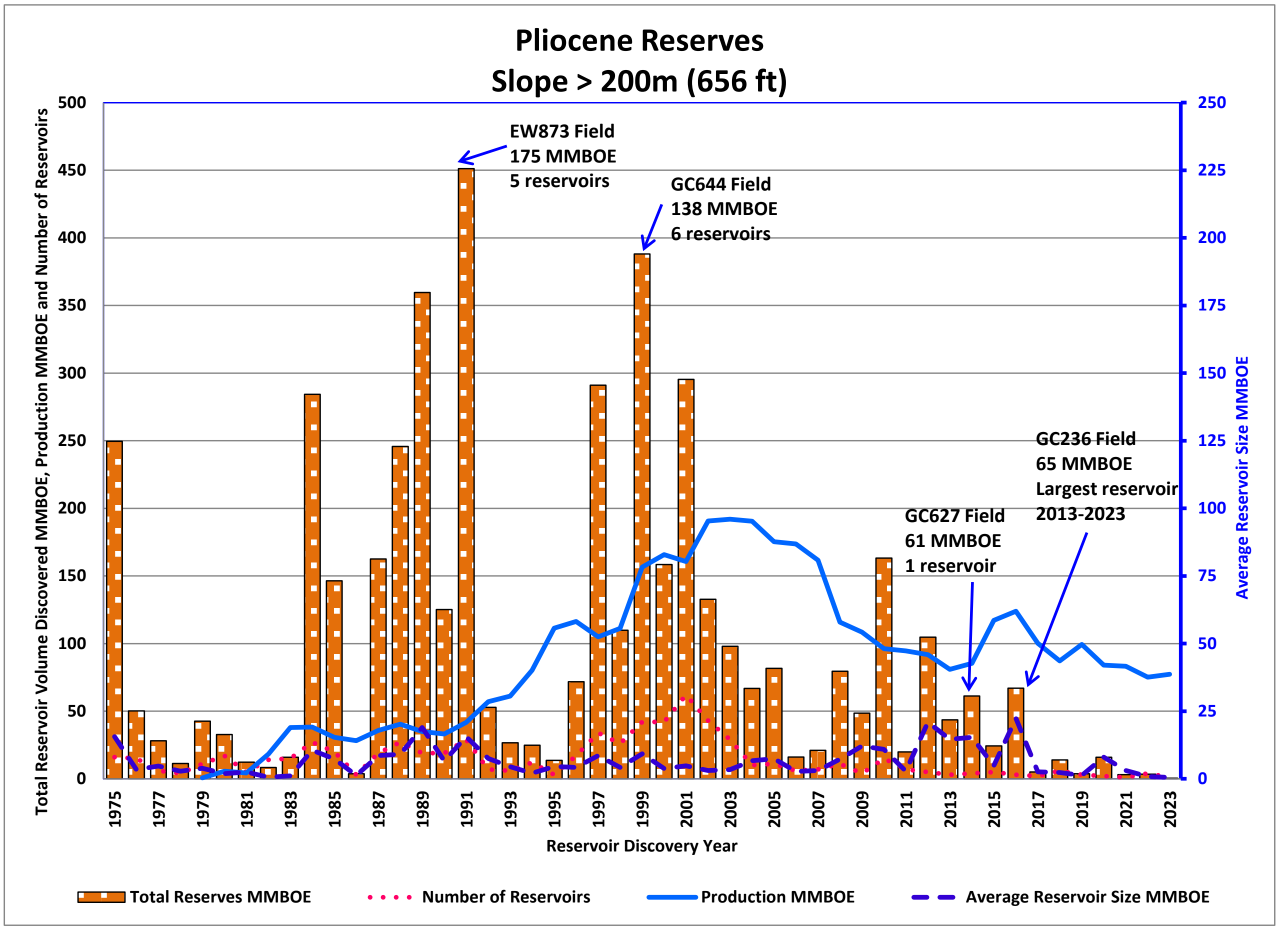

Figure 47. Pliocene Slope Development

Upper Miocene

For the Upper Miocene shelf, both the production and the number of reservoirs discovered have decreased since 1998 (Figure 48). On the slope, reserves discovered peaked in 1989 with discoveries in the Mars (Mississippi Canyon 807) Field and the Pompano (Viosca Knoll 990) Field (Figure 49). Discoveries in 2014 and 2015 in the Kaikias (Mississippi Canyon 768) Field caused an increase in total reserves discovered during that time. While there has been an overall decrease in average reservoir size since 2015, there has been a slight increase in the production rate.

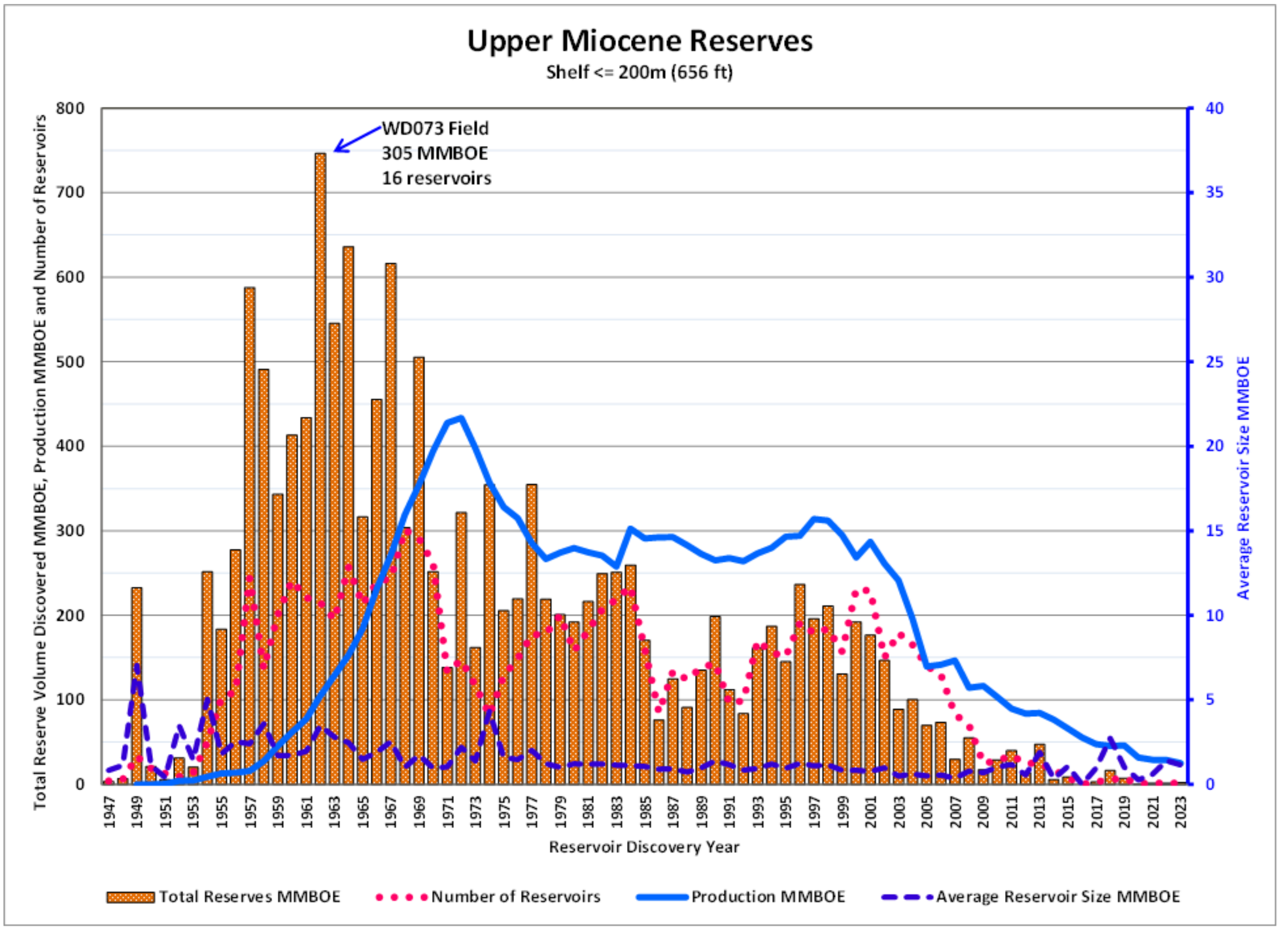

Figure 48. Upper Miocene Shelf Development

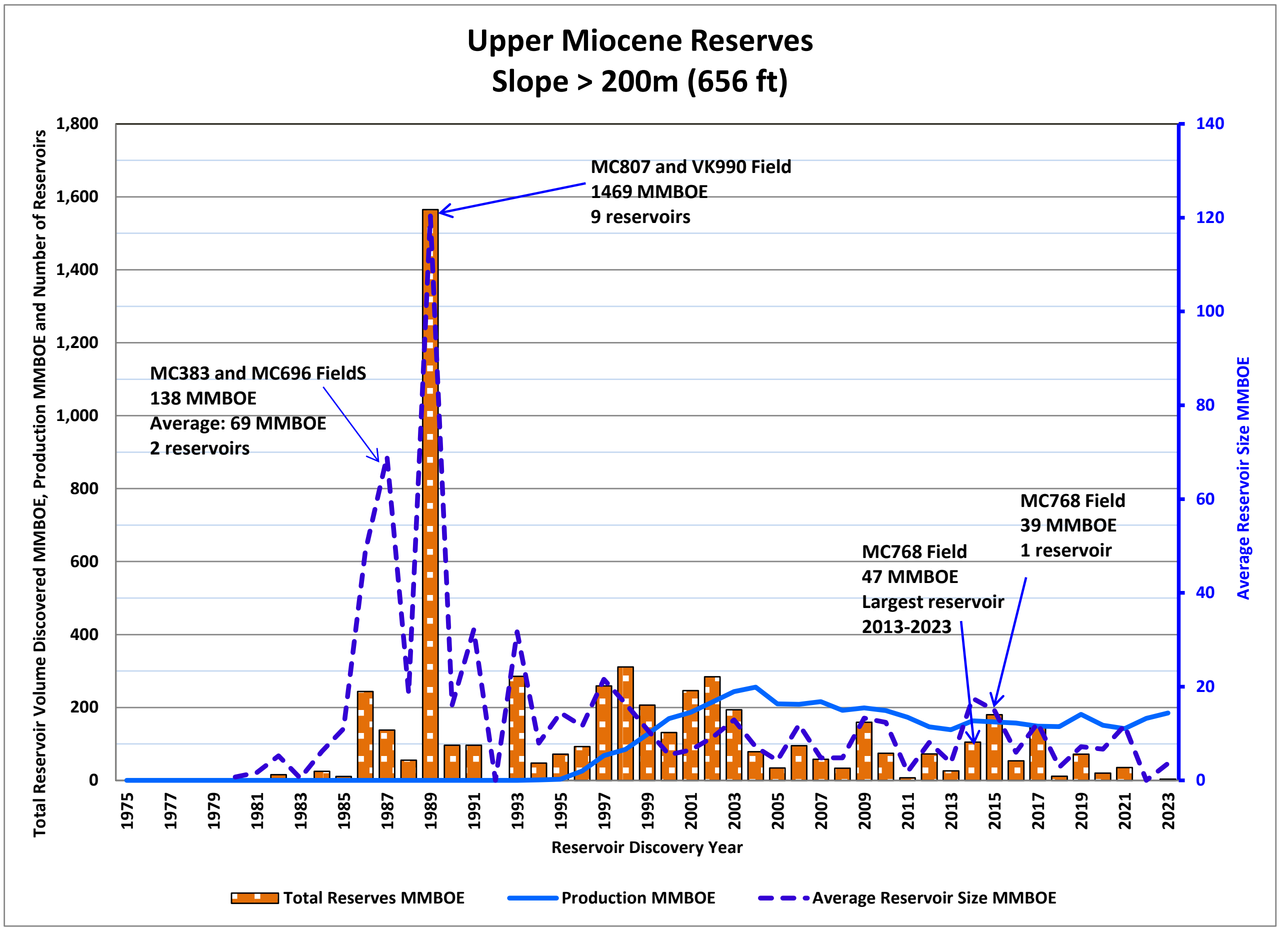

Figure 49. Upper Miocene Slope Development

Middle Miocene

The total reserves discovered as well as average reservoir size and production on the Middle Miocene shelf have all remained consistently low over the last decade (Figure 50). The Middle Miocene slope is highlighted by discoveries in the Thunder Horse North (Mississippi Canyon 776) Field, the Atlantis (Green Canyon 743) Field, and the Tahiti (Green Canyon 640) Field. The Middle Miocene slope has experienced an overall rise in production since 2013, yet no new discoveries since 2020 (Figure 51).

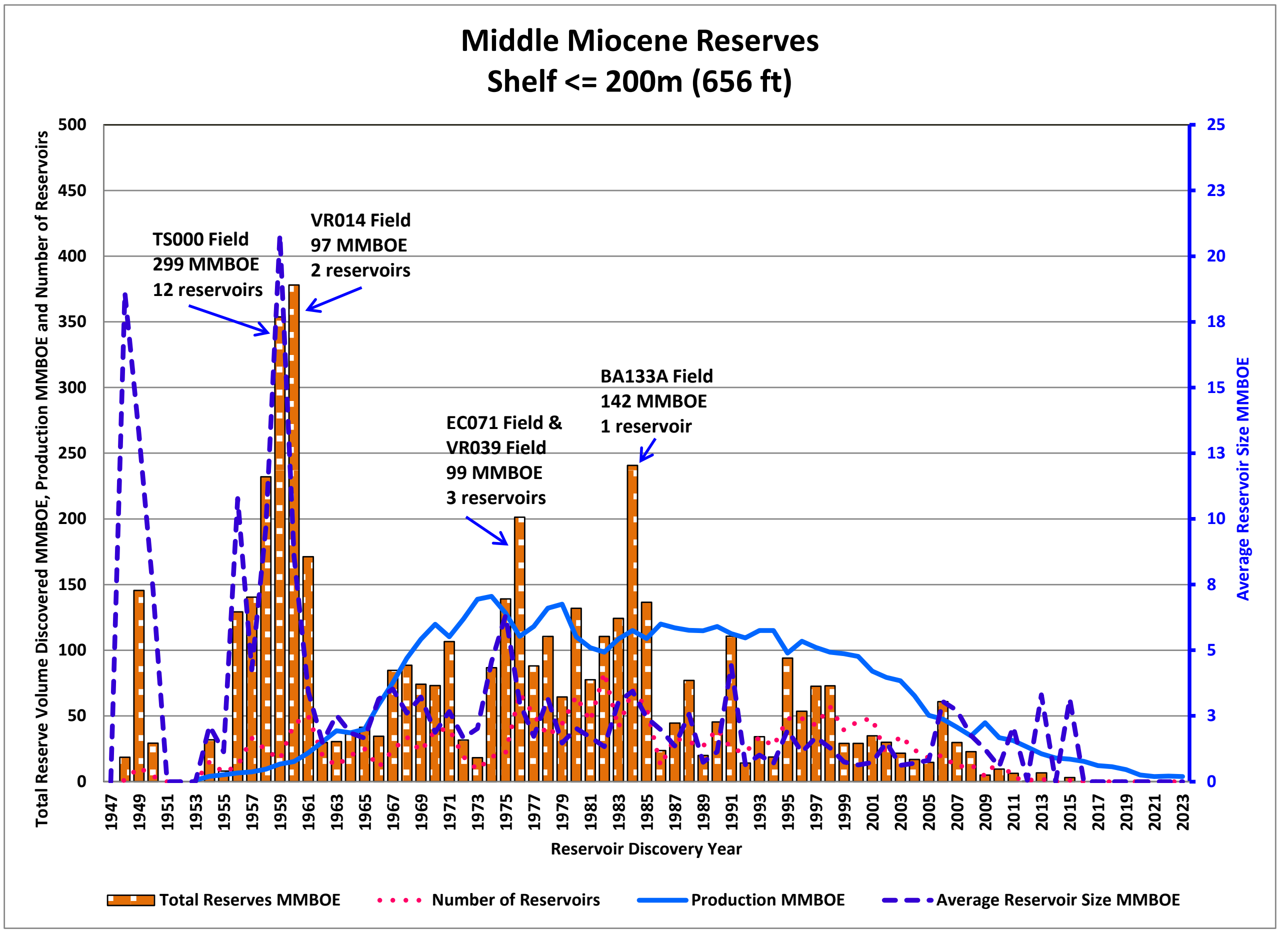

Figure 50. Middle Miocene Shelf Development

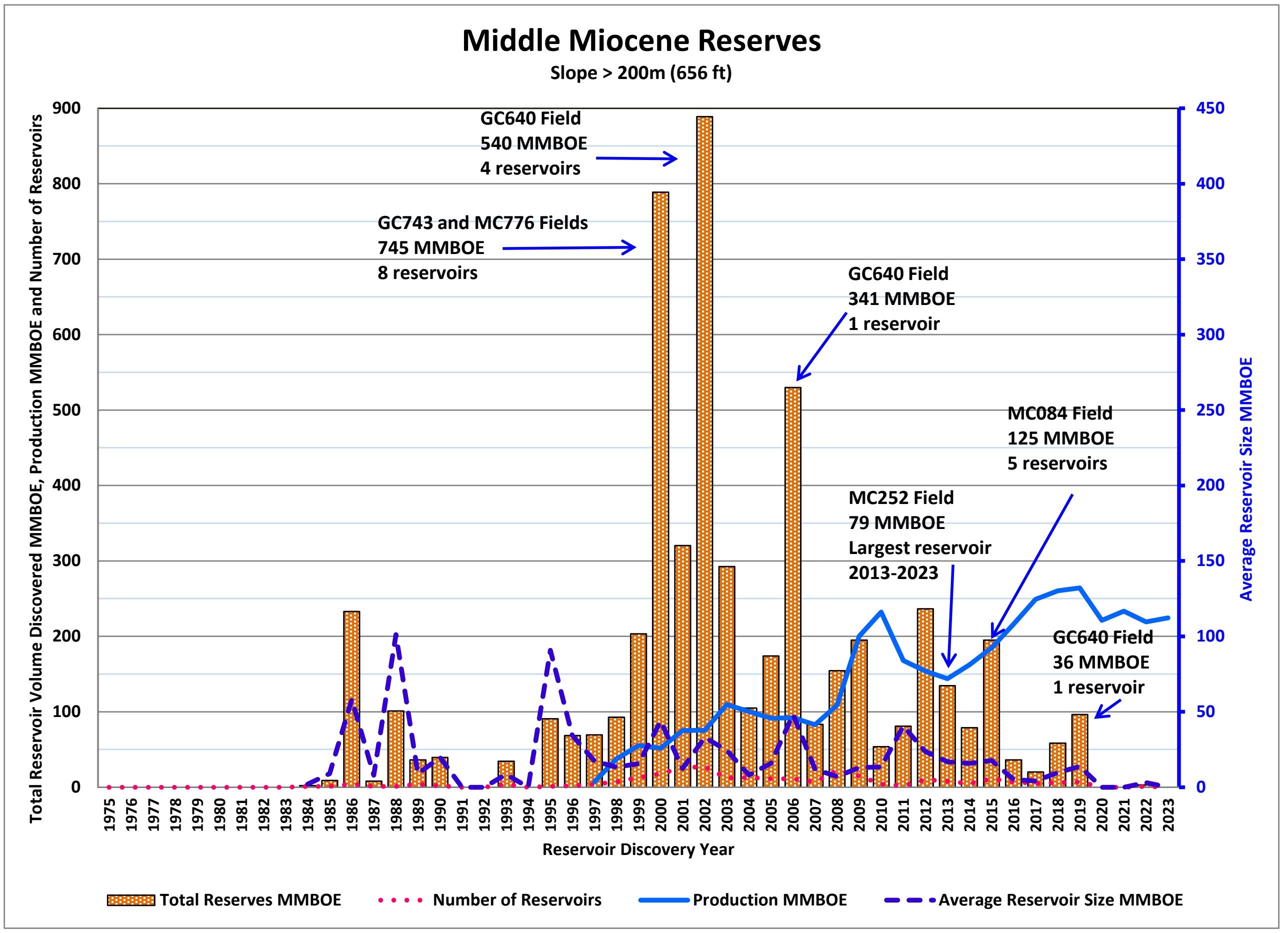

Figure 51. Middle Miocene Slope Development

Lower Miocene

Reserves on the Lower Miocene shelf peaked in 1982 (Figure 52), with a peak in production occurring in 1990, followed by an overall decline to date. The first discoveries on the Lower Miocene slope occurred in the Neptune (Atwater Valley 575) Field and Mad Dog (Green Canyon 826) Field. A major discovery of 386 MMBOE was later made in the Shenzi (Green Canyon 654) Field, followed by the discovery of 361 MMBOE across two reservoirs in the Vito (Mississippi Canyon 940) Field in 2009 (Figure 53). The largest average reservoir size was seen in 2010, with just over 225 MMBOE. Lower Miocene production peaked in 2009, followed by a slight decline until 2011. Production held steady until 2022, when it experienced a significant increase, surpassing the previous high set in 2009.

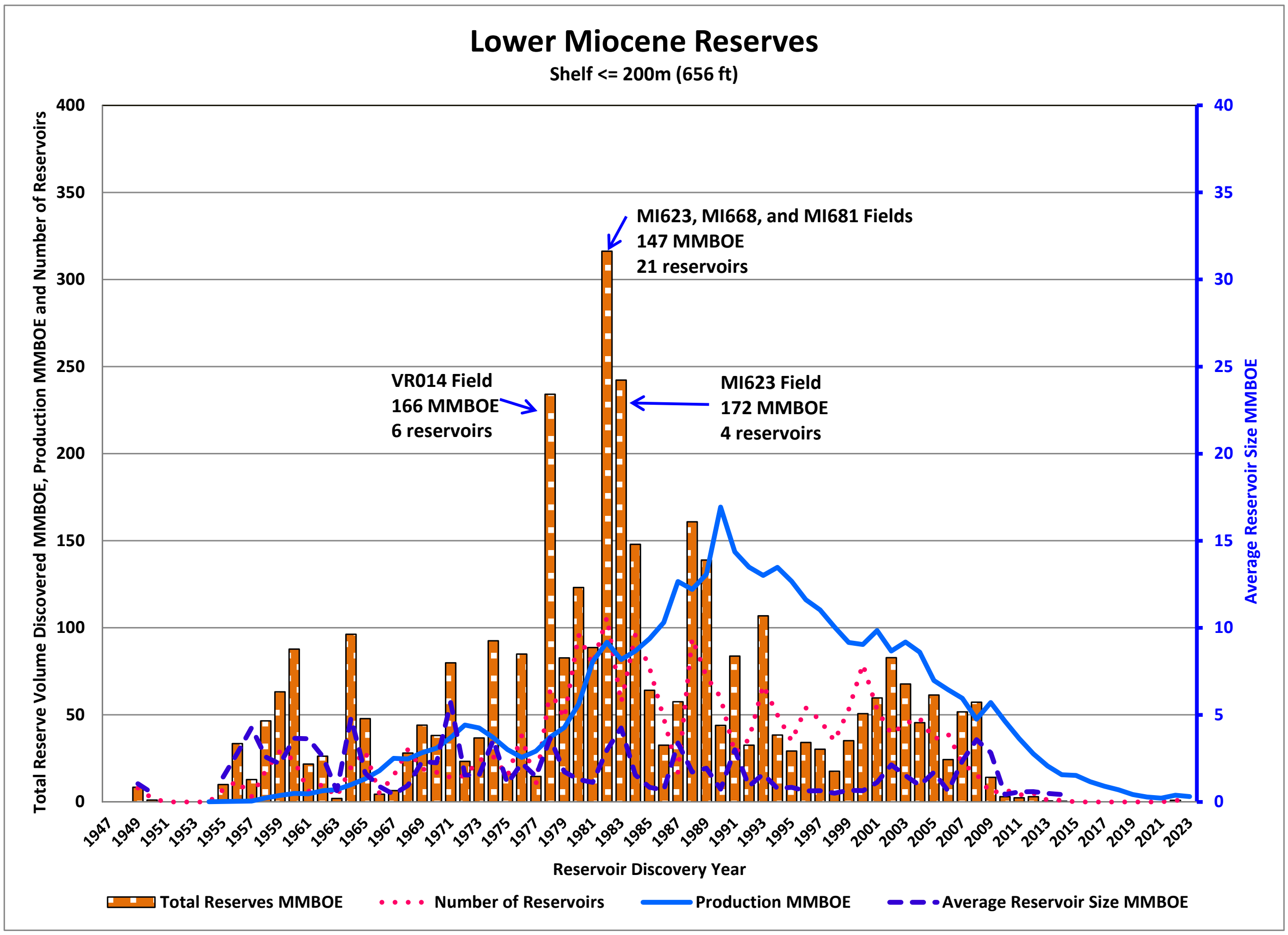

Figure 52. Lower Miocene Shelf Development

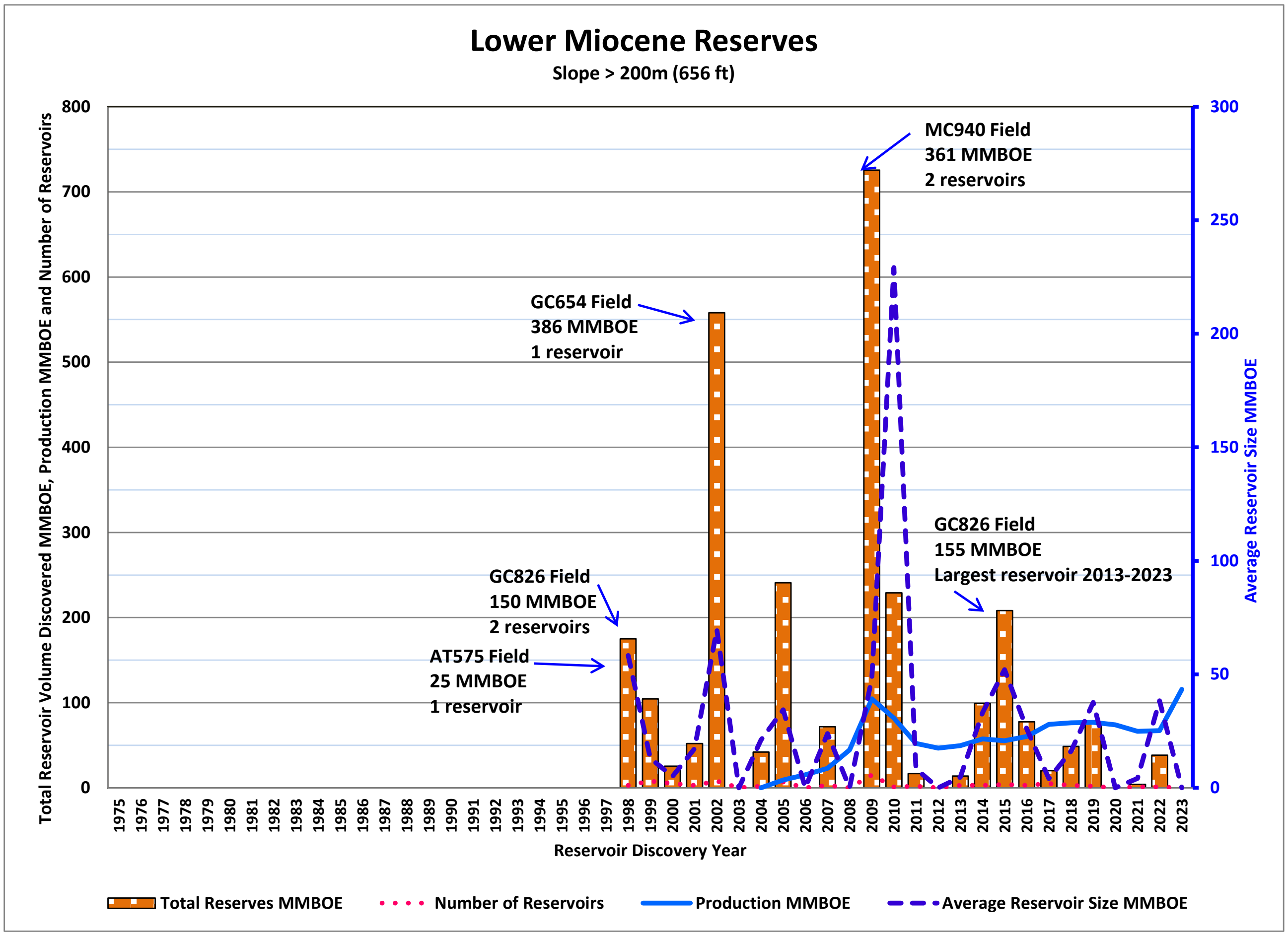

Figure 53. Lower Miocene Slope Development

Lower Tertiary

The Lower Tertiary play (Figure 54) was first confirmed in 1996 at the Baha prospect in Alaminos Canyon Block 600, proving a new exploration play in the deepwater. In 2002, the Great White (Alaminos Canyon 857) Field was discovered comprising several reservoirs, with one reservoir containing over 160 MMBOE. The largest average reservoir size of 90 MMBOE in the play occurred in 2022 with the discovery of a single reservoir in the Buckskin (Keathley Canyon 872) Field. The discovery of the largest total reserves in a single year for the Lower Tertiary occurred in 2008, which included the addition of 211 MMBOE from two reservoirs in the St. Malo (Walker Ridge 678) Field. Production in this play began in 2010, increased until 2019, and has remained steady to date.

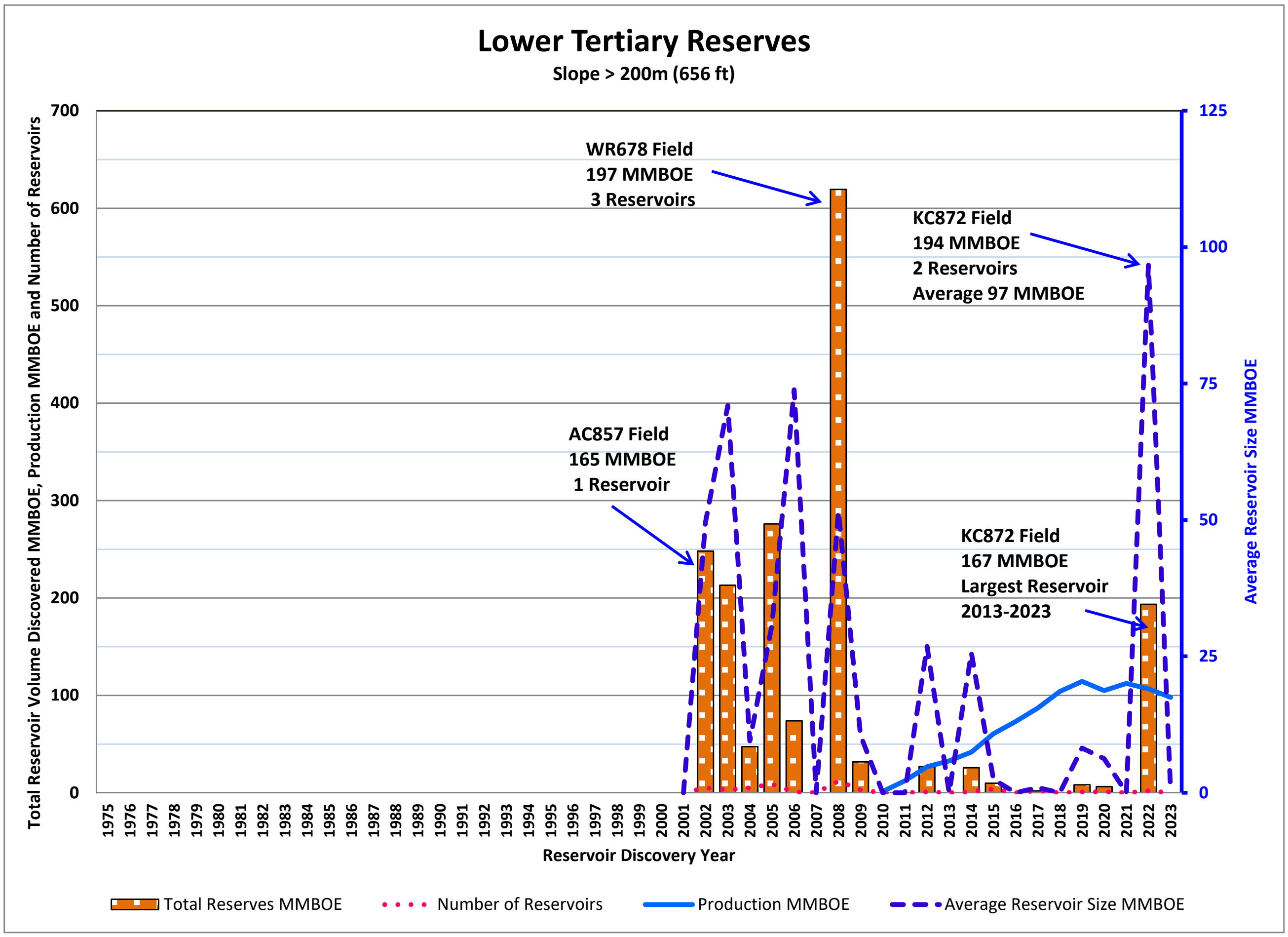

Figure 54. Lower Tertiary Slope Development

James

The first discovery in the James play came in 1993. In 1997, 5 reservoirs were discovered across the VK069, VK114, and VK251 fields, containing 33 MMBOE, which is the greatest total reserves discovered for the play (Figure 55). Production in this play peaked in 2002 with a subsequent rapid decline.

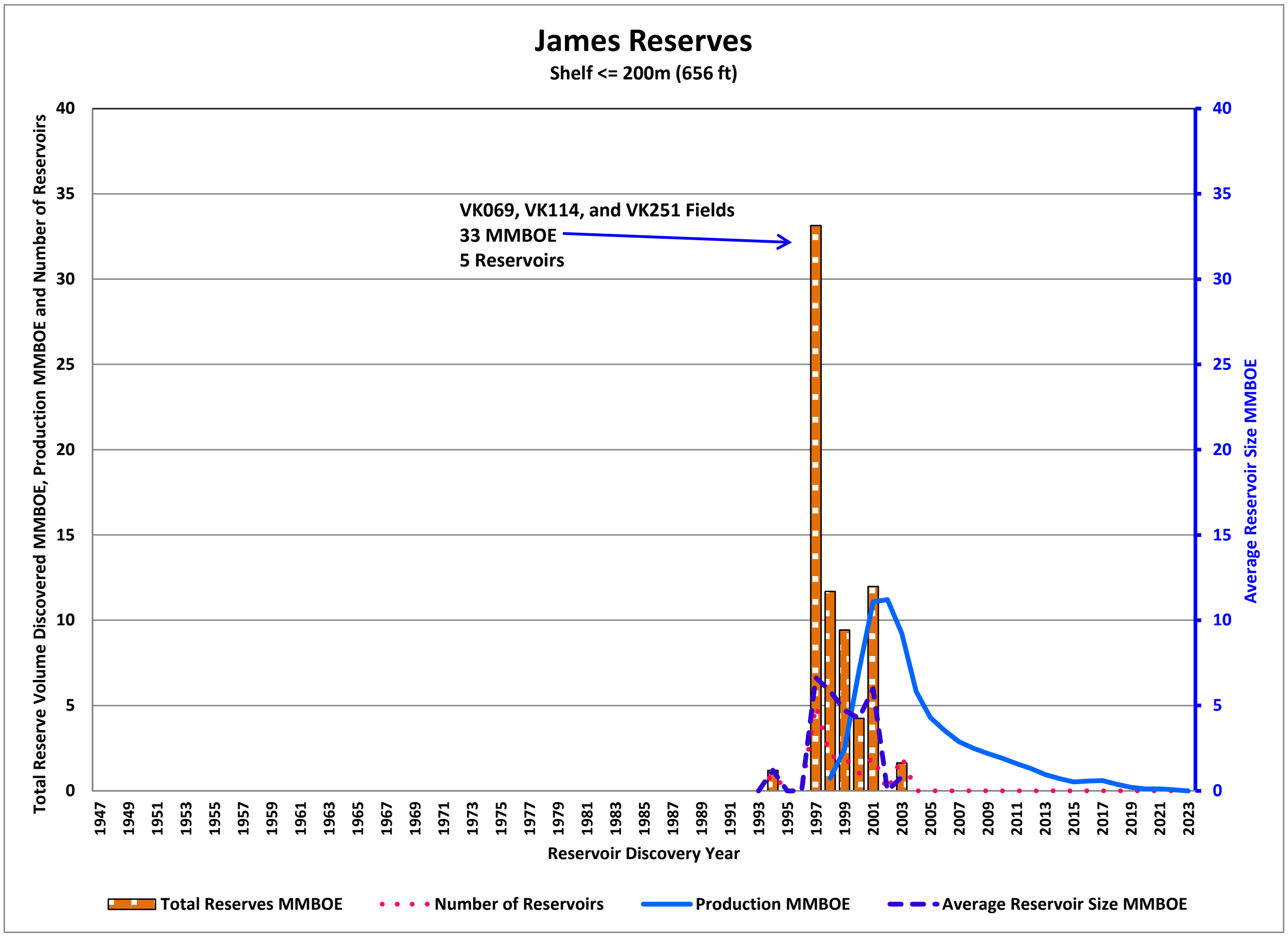

Figure 55. James Shelf Development

Norphlet

The 1983 discovery in the MO823 Field yielded the largest total reserves on the Norphlet shelf (Figure 56). All fields discovered on the Norphlet Shelf were gas, with production beginning in 1991 and additional discoveries continuing into the mid-1990s. Norphlet shelf production peaked in 1997 and has steadily declined since. The initial Norphlet slope discovery was made in 2003 with the Shiloh prospect in DeSoto Canyon Block 269; however, the discovery did not contain commercial quantities of oil. In 2007, a discovery was made in the Vicksburg (Mississippi Canyon 393) Field, with subsequent reserve additions in this field confirmed in 2013 through further appraisal and delineation. This was followed by a discovery in 2009 in the Appomattox (Mississippi Canyon 392) Field, which holds both the largest total discovered reserves and average reservoir size. All discoveries on the Norphlet slope are oil reservoirs, underscoring the region's significance as a major oil-producing trend. Appomattox was the first field to produce on the Norphlet slope, with production beginning in 2019 and increasing rapidly until 2022, where it encountered a slight decline until 2023 (Figure 57).

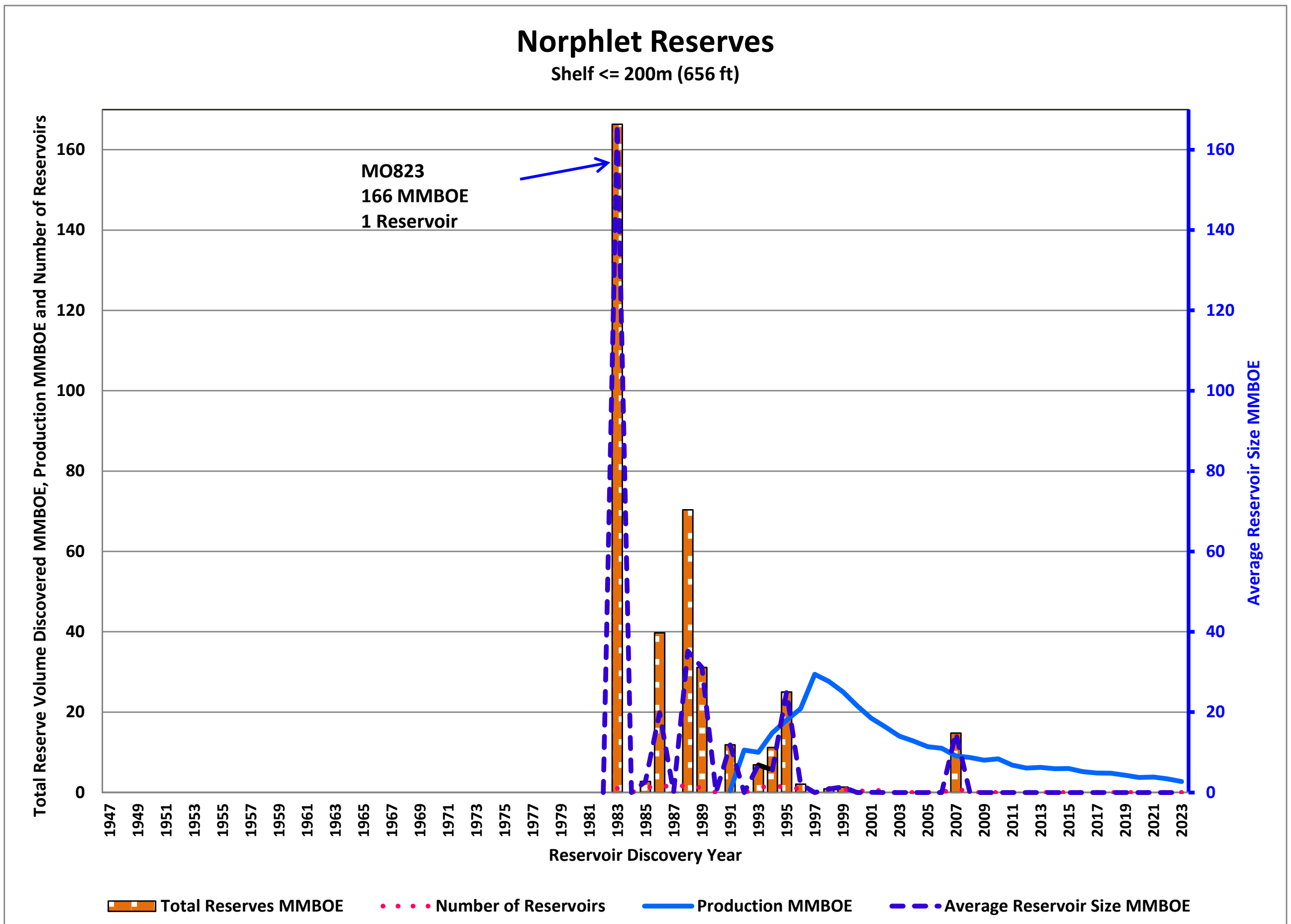

Figure 56. Norphlet Shelf Development

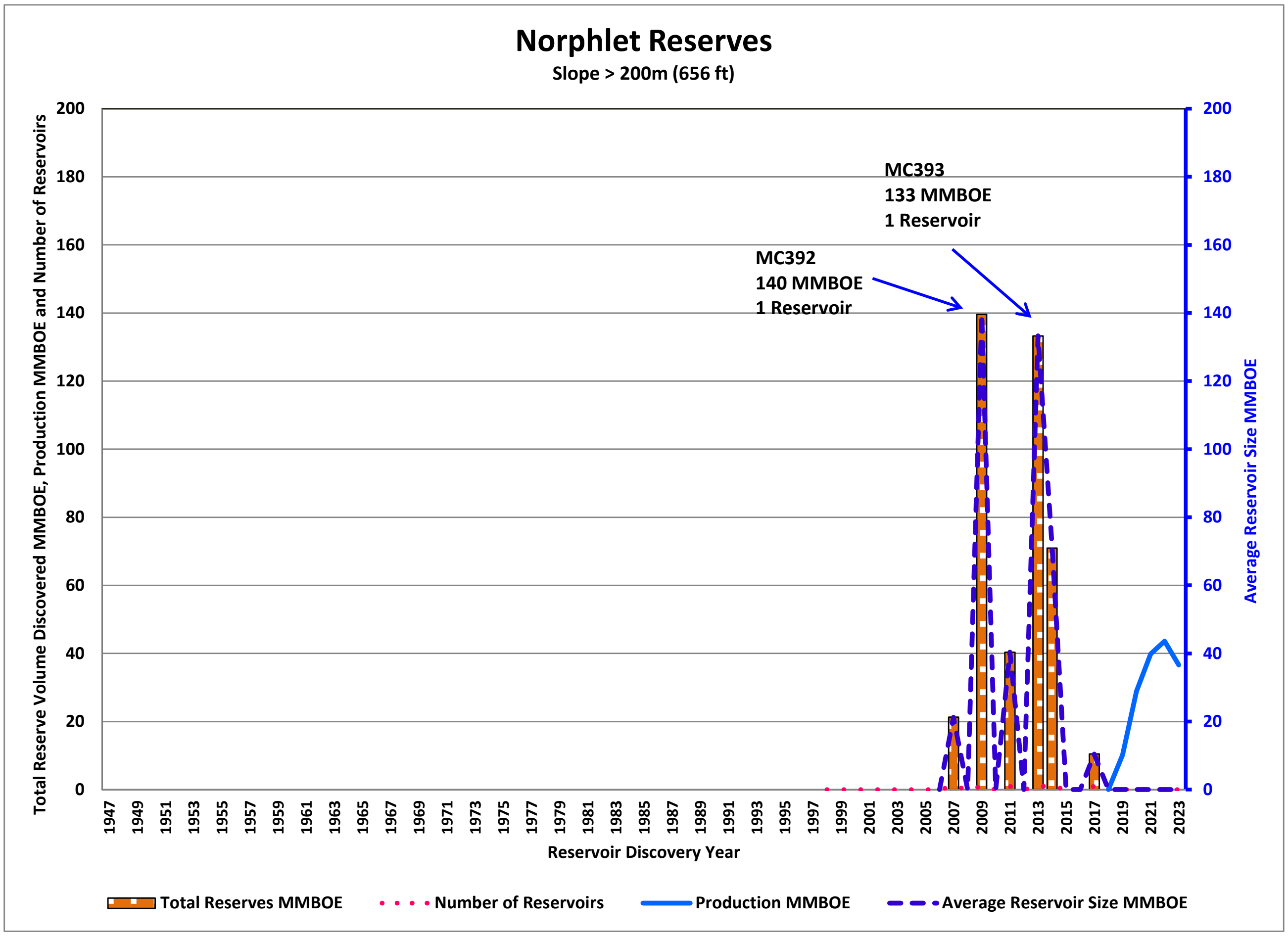

Figure 57. Norphlet Slope Development

12.0 CONTINGENT RESOURCES

Contingent Resources are defined as hydrocarbon accumulations that are estimated, as of a specified date, to be potentially recoverable from known accumulations through development projects. The Contingent Resources reported in the EOGR Report are discovered volumes with at least one well penetration but are not currently considered recoverable due to one or more contingencies. Contingent Resources in this report are limited to the GOA slope. This decision reflects the maturity and economic realities of the basin. On the GOA shelf, many Contingent Resources are relatively small, technically mature, and often uneconomic to develop under current market conditions. These resources typically lack the scale needed to justify new infrastructure or significant investment, especially in a region with extensive existing production and declining marginal returns. In contrast, the GOA slope holds larger, less developed Contingent Resources with greater upside potential. Although these projects require higher capital expenditure due to deepwater drilling and complex development scenarios, they offer a more attractive return on investment. As a result, operators are more likely to prioritize and invest in slope resources, making them more relevant for forward-looking resource planning and reporting. Total mean Contingent Resources on the GOA slope are estimated to be 2.49 BBO and 3.88 Tcf of gas, or 3.19 BBOE as of December 31, 2023. As shown in Table 7 below, 2.24 BBOE, representing 70.2 percent of Contingent Resources, are in leased (active) blocks, while .95 BBOE, or 29.8 percent, are found in unleased blocks as of December 31, 2023. Table 7 provides a detailed breakdown of Contingent Resources on the GOA slope. Contingent Resources were not reported in the 2019 *Estimated Oil and Gas Reserves Report*.

Table 7. GOA Mean Contingent Resources (>200 meters or 656 feet depth)

Contingent Resources in the Deepwater Gulf of America (>200 meters or 656 feet)			
Contingent Resources	Oil (Bbbl)	Gas (Tcf)	BOE (BBOE)
Contingent Resources on Active Leases	1.86	2.13	2.24
Contingent Resources on Unleased Blocks	0.63	1.75	0.95
Total Contingent Resources Deepwater GOA	**2.49**	**3.88**	**3.19**

BOEM may classify a reservoir as a Contingent Resource either upon discovery on an active lease or if all leases within the field have expired, terminated, or relinquished. The development of Contingent Resources is dependent on evaluating uncertainties related to the technical and economic aspects of projects. A clear understanding of the uncertainties that influence the viability and recovery of Contingent Resources, particularly geological uncertainties and technological limitations, is vital for determining commercial recovery potential, as many hydrocarbon accumulations once considered unfeasible can be revisited as exploration technologies improve and knowledge of subsurface geology advances. Continuous investment in geophysical surveys and exploration drilling is critical for assessing the commercial viability of these resources. There is significant potential for Contingent Resources to transition into Reserves if the associated uncertainties are resolved through technological advancements and evaluations.

When an operator decides to move forward with commercial development, a Development Operations Coordination Document or a Development and Production Plan is submitted. At this time, the Contingent Resource will be classified as a Reserve. Additionally, if a known hydrocarbon accumulation is on a lease that is terminated, relinquished, or expired, the accumulation is also considered a Contingent Resource. A spatial representation of Contingent Resources on active and expired leases on the GOA slope as of December 31, 2023, is provided below (Figure 58).

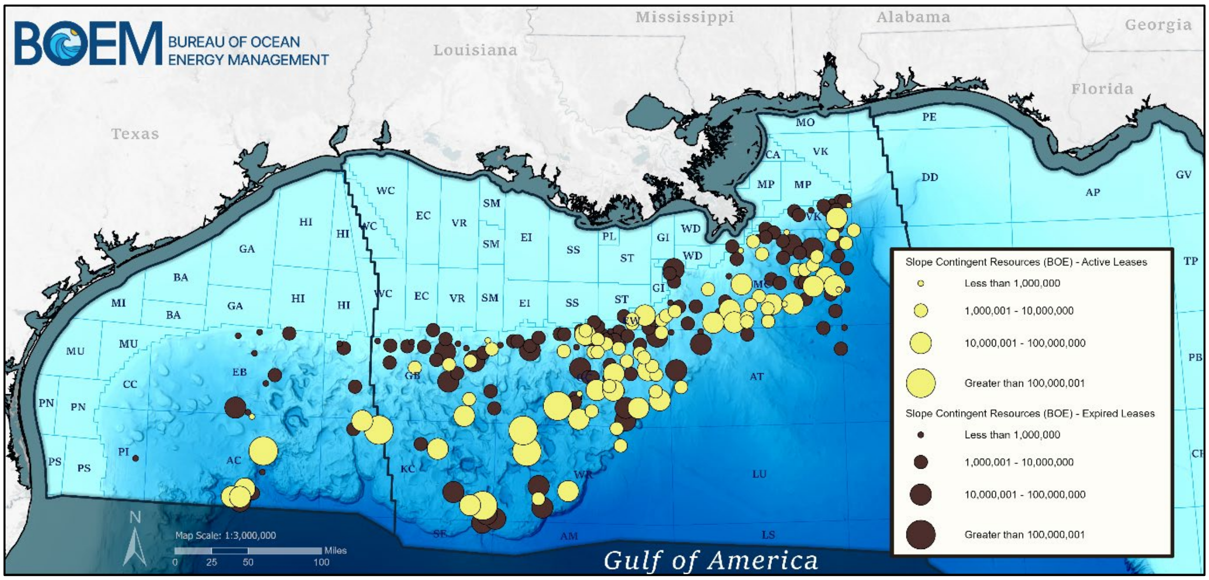

Figure 58. GOA Slope Contingent Resources on Active Leases and Non-Leased Acreage.

The development of Contingent Resources presents both opportunities and challenges. Contingent Resources play a key role in meeting energy demands and enhancing energy security. However, external factors, such as fluctuating oil prices, can influence the pace and viability of development.

13.0 RESERVES AND CONTINGENT RESOURCES, COMPARISONS AND CONCLUSIONS

As of December 31, 2023, the federally regulated portion of the GOA OCS encompasses 1,336 oil and gas fields. These fields have mean Original Reserves estimated at 30.43 BBO, 201.17 Tcf of gas, or 66.22 BBOE. Cumulative production from these fields totals 24.66 BBO, 194.02 Tcf of gas, or 59.18 BBOE. The mean remaining reserves for the 424 active fields are estimated at 5.77 BBO, 7.15 Tcf of gas, or 7.04 BBOE. Total mean Contingent Resources on the GOA slope are estimated to be 2.49 BBO and 3.88 Tcf of gas, or 3.19 BBOE. Table 8 provides a comprehensive summary and comparison of mean oil and gas Reserves and slope Contingent Resources on the GOA OCS as of December 2023.

Table 8. Summary of GOA Mean Oil and Gas Reserves and Slope Contingent Resources December 31, 2023

	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Original Reserves:			
Previous Estimate, as of 12/31/2019	**26.77**	**197**	**61.83**
Reserves from Fields Added 2020-2023	0.52	0.49	0.60
Revisions from Reservoir Maintenance 2020-2023	3.14	3.68	3.79
Estimate, as of 12/31/2023	**30.43**	**201.17**	**66.22**
Cumulative Production:			
Previous Estimate, as of 12/31/2019	**22.12**	**190.9**	**56.09**
Production during 2020-2023	2.54	3.12	3.09
Estimate, as of 12/31/2023	**24.66**	**194.02**	**59.18**
Remaining Reserves:			
Previous Estimate, as of 12/31/2019	**4.65**	**6.10**	**5.74**
Reserves from Fields Added 2020-2023	0.52	0.49	0.60
Revisions from Reservoir Maintenance 2020-2023	3.14	3.68	3.79
Production during 2020-2023	-2.54	-3.12	-3.09
Estimate, as of 12/31/2023	**5.77**	**7.15**	**7.04**
Contingent Resources in the Deepwater Gulf of America (>200 meters or 656 feet)			
Contingent Resources	Oil (Bbbl)	Gas (Tcf)	BOE (BBOE)
Contingent Resources on Active Leases	1.86	2.13	2.24
Contingent Resources on Unleased Blocks	0.63	1.75	0.95
Total Contingent Resources Deepwater GOA	**2.49**	**3.88**	**3.19**

Table 9 and Figure 59 present previous reserve estimates. Due to adjustments and corrections to production data submitted by GOA OCS operators, the difference between historical cumulative production for successive years does not always equal the annual production for the latter year.

Table 9. Oil and Gas Reserves and Cumulative Production at End of Year, 1975-2023*

Year	Number of fields included	Original Reserves			Historical Cumulative Production			Remaining Reserves		
		Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
1975	255	6.61	59.9	17.27	3.82	27.2	8.66	2.79	32.7	8.61
1980	435	8.04	88.9	23.86	4.99	48.7	13.66	3.05	40.2	10.20
1985	575	10.63	116.7	31.40	6.58	71.1	19.23	4.05	45.6	12.16
1990	782	10.64	129.9	33.75	8.11	93.8	24.80	2.53	36.1	8.95
1995	899	12.01	144.9	37.79	9.68	117.4	30.57	2.33	27.5	7.22
2000	1,050	14.93	167.3	44.70	11.93	142.7	37.32	3.00	24.6	7.38
2005	1,196	19.80	181.8	52.15	14.61	163.9	43.77	5.19	17.9	8.38
2010	1,282	21.50	191.1	55.50	17.11	179.3	49.01	4.39	11.8	6.49
2015	1,312	23.06	193.8	57.56	19.58	186.5	52.78	3.48	7.3	4.78
2016	1,315	23.73	194.6	58.37	20.16	187.8	53.58	3.57	6.8	4.79
2017	1,319	24.65	195.2	59.39	20.78	188.9	54.39	3.87	6.3	5.00
2018	1,319	24.86	195.5	59.66	21.42	189.8	55.21	3.44	5.7	4.45
2019	1,325	26.77	197.0	61.83	22.12	190.9	56.09	4.65	6.1	5.74
2023	1,336	30.43	201.17	66.22	24.66	194.0	59.18	5.77	7.15	7.04

"Oil" includes crude oil and condensate; "gas" includes associated and nonassociated gas. Reserves estimated as of December 31 each year.

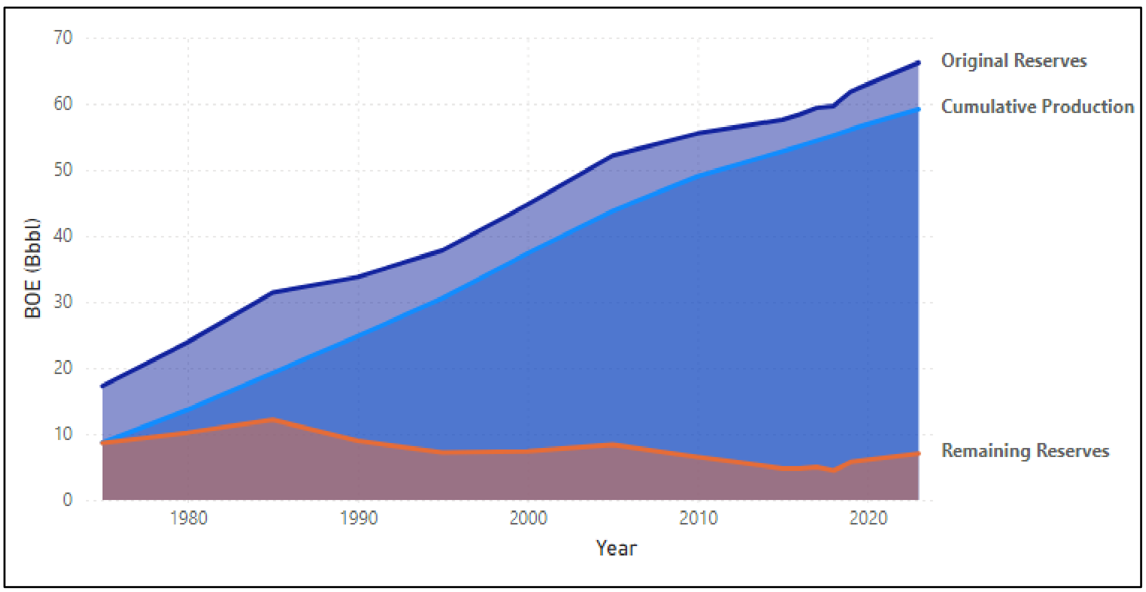

Figure 59. Oil and Gas Reserves and Cumulative Production at End of Year, 1975-2023

Since transitioning to probabilistic reserves estimation in 2020, BOEM has conducted comprehensive studies on over 140 fields, including 18 new discoveries. Additionally, BOEM has reviewed more than 37,000 reservoirs across the 1,336 fields of the GOA OCS. These analyses have resulted in the addition of 4.39 BBOE in Original Reserves. After accounting for 3.09 BBOE of production during this period, the remaining reserves have increased by 1.30 BBOE, or 22.6%. The increase in reserves is attributed to the addition of nearly 250 new reservoirs and ongoing reservoir maintenance. In addition to Reserves, total mean Contingent Resources on the GOA slope are estimated to be 2.49 BBO and 3.88 Tcf of gas, or 3.19 BBOE as of December 31, 2023. Together, these efforts underscore the GOA's viability as a premier oil and gas basin.

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Appendix A - Definitions of Field, Resource, and Reserves Terms

Aggregation - The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country, or company totals.

Analogs - Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure), and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.

API Gravity - A measure of how heavy or light petroleum liquid is compared to water.

Assessment Unit - A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment; also referred to as a "play."

Barrels of Oil Equivalent (BOE) - A unit of measurement used to compare the energy produced by oil and gas.

Bureau of Ocean Energy Management (BOEM) - The U.S. agency responsible for the management of the nation's ocean resources and the regulation of offshore energy development.

Chronozone - A body of rock formed during the same time span, bounded by biostratigraphic or correlative seismic markers.

Cumulative distribution functions (CDF) - Represents the accumulated probability up to a specific point.

Contingent Resources - Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies.

Cumulative Production - Cumulative production is the sum of all produced volumes of oil and gas prior to a specified date.

Developed Reserves - Developed reserves can be expected to be recovered through existing wells and facilities and by existing operating methods. Improved recovery reserves can be considered as developed reserves only after an improved recovery project has been installed and favorable response has occurred or is expected with a reasonable degree of certainty. Developed reserves are expected to be recovered from existing wells, including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Developed Non-producing Reserves – Developed, non-producing reserves are precluded from producing due to being shut-in or behind-pipe. Shut-in includes (1) completion intervals which are open at the time of the estimate, but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe refers to zones in existing wells which will require additional completion work or future re-completion prior to the start of production. In both cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Developed Producing Reserves – Developed, producing reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Estimated Oil and Gas Reserves (EOGR) Report - A BOEM publication reporting estimates of oil and gas reserves and Contingent Resources.

Field - A concentration of oil and/or gas accumulations that share a common geologic structure or stratigraphic condition and are typically developed as a single unit.

Field Classification Framework - The systematic categorization of oil and gas fields based on certain criteria, such as production status, type, and economic viability.

Flow Rate - The volume of oil or gas that is produced over a specified time.

Gas-Oil Ratio - The relationship between the volume of gas produced and the volume of oil produced.

Mean - Measure of central tendency that represents the average value of a set of numbers.

Monte Carlo Simulation - A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions to generate a resulting distribution.

Original Gas in Place - The total estimated volume of gas in a reservoir, both recoverable and non-recoverable, prior to production.

Original Reserves - The total estimated recoverable reserves prior to any production, as of a specified date; also referred to as total reserves.

Outer Continental Shelf (OCS) - All submerged lands lying seaward and outside of the area of lands beneath navigable waters, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control or within the exclusive economic zone of the United States and adjacent to any territory of the United States; and does not include any area conveyed by Congress to a territorial government for administration.

P10, P50, P90 - Probabilistic estimates indicating that there is a 90%, 50%, and 10% chance of achieving those reserve estimates, respectively.

Play - A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment.

Probabilistic Estimates - Statistical methods used to assess the likelihood of various outcomes based on uncertainties in data.

Project - A Project represents the link between petroleum accumulation and the decision-making process, including budget allocation. A project, for BOEM's classification of resources and reserves, is the Field (see also Field).

Remaining Reserves - Remaining reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied. Reserves are further sub-classified based on economic certainty.

Reserves Justified for Development - The lowest level of reserves certainty. Implementation of the development project is justified based on a reasonable forecast of commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained.

Reservoir - A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).

Resources - Resources encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional.

Shelf - The portion of the OCS with a water depth of less than 200 meters.

Slope - The portion of the OCS with a water depth equal to or greater than 200 meters.

Stock Tank Oil Originally in Place - The total estimated volume of oil in a reservoir before any production takes place.

Undeveloped Reserves - Undeveloped reserves are those reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects.

Undiscovered Resources - Resources postulated, based on 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. BOEM assesses two types of undiscovered resources: Undiscovered Technically Recoverable Resources and Undiscovered Economically Recoverable Resources.

Unrecoverable - The portion of discovered or undiscovered initially in-place hydrocarbons which are estimated, as of a given date, not to be recoverable. A portion of these hydrocarbons may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

Notice

This report, Estimated Oil and Gas Reserves, GOA OCS Region, December 31, 2023, has undergone numerous changes over the last few years. We are continually striving to provide meaningful information to the users of this document. Suggested changes, additions, or deletions to our data or statistical presentations are encouraged so that we can publish the most useful report possible. Please contact the Office of Resource Evaluation at (800) 200-4853 or BOEMGulfResourceEvaluation@boem.gov to communicate your ideas for consideration in our next report. An overview of the Reserves Inventory Program is available at https://www.boem.gov/oil-gas-energy/resource-evaluation/discovered-resources.

For free publication and digital data, visit the BOEM Data Center under the Field widget. The report can be accessed as an Acrobat .pdf (portable document format) file, which allows you to view, print, navigate, and search the document with the free downloadable Acrobat Reader. Digital data used to create the tables and figures presented in the document are also accessible as Excel® Worksheet file (.xlsx; using the Microsoft® Excel spreadsheet viewer, a free file viewer for users without access to Excel). These files are made available in a zipped format, which can be unzipped with the downloadable WinZip program.

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