

2026 Assessment of Undiscovered Technically and Economically Recoverable Oil and Natural Gas Resources of the Gulf of America Outer Continental Shelf



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Published by:

U.S. Department of the Interior
Bureau of Ocean Energy Management
Gulf of America OCS Region
Office of Resource Evaluation
New Orleans, Louisiana
June 2026

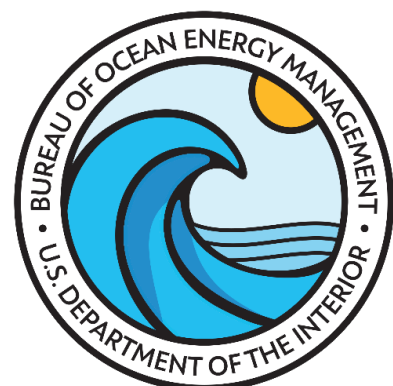


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ABBREVIATIONS AND ACRONYMS

°C	degrees Celsius
°F	degrees Fahrenheit
2D	two-dimensional
3D	three-dimensional
A	organic matter acme
AU	assessment unit
Bbbl	billion barrels
BBOE	billion barrels of oil equivalent
Bcf	billion cubic feet
BH	Baldwin High
BOE	barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management
BSTB	billion stock tank barrels
BT	Bravo Trough
BTF	Brazos Transfer Fault
CA	Conecuh Arch
CAMP	Central Atlantic Magmatic Province
CH	Chattahoochee Arch
CHX	Chicxulub Crater
CMA	Campeche Magnetic Anomaly
CSB	Campeche Salt Basin
DCSB	De Soto Canyon Salt Basin
DD	Destin Dome
DOI	Department of the Interior
EMT	Eastern Mexico Transform
ETSB	East Texas Salt Basin
ft	feet
FMA	Florida Magnetic Anomaly
FP	Florida Plain
Ga	billions of years
GOA	Gulf of America
GOR	gas-oil-ratio
GTF	Galveston Transfer Fault
HE	Henderson
HMA	Houston Magnetic Anomaly
HTF	Hackberry Transfer Fault
ISB	Isthmian Salt Basin
JD	Jackson Dome
JTF	Jacksonville Transfer Fault
km	kilometers
KTF	Keathley Transfer Fault
LA	Lasalle Arch
LK	Lower Cretaceous Shelf Edge
NLSB	North Louisiana Salt Basin
LU	Lund

m	meters
Ma	millions of years
MATF	Matagorda Transfer Fault
Mcf	thousand cubic feet
MG	Middle Ground Arch
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MOTF	Mobile Transfer Fault
MRTF	Mississippi River Transfer Fault
MSSB	Mississippi Salt Basin
MU	Monroe Uplift
Myr	million years
NLSB	North Louisiana Salt Basin
OAE	oceanic anoxic event
OCS	Outer Continental Shelf
PA	Peninsular Arch
PE	Pensacola Arch
PETM	Paleocene–Eocene Thermal Maximum
PFT	Peripheral Fault Trend
PRTF	Pearl River Transfer Fault
PSJTF	Port Saint Joe Transfer Fault
SA	Sarasota Arch
SDR	seaward dipping reflector
SF	South Florida Basin
SGB	South Georgia Basin
SMO	Sierra Madre Oriental
SP	Southern Platform
SPTF	South Padre Transfer Fault
STF	Sabine Transfer Fault
SU	Sabine Uplift
TATF	Tallahassee Transfer Fault
Tcf	trillion cubic feet
TE	Tampa Embayment
TFZ	transfer or transform fault zone
TTF	Terrebonne Transfer Fault
UERR	undiscovered economically recoverable resources
U.S.	United States
UTRR	undiscovered technically recoverable resources
WA	Wiggins Arch
WFSB	West Florida Salt Basin
WR	Walker Ridge
YSB	Yucatan Salt Basin

SUMMARY

This report presents the [Bureau of Ocean Energy Management's \(BOEM\)](#) estimates of undiscovered technically recoverable resources (UTRR) and undiscovered economically recoverable resources (UERR) for oil and gas in the Gulf of America (GOA) Outer Continental Shelf (OCS).

Based on grown discovered resources as of January 1, 2024, BOEM estimates mean-level UTRR values of

- 26.903 billion barrels (Bbbl) of oil
- 45.593 trillion cubic feet (Tcf) of gas
- 35.016 billion barrels of oil equivalent (BBOE)

This is a 4.330 BBOE decrease in UTRR from that of [BOEM's 2021 resource assessment](#) (U.S. DOI, 2021b). That decrease is attributed to the highly explored and mature Neogene–Quaternary Shelf and Slope Plays. As was the same for the 2021 assessment, the Lower Tertiary **Wilcox Slope** sandstones are estimated to contain the greatest undiscovered potential in the GOA. Of the Mesozoic-aged plays, Jurassic **Norphlet Slope** aeolian dunes and **Smackover** grainstones are forecast to hold the largest amounts of UTRR.

Based on oil and gas price pairs of \$160/bbl and \$8.54/Mcf, BOEM estimates mean-level UERR values of

- 21.826 Bbbl of oil
- 19.653 Tcf of gas
- 25.323 BBOE

Estimates of UTRR and UERR represent comprehensive and collaborative appraisal by geologists, geophysicists, petroleum engineers, petrophysicists, paleontologists, and supporting personnel of the Gulf of America Region, Office of Resource Evaluation, in New Orleans, Louisiana. These professional scientists and engineers utilized the latest (1) geologic, geophysical, technological, and economic data, (2) geologic and reservoir engineering databases, (3) structural, depositional, and salt tectonic maps, and (4) scientific literature to determine a reasonable number and size of undiscovered pools in the Gulf of America OCS.

Key points moving forward:

- This study uses data discovered up to January 1, 2024.
- Discovered volumes are grown and equal to reserves plus contingent resources.
- Lognormal probability models describe hydrocarbon distributions by geologic play.
- Crude oil and condensate are collectively reported as oil, and associated and non-associated natural gas are collectively reported as gas.

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INTRODUCTION

[BOEM](#) is an agency within the [Department of the Interior \(DOI\)](#) whose responsibilities include assessing the amounts of undiscovered recoverable oil and gas resources located outside of known oil and gas fields in the OCS. The OCS comprises the portion of the submerged seabed whose mineral estate is subject to United States (U.S.) jurisdiction. BOEM publishes the National Assessment of Undiscovered Oil and Gas Resources of the OCS every 5 years. This report presents BOEM's estimates of undiscovered recoverable resources for oil and gas in the Gulf of America OCS ([Figure 1](#)). Detailed geologic descriptions are also provided for the GOA Basin and its 30 assessed oil and gas plays.

For this report, the date at which no new data was accepted into the discovered dataset is January 1, 2024. The mean values of discovered volumes are the BOEM classes of reserves and contingent resources totaled ([Table 1](#)). Regarding the discovered volumes, BOEM began transitioning from deterministic to probabilistic reserves estimations in 2020 (U.S. DOI, 2025a). This probabilistic methodology is consistent with the Society of Petroleum Engineers (2018) Petroleum Resources Management System (PRMS) and was adopted by BOEM to better account for the uncertainty in reserves estimations. See BOEM's [2025 Gulf of America Oil and Gas Reserves Report](#) (U.S. DOI, 2026) for more information. This is the first GOA assessment to use the results of probabilistic reserves calculations to forecast undiscovered oil and gas resource volumes.

The observed incremental increase through time in the estimates of reserves of an oil or gas field is known as reserves growth or appreciation. This phenomenon is that portion of known resources over reserves that may be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. To account for this phenomenon, a growth factor was applied to the original estimates of known resources. All discovered volumes presented herein are grown values.

A geologic play-based approach was employed to estimate oil and gas resources that have not yet been discovered. This method works for conceptual plays, where specific data is limited, as well as established plays with known fields, where extensive details are available. The approach closely links insights from exploration activities to the geological models created by assessment teams. Significant effort went into constructing play models, defining their geographic boundaries, and gathering key geologic and reservoir engineering data. These parameters were essential for calculating the total amounts of undiscovered resources in each play.

Due to uncertainty in estimating undiscovered resources, probabilistic methods were used and results are given as ranges reflecting different likelihoods. Lognormal probability models describe hydrocarbon distributions by play. Sparse data areas relied on subjective probability analogs, while mature regions with ample data used statistical analysis of discovered pools and historical trends.

The undiscovered resources reported herein are categorized as (1) undiscovered technically recoverable resources (UTRR) that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary conventional recovery methods and (2) undiscovered economically recoverable resources (UERR), which is the portion of the UTRR that is economically recoverable under imposed economic and technologic conditions ([Table 1](#)). Values for UTRR and UERR are reported at the 95th and 5th percentile levels, along with the calculated means of their respective distributions. These estimates correspond to a 95% probability (19 out of 20 chance) and a 5% probability (1 out of 20 chance) that higher amounts may be present. The 95th and 5th percentiles are regarded as reasonable lower and upper bounds, while the means represent the average value of the distribution.

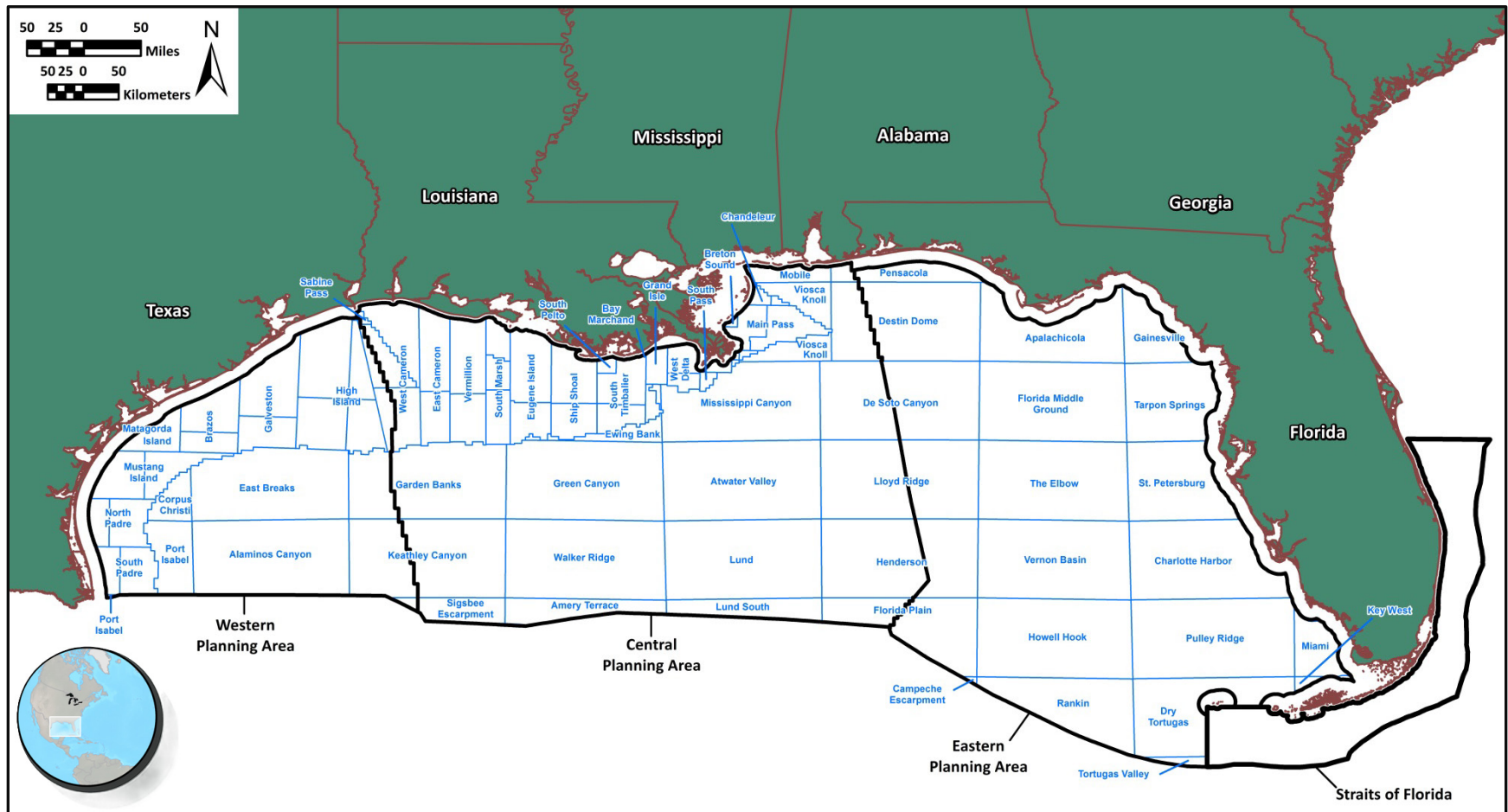
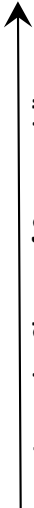


Figure 1. Gulf of America OCS waters delineated by planning areas and protraction areas.

The petroleum commodities assessed and reported in this inventory are crude oil, natural gas liquids (condensate), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. Crude oil and condensate are reported jointly as oil; associated and non-associated natural gas are reported jointly 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 non-associated) expressed in terms of its energy equivalence to oil (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 barrels of oil equivalent (BOE) and is reported in barrels. 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, or natural gas hydrates.

Table 1. BOEM resource classification. Modified from Burgess et al. (2020).

BOEM Resource Classification	
Classes	Sub-Classes
Reserves	Developed Producing
	Developed Non-Producing
	Undeveloped
	Reserves Justified for Development
Contingent Resources	
(unrecoverable)	
Undiscovered Resources	UTRR and UERR estimates are provided in this report.
(unrecoverable)	



Increasing Chance of Commerciality

BIOSTRATIGRAPHY AND CHRONOSTRATIGRAPHY

The [BOEM Gulf of America Biostratigraphic Chart](#) (Witrock, 2017) is a reference section of paleo-events (e.g., extinctions, increases, acmes) and preferred taxonomy synthesized from differing biostratigraphic charts in use by oil industry paleontological consultants and operators. The chart is the basis upon which BOEM subdivides the sedimentary section in the GOA Basin into geologic ages and plays for assessment purposes. The foraminiferal, coccolith, dinoflagellate, ostracod, radiolarian, and pollen biostratigraphic markers are placed in a chronological, chronostratigraphic, and chronozoneal context, where a chronozone is a body of rock formed during the same time span, bounded by biostratigraphic or correlative seismic markers.

Relative age changes on the biostratigraphic charts of industry consultants Waterman (Paleo-Data) (2017) and Applied Biostratigraphix (2009), along with new chronostratigraphy (Gradstein et al, 2012), prompted significant revisions to BOEM's biostratigraphy in 2018. Paleo-event ages from BOEM chronostratigraphy resulted in additional changes to foraminiferal and nannoplanktic marker age assignment. Revisions include:

- The Gelasian Stage was moved from the Pliocene Series to the Pleistocene Series by the International Union of Geological Sciences (IUGS).
- Similarly, the IUGS moved the Quaternary System and Pleistocene bases to coincide with the base of the Gelasian Stage Global Stratotype Section and Point (GSSP) in Italy.
- Relative positions of several foraminiferal and nannoplanktic markers were reordered throughout the Miocene.
- Several radiolarian acmes were added to Middle and Early Eocene sections.
- Numerous Early Paleocene (Danian) to Early Eocene (Ypresian) markers were added, providing enhanced delineation of the Wilcox Formation and older Paleogene sections.
- The Mesozoic biostratigraphy was revised to incorporate additional microfossil markers resulting in adjustments to previous stratigraphic assignments.

These changes and additions reflect stratigraphy more consistent with current GOA industry biostratigraphic usage. Abbreviated Cenozoic and Mesozoic versions of BOEM's 2018 biostratigraphic chart are presented in [Table 2](#) and [Table 3](#), respectively.

In addition to significant revisions of the biostratigraphic framework, BOEM regularly refines its OCS-wide chronostratigraphic interpretations based on the latest seismic, well, and paleontological data. This continual process often results in chronozone reassignment of hydrocarbon reservoirs with each resource assessment.

Table 2. BOEM Cenozoic biostratigraphy and associated chronostratigraphy.

Chronostatigraphic Units					Biostratigraphy ¹				
Erathem	System	Series	Stage	Chronozone	Foraminifera	Nannoplankton			
Cenozoic	Quaternary	Pleistocene	Upper	Tarantian	Upper Pleistocene				
			Middle	Ionian	Middle Pleistocene	<i>Globorotalia flexuosa</i> acme <i>Trimosina</i> "A"	<i>Emiliana huxleyi</i> (base of acme) <i>Pseudoemiliana lacunosa</i> "B"		
			Lower	Calabrian	Lower Pleistocene	<i>Stilostomella antillea</i> <i>Sphaeroidinella dehiscons</i> acme A <i>Sphaeroidinella dehiscons</i> acme B <i>Globorotalia crassula</i> acme, <i>Globorotalia praeirsuta</i> <i>Menardella miocenica</i>	<i>Pseudoemiliana ovata</i> <i>Gephyrocapsa aperta</i> acme <i>Calcidiscus macintyreii</i> <i>Discoaster brouweri</i> <i>Discoaster surculus</i>		
		Gelasian		<i>Discoaster tamalis</i> <i>Sphenolithus abies</i>					
		Pliocene	Upper	Piacenzian	Upper Pliocene	<i>Dentoglobigerina altispira</i> = <i>Valvulineria</i> "H" <i>Textularia</i> 1	<i>Reticulofenestra pseudoumbilica</i>		
			Lower	Zanclean	Lower Pliocene	<i>Globorotalia margaritae</i> <i>Globigerina nepenthes</i> <i>Globorotalia plesiotumida</i> acme	<i>Ceratolithus acutus</i>		
		Neogene	Miocene	Upper	Messinian	Upper Upper Miocene	<i>Menardella menardii</i> coil change, right-to-left	<i>Discoaster quinqueramus</i>	
					Tortonian		Lower Upper Miocene	<i>Bigenerina floridana</i> / "A" <i>Globorotalia acostaensis</i> coil change, right-to-left <i>Globigerina nepenthes</i> acme A	<i>Discoaster berggrenii</i> <i>Discoaster berggrenii</i> "A" <i>Discoaster neohamatus</i>
								<i>Globigerina nepenthes</i> acme B <i>Bolivina thalmani</i> , <i>Globorotalia languensis</i>	<i>Reticulofenestra gelida</i> acme <i>Discoaster preparentariatus</i> increase
				Middle	Serravallian	Upper Middle Miocene	<i>Uvigerina</i> 3 <i>Fohsella robusta</i> <i>Textularia</i> "W"	<i>Coccolithus miopelagicus</i> <i>Discoaster kugleri</i> increase <i>Cyclicargolithus floridanus</i>	
	Langhian				Middle Middle Miocene	<i>Fohsella lobata</i> <i>Fohsella fohsi</i> <i>Fohsella peripheroronda</i>	<i>Discoaster sanmiguelensis</i> increase <i>Sphenolithus heteromorphus</i>		
					Lower Middle Miocene	<i>Cibicides opima</i> <i>Praeorbulina glomerosa</i> <i>Globigerinoides bisphericus</i>	<i>Discoaster petaliformis</i> <i>Helicosphaera ampliapertura</i> <i>Discoaster deflandrei</i> acme		
	Lower		Burdigalian	Upper Lower Miocene	<i>Robulus</i> "L" / 43 <i>Catapsydrax stainforthi</i>	<i>Discoaster calculosus</i> <i>Sphenolithus disbelemnos</i>			
				Middle Lower Miocene	<i>Catapsydrax dissimilis</i> <i>Robulus chambersi</i> , <i>Discorbis bolivarensis</i> / "B" <i>Globigerinoides primordius</i>	<i>Sphenolithus belemnos</i> <i>Triquetrorhabdulus carinatus</i> <i>Cyclicargolithus abisectus</i>			
			Aquitanian	Lower Lower Miocene	<i>Siphonina davisii</i>	<i>Sphenolithus dissimilis</i>			
			<i>Paragloborotalia kugleri</i> <i>Lenticulina jeffersonensis</i> = <i>Cristellaria</i> "R" <i>Globigerina ciproensis ciproensis</i> <i>Globigerina angulosuteralis</i> <i>Paragloborotalia opima opima</i>	<i>Cyclicargolithus abisectus</i> increase <i>Triquetrorhabdulus challengerii</i> <i>Dictyococcites bisectus</i> <i>Triquetrorhabdulus carinatus</i> acme <i>Sphenolithus predistentus</i>					
	Paleogene (Lower Tertiary)	Oligocene	Upper	Chattian	Upper Oligocene	<i>Chiloguembelina cubensis</i> <i>Turborotalia increbescens</i>	<i>Helicosphaera compacta</i> <i>Ericsonia formosa</i> increase		
			Lower	Rupelian	Lower Oligocene	<i>Turborotalia cerroazulensis coccaensis</i> <i>Turborotalia pomeroli</i> <i>Globigerinatheka mexicana</i>	<i>Discoaster saipanensis</i> , <i>Chiasmolithus consuetus</i> <i>Criboecentrum reticulatum</i> <i>Sphenolithus obtusus</i>		
		Eocene	Upper	Priabonian	Upper Eocene	<i>Acarinina spinuloinflata</i> <i>Acarinina bulbrookii</i> <i>Igorina broedermanni</i> <i>Morozovella aragonensis</i> <i>Morozovella caucasica</i>	<i>Chiasmolithus grandis</i> <i>Sphenolithus furcatolithoides</i> increase <i>Discoaster wemmelensis</i> <i>Chiasmolithus gigas</i> <i>Discoaster ladaensis</i>		
			Middle	Bartonian	Middle Eocene	<i>Acarinina soldadoensis</i>	<i>Discoaster kuepperi</i>		
				Lutetian		<i>Apectodinium homomorphum</i> acme (dinoflagellate) / PETM ²	<i>Fasciculithus tympaniformis</i>		
		Lower	Ypresian	Lower Eocene	<i>Bathysiphon</i> spp increase <i>Subbotina triloculinoidea</i> <i>Igorina pusilla pusilla</i> <i>Morozovella conicotruncana</i> <i>Planorotalites compressa</i>	<i>Ericsonia robusta</i> <i>Prinsius martinii</i> increase <i>Chiasmolithus danicus</i> <i>Cruciplacolithus edwardsii</i> <i>Fasciculithus chowii</i>			
	Paleocene	Upper	Thanetian	Upper Paleocene	<i>Parasubbotina pseudobulloides</i> <i>Globocentusa daubjergensis</i> <i>Parularugoglobigerina eugubina</i>	<i>Neochiastozygus esaeepes</i> <i>Hornibrookina edwardsii</i> <i>Neobiscutum romelini</i>			
		Lower	Danian		Lower Paleocene				

¹ All species represent extinction points unless noted.

² Paleocene-Eocene Thermal Maximum

Table 3. BOEM Mesozoic biostratigraphy and associated chronostratigraphy.

Chronostatigraphic Units					Biostratigraphy*		
Erathem	System	Series	Stage	Chronozone	Foraminifera	Nannoplankton	
Mesozoic	Cretaceous	Upper	Maastrichtian	Upper Upper Cretaceous	<i>Contusotruncana contusa</i>	<i>Micula decussata</i>	
						<i>Rosita fornicata</i>	<i>Tranolithus orionatus</i>
						<i>Globotruncana ventricosa</i>	<i>Aspidolithus parvus constrictus</i>
						<i>Globotruncana calcarata</i>	<i>Reinhardtites anthophorus</i>
						<i>Marginotruncana coronata</i>	<i>Lithastrinus grilli</i>
						<i>Whiteinella baltica</i>	<i>Eprolithus floralis</i>
				<i>Dicarinella asymetrica</i>			
				<i>Marginotruncana sinuosa</i>	<i>Zeughrabdodus noeliae</i>		
				<i>Marginotruncana sigali</i>	<i>Chiastozygus platyrhethus</i>		
				<i>Whiteinella archaeocretacea</i>	<i>Lithastrinus septenarius</i>		
				<i>Hedbergella planispira</i>	<i>Stoverius achylosus</i>		
				<i>Dicarinella hagni</i>			
			Turonian	Lower Upper Cretaceous	<i>Planulina eaglefordensis</i>	<i>Lithraphidites pseudoquatratus</i>	
					<i>Helvetoglobotruncana helvetica</i>	<i>Calculites axosuturalis</i>	
					<i>Dicarinella algeriana</i>		
				<i>Praeglobotruncana stephani, Helvetoglobotruncana praehelvetica</i>			
				<i>Rotalipora cushmani</i>	<i>Helena chiesta</i>		
				<i>Globigerinelloides bentonensis</i> increase	<i>Braarudosphaera stenorhetha</i>		
				<i>Planomalina buxtoni</i>	<i>Hayesites albiensis</i>		
				<i>Biticinella breggiensis</i>	<i>Crucicribrum anglicum</i>		
				<i>Rotalipora subticinensis</i>			
				<i>Hedbergella gorbachikae</i>	<i>Sollasites falklandensis</i>		
				<i>Hedbergella infracretacea</i>	<i>Diadorhombus rectus</i>		
				<i>Paraticinella transitoria</i>			
		Lower		Upper Lower Cretaceous	<i>Paraticinella eubejaouaensis</i>	<i>Assipetra infracretacea</i>	
						<i>Favusella hoteriva</i>	<i>Conusphaera rothii</i>
						<i>Epistomina hechti</i>	
						<i>Lenticulina saxonica</i>	<i>Conusphaera mexicana</i>
						<i>Lenticulina ouachensis</i> increase	<i>Eprolithus antiquus</i>
						<i>Muderongia simplex</i> (dinoflagellate)	<i>Lithraphidites bollii</i>
				<i>Everticyclammina virginulina</i>	<i>Crucellipsis cuvillieri</i>		
					<i>Eiffellithus windii</i>		
					<i>Rucinolithus wisei</i>		
					<i>Micrantholithus speetonensis</i>		
					<i>Conoglobigerina helvetojurassica</i>		
					<i>Globuligerina oxfordiana</i>		
					<i>Lenticulina busnardoii</i>		
					<i>Epistomina stellacostata</i>	<i>Polycostella senaria</i>	
					<i>Anchispirocyclina lusitanica</i>		
	Jurassic	Upper	Tithonian	Upper Jurassic	<i>Hutsonia vulgaris / callahani, Galliaecytheridea postronda</i> (ostracods)	<i>Lotharingius sigillatus</i>	
						<i>Alveosepta jaccardi</i>	<i>Hexalithus noelae</i>
						<i>Reinholdella A</i> increase	<i>Anfractus harrisonii</i>
					<i>Gonyaulacysta jurassica</i> (dinoflagellate)		
					<i>Haplophragmoides canui</i>	<i>Crepidolithus perforatus</i>	
					<i>Praekumbria crusei</i>		
					<i>Alveosepta jaccardi</i> acme	<i>Lotharingius crucicentralis</i>	
					<i>Globuligerina oxfordiana</i> increase	<i>Stephanolithion hexum</i>	
		Middle		Middle Jurassic	<i>Globuligerina calloviensis</i>	<i>Lotharingius velatus</i>	
						<i>Reinholdella crebra</i> increase, <i>Garantella ornata</i>	<i>Stephanolithion speciosum</i>

*All species represent extinction points unless noted.

No biostratigraphic markers have been found older than Middle Jurassic in the northern GOA.

ASSESSMENT UNITS

2026 CENOZOIC ASSESSMENT UNITS

For this inventory of undiscovered resources in the Cenozoic sediments of the Gulf of America OCS, the geologic analyses inherent in resource assessments occur at the play level. As with past GOA assessments, each discovered reservoir in a BOEM-designated field is evaluated and assigned to a distinctive play that shares common geologic factors that influence the accumulation of hydrocarbons. See GOA's [OCS Operations Field Directory](#) for details on how fields are defined (U.S. DOI, 2025b). Because resource assessments strive to predict ultimate hydrocarbon volumes, reserves growth is applied to each BOEM-designated field based on when the field was discovered. The older a field is, the less growth that is expected in the future.

For modeling purposes, Cenozoic plays are aggregated into “assessment units” (AU) based on the following two criteria.

1. Geographic Setting ([Figure 2](#)):

- modern shelf
- modern slope
- modern basin floor

2. Geologic Age ([Table 4](#)):

- Pleistocene
- Pliocene
- Upper Miocene
- Middle Miocene
- Lower Miocene
- Lower Tertiary

Aggregating plays into assessment units provides a larger population of data for modeling, which reduces uncertainty and improves forecasting. Additionally, the focus of the Cenozoic assessment on the modern shelf (“shallow water”) and slope (“deep water”)—the approximate boundary located at a water depth of 656 feet (ft) or 200 meters (m)—results in assessment units with disparate geologic and technologic (e.g., drilling wells in shallow water vs. drilling wells in deep water) considerations.

Within these assessment units, hydrocarbon volumes of the specific ages that are associated with a particular oil and/or gas field are aggregated. **For example, all reservoirs within a single field located on the slope that are of Middle Miocene age are combined into a single volume, or “pool.”** These pools are identified by the field from which they are derived (e.g., Mississippi Canyon 778—Thunder Horse). Note that a single BOEM-designated field may contain more than one pool. For this Cenozoic assessment, data from 1,735 pools on the shelf and 458 pools on the slope were utilized.

The combination of geography and geologic age results in 15 Cenozoic AUs, 6 on the modern shelf, 7 on the modern slope, and 2 on the modern basin floor ([Table 4](#)). Fourteen of the Cenozoic AUs were assessed herein, with one lacking a significant prospect inventory for assessment. Because the individual Neogene–Quaternary Shelf and Slope AU locations reference the modern shelf-slope break, all the Neogene and Quaternary Shelf AUs are geographically identical, as are all the Neogene and Quaternary Slope AUs. Because of high temperature exclusions and variations in prospective areas, see individual descriptions of the [Lower Tertiary Plays](#) for the actual geographic areas.

Table 4. BOEM Cenozoic chronostratigraphy and associated assessment units.

Chronostratigraphic Unit					Stratigraphic Unit	Gulf of America Assessment Unit						
Erathem	System	Series	Stage	Chronozone		Shelf (Eastern)	Slope (Eastern)	Shelf (Central/Western)	Slope (Central/Western)	Abyssal Plain		
Cenozoic	Quaternary	Pleistocene	Upper	Tarantian	PLU	Glacial/Interglacial Stages			Pleistocene Shelf	Pleistocene Slope	Neogene-Quaternary Basin Floor	
			Middle	Ionian	PLM							
			Lower	Calabrian Gelasian	PLL							
	Neogene	Pliocene	Upper	Piacenzian	PU	Citronelle Formation			Pliocene Shelf	Pliocene Slope		
			Lower	Zanclean	PL							
		Miocene	Upper	Messinian		MUU	Fleming Formation			Upper Miocene Shelf		Upper Miocene Slope
				Tortonian		MLU						
			Middle	Serravallian		MUM						
						MMM						
				Langhian		MLM						
			Lower		Burdigalian					MUL		
						MML						
					Aquitanian					MLL		
	Lower Tertiary (Paleogene)	Oligocene	Upper	Chattian	OU	Anahuac Formation			Lower Tertiary Shelf	Frio Slope		
			Lower	Rupelian	OL	Frio Formation Vicksburg Formation						
		Eocene	Upper	Priabonian		EU	Jackson Group			Lower Tertiary Shelf	Lower Tertiary Basin Floor	
			Middle	Bartonian Lutetian		EM	Claiborne Group					
			Lower	Ypresian		EL						
		Paleocene	Upper	Thanetian Selandian		LU	Wilcox Formation			Wilcox Slope		
			Lower	Danian		LL	Midway Group					
Symbology:												
Predominantly Clastics												
BOEM Assessment Unit (assessed)												
BOEM Assessment Unit (not assessed)												

2026 MESOZOIC ASSESSMENT UNITS

Unlike the aggregated plays of the Cenozoic sediments, most Mesozoic sediments are differentiated by specific rock formations (e.g., Norphlet, Smackover, Sunniland). Several of these Mesozoic plays in the OCS continue onshore, and they too are technically AUs due to the necessity of an offshore distinction. However, the terms “play” and “assessment unit” are used interchangeably herein.

Table 5 and **Table 6** illustrate generalized stratigraphy of Mesozoic rock groups and formations in the northeastern coastal region of the GOA and the South Florida Basin area of Florida, respectively. Parts of the stratigraphic columns are modeled after onshore sections; therefore, rock units listed may or may not be present throughout the entire OCS.

Specifically, Mesozoic sediments are divided into 20 AUs, 16 of which are assessed in this study (**Table 5** and **Table 6**). The 4 unassessed AUs are deemed to contribute insignificant volumes of resources to the GOA Basin or lack a significant prospect inventory. There are 3 Mesozoic AUs (**Norphlet Shelf**, **Norphlet Slope**, and **Lower Cretaceous Carbonate**) with discoveries, comprising a total of 37 pools in the OCS. For most of the remaining 13 assessed Mesozoic AUs with no discoveries, onshore Gulf Coast discoveries were used as pool-size analogs for modeling undiscovered resources.

COMPARISON OF BOEM ASSESSMENT UNITS FROM 2021 TO 2026

This 2026 resource assessment utilizes the same geologic framework established for the 2021 resource assessment. The 2021 resource assessment was a departure from previous BOEM assessments in that more emphasis was placed on the structural controls of AU extents. As previously stated, Cenozoic AUs are grouped as a function of modern bathymetric setting and geologic age. However, the position of Mesozoic AUs is more closely aligned with their respective depositional shelf-slope break, and their areal extents are aligned with structural boundaries associated with basement lineaments, faults, and salt features thought to exert fundamental controls on sediment fairways, facies patterns, burial history, and hydrocarbon systems. See [BOEM’s 2021 resource assessment report](#) (U.S. DOI, 2021b) for details.

Table 5. BOEM Mesozoic chronostratigraphy and associated assessment units.

Chronostatigraphic Unit					Gulf of America					
Erathem	System	Series	Stage	Chronozone	Stratigraphic Unit (Generalized Louisiana Coast/NE Gulf of America)	Assessment Unit				
						Shelf (Eastern)	Slope (Eastern)	Shelf (Central/Western)	Slope (Central/Western)	Abyssal Plain
Mesozoic	Cretaceous	Upper	Maastrichtian	KUU						
			Campanian		Selma Group					
			Santonian		Eutaw Formation					
			Coniacian							
			Turonian	KLU	Upper Tuscaloosa	Tuscaloosa Marine Shale	Tuscaloosa Marine Shale			
			Cenomanian		Lower Tuscaloosa	Lower Tuscaloosa Shelf	Lower Tuscaloosa Slope			
		Lower	Albian	KUL	Washita Group-Dantzler Formation	Lower Cretaceous Clastic Shelf	Lower Cretaceous Clastic Slope	Mesozoic Shelf	Mesozoic Slope	Mesozoic Basin Floor
					Washita/Fredericksburg Group-Andrew Formation	Lower Cretaceous Carbonate				
				KML	Paluxy Formation	Lower Cretaceous Clastic Shelf	Lower Cretaceous Clastic Slope			
					Mooringsport Formation					
					Ferry Lake Anhydrite					
					Rodessa Formation					
			Aptian	KLL	Bexar Shale					
					Upper James Limestone	Lower Cretaceous Carbonate				
					Lower James Limestone (Pine Island Shale)					
					Sligo Formation					
					Hosston Formation	Lower Cretaceous Clastic Shelf	Lower Cretaceous Clastic Slope			
					Cotton Valley Carbonates	Knowles Carbonate				
	Berriasian	JU	Upper	Cotton Valley Clastics	Cotton Valley Clastic Shelf	Cotton Valley Clastic Slope				
				Haynesville-Buckner						
				Smackover Formation	Smackover					
			Middle	JM	Norphlet Formation	Norphlet Shelf	Norphlet Slope			
					Louann Salt		Expanded Jurassic			
					Werner Formation					
Lower	JL	Eagle Mills Formation		Pre-Salt or Equivalent						
		Formation								
Triassic										

Symbology:	
	Predominantly Clastics
	Predominantly Carbonates and Evaporites
	BOEM Assessment Unit (assessed)
	BOEM Assessment Unit (not assessed)
	Major Unconformity
	Basement
	Transitional Boundary

Table 6. South Florida Mesozoic chronostratigraphy and associated assessment units.

Chronostatigraphic Unit					South Florida		
Erathem	System	Series	Stage	Chronozone	Stratigraphic Unit	Assessment Unit	
Mesozoic	Cretaceous	Upper	Maastrichtian	KUU	Pine Key Formation		
			Campanian				
			Santonian				
			Coniacian				
			Turonian	KLU			Atkinson Formation
			Cenomanian				
		Lower	Albian	KUL	Corkscrew Swamp Formation	Naples Bay Group	
					Rookery Bay Formation		
					Panther Camp Formation		
					Dollar Bay Formation	Big Cypress Group	
					Gordon Pass Formation		
					Marco Junction Formation		
			Aptian	KML	Rattlesnake Hammock Formation	Ocean Reef Group	
					Lake Trafford Formation		
					Sunniland Formation		
					Punta Gorda Anhydrite		
		Barremian	KLL	Able Member	Glades Group		
	Twelve Mile Member (Brown Dolomite Zone)						
	West Felda Shale Member						
	Pumpkin Bay Formation						
	Bone Island Formation						
	Valanginian	JU	Wood River Formation				
	Berriasian						
Jurassic	Upper	Tithonian	Florida Basement Clastic				
		Kimmeridgian					
		Oxfordian					
Middle	JM	Basement Clastics					
Lower	JL						
Triassic							
Symbology:							
Predominantly Clastics							
Predominantly Carbonates and Evaporites							
BOEM Assessment Unit (assessed)							
Major Unconformity							
Basement							

RESERVES GROWTH

Estimates of the quantity of reserves in a field typically increase as the field is developed and produced. This is known as reserves growth (also known as, reserves appreciation) and was first reported by Arrington (1960). The reserves growth phenomenon contributes a significant portion of the current domestic petroleum supply and must be an integral part of any resource assessment. Root and Attanasi (1993) estimated that the growth of known fields from 1978 to 1990 in the United States accounted for 90% of the annual additions to domestic reserves. The National Petroleum Council (NPC) (1992) estimated that field growth accounts for roughly two-thirds of the annual additions to domestic reserves. Characteristically, the relative magnitude of this growth is proportionally larger the younger the field. This growth phenomenon is complex and not completely understood. It is, however, a consequence of a multitude of factors, which include

- areal extension of existing reservoirs,
- discovery of new reservoirs,
- increases in reserve estimates in existing reservoirs as production experience is gained,
- improved recovery technologies,
- increases in prices and/or reductions in costs, which reflect the influences of market economics and technology,
- systematic assessment bias toward conservatism, which typically exists in initial estimates of field sizes, and
- reporting practices with respect to reserves.

The objectives of the reserves growth effort in this resource assessment were to (1) estimate the quantity of reserves from known fields that, owing to the reserves growth phenomenon, would likely contribute to the Nation's future oil and gas supply and (2) explicitly incorporate field growth in the measure of past performance, which forms the basis for projecting future discoveries within defined plays.

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. Techniques for modeling reserves growth 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 important that the period encompassed by the reserve estimates data series reflects the cyclic nature of technologic innovations as well as market conditions. The effect on reserves growth 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 would likely be similar to those introduced during the time span encompassed by the data series.

Root and Attanasi (1993) reviewed the history and basic approaches traditionally employed to model the reserves growth phenomenon. The approach employed in this study was to calculate annual growth factors (AGFs) 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. Using the

BOEM database of OCS fields with reserves, AGFs were calculated by dividing the estimate of reserves for all fields of the same age by the estimate of 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 AGFs is likely to differ from one year to the next as some fields are depleted and abandoned, whereas others continue to produce. Growth factors can also be expressed as cumulative growth factors (CGFs), 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. For this study, the time period is the life of the field. 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 growth have operated, and
- the factors causing future growth will likely result in patterns and magnitudes of growth similar to those observed in the past.

Since growth factors are calculated from revisions to estimates of 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 likely calculate different AGFs than more cautious assessors, given the same initial estimate of reserves, although both should arrive at the same final CGF (Megill, 1993).

The working hypothesis for this effort was that OCS fields in the GOA characteristically grow at a lower rate and possibly for a shorter duration than onshore fields; therefore, growth functions specific to the OCS were required. 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 this data with seismic data prior to field development decisions,
- the additional years elapsed after field discovery prior to the initial estimate of reserves, and
- the obligation of the assessor to not intentionally and significantly underestimate reserves, which is inherent in requirements to reflect reserves potential more accurately at the time development decisions are made due to the increased capital requirements and more rigorous design criteria for offshore versus onshore infrastructure.

POOL-SIZE DISTRIBUTIONS

The second objective of the reserves growth 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 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 BOEM. Thus, it is imperative that the reserves growth phenomenon be considered as an integral part of this assessment process. This was accomplished, in this study, by appreciating the discovered fields prior to matching them to a characteristically lognormal distribution of individual field

sizes for accumulations in a play (Lee and Wang, 1986).

Efforts to quantify growth 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 growth to a given point in the future. The complication arises because the play consists of grouped reservoirs (termed “pools” in this effort) within individual fields that produce from the same geologic age and depositional sequence and not entire fields. In other words, a pool represents that portion of the field’s ultimate recovery that is attributable to a particular play.

The strategy used to resolve the dilemma regarding the use of pool-level plays in this assessment was to use fields that consisted of just one play (single pool fields) for the derivation of the growth equation. The resulting growth equation was then applied to every pool within each field to estimate the final size of the pool. The grown pool sizes were then fit into lognormal distributions, representing ultimate reserves with which to forecast undiscovered pool sizes. This approach allowed the theory of field growth to be applied at the pool level. Almost 60% of Gulf of America OCS fields are defined as single pool fields, which provided sufficient data for the generation and validity of this concept.

The effects of incorporating reserves growth 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 growth 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 accumulations will be projected to experience significant growth, creating gaps in the projected pool-size distribution, which will then accommodate significant-sized pools. The effect of explicitly considering reserves growth 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 growth phenomenon. Alternatively, a resource assessment for moderately mature to immature plays will project larger quantities of undiscovered resources when growth is considered.

ASSESSMENT METHODOLOGY

Assessment teams generally follow a workflow that comprises several crucial steps, including

- compilation of play data (e.g., maps, databases),
- develop a distribution for the number of prospects,
- for established plays, determine if the largest pool is discovered or undiscovered,
- for conceptual plays, provide analog pool sizes, and
- estimate the play and prospect risk.

NUMBER OF PROSPECTS

Where possible, prospects were identified through subsurface mapping of structural and stratigraphic traps. Sources included internal BOEM Fair Market Value reports and databases, regional studies, and proprietary company submissions. Using this inventory of known traps and knowledge of the regional geologic setting, a probabilistic distribution of the number of undiscovered prospects was estimated for each play.

In areas where data quality was poor, knowledge of salt systems and likely trapping geometries was used to forecast the number of prospects. It has long been recognized that there is a close association between salt-related structures and hydrocarbon migration and entrapment. Detailed mapping of remnant autochthonous salt and associated salt feeders, vertical welds, and counter-regional faults reveals a close association with these primary structures and discoveries in the deepwater subsalt areas and the deep shelf. Furthermore, these deep autochthonous salt structures are linked to shallow allochthonous salt bodies by families of related faults and welds, which partition the salt canopy into discrete structural systems. A variety of characteristic trap types may be anticipated with each of these systems.

For some conceptual plays, particularly in the eastern GOA, seismic data coverage was insufficient to delineate individual prospects across some or all of the area. In cases where seismic data could be used to generate a prospect inventory over only a portion of a play, a prospect density was, therefore, calculated and extrapolated across the remaining area. If no OCS prospect inventory could be generated, the prospect density was calculated from onshore analogs and applied to the play area. Basement structure from proprietary gravity and magnetic surveys and reports was also used as a proxy to high grade prospective areas for some deep Mesozoic plays.

SIZE OF POOLS

For an established play, the size of undiscovered pools is controlled by discovered pool sizes, with the undiscovered pools fitting into gaps in a pool-rank plot. One of the important questions for the assessment teams is whether the largest pool has been found or not, which will influence the overall UTRR for the play.

For a conceptual play, the size of undiscovered pools is controlled by the size of discovered pools in an analog play. Because most conceptual plays in the OCS are downdip extensions of onshore plays, these analogs come mostly from onshore Gulf Coast discoveries. One of the important questions for the assessment teams is the size of the largest pool based on mapped OCS prospects or leads and regional studies.

GEOLOGIC RISK ANALYSIS

Geologic risk assessment is the process of subjectively estimating the chance that at least a single hydrocarbon accumulation is present in the play area being assessed. A play is defined as a group of

prospects within a geographic area, and of the same geologic age, where mutually related geologic factors must be present for the discovery of hydrocarbons. 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, traps, and reservoir rocks are present. An important timing condition is that the traps were formed before the migration of hydrocarbons ceased.

In play assessment, the probability factors are separated into two groups. The first is the marginal play chance factors (play level), and the second is the conditional prospect chance factors (prospect level). **The marginal play chance** considers the petroleum system that is common for all prospects for a given play. This analysis assesses the probability of occurrence for each of the geologic components. Any play confirmed by a well that penetrates a reservoir with hydrocarbons, proving the geologic components are present, is considered an established (discovered) play, and the play chance is assigned a value of 1. At the other extreme, if any of these essential factors are not present, the play will likely not exist. The play-level assessment of risk consists of a subjective analysis performed on each of the critical components necessary for a productive play—the hydrocarbon source, reservoir presence, and trap retention of hydrocarbons after accumulation. There is a dependency between the elements of play chance. The risk assessment was documented on a worksheet ([Table 7](#)) for each play. 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. The overall play chance is the product of the three play chance factors.

The conditional prospect chance considers an average probability factor for all mapped and unmapped prospects in a play. Some prospects will have a greater chance, and some will have a lower chance than the average value. The prospect chance components are geologically and statistically independent from the others. The prospect chance utilizes a three-component system of hydrocarbon fill, reservoir, and trap. These three primary components are determined while considering a variety of sub-components for each. Hydrocarbon fill considers the probability of occurrence of presence of mature source rock, effective expulsion, and migration pathway sub-components. The reservoir component considers the probability of presence of reservoir rock, quality, effectiveness, and continuity as its sub-components. The trap component considers the probability of presence of trap with a minimum rock volume, structural configuration confidence, and vertical and lateral seal as its sub-components. The fractional estimation for the presence of these essential geologic factors is determined, and only the lowest fractional probability under each component is used to calculate the average conditional prospect chance. The lowest sub-component under each component is the weak link or critical sub-component risk. The three remaining fractional components, representing each category, are then multiplied to determine the average conditional prospect chance.

Once a conceptual play has been defined, it is necessary to address the question of its probable presence. However, in conceptual plays, even at the earliest stages of exploration, we cannot state with absolute confidence that these critical factors occur throughout the extent of the delineated play. 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 reflects the analog model.

This play-level analysis differs from the prospect-level analysis, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect. The play-level risk 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 its prospects.

[Figure 3](#), [Figure 4](#), and [Figure 5](#) present play-level, prospect-level, and overall exploration chance of successes, respectively, for the 30 assessment units analyzed for undiscovered resources in this study. A play-level chance of success equaling 100% means the play either has discovered pools or has at least one

hydrocarbon-bearing well proving a petroleum system. See the individual assessment unit descriptions for details. Completed risk worksheets for each assessed play are presented in [Appendix A](#) (Mesozoic) and [Appendix B](#) (Cenozoic).

Table 7. BOEM play and prospect risk analysis worksheet.

BOEM Play and Prospect Risk Analysis Form					
Assessment Province:		Assessment Unit Name:			
Assessor(s):		Play-Level Risk:			
Date:		Assessment:			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	0.0000		0.0000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a			
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b			
2. Reservoir Component		2	0.0000		0.0000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a			
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b			
3. Trap Component		3	0.0000		0.0000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a			
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b			
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors			0.0000		
Average Conditional Prospect Chance¹ (1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors ¹ Assumes that the play exists (where all play chance factors = 1.0)					0.0000
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)		Overall Exploration Chance			
		0.0000			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

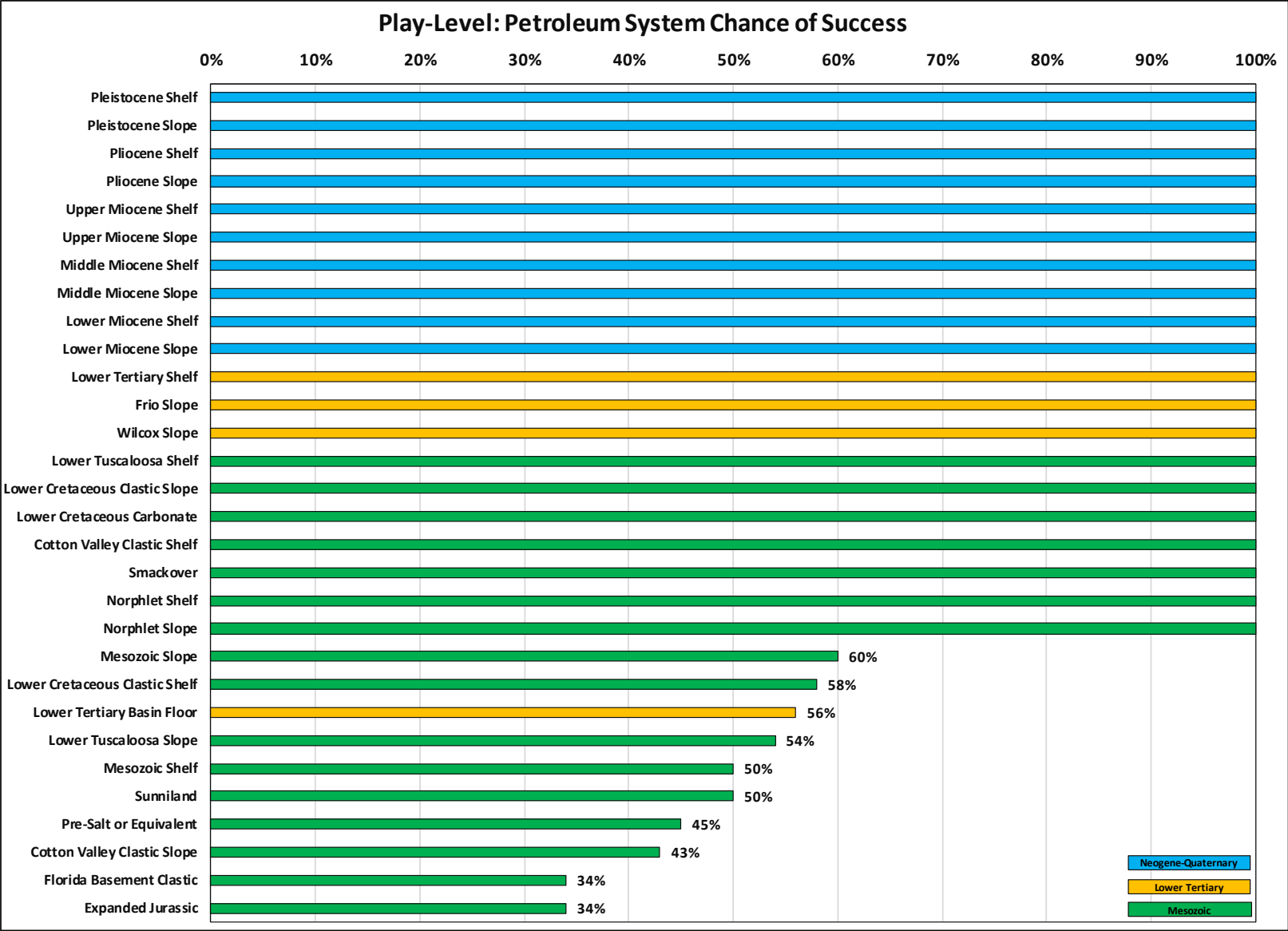


Figure 3. Petroleum system chance of success for the evaluated assessment units.

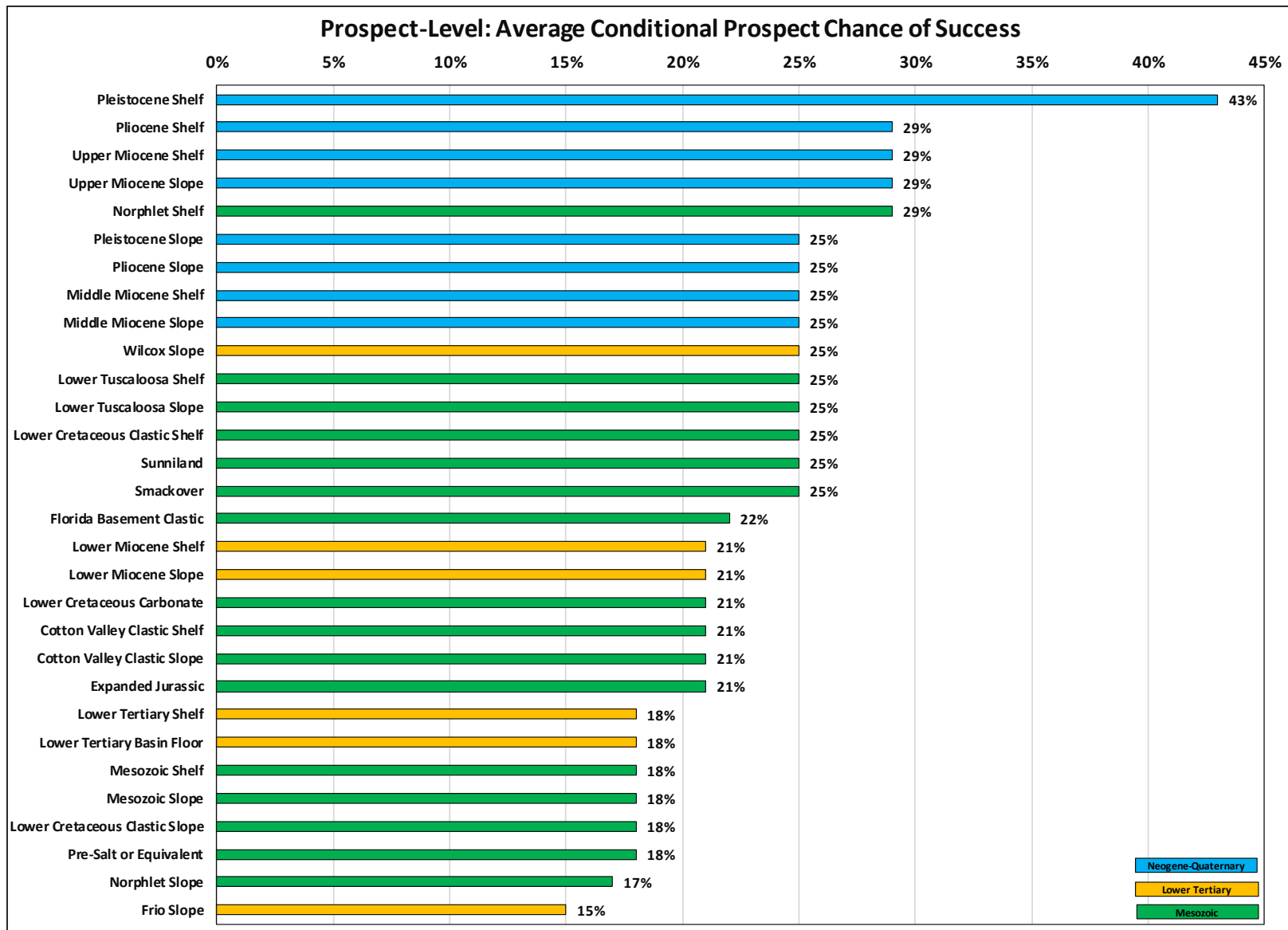


Figure 4. Average conditional prospect chance of success for the evaluated assessment units.

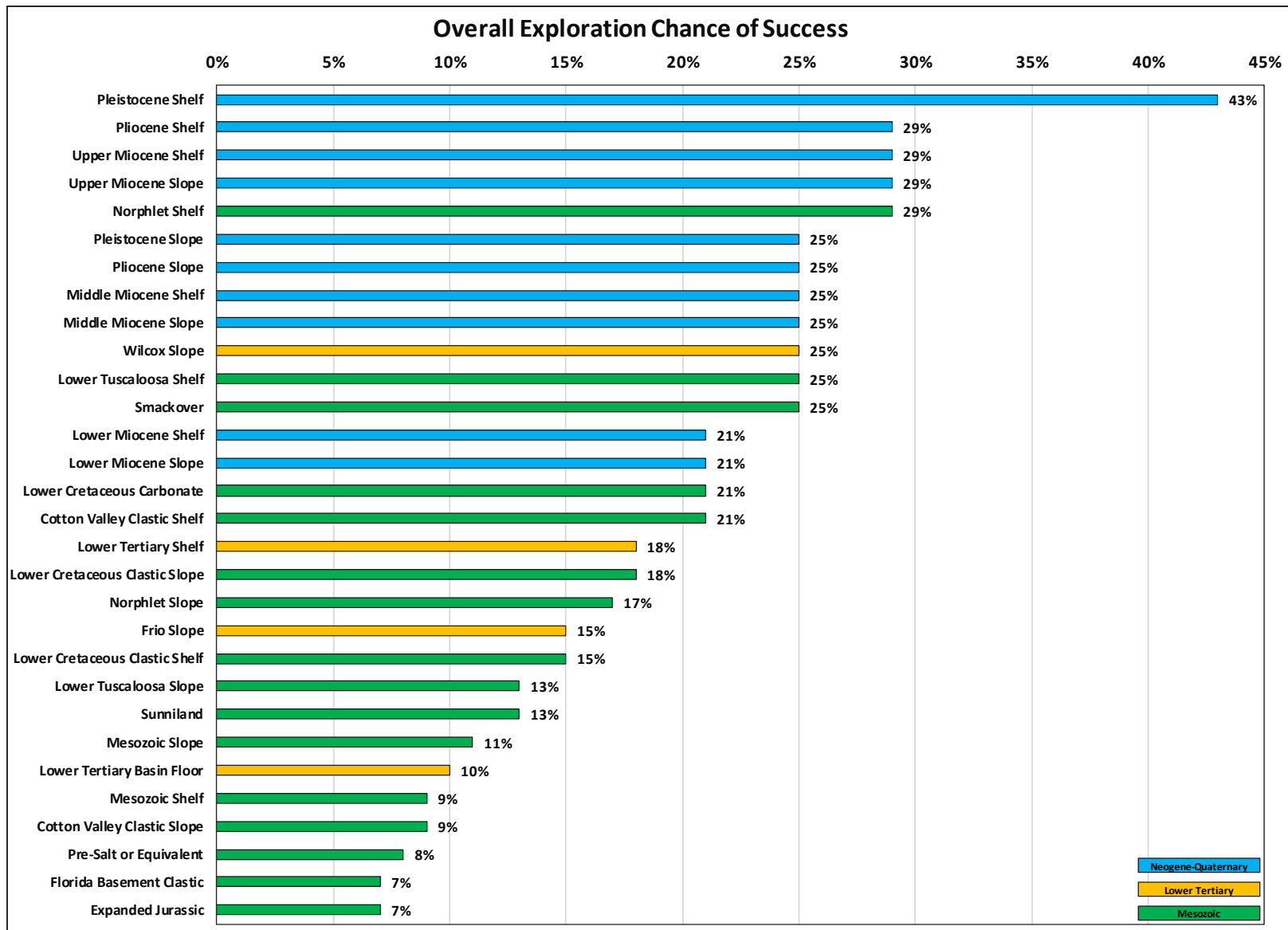


Figure 5. Overall exploration chance of success for the evaluated assessment units.

ASSESSMENT MODELING PROGRAM

MODEL OVERVIEW

BOEM assesses the undiscovered technically recoverable resource potential of oil and natural gas plays using the Geologic Resource Assessment Program (GRASP). The current version of the program was adapted by BOEM from the Geological Survey of Canada's PETRIMES (Petroleum Resources Information Management and Evaluation System) suite of programs. The GRASP model is designed for a geologic play-based assessment of oil and natural gas resources in an offshore environment. The model utilizes a single parametric distribution—the lognormal distribution (Lore et al., 2001).

For modeling purposes within GRASP, geologic plays can be either defined as subjective or discovered. A subjective assessment is an estimation of the resources for an area which has no known oil and gas discoveries, while a discovered assessment utilizes the existing oil and gas discoveries in an area to assist in projecting additional oil and gas resources and types of pools which may be present in a geologic formation. Currently, the model can run discovered plays under a subjective analysis if discovered pools are removed from the final distribution of pools. As the model is run now, all BOEM regions (Alaska, Atlantic, GOA, and Pacific) implement a subjective workflow while trimming out discovered volumes to avoid double counting pools.

The GRASP model predicts the possible number of pools as a distribution based on the assessors' estimation of the number of potential prospects contained in a geologic play. A geologic pool represents one of three configurations in determining the volumes of oil and gas present. The first is an oil deposit with dissolved solution gas present. The second is a gas deposit with condensate present. The third is a combination of the first and second configurations as an oil deposit with a gas cap present.

The assessment of undiscovered technically recoverable resources of the Gulf of America OCS is performed irrespective of any consideration of economic constraints. Commerciality of the resource is considered in the subsequent economic analysis phase. The economic component of GRASP takes the oil and gas pools identified by geologic model analysis and applies user-identified economic and engineering parameters to those pools. The economic model will then apply a series of different oil and gas prices along with engineering distributions and identify those pools determined to be “economically successful” at the given oil and gas price pair.

GEOLOGIC MODEL

Geologic plays in the GOA are described as either conceptual or established. Conceptual plays are hypothesized to exist but not yet verified by hydrocarbon discoveries. Established plays have hydrocarbons found in at least one well. When GRASP was first adopted by BOEM in the early 1990s, conceptual plays were assessed with subjective inputs and the subjective computer modules of GRASP. These plays were associated with the “subjective methodology” process. The plays with discoveries were assessed with discovered inputs and the discovered modules of GRASP. These plays became associated with the “discovered methodology” process.

For this and the last three Gulf of America OCS assessments, the methodology was revised so all plays would be assessed using the subjective methodology. For plays with discoveries, the MATCH and TRIMPOOLS modules were used to facilitate this change in methodology. This improvement makes the process consistent with the methodology used in all BOEM regions. [Figure 6](#) illustrates the general geologic GRASP model methodology. The revised subjective methodology results in a much wider range of undiscovered resource volumes. The entire pool-size distribution is now sampled and is not restricted to the undiscovered portion of the distribution as it was done with the discovered methodology. Additionally, pools similar in size to the pools already discovered may remain after the TRIMPOOLS module is used.

Conceptual Plays

The subjective methodology begins with the development of a lognormal pool-size distribution. Since pools have not been found in conceptual plays, their volumes are estimated based on those of similar analog plays. The resulting distribution is further refined by truncation. Because the lognormal curve is infinite at both the high and low ends, the assessment team must constrain the expected size of the largest and smallest pools based on geologic considerations. The resulting truncated volume distribution is entered into GRASP and is sampled over 10,000 trials. The number of pools that is generated on each trial is based on a distribution of the number of pools that is expected to be discovered in the play. A final summation of the pool volumes is calculated by GRASP, and the results are presented in a percentile table of total BOE, oil, condensate, non-associated gas, and solution gas.

Established Plays

The pools discovered in an established play represent only a partial set of volumes that will ultimately define the pool-size distribution at the end of a play's life. The MATCH module utilizes these discovered pools to develop a pool-size distribution and predict additional undiscovered pools. As a result, the MATCH distribution represents all pools, both discovered and undiscovered. As plays become more mature and the number of discoveries increases, MATCH can produce distributions that more accurately describe the entire play distribution.

The first step in the modeling process of an established play is to develop a lognormal distribution of the discovered pools and obtain a *mu* and *sigma*. The *mu* (μ) defines the mean of the distribution and *sigma* (σ) defines the standard deviation, or spread of the values, from the mean. Because this is only the *mu* and *sigma* of the existing discoveries, the final distribution will change. Generally, the largest pools in a play are discovered first. As a result, it is expected that the mean pool size decreases as smaller pools are discovered. Similarly, the spread of the sizes from the mean usually increases. In MATCH, these assumptions can be examined. Using various stepped series of *mu*, *sigma*, and number of pools as inputs, MATCH generates a distribution for each combination. The results are then grouped by several criteria such as size of expected pools, number of pools, gaps in the distribution, *mu*, and *sigma*. From this, the analyst can select the scenarios that satisfy the best geologic expectation of the play. Further adjustments to the inputs are made, and iterations continue until the analyst can choose the scenario that most closely represents the play as described by the assessment team. As with subjective plays, the chosen distribution is truncated at the high and low ends and is sampled 10,000 times. The number of pools that is generated on each trial is controlled by the ultimate number of pools distribution for the play supplied by the assessment teams.

As discussed above, because there are no discoveries in conceptual plays, the pool-size distributions are based completely on play analog discoveries. For the established plays, the discoveries are included in the selected distribution generated by MATCH. Therefore, another step is necessary to remove the discovered volumes from the total pools that are projected.

An additional module, TRIMPOOLS, was developed and added into the module sequence and completes the analysis of the undiscovered pool volumes before being summed together to determine the play potential. The TRIMPOOLS process reviews the pool volumes that were previously sampled over the 10,000 trials. On each trial, the discovered pool volumes are compared to all the volumes on the trial. The discovered volume that is closest in size to a projected volume is removed from the set of volumes for that trial. The remaining pools are considered the undiscovered volumes. These volumes are summed and complete the geologic assessment for play potential. Again, the results are presented in a percentile table of total BOE, oil, condensate, non-associated gas, and solution gas.

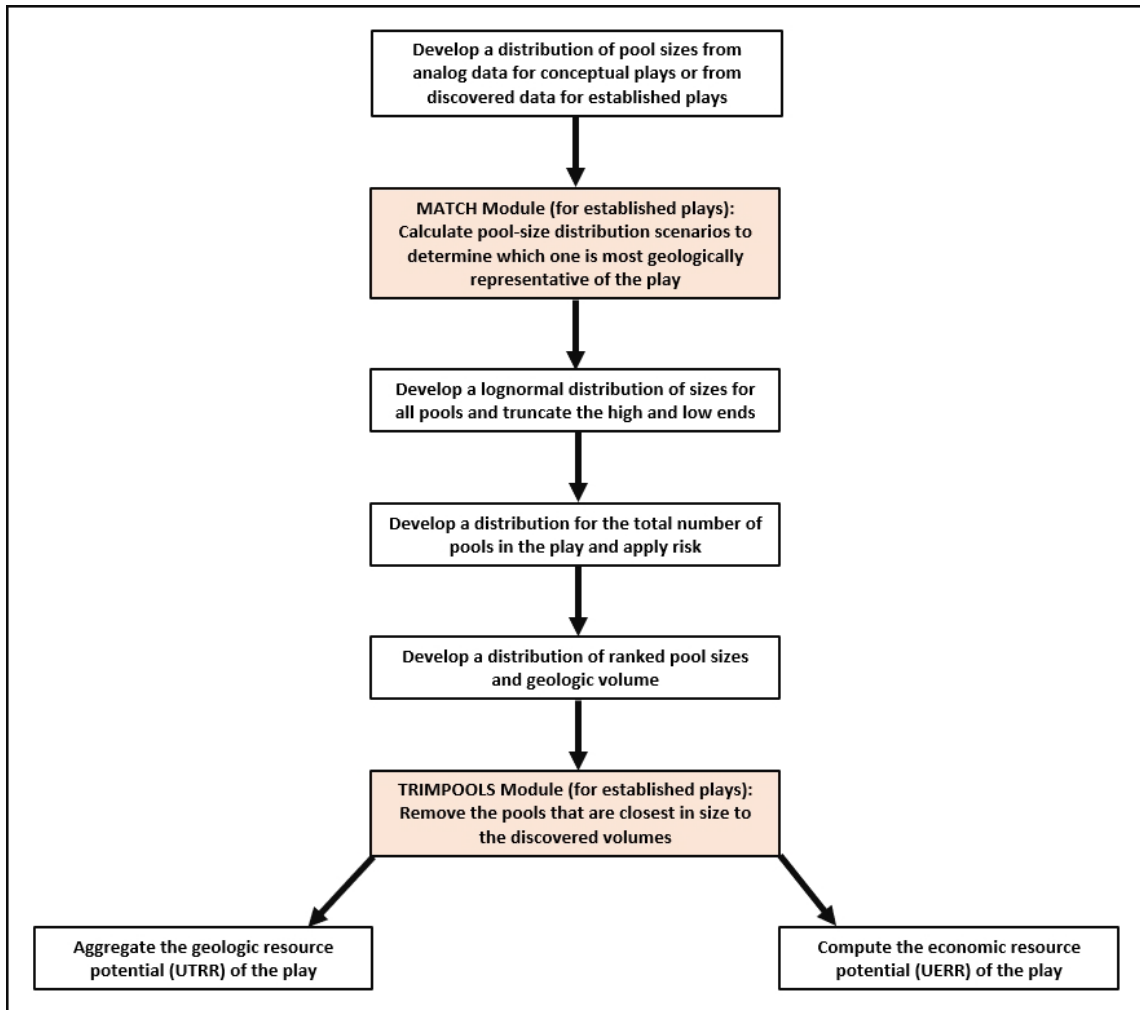


Figure 6. GRASP geologic model methodology.

ECONOMIC ANALYSIS

The objective of the economic analysis phase of this assessment was to estimate the portion of the undiscovered technically recoverable resources that is expected 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 point in time at which profitability is measured. Since the resource assessment and economic evaluation of recoverable resources must be performed “pre-drill,” there is considerable uncertainties surrounding these evaluations.

The ability to develop and produce all or a portion of the undiscovered technically recoverable resources depends primarily upon (1) the total volume of technically recoverable resource, (2) the extraction cost, and (3) the price obtained. Ideally, an exploration well may be drilled in each prospect to determine if it is hydrocarbon bearing. If the exploration well encounters hydrocarbons that are initially assessed to be of a size and characteristic sufficient to warrant additional drilling, further exploration and delineation wells would be drilled to justify the installation and determine the appropriate size of a platform or satellite complex. A development drilling program leading to production will also be determined. If the inter-relationships of these factors result in a forecast of real-term profits, the accumulation is developed. The production profile will subsequently size production equipment and pipelines for timely installation and transportation of production to the market. Ultimately, the field would be abandoned when the revenue

from production was insufficient to cover the costs of production (operating costs, taxes, and royalties). Economically recoverable resources represent only a fraction of the physically recoverable resource.

The geologic resource potential generated by GRASP for each play is the key input for the economic analysis performed. This economic analysis is conducted using BOEM's proprietary resource evaluation model. This model 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 standard in petroleum and other industries for making decisions under conditions of uncertainty. The technique enables the evaluator to incorporate uncertainty as a range of variables, rather than being restricted to single point estimates. The model contains mathematical statements that specify the relationships among all variables affecting the outcome. Many iterations or trials are performed to simulate a range of possible outcomes or states of nature. In each iteration, different values are selected from the range of uncertain variables, with each iteration yielding one possible state of nature.

Figure 7 illustrates the general economic evaluation methodology. Exploration and development scenarios—assumptions about the timing and cost of exploration, delineation, development, and transportation activities—were developed specifically for each planning area (**Figure 1**) and the combined Gulf of America OCS 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 economically recoverable resources were then derived through a stochastic discounted cash flow simulation process for specific product prices using a distribution for exploration and development inputs with their associated development scheduling scenarios for each assessment unit. The basic economic test was performed at the pool level. 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 an 11% discount rate.

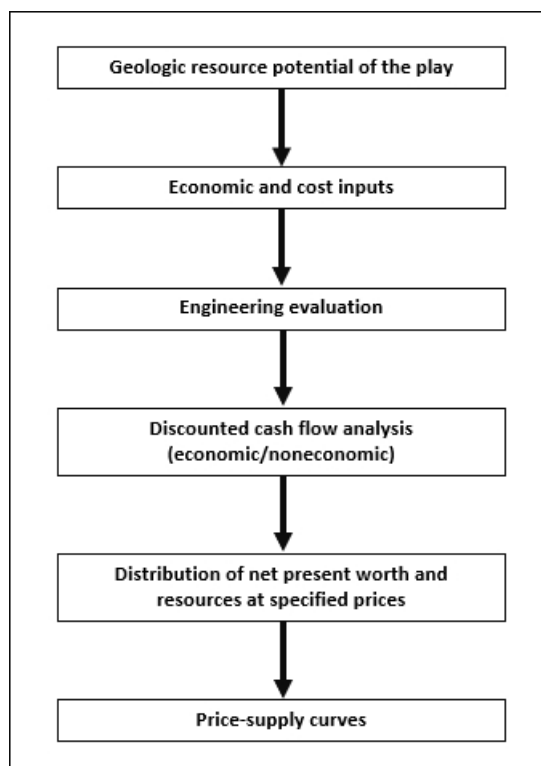


Figure 7. Economic evaluation methodology.

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 it does consider all leasehold, geophysical, geologic, and exploration costs incurred after 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. 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 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.

The Gulf of America OCS contains "stacked plays" (i.e., plays that overlie other plays at different depths). In determining the economic viability of such plays, assessors considered the concurrent exploration, development, and production of possible pools in these plays to properly determine the economic viability of the prospect's resources.

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

Figure 8 is an example price-supply scenario showing 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 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. In the example in **Figure 8**, if a \$30/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. The two vertical lines indicate the mean estimates of undiscovered technically recoverable natural gas and oil resources. As prices increase, the estimate of economically recoverable resources approaches this limit. It should be noted that entire resource distributions, not only the mean cases, are generated at each price level.

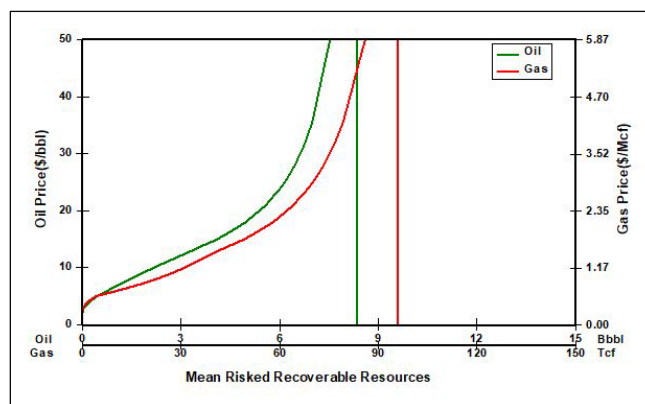


Figure 8. Example price-supply curves.

ASSESSMENT RESULTS

UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES (UTRR)

Starting with a database of grown discovered resources (includes cumulative production, remaining reserves, and contingent resources) estimated at 44.439 Bbbl of oil and 243.476 Tcf of gas (total BOE of 87.762 Bbbl), BOEM estimates 26.903 Bbbl of oil and 45.593 Tcf of gas (total BOE of 35.016 Bbbl) mean-level UTRR remain to be found in the Gulf of America OCS ([Figure 9](#))

Assessment units ranked by mean-level UTRR are shown in [Figure 10](#). The Wilcox Slope is estimated to contain the most UTRR, with the Miocene-aged plays on the modern slope holding significant undiscovered resource potential as well. Of the Mesozoic-aged plays, Norphlet Slope aeolian dunes and Smackover grainstones hold the greatest potential for discoveries.

Detailed values of UTRR are presented by individual AU ([Table 8](#)) and by water depth categories within each planning area ([Table 9](#)). [Figure 11](#) and [Figure 12](#) graphically present the range of UTRR values for the Cenozoic and Mesozoic assessment units, respectively. Because of the play-level petroleum system risk, the GRASP results for some of the plays do not return successful case values for the 95th percentile.

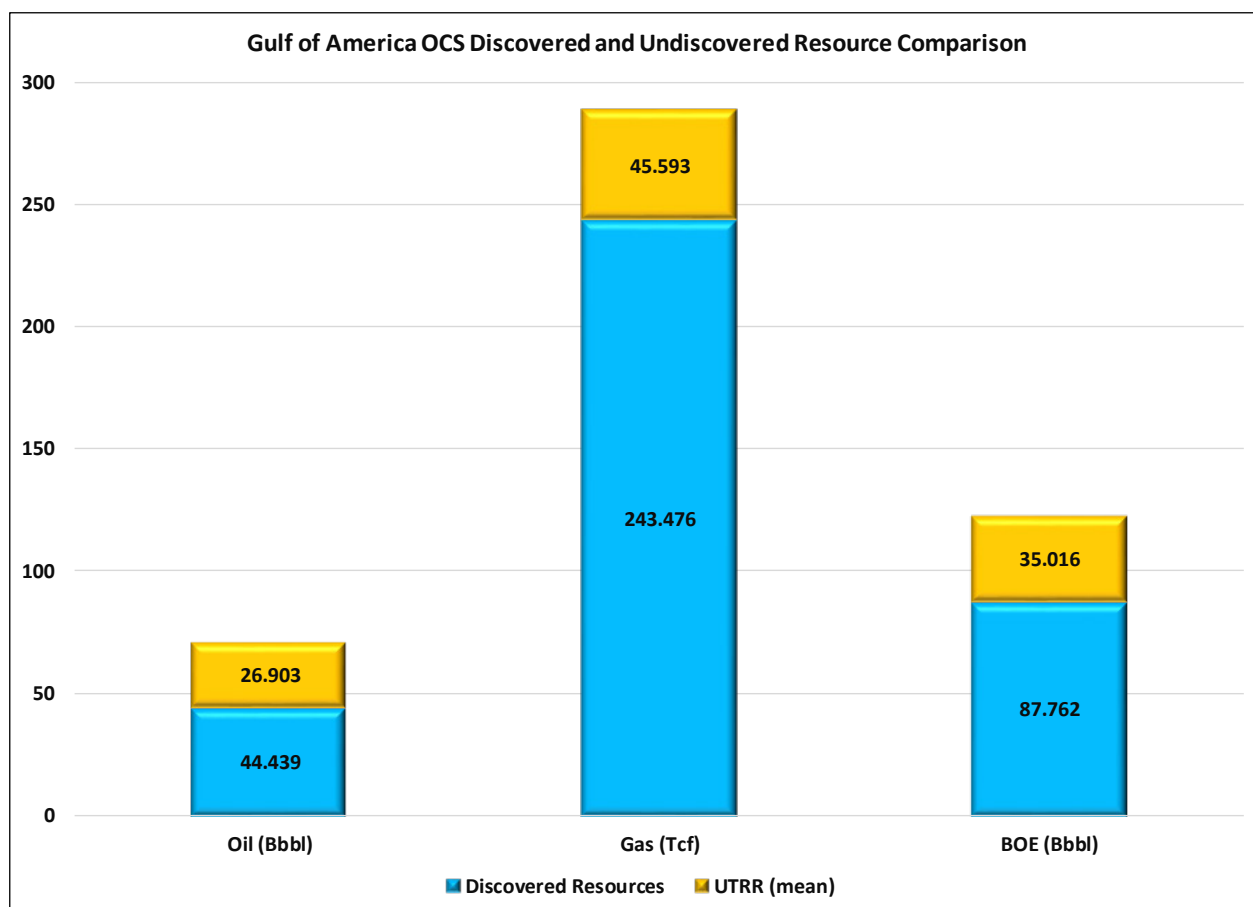


Figure 9. Comparison of grown discovered resources and UTRR in the Gulf of America OCS.

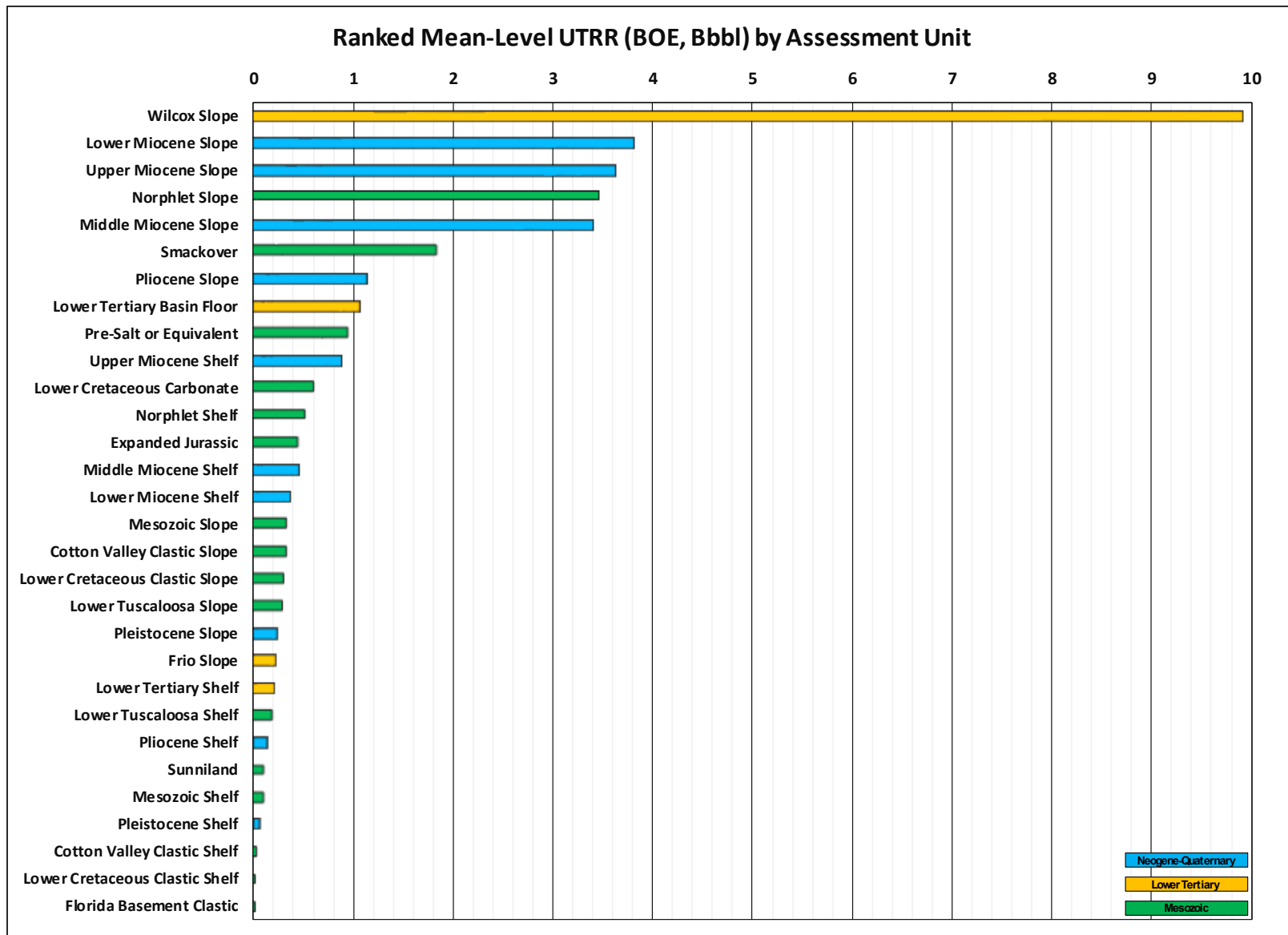


Figure 10. Assessment units ranked by mean-level UTRR.

Table 8. Grown discovered resources and UTRR by assessment unit.

2026 Gulf of America OCS		Grown Discovered Resources			Undiscovered Technically Recoverable Resources (UTRR)										
Era	Assessment Unit	# of pools	Oil	Gas	BOE	# of pools (mean)	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
			(Bbbl)	(Tcf)	(Bbbl)		95th	mean	5th	95th	mean	5th	95th	mean	5th
Cenozoic	Pleistocene Shelf	392	2.112	35.940	8.507	30	0.001	0.014	0.023	0.022	0.251	0.733	0.005	0.059	0.153
	Pleistocene Slope	104	1.360	7.605	2.713	80	0.026	0.114	0.242	0.102	0.638	1.608	0.044	0.227	0.528
	Pliocene Shelf	477	5.440	50.114	14.357	45	0.007	0.053	0.097	0.046	0.482	1.432	0.015	0.138	0.352
	Pliocene Slope	112	4.950	12.679	7.206	90	0.152	0.781	1.875	0.320	1.986	4.250	0.209	1.134	2.631
	Upper Miocene Shelf	471	7.405	51.655	16.596	80	0.060	0.385	1.364	0.430	2.707	7.189	0.137	0.866	2.643
	Upper Miocene Slope	106	5.550	14.776	8.179	130	0.277	2.464	4.736	0.801	6.497	17.711	0.420	3.620	7.887
	Middle Miocene Shelf	225	0.671	27.493	5.563	70	0.001	0.055	0.224	0.018	2.201	8.464	0.004	0.447	1.730
	Middle Miocene Slope	87	6.553	10.655	8.449	120	0.492	2.634	5.921	0.588	4.238	8.698	0.596	3.388	7.469
	Lower Miocene Shelf	168	0.307	22.801	4.364	35	0.001	0.026	0.186	0.093	1.887	6.327	0.018	0.361	1.312
	Lower Miocene Slope	12	3.989	1.923	4.331	60	0.653	3.507	7.336	0.315	1.690	3.536	0.709	3.807	7.965
	Lower Tertiary Shelf	2	0.001	0.046	0.009	18	0.005	0.013	0.023	0.432	1.075	1.877	0.082	0.205	0.357
	Frio Slope	5	0.349	0.247	0.393	20	0.061	0.192	0.388	0.042	0.136	0.268	0.068	0.217	0.435
	Wilcox Slope	32	4.643	2.826	5.146	88	4.329	8.929	13.853	2.636	5.438	8.436	4.798	9.897	15.354
	Lower Tertiary Basin Floor	0	0.000	0.000	0.000	8	0.000	1.004	3.042	0.000	0.289	0.876	0.000	1.056	3.198
Mesozoic	Mesozoic Shelf	0	0.000	0.000	0.000	5	0.000	0.011	0.040	0.000	0.510	1.828	0.000	0.102	0.365
	Mesozoic Slope	0	0.000	0.000	0.000	8	0.000	0.281	0.962	0.000	0.345	1.180	0.000	0.343	1.172
	Lower Tuscaloosa Shelf	0	0.000	0.000	0.000	10	0.012	0.087	0.133	0.095	0.601	1.569	0.029	0.194	0.412
	Lower Tuscaloosa Slope	0	0.000	0.000	0.000	7	0.000	0.260	0.916	0.000	0.172	0.607	0.000	0.291	1.024
	Lower Cretaceous Clastic Shelf	0	0.000	0.000	0.000	6	0.000	0.013	0.044	0.000	0.089	0.417	0.000	0.029	0.118
	Lower Cretaceous Clastic Slope	0	0.000	0.000	0.000	7	0.024	0.275	0.730	0.016	0.182	0.484	0.026	0.308	0.816
	Lower Cretaceous Carbonate	12	<0.001	0.595	0.106	42	0.104	0.228	0.544	0.266	2.116	3.518	0.151	0.604	1.170
	Sunniland	0	0.000	0.000	0.000	18	0.000	0.115	0.346	0.000	0.000	0.000	0.000	0.115	0.346
	Cotton Valley Clastic Shelf	0	0.000	0.000	0.000	11	0.004	0.017	0.042	0.003	0.117	0.506	0.005	0.038	0.096
	Cotton Valley Clastic Slope	0	0.000	0.000	0.000	8	0.000	0.299	1.134	0.000	0.199	0.753	0.000	0.335	1.268
	Florida Basement Clastic	0	0.000	0.000	0.000	9	0.000	0.021	0.095	0.000	0.026	0.117	0.000	0.025	0.115
	Smackover	0	0.000	0.000	0.000	117	0.349	0.828	2.274	0.808	5.621	7.835	0.493	1.828	3.668
	Norphlet Shelf	16	0.001	3.385	0.603	23	<0.001	<0.001	0.001	1.143	2.960	5.283	0.204	0.527	0.941
	Norphlet Slope	9	1.108	0.735	1.239	66	1.086	3.086	5.180	0.720	2.047	3.435	1.214	3.450	5.791
	Expanded Jurassic	0	0.000	0.000	0.000	7	0.000	0.403	1.610	0.000	0.267	1.068	0.000	0.451	1.800
	Pre-Salt or Equivalent	0	0.000	0.000	0.000	14	0.000	0.808	2.552	0.000	0.826	2.609	0.000	0.955	3.016
Total Gulf of America OCS		2,230	44.439	243.476	87.762	1,232	19.174	26.903	34.920	35.125	45.593	57.608	25.424	35.016	45.171

Only mean values are additive. Additionally, total mean values may not equal the sum of the component values due to independent rounding.

Table 9. UTRR by planning areas and water depth.

2026 Gulf of America OCS	Undiscovered Technically Recoverable Resources (UTRR)								
Planning Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
Water Depth	95th	Mean	5th	95th	Mean	5th	95th	Mean	5th
Total Gulf of America	19.174	26.903	34.920	35.125	45.593	57.608	25.424	35.016	45.171
0 - 200 m	0.841	1.765	2.837	10.859	17.257	26.207	2.774	4.835	7.500
200 - 800 m	3.548	5.083	6.735	5.373	7.491	9.892	4.504	6.416	8.495
800 - 1,600 m	6.008	8.913	11.925	6.922	9.772	13.176	7.240	10.652	14.270
1,600 - 2,400 m	4.576	6.758	9.040	4.515	6.766	9.169	5.379	7.962	10.671
> 2,400 m	2.460	4.380	6.623	2.986	4.305	5.636	2.991	5.146	7.626
Western Gulf of America	4.029	6.162	8.414	6.294	9.272	12.387	5.149	7.812	10.618
0 - 200 m	0.068	0.211	0.475	1.042	3.456	7.221	0.253	0.826	1.760
200 - 800 m	0.936	1.474	2.040	1.022	1.556	2.120	1.117	1.751	2.417
800 - 1,600 m	1.975	3.153	4.383	2.072	3.055	4.129	2.344	3.696	5.117
1,600 - 2,400 m	0.673	1.068	1.478	0.673	1.015	1.396	0.792	1.249	1.726
> 2,400 m	0.150	0.256	0.368	0.127	0.189	0.255	0.172	0.290	0.414
Central Gulf of America	11.712	17.001	22.458	18.981	25.136	32.389	15.089	21.474	28.221
0 - 200 m	0.266	0.491	0.946	4.270	7.889	12.939	1.026	1.895	3.248
200 - 800 m	2.009	3.032	4.139	2.257	3.565	5.038	2.410	3.666	5.035
800 - 1,600 m	3.605	5.380	7.278	3.985	5.877	7.981	4.314	6.425	8.698
1,600 - 2,400 m	3.770	5.574	7.449	3.709	5.568	7.532	4.430	6.565	8.789
> 2,400 m	1.232	2.524	4.171	1.423	2.238	3.058	1.486	2.922	4.715
Eastern Gulf of America	2.121	3.732	5.562	7.238	11.182	15.878	3.409	5.721	8.387
0 - 200 m	0.344	1.063	2.087	3.544	5.911	8.452	0.975	2.115	3.590
200 - 800 m	0.288	0.575	0.957	1.071	2.370	3.751	0.479	0.996	1.624
800 - 1,600 m	0.194	0.378	0.577	0.509	0.839	1.213	0.284	0.528	0.793
1,600 - 2,400 m	0.068	0.116	0.169	0.114	0.183	0.250	0.088	0.148	0.213
> 2,400 m	0.934	1.600	2.305	1.324	1.878	2.520	1.170	1.934	2.753
Straits of Florida	0.000	0.009	0.023	0.000	0.002	0.005	0.000	0.009	0.024
0 - 200 m	0.000	0.003	0.007	0.000	0.001	0.002	0.000	0.003	0.007
200 - 800 m	0.000	0.003	0.008	0.000	0.001	0.001	0.000	0.003	0.008
800 - 1,600 m	0.000	0.003	0.009	0.000	0.001	0.002	0.000	0.003	0.009

Only mean values are additive.

Additionally, total mean values may not equal the sum of the component values due to independent rounding.

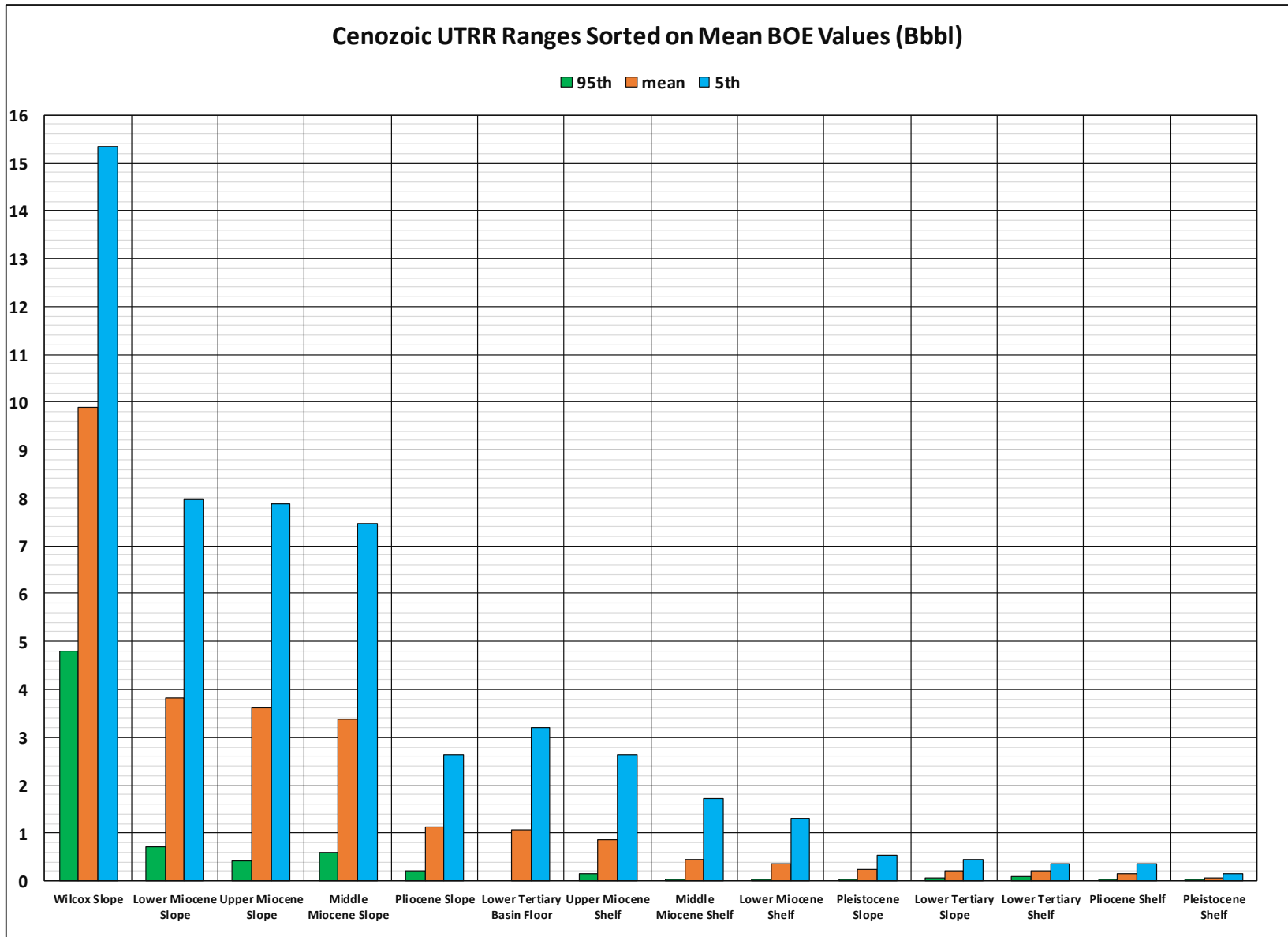


Figure 11. Undiscovered resource ranges for the Cenozoic assessment units sorted on the mean value.

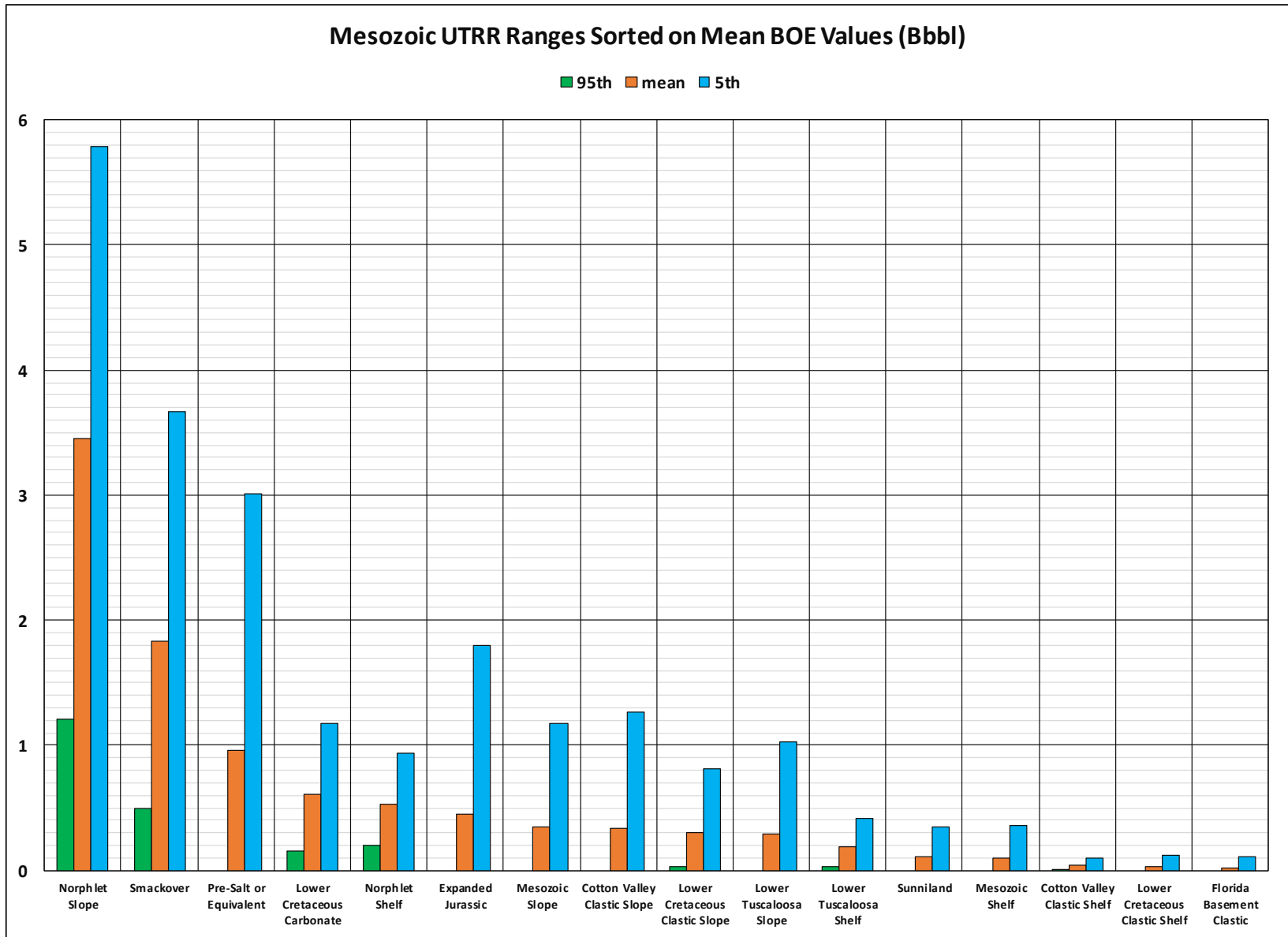


Figure 12. Undiscovered resource ranges for the Mesozoic assessment units sorted on the mean value.

COMPARISON OF UTRR FROM 2021 TO 2026

Based on mean-level BOE, this 2026 analysis results in a 4.330 Bbbl decrease in UTRR from that of [BOEM's 2021 resource assessment](#) (U.S. DOI, 2021b). That decrease is attributed to the highly explored and mature Neogene and Quaternary Shelf and Slope AUs ([Figure 13](#) and [Table 10](#)). The 2026 UTRR values for the Lower Tertiary and Mesozoic AUs did not change significantly from the 2021 UTRR values ([Figure 13](#) and [Table 10](#)).

← The Shelf AUs

- have hundreds of discoveries with exploration histories dating back to the late 1940s.
- have present-day cumulative resources curves that are generally flat, indicative of mature, highly explored plays with minimal discovered volumes being added.
- have not had a discovery sized at more than 35 million (MM) BOE since 2002.

← The Slope AUs

- have 421 total pool discoveries, but only 28 have been discovered since the end of 2013.
- have only 3 discoveries that were of a substantial size (greater than 100 MMBOE) to be economic for deep water since the end of 2013.

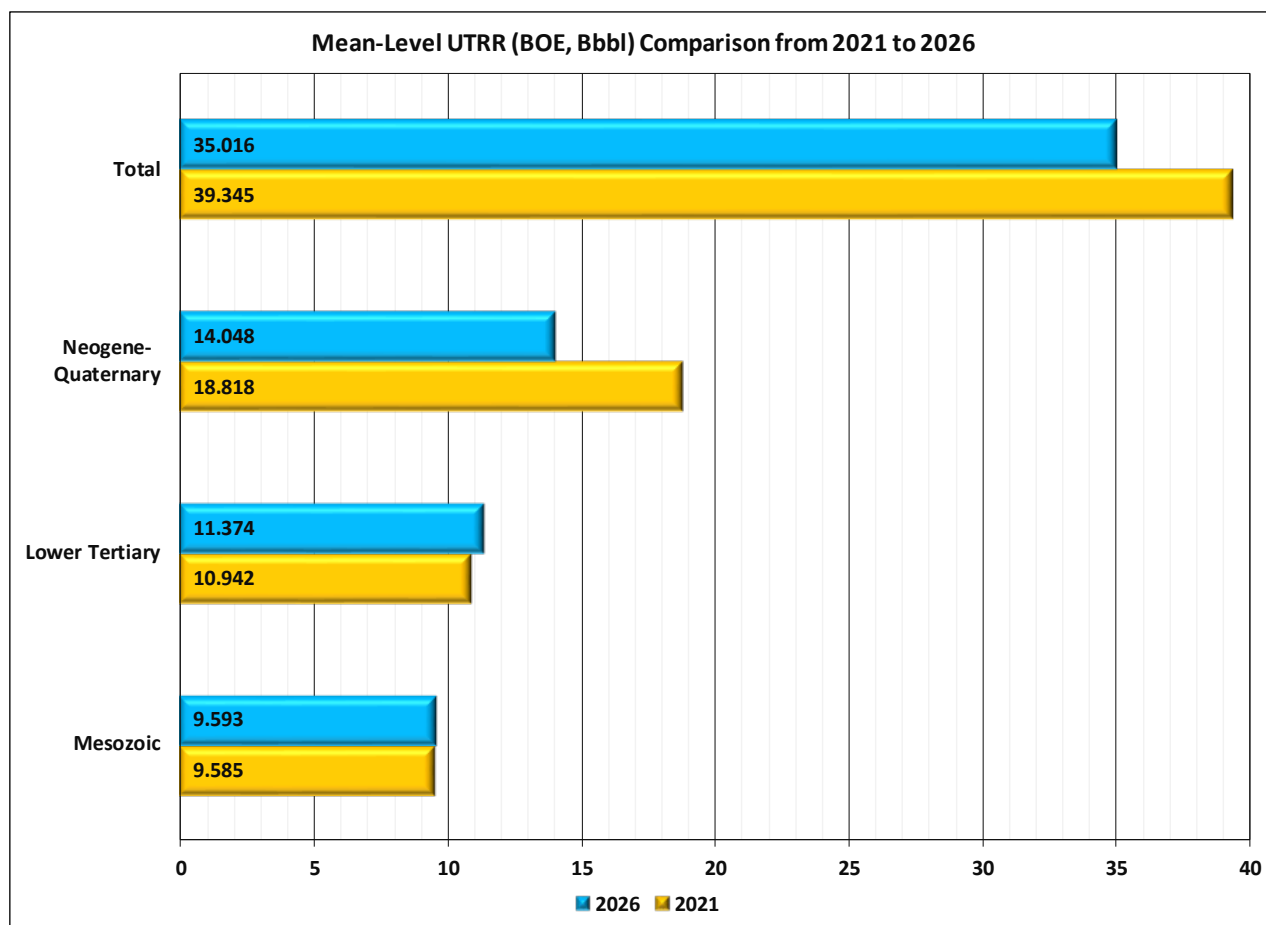


Figure 13. Comparison of mean-level UTRR for the 2021 and 2026 assessments.

Table 10. Change in mean-level UTRR from the 2021 to 2026 assessments.

Age	2021 UTRR	2026 UTRR	Change
	(mean BOE, Bbbl)	(mean BOE, Bbbl)	(BOE, Bbbl)
Neogene-Quaternary	18.818	14.048	-4.770
Lower Tertiary	10.942	11.374	0.432
Mesozoic	9.585	9.593	0.008
Total	39.345	35.016	-4.330

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES (UERR)

Undiscovered economically recoverable resources presented herein are full-cycle results associated with a 30% economic value of gas relative to oil. **Figure 14** compares mean-level values of UERR at three specific price pairs with UTRR for the entire Gulf of America OCS. **Table 11** presents detailed economic results under these price-pair scenarios.

Economic results are also presented in a series of price-supply curves showing the complete relationship of price to UERR (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). These curves are presented for the entire Gulf of America OCS (**Figure 15**) and for each planning area within the Gulf of America OCS (**Figure 16**, **Figure 17**, **Figure 18**, and **Figure 19**). The price-supply charts contain two curves and two price scales, one for oil and one for gas. The curves represent mean values at any specific price. The two vertical lines indicate the mean estimates of oil and gas UTRR and are independent of commodity prices.

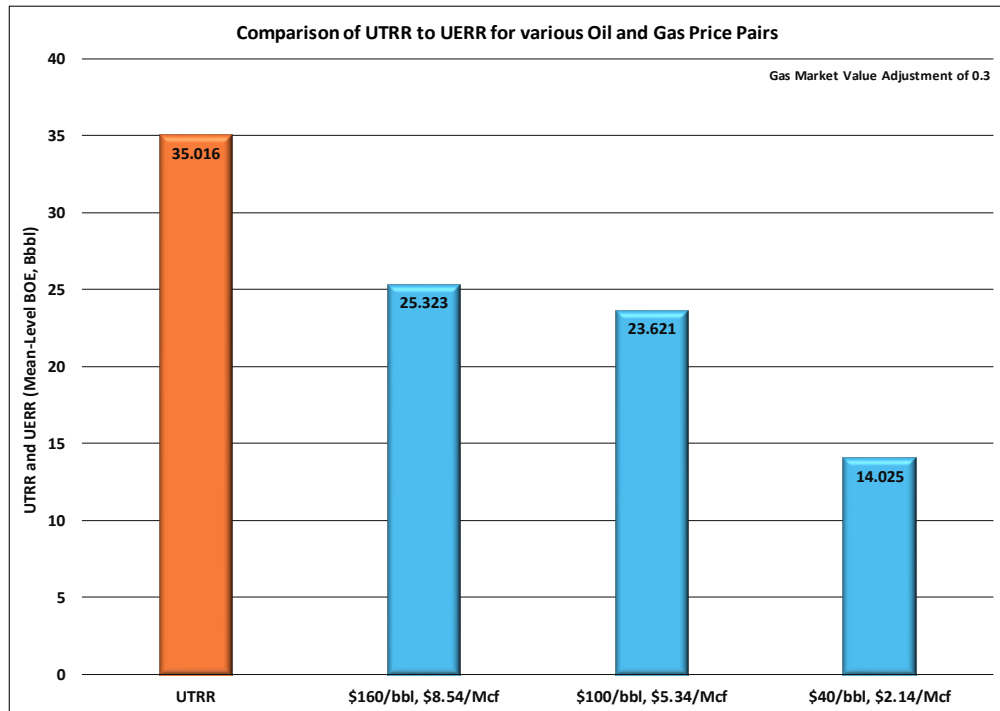


Figure 14. Mean-value comparison of UTRR to UERR for various oil and gas price pairs.

Table 11. Mean-level UERR values at specific oil and gas price pairs.

2026 Gulf of America OCS	Undiscovered Economically Recoverable Resources (UERR)								
	Mean Values with a Gas Market Value Adjustment of 0.3								
Planning Area	\$40/bbl, \$2.14/Mcf			\$100/bbl, \$5.34/Mcf			\$160/bbl, \$8.54/Mcf		
Water Depth	oil (Bbbl)	gas (Tcf)	BOE (Bbbl)	oil (Bbbl)	gas (Tcf)	BOE (Bbbl)	oil (Bbbl)	gas (Tcf)	BOE (Bbbl)
Total Gulf of America	12.420	9.025	14.025	20.509	17.488	23.621	21.826	19.653	25.323
0 - 200 m	0.133	0.193	0.168	0.675	2.057	1.040	0.781	2.897	1.297
200 - 800 m	2.450	1.844	2.778	3.851	3.217	4.424	4.081	3.510	4.706
800 - 1,600 m	4.710	3.351	5.306	7.185	5.568	8.176	7.557	6.007	8.625
1,600 - 2,400 m	3.573	2.546	4.026	5.502	4.244	6.258	5.796	4.577	6.610
> 2,400 m	1.554	1.091	1.748	3.295	2.402	3.723	3.611	2.661	4.084
Western Gulf of America	3.412	2.397	3.839	4.983	4.133	5.719	5.206	4.569	6.019
0 - 200 m	0.009	0.035	0.015	0.043	0.430	0.119	0.054	0.611	0.163
200 - 800 m	0.831	0.595	0.937	1.203	0.944	1.371	1.256	1.014	1.436
800 - 1,600 m	1.814	1.251	2.036	2.627	1.953	2.974	2.737	2.085	3.108
1,600 - 2,400 m	0.611	0.423	0.686	0.891	0.663	1.009	0.930	0.709	1.056
> 2,400 m	0.148	0.093	0.165	0.220	0.142	0.245	0.229	0.150	0.256
Central Gulf of America	8.243	6.021	9.314	13.217	11.141	15.200	14.045	12.472	16.264
0 - 200 m	0.022	0.053	0.032	0.113	0.819	0.259	0.140	1.254	0.363
200 - 800 m	1.554	1.196	1.767	2.357	2.029	2.718	2.492	2.213	2.886
800 - 1,600 m	2.829	2.051	3.194	4.314	3.433	4.925	4.545	3.716	5.206
1,600 - 2,400 m	2.933	2.101	3.307	4.531	3.518	5.157	4.777	3.799	5.453
> 2,400 m	0.904	0.619	1.015	1.902	1.342	2.140	2.090	1.490	2.355
Eastern Gulf of America	0.764	0.607	0.872	2.308	2.214	2.702	2.574	2.612	3.039
0 - 200 m	0.103	0.105	0.121	0.519	0.807	0.663	0.587	1.032	0.771
200 - 800 m	0.065	0.053	0.074	0.291	0.244	0.334	0.333	0.283	0.383
800 - 1,600 m	0.067	0.048	0.075	0.244	0.181	0.276	0.274	0.205	0.311
1,600 - 2,400 m	0.029	0.022	0.033	0.080	0.063	0.091	0.089	0.070	0.101
> 2,400 m	0.501	0.379	0.569	1.174	0.918	1.337	1.291	1.022	1.473
Straits of Florida	<0.001	0.000	<0.001	0.001	<0.001	0.001	0.002	<0.001	0.002
0 - 200 m	<0.001	0.000	<0.001	<0.001	<0.001	<0.001	0.001	<0.001	0.001
200 - 800 m	<0.001	0.000	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
800 - 1,600 m	<0.001	0.000	<0.001	<0.001	<0.001	<0.001	0.001	<0.001	0.001

Total values may not equal the sum of the component values due to independent rounding.

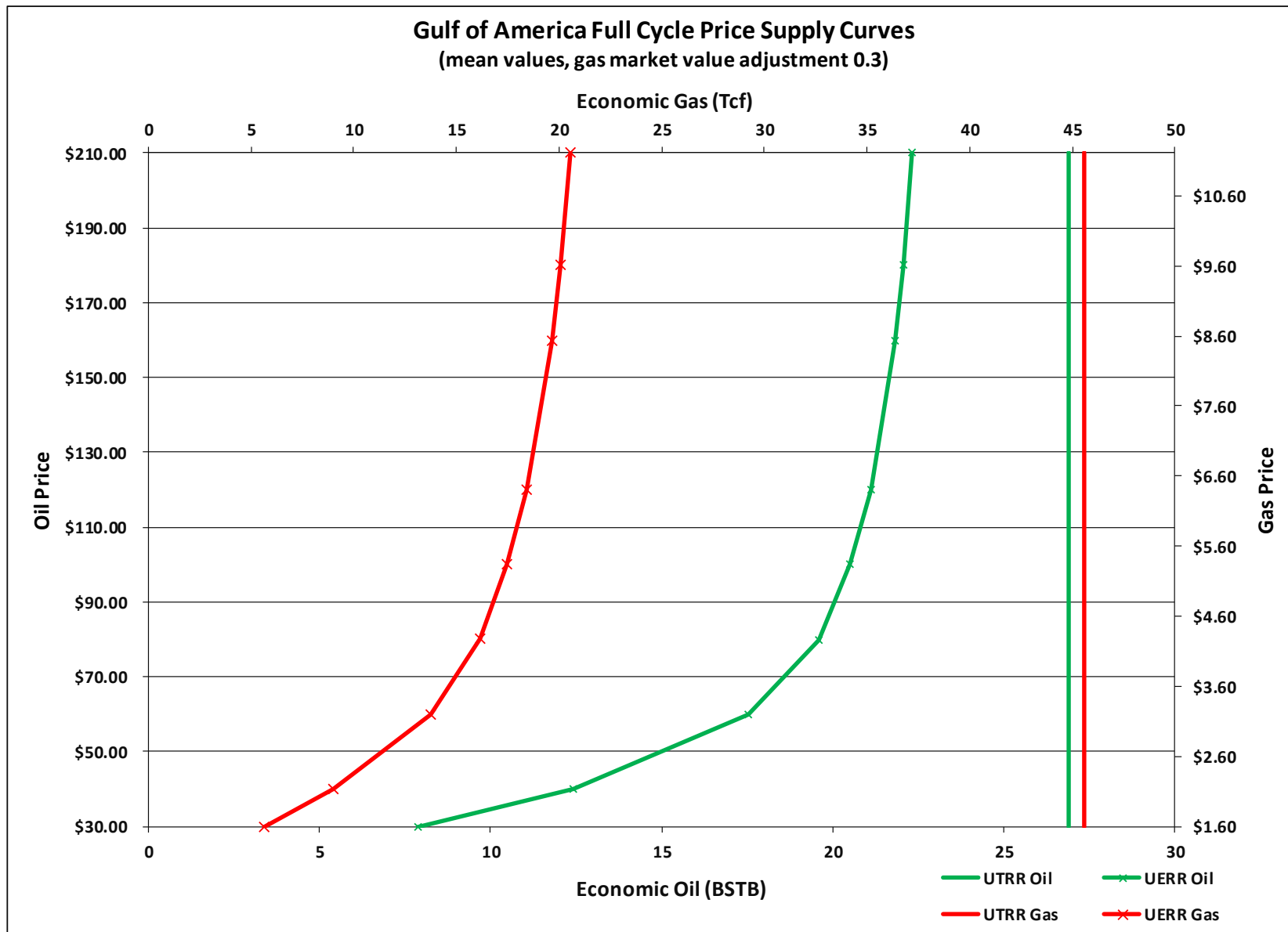


Figure 15. Mean-level price-supply curves for the Gulf of America OCS.

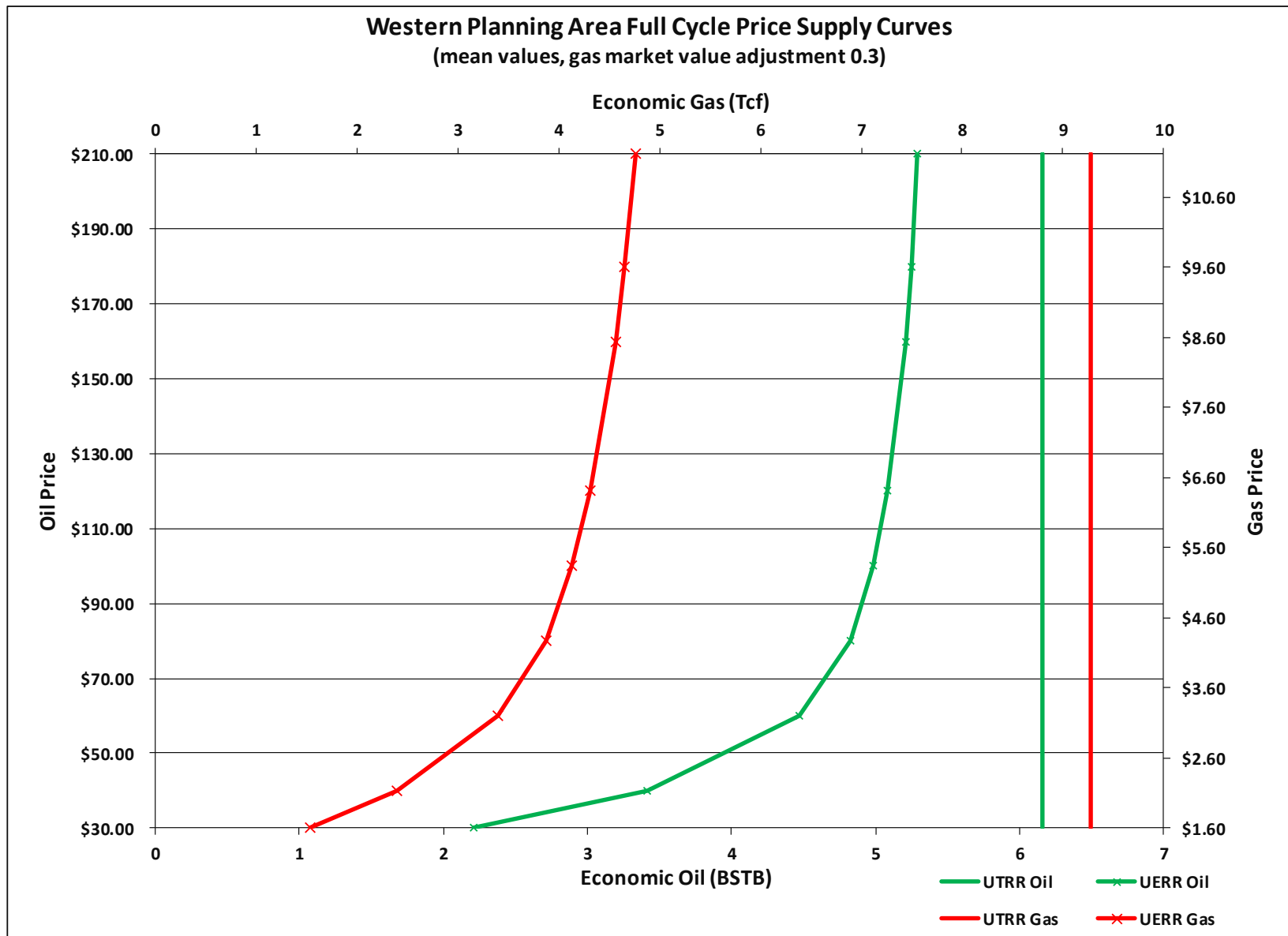


Figure 16. Mean-level price-supply curves for the Western Planning Area.

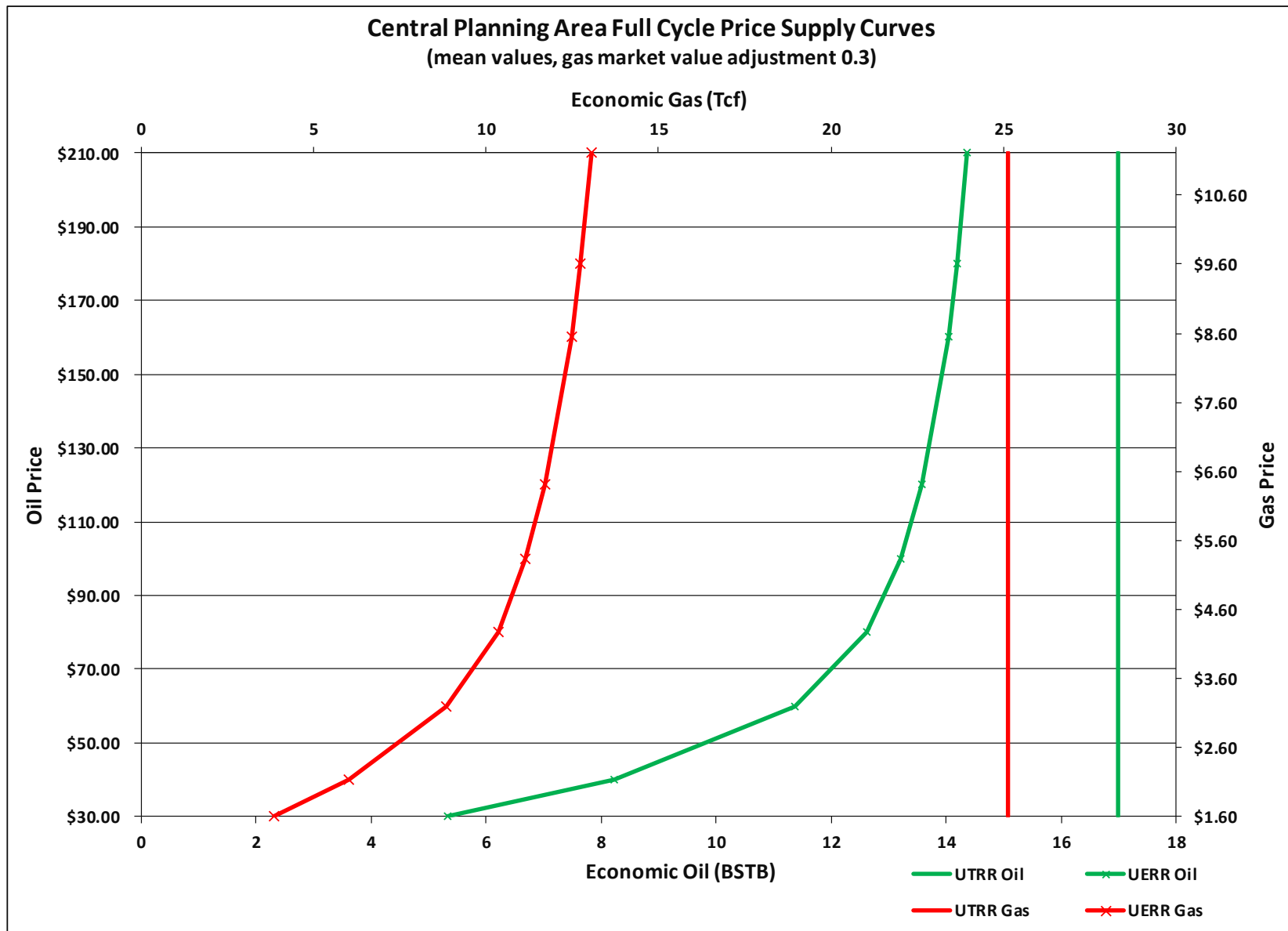


Figure 17. Mean-level price-supply curves for the Central Planning Area.

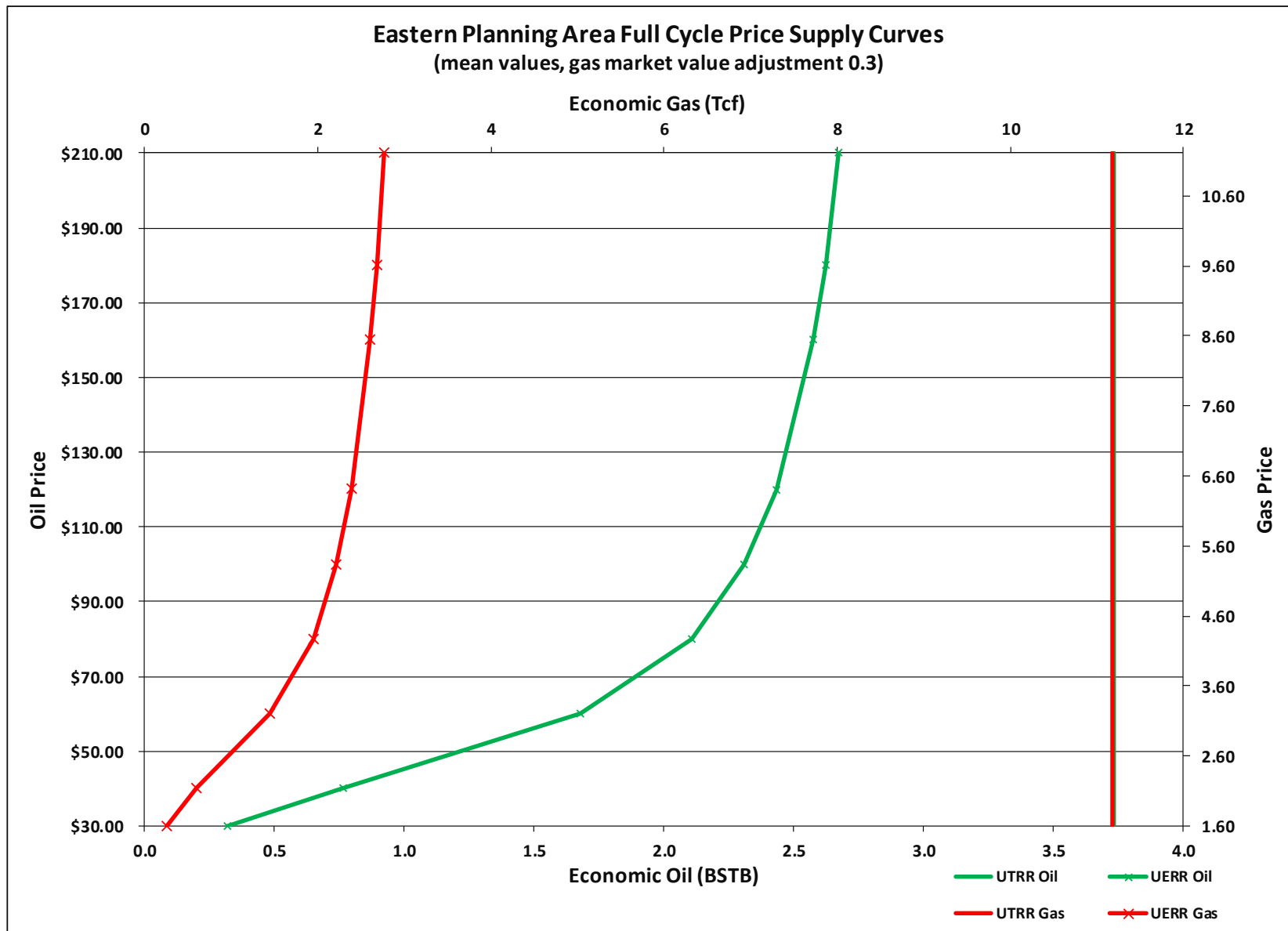


Figure 18. Mean-level price-supply curves for the Eastern Planning Area.

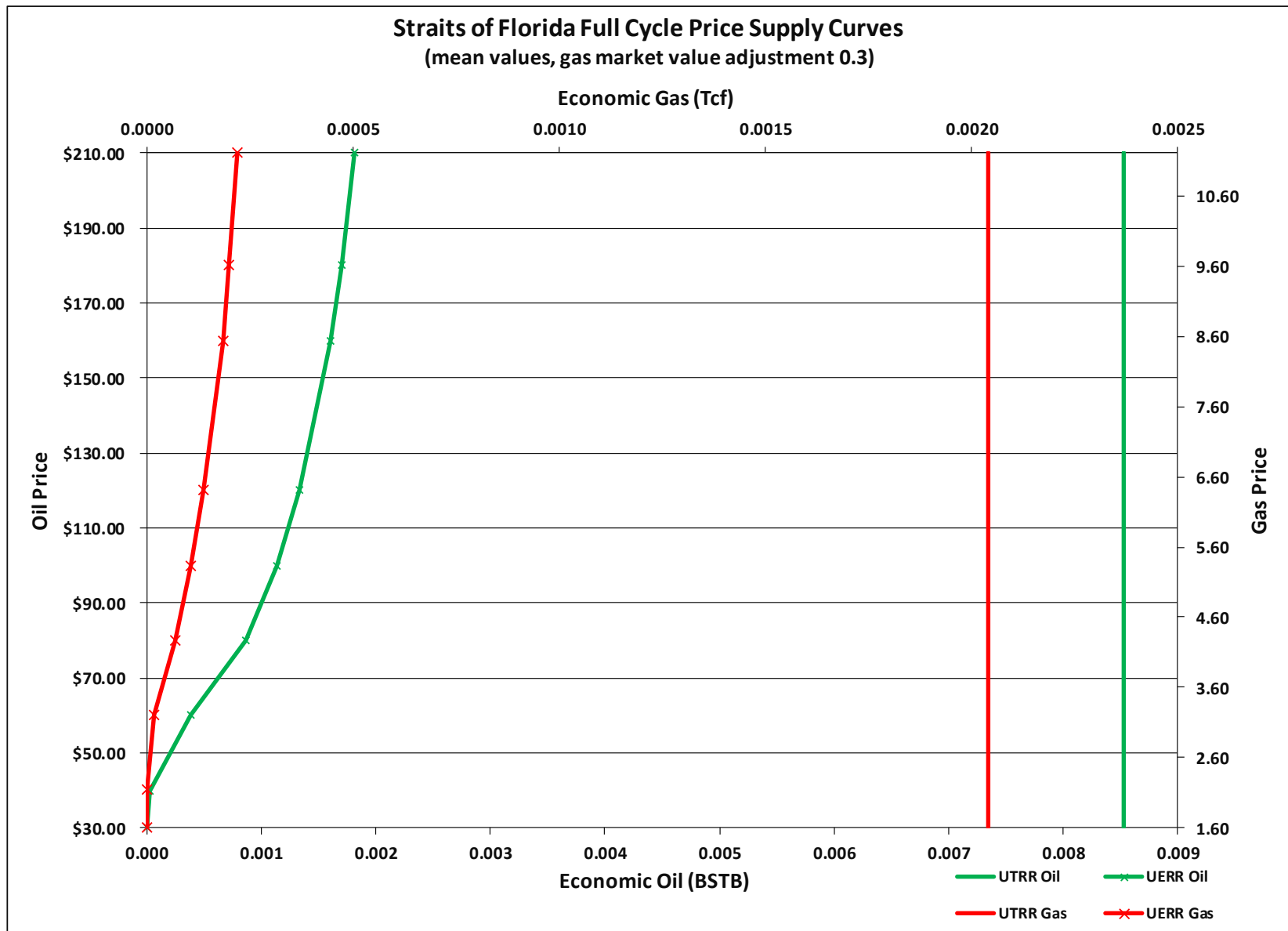


Figure 19. Mean-level price-supply curves for the Straits of Florida.

GEOLOGIC OVERVIEW

The geology of the GOA Basin and the distribution of hydrocarbon accumulations are the product of the complex interactions of plate tectonics, salt tectonics, and sedimentation operating over nearly 2 billion years of geologic time. The following section summarizes salient events and features relevant to the geologic evolution and hydrocarbon potential of the northern Gulf of America OCS. For historical and current overviews, the reader is referred to Salvador (1991), Galloway (2008), and Snedden and Galloway (2019).

RECENT DEVELOPMENTS

Although much uncertainty remains, great progress has been made in the past decade in resolving the plate tectonic history of the opening of the GOA. Satellite, aerial, and marine potential field datasets have revealed the extent of oceanic crust underlying the GOA Basin and helped to refine plate reconstructions (Sandwell et al., 2014; Norton et al., 2016; Pindell et al., 2016; Filina and Beutel, 2025). Recognition of the older age of the Louann Salt and previously unrecognized pre- and post-salt Jurassic formations have driven new play concepts. Source to sink studies employing detrital zircon geochronology are providing new insights into the tectonic evolution of the hinterlands and sediment routing to GOA depositional systems (e.g., Blum & Pecha, 2016; Sharman et al., 2017).

Long offset 2D seismic reflection and refraction surveys have imaged the deep crustal structure to unprecedented depths (e.g., Pindell et al., 2014; Pascoe et al., 2016; Van Avendonk et al., 2016) and provided new insights into crustal evolution. Improved seismic imaging of subsalt areas has been achieved through more robust seismic acquisition techniques, and advances in depth migration of 3D seismic data have led to better imaging and understanding of the deepwater subsalt province (e.g., Hudec et al., 2013a, b). As of this writing, a new generation of 3D surveys acquired with long offset, low frequency sparse ocean bottom nodes (OBN) are coming online, revealing unprecedented imaging of the subsalt, pre-salt, and basement of the deepwater OCS.

The Lower Tertiary Trend of the deepwater OCS continues to mature. The deepwater Norphlet Trend has seen ongoing development (Godo, 2019), and industry has shown some interest in older and younger Mesozoic plays (Harding et al., 2016; Godo and Landry, 2024; Godo, 2025). Industry interest and exploration efforts in Mexican waters have led to the acquisition of a great deal of modern seismic and potential field (gravity and magnetic) data. Limited publication of these studies has improved our understanding of the northern GOA and provided analogs for some Mesozoic plays (e.g., Williams-Rojas et al., 2012; Steier & Mann, 2019; Shann et al., 2020). New 3D seismic surveys on the abyssal plain have revealed details of the extinct ocean ridge at the basin center and provide further support for sand deposition in some units to the limit of U.S. waters (Kegel et al., 2016).

TECTONIC HISTORY OF THE GULF OF AMERICA BASIN

Discussions of the GOA Basin typically begin with the breakup of the supercontinent Pangaea in the Triassic, about 200 Ma, when Africa and South America (Gondwana) separated from North America (Laurasia). However, the basement fabric of eastern North America and the northern GOA is to some degree inherited from Precambrian and Paleozoic events (Salvador, 1991; Thomas, 2006; Keller et al., 2016).

Aspects of this regular basement fabric can be discerned from published studies of the North American craton and published and proprietary potential field datasets from the Gulf Coast and GOA region. To the extent that they can be understood, these patterns can be used to predict subsurface conditions in offshore regions where they are not directly observable.

Basement structure is believed to exert first-order control on hydrocarbon system elements and play distributions. An understanding of basement structure can give clues to rift evolution, heat-flow, thermal subsidence, and basin thermal history. These factors also influence the depositional extent and environment of deposition of source rocks as well as their thermal maturity. The basement fabric directly impacts salt deposition and future deformation, which influences the location of different trap domains, trap density and distribution, as well as sedimentary dispersal mechanisms and fairways. Older basement faults and lineaments may impact the arrangement of salt ascension zones and salt walls, which directly impacts secondary hydrocarbon migration pathways and the distribution of pools in play areas.

Two Wilsonian cycles—the formation and breakup of the Proterozoic supercontinent Rodinia followed by the formation and breakup of the Paleozoic supercontinent Pangea—resulted in the inherited basement fabric evident today across the greater GOA Basin. The accretion events that resulted in the assembly of the supercontinent Rodinia are not pertinent to this overview but are detailed in Whitmeyer and Karlstrom (2007).

Proterozoic Rifting: 1.7 Ga; the Breakup of Rodinia: 760 Ma–530 Ma; Tectonic Inheritance

The map in [Figure 20](#) juxtaposes selected Proterozoic structural trends from the continental interior (solid red lines) with the Paleozoic and Mesozoic continental margins and oceanic crust at the center of the GOA Basin (gray). Precambrian fault locations (solid red lines) are from Sims et al. (2008). The basement fabric of eastern North America is characterized by a network of NWSE- and NESW-trending faults (solid red lines) that record Precambrian rifting and collisional events (Barosh, 1991; McBee 2003; Sims et al., 2005). The NWSE-trending lineaments, or megashears, are also evident in offsets in the Late Precambrian to Early Cambrian (Eocambrian) continental margin associated with the breakup of Rodinia ([Figure 20](#)) and formation of the Cambrian-to-Mississippian age Iapetus Ocean (Gatewood and Fay, 1991; Thomas, 2006). The rifted margin of Rodinia was offset by many prominent NWSE-trending lineaments (heavy dark red), which were apparently associated with zones of crustal weakness aligned with the Precambrian shear zones. These zones of crustal weakness were maintained through the subsequent Appalachian, Ouachita, and Marathon Orogenies ([Figure 20](#)), which closed the Iapetus Ocean during the assembly of the supercontinent Pangea.

Through tectonic inheritance, these same trends associated with zones of crustal weakness were reactivated through the early stages of Triassic rifting during the breakup of Pangea and the opening of the GOA (Thomas, 2006). Some of these basement faults may have been reactivated during the Cretaceous Laramide Orogeny (Jackson and Laubach, 1988; Adams, 2009; Zahm et al., 2016). These basement lineaments, or shear zones, have been referred to as transfer or transform fault zones (TFZ) (Kinsland, 1984; Adams, 1993, 1997; Bradshaw & Watkins, 1995;) and partition the continental margin into conjugate segments, perhaps related to alternating upper plate-lower plate boundaries in the sense of Wernicke (1985). The segments in the basement beneath the continental margin are more finely partitioned into structural corridors, which is often apparent in the structural fabric of the overlying sedimentary cover (Bradshaw and Watkins, 1995; Stephens, 2009, 2013). Stephens (2009) proposed 14 major TFZs across the northern Gulf Coast from south Texas to Florida ([Figure 20](#), [Figure 21](#), [Figure 22](#), and [Figure 23](#)), which generally align with the Precambrian and Paleozoic NWSE fault trends. These structural lineaments are evident in the distribution of Mesozoic and Cenozoic fault families and salt systems ([Figure 23](#)) and exert varying degrees of control on the play extents described in this report.

The Breakup of Pangea and Mesozoic Rifting: 230 Ma–170 Ma

The consensus view is that the GOA is a small ocean basin formed during the Triassic–Jurassic breakup of the supercontinent Pangea. Triassic crustal stretching and rifting was initially from northwest to southeast, forming a series of rift basins (orange polygons, [Figure 20](#)) extending from Canada to Mexico (Salvador, 1991) that are largely hidden beneath the deep sedimentary cover of the GOA. Red-beds and

interbedded volcanics of the Eagle Mills Formation were deposited in the rift basins (Millekin, 1988; Salvador 1991; Frederick et al., 2016) and capped in some places by thin post-rift sag basin sequences (Norton et al., 2018; Storey, 2020; Godo, 2025). “Rift” structures in the deep subsurface of the Gulf Coast and GOA waters (**Figure 20**) have herein been compiled from seismic data and a proprietary interpretation of the depth to magnetic basement. There are basement lows which could represent rifts, sags, or features of other origins. These basement lows are delimited by the NWSE transfer fault zones that may have been trends of crustal weakness that were exploited during the rift-to-drift transition and may have been preferential pathways for volcanics and lava flows of the seaward dipping reflectors complexes of the eastern GOA that preceded the oceanic crust (**Figure 21**). We interpret this fabric to be an aerial depiction of rifted crust as interpreted by Van Avendonk et al. (2015) based on deep seismic reflection and refraction surveys. This crustal architecture is depicted artistically in **Figure 24**, which combines interpretations of regional seismic time and depth traverses after Peel et al. (1995) and Pilcher et al. (2011), respectively (see **Figure 20** and **Figure 23** for line location). In this depiction, Late to Middle Jurassic rift basins are situated beneath autochthonous welds that were paleo-salt thicks and basement steps at rift shoulders coincide with autochthonous salt pillows and salt feeders that source the allochthonous salt canopy. Rifts inferred along the Yucatan Margin (**Figure 20**) are schematic and are delimited by the pre-spreading projections of the northern GOA transfer fault zones of Stephens (2009) using the restorations of Norton et al. (2016) and Norton in Snedden and Galloway (2019) (**Figure 21**).

A second phase of crustal stretching and rifting from northeast to southwest preceded the emplacement of oceanic crust (Imbert and Philippe, 2005). A series of TFZs trending NESW align with transform faults in the subsequently emplaced oceanic crust and appear to offset the earlier NWSE trending lineaments (**Figure 21**). The later TFZs have been named with a lettered prefix corresponding to the protraction area in which they intersect the spreading center and a numeric suffix indicating the distance from the pole of rotation in miles. This observation is further discussed in the **Pre-Salt or Equivalent Play**. Seaward dipping reflectors (SDR) (**Figure 21**) observed in 2D and 3D seismic surveys in the eastern GOA in the vicinity of the Florida Magnetic Anomaly (FMA, **Figure 20**) are thought to represent subaerial lava flows emplaced during this second phase of crustal stretching prior to the emplacement of oceanic crust (Imbert, 2005; Liu et al., 2019). Seaward dipping reflectors are also present along the Yucatan conjugate margin with inferred ages of 190–200 Ma, equivalent to the Central Atlantic Magmatic Province (CAMP) (Filina and Beutel, 2025). The Houston Magnetic Anomaly (HMA, **Figure 20**), parallels the Texas and Louisiana coasts and has been interpreted to be indicative of a volcanic rifted margin beneath the northern Gulf Coast (Mickus et al., 2009). The Campeche Magnetic Anomaly (CMA, **Figure 20**) in the southern GOA is symmetrically opposed to the Houston Magnetic Anomaly on Middle Jurassic plate reconstructions (Norton et al., 2016; Pindell et al., 2016) just prior to the emplacement of oceanic crust and may have similar volcanic origins associated with GOA rifting or older events. Magnetic anomalies and Permo–Triassic section in eastern Mexico across the East Mexico Transform (EMT, **Figure 20**) may have been translated from the northeast and be unrelated to the opening of the GOA (Norton et al., 2016).

The region along the continent-ocean transition is underlain by crust of uncertain type (**Figure 20**), perhaps highly attenuated continental crust, intruded volcanic crust (Pascoe et al., 2016), or possibly exhumed mantle (Pindell et al., 2016; Curry et al., 2018). Much of the deepwater GOA exploration frontier sits astride this region of uncertain crust above the presumed continent-ocean transition. Recently acquired deep reflection seismic data have revealed pre-salt sediments of presumably Lower to Middle Jurassic age in the northeastern GOA that may have equivalents in the southern GOA (**Figure 20**) beneath the Campeche Salt Basin (Williams-Rojas et al., 2012; Miranda-Peralta et al., 2014; Curry et al., 2024). These sediments, along with the Triassic Eagle Mills Formation, are the objectives of the **Pre-Salt or Equivalent Play**.

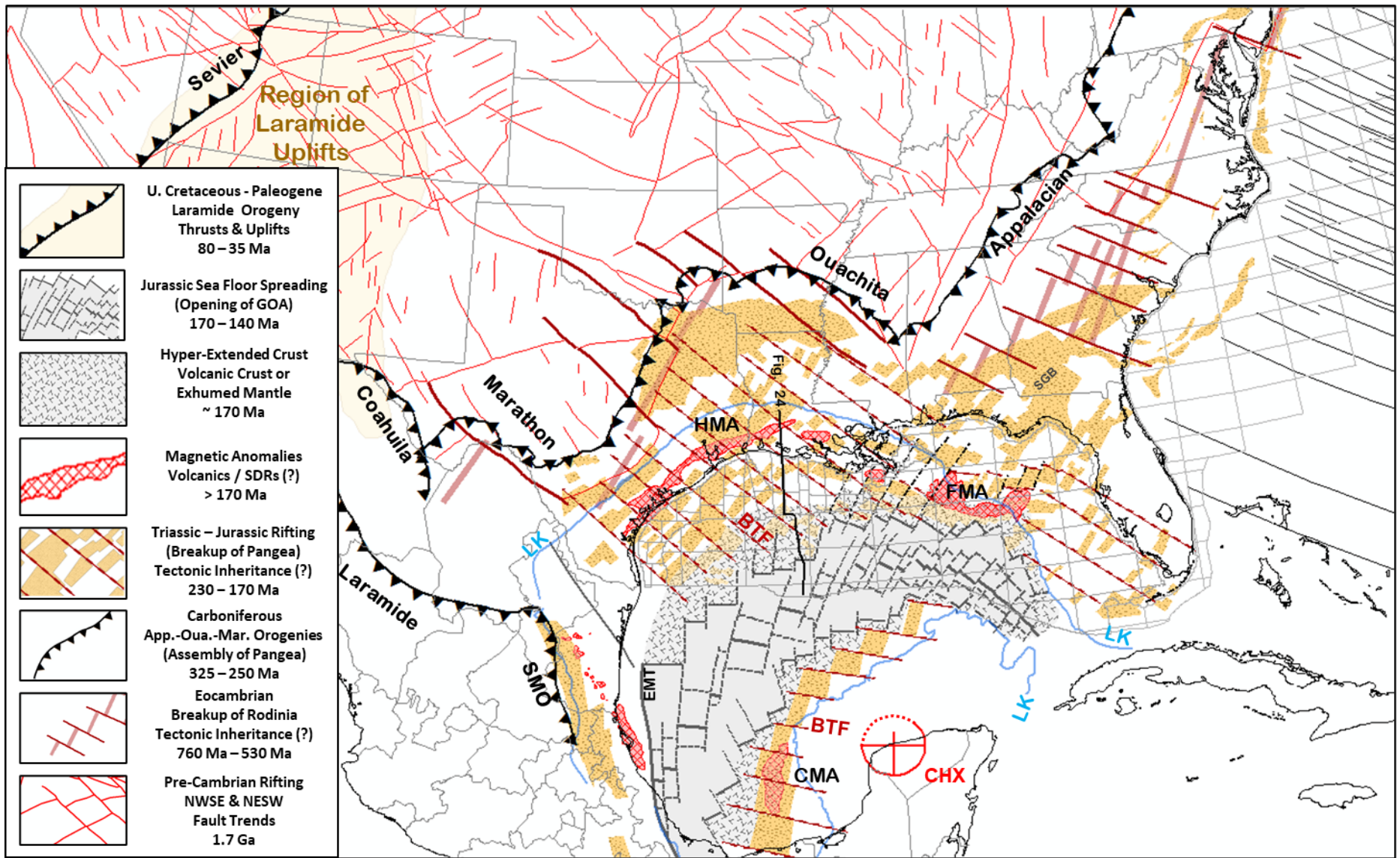


Figure 20. Basement fabric and selected Proterozoic through Cenozoic tectonic events of North America and the Gulf of America.

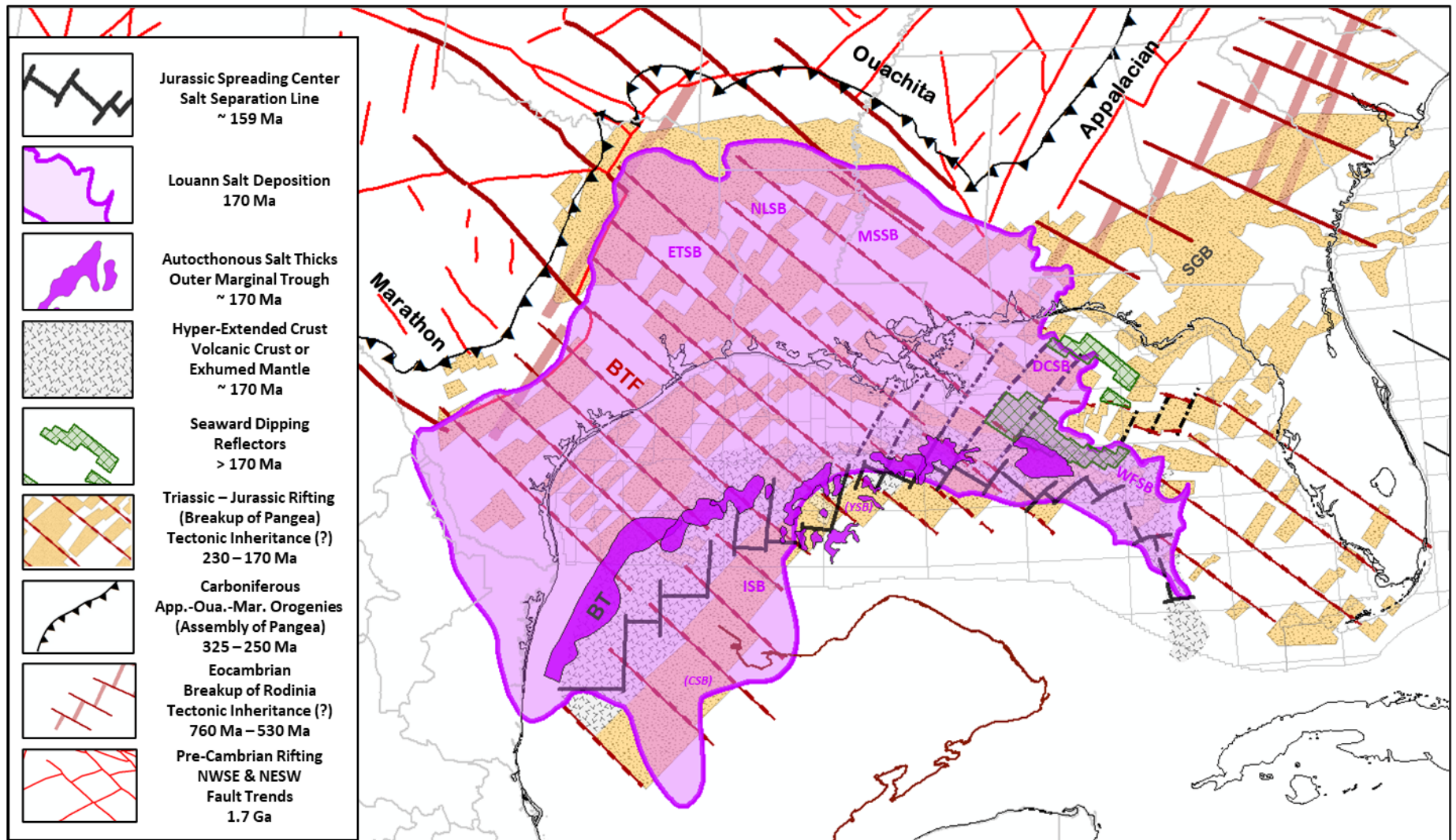


Figure 21. Depositional extent of Louann Salt restored to 170 Ma (after Snedden and Galloway, 2019) superimposed on selected basement trends and inferred rift architecture.

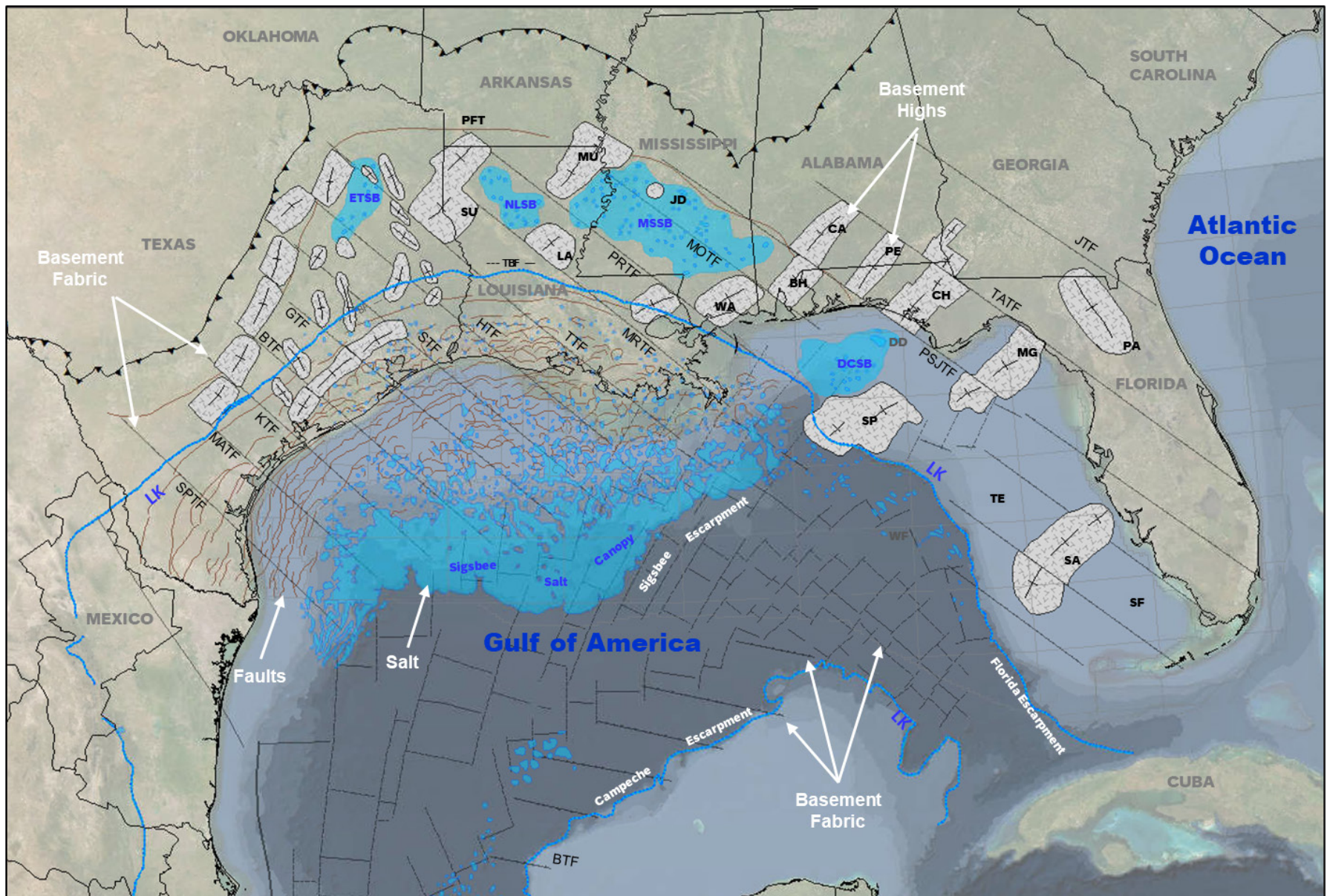


Figure 22. Selected physiographic and structural features of the northern Gulf of America Basin.

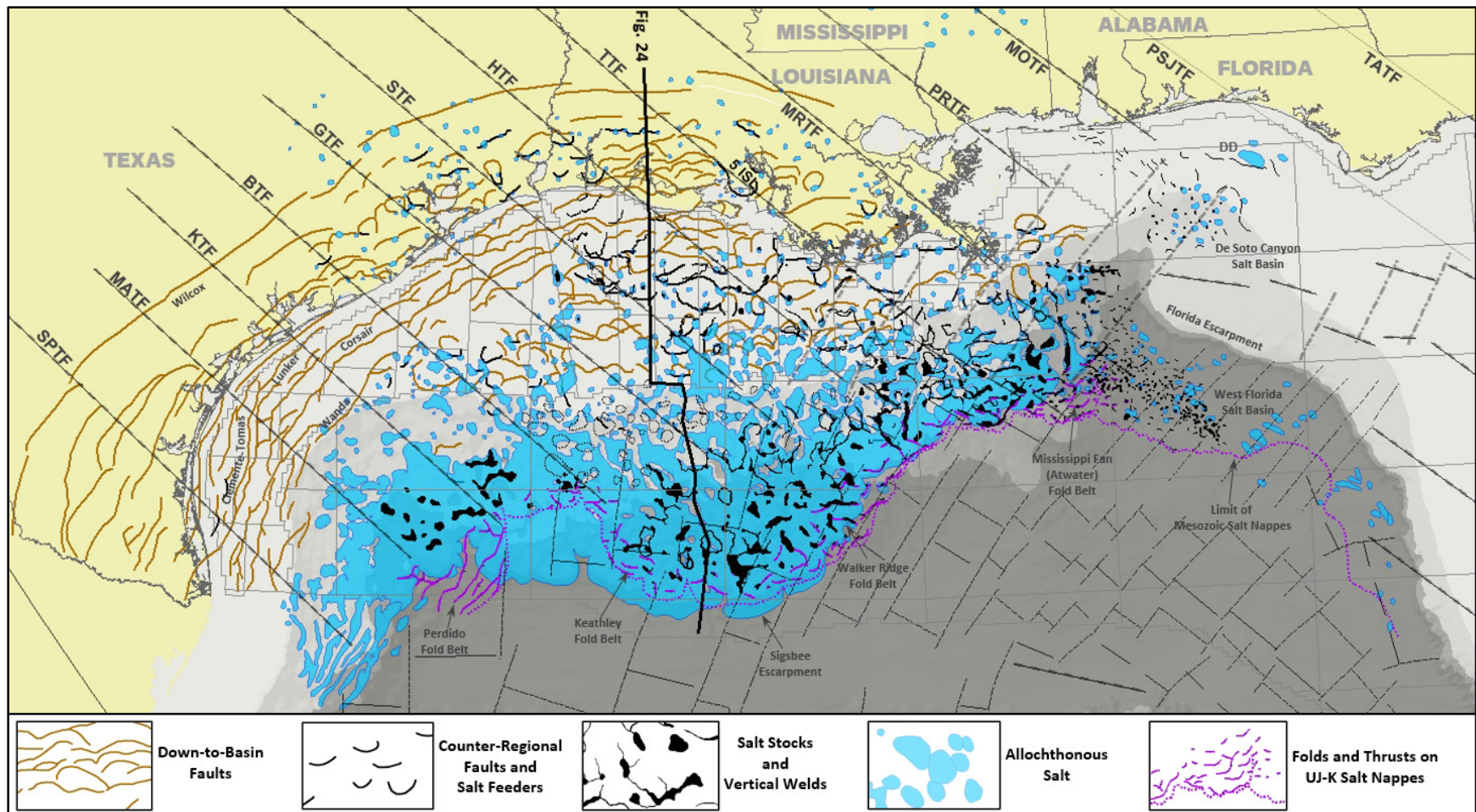


Figure 23. Allochthonous salt and salt-related structural features of the northern Gulf of America. Salt after Muehlberger (1992), Simmons (1992), and Lopez (1995). Faults after Diegel et al. (1995). Folds after Weimer et al. (2017). Stocks and welds from BOEM. Oceanic transform faults after Pindell et al. (2016). Transfer fault zones after Stephens (2009).

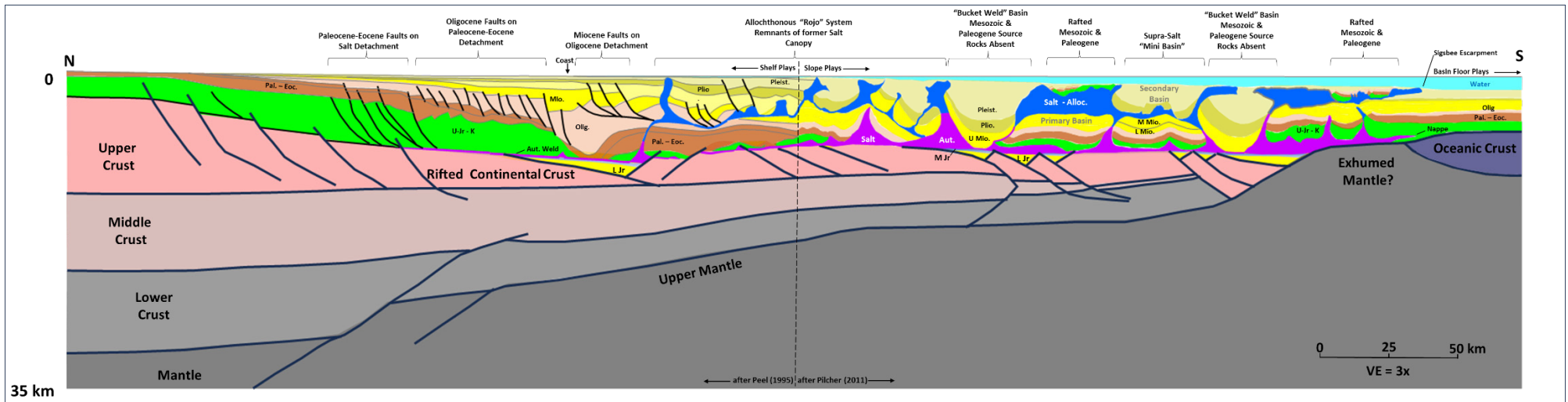


Figure 24. Regional transect from onshore Louisiana through the Sigsbee Salt Canopy illustrating crustal architecture, salt structures, and primary and secondary sedimentary basins. Modified from Peel et al. (1995) and Pilcher et al. (2011). Pre-salt geology from unpublished BOEM restoration is conjectural. Vertical exaggeration = 3X. See Figure 20 and Figure 23 for location.

Deposition of the Louann Salt: 170 Ma

With the initial incursion of sea water into the basin, thick salt deposits of the Louann Formation filled this early rift architecture and/or post-rift sag basins, producing the offshore GOA, Isthmian (ISB), De Soto Canyon (DCSB), and West Florida (WFSB) Salt Basins, and the interior East Texas (ETSB), North Louisiana (NLSB) and Mississippi (MSB) Salt Basins, as well as limited deposits in South Alabama, and Western Florida (Figure 21). A crustal hinge zone, the Toledo Bend Flexure (TBF, Figure 22), is coincident with the Lower Cretaceous reef trend in Texas and Louisiana and separates the interior salt basins and the GOA Salt Basin (Hudec et al., 2013b). Connection to the world ocean has long been thought to have come from the Pacific (Salvador, 1987), but recent research points to an Atlantic-Tethys source for the concentrated brines from which the Louann Salt was precipitated (Peel, 2019; Peel & Apps 2021). The age of the Louann Salt was deposited around 170 Ma (Bajocian, Figure 25) based on isotopic studies (Pullham et al., 2019) and plate reconstructions in perhaps only a few tens of thousands of years (Peel and Apps, 2021). Mesozoic rift architecture and basement topography (Figure 21) have been inferred to have controlled the depositional thickness of the salt (Bradshaw and Watkins, 1985; Stephens, 2009; Hudec et al., 2013b). However, the degree to which the basal Louann surface was smoothed by fill and the post-rift unconformity remains uncertain. Nevertheless, the importance of subsequent salt tectonism to the structural and stratigraphic evolution of the GOA and the distribution of hydrocarbon accumulations cannot be overstated.

The thickest autochthonous salt may have been deposited adjacent to the incipient spreading center, perhaps in part in the “Outer Marginal Trough” (OMT) described by Pindell et al. (2014) that formed astride the continent-ocean transition or the “Marginal Rift System” described by Liu et al. (2019). A series of collapse basins thought to represent the evacuated remnants of areas of thick autochthonous salt that were the roots of the Sigsbee Salt Canopy (Figure 22) extend from the Bravo Trough (BT) in Mexican waters (Hudec et al., 2020) through Alaminos Canyon and eastward to Mississippi Canyon (Figure 21). These features may have influenced Mesozoic and Paleogene sediment fairways and have implications for Mesozoic source rock distribution as discussed in later sections. An older feature associated with the **Expanded Jurassic Play** in the West Florida Salt Basin (Figure 23) may have similar origins.

Emplacement of Oceanic Crust: 170 Ma–140 Ma

Deposition of the Louann Salt was closely followed by counter-clockwise rotation of the Yucatan Block out of the GOA in Middle Jurassic time forming a swath of oceanic crust in the center of the basin, which was complete by latest Jurassic to earliest Cretaceous time (Norton et al., 2016; Pindell et al., 2016; Filina and Beutel, 2025). This is commonly referred to as the “drift” phase (Salvador, 1991). Volcanic xenoliths radiometrically dated to 160 Ma (Oxfordian) have been collected from salt domes (5 ISL, Figure 23) in south Louisiana (Ren et al., 2009) and demonstrate volcanism away from the spreading ridge. These domes are part of the Five-Island Trend (Fisk, 1944), thought to be aligned with an underlying NW-SE basement lineament (Lock and Duex, 1996), the Terrebonne Transfer Fault (TTF, Figure 23) of Stephens (2001, 2009).

The emplacement of oceanic crust split the GOA Salt Basin in two, the southern portion becoming the Isthmian Salt Basin, which was rotated into its current position in Mexican waters, along with the southern trailing edge of the rifted margin (Figure 20). We speculate that the Isthmian Salt Basin was segmented in similar fashion as the northern GOA Salt Basin. Transfer fault zones of the northern GOA have been projected onto the conjugate margin of the southern GOA to the Campeche shelf in their pre-spreading position (Figure 21) and post-spreading position (Figure 20) based on the plate reconstructions of Norton et al. (2016). The position of the Brazos Transfer Fault (BTF) is labeled on both sides of the swath of oceanic crust (gray) at the center of the basin (Figure 20) and in its pre-spreading position restored to 170 Ma (Figure 21).

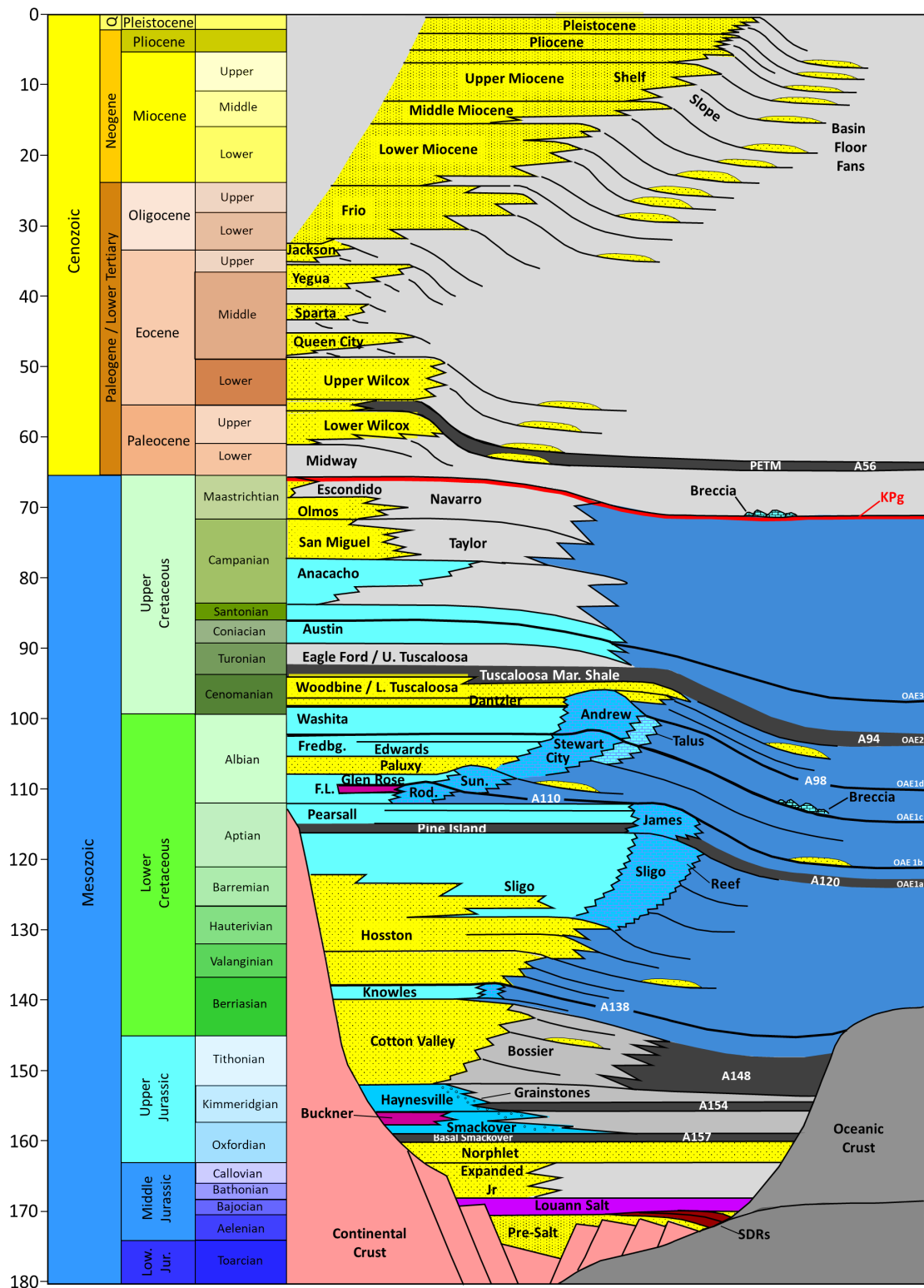


Figure 25. Stratigraphy and depositional architecture of the northern Gulf of America (after Galloway 2008).

The rotated projection of the Brazos Transfer Fault seems to coincide with the structural hinge noted by Hudec and Norton (2019) separating the Yucatan and Campeche Sub-basins. Collapse of the continental margin coincident with the rift-to-drift transition may have been rapid (Pindell et al., 2014), and, along with subsequent thermal cooling, the center of the basin subsided to oceanic depths. The flanks of the basin are underlain by a landscape of high-standing blocks of variably attenuated continental and transitional crust (**Figure 22**), which may have been structurally active as early as the Pennsylvanian Period, and influenced the depositional topography of subsequent Mesozoic and Cenozoic sedimentary sequences.

Figure 22 illustrates several prominent basement highs and intervening salt basins around the GOA Basin. Basement highs include the Sabine Uplift (SU), Monroe Uplift (MU), Lasalle Arch (LA), Wiggins Arch (WA), Baldwin High (BH), Conecuh Arch (CA), Pensacola Arch (PE), Chattahoochee Arch (CH), Southern Platform (SP), Middle Ground Arch (MG), Sarasota Arch (SA), and Peninsular Arch (PA). Salt basins include the East Texas Salt Basin (ETSB), North Louisiana Salt Basin (NLSB), Mississippi Salt Basin (MSB), De Soto Canyon Salt Basin (DCSB), Tampa Embayment (TE), and South Florida Basin (SFB).

Post-Salt Mesozoic Sedimentation and Salt Tectonism 165 Ma–66 Ma

Salt mobilization began immediately after, if not synchronously with, deposition. Rapid basinward tilting at the onset of seafloor spreading (Pindell et al., 2014) encouraged the salt to flow downdip, encroaching on then-forming oceanic crust at the basin floor. These primary allochthonous sheets continued to advance into Cretaceous time, forming a series of salt nappes (Peel et al., 2002; Rowan et al., 2004) that coalesced into a paleo-salt canopy in the region of the continent-ocean boundary (**Figure 23** and **Figure 24**). Gravity gliding caused large regions of Jurassic sediments to raft downdip of their depositional location on the underlying Louann salt, which served as a detachment layer (Hudec et al., 2013a; Pilcher et al., 2014). Mesozoic extensional fault systems related to rafting in the eastern GOA are partitioned along corridors related to the transform faults on both sides of the Jurassic spreading ridge (Pilcher et al., 2014; Steier and Mann, 2019) and are further discussed in the **Norphlet** and **Smackover** Plays. Flow of the salt across an irregular basement topography focused inflation of the autochthonous salt and produced a variety of salt pillows, salt walls, and associated extensional faults and compressional structures now preserved as relict pillows, stocks, and welds (black polygons and lines, **Figure 23**), which collectively focused not only Mesozoic sediment fairways, but also subsequent hydrocarbon migration pathways and areas of accumulation (Pilcher et al., 2011; Dooley and Hudec, 2017). Inflation of areas of thickest autochthonous salt deposited adjacent to the incipient spreading center probably influenced Mesozoic and Paleogene depositional fairways. Mesozoic section in the carapaces of diapirs rising from this autochthonous layer was rafted basinward on the salt canopy leaving bucket-weld basins (Pilcher et al., 2014) filled with Neogene sediments and devoid of Mesozoic source rocks (**Figure 24**).

The oldest known post-salt deposition in the subsiding basin consisted of a large erg, or sand sea, comprising aeolian sand dunes. These deposits constitute the productive Oxfordian Norphlet Formation of the northeastern GOA (**Figure 25**). Along strike and updip are fluvial braided stream and alluvial fan facies, which are not of reservoir quality. Recent depth-migrated 3D seismic surveys in the deep water of the Central Planning Area of the Gulf of America OCS indicate the presence of a previously unknown post-salt, pre-Norphlet sedimentary section, which is the basis for the **Expanded Jurassic Play** (**Figure 25**). With the establishment of open marine conditions by about 157 My, carbonate shoals, banks, and platforms formed in shallow waters above inflated salt features and high-standing crustal blocks. The Jurassic (Oxfordian) Smackover Formation includes algal reefs (thrombolites) formed on basement highs around the periphery of the basin in Middle Jurassic time, along with grainstone shoals in higher energy settings on the carbonate ramp (**Figure 25**). The Lower Cretaceous Knowles Lime (Berriasian) formed the first carbonate platforms and rimmed margin (Petty, 2008). A series of successive shelf-margin reef trends formed in the Sligo Formation and James Limestone (Aptian) and the Andrew Formation (Albian) (**Figure**

25), collectively referred to as the Cretaceous shelf edge or reef trend. The reef margin formed above a basement hinge, the Toledo Bend Flexure (TBF, [Figure 22](#)), generally aligned with the boundary between continental and transitional crust (LK, [Figure 20](#) and [Figure 22](#)) and constitute the reservoirs in the **Lower Cretaceous Carbonate AU**. These reef trends circumscribe the perimeter of the entire GOA Salt Basin and outlying basement highs and separate it from the interior salt basins of onshore Texas, Louisiana, and Mississippi ([Figure 22](#)).

Carbonate sedimentation was interrupted by several pulses of clastic sediments. These clastic rocks include the Cotton Valley (Tithonian–Berriasian), Hosston (Valanginian–Barremian), Paluxy (Albian), and Tuscaloosa-Woodbine (Cenomanian–Turonian) Formations ([Figure 25](#)), which prograded into the basin to varying degrees in response to tectonic and climatic processes in the hinterlands, and are the reservoirs for the **Cotton Valley Clastic**, **Lower Cretaceous Clastic**, **Mesozoic**, and **Lower Tuscaloosa** Plays.

Mesozoic and Cenozoic Source Rock Families

The majority of the hydrocarbon source rocks in the GOA are Mesozoic and are centered around basin-wide depositional acmes designated by an “A” prefix followed by age in Ma ([Figure 25](#)), some of which coincide with global oceanic anoxic events (OAEs) or other times of reduced circulation (Hood et al., 2002; Olsen et al., 2015; Pepper, 2016). Jurassic source rocks are contained within the Oxfordian-A157 basal Smackover Formation, Kimmeridgian-A154 Haynesville Shale, and Tithonian-A148 Bossier Shale. Lower Cretaceous source rock intervals include the Valanginian-A138, Aptian-A120 Pine Island and Bear Shales, and Albian-A110 Glen Rose Formation. Upper Cretaceous source rock intervals include the Cenomanian-A98 and Turonian-A94 centered Eagleford-Tuscaloosa Marine Shale Source rock families. These are augmented by a Lower Tertiary Paleocene–Eocene-A56 hydrocarbon system associated with the Paleocene–Eocene Thermal Maximum (PETM) and the Wilcox Big Shale-Yoakum Canyon Shale (Blanke et al., 2009). These Mesozoic and Cenozoic source rock families have contributed to an array of hydrocarbon systems that overlapped in space and time such that reservoirs of oils and gasses in most areas of the GOA represent a mixture of multiple sources (Cole et al., 2001; Hood et al., 2002). The timing of source rock maturation and hydrocarbon generation can vary spatially, particularly in areas of active salt tectonism where subsidence rates and burial history can vary dramatically (e.g., Weimer et al., 2016). Additionally, source rocks may be absent from erosion or non-deposition above inflated salt or rafting on allochthonous salt (Pilcher et al., 2014). In areas of oceanic crust, older Jurassic source rocks may be truncated or absent (Pepper, 2016) and will be discussed further in the **Mesozoic Basin Floor Play**.

Laramide Uplifts & Paleogene Drainage Reorganization 75 Ma–45 Ma

Uplift of the North American Continent due to the Laramide Orogeny ([Figure 20](#)) in latest Cretaceous to early Tertiary time provided the source for large amounts of siliciclastic sediments that were transported to the Texas and Louisiana coastal areas by several ancient river systems throughout the Cenozoic Era ([Figure 25](#)), along with Appalachian sources. It has long been recognized that the courses of major rivers are structurally controlled (Potter, 1978), and it is likely that the continental drainage systems delivering sediments from the continental interior to the GOA were influenced by the basement fabric described in previous sections ([Figure 20](#)). Recent source-to-sink studies utilizing detrital zircon geochronology suggest GOA drainage capture of the region of Sevier-Laramide uplifts provided a large pulse of sediment in Paleocene–Eocene time (Sharman et al., 2017) coincident with the deposition of Wilcox Group submarine fan systems in the deep basin ([Figure 25](#)).

Chicxulub Meteor Impact and K-Pg Unit: 66 Ma

The end of the Mesozoic, the Cretaceous-Paleogene boundary (K-Pg), was punctuated by the Chicxulub meteor impact on the northern coast of the Yucatan Peninsula (CHX, [Figure 20](#)). It was postulated that the global mass extinctions at the end of the Cretaceous Period and a layer in strata of the same age enriched in the element iridium were the products of a large meteor impact (Alvarez et al., 1980). The

ensuing search led to the identification of a ring structure on magnetic and gravity data near the town of Chicxulub, Mexico, that was proposed as a candidate for the hypothesized impact crater (Hildebrand et al., 1991). Subsequent investigations have identified a seismically distinct layer penetrated by numerous wells across the northern GOA corresponding to a single graded bed containing breccias ejected from the crater by the impact and finer material that settled from the water column and atmosphere (red line, [Figure 25](#)) over a period of days to weeks following the impact (Scott et al., 2014). Megadunes deposited by the receding tsunami that accompanied the impact have been identified from seismic surveys and wells in northern Louisiana (Kinsland, 2019), and outcrop studies have revealed Chicxulub deposits in Missouri (Campbell et al., 2008) and North Dakota (DePalma et al., 2019). Across the modern OCS, the impact caused major structural failures and collapse of the Cretaceous shelf margin, depositing large megabreccia blocks onto the basin floor outboard of the Florida Escarpment (Snedden et al., 2014). The full implications of the Chicxulub impact on the stratigraphic and structural evolution of the northern GOA are not known, but it did modify the depositional topography of the Wilcox Formation, and Chicxulub breccias are the reservoirs for some of the giant Mexican oil fields in the southern GOA.

Cenozoic Sedimentation and Salt Sediment Interaction 65 Ma–Present

The Cenozoic sedimentary record in the northern GOA consists of approximately forty-five (45) 3rd order transgressive-regressive cycles with durations of 0.5–3 Myr (Lawless et al., 1997). These cycles can be linked to glacio-eustatic fluctuations in sea level (Fillon and Lawless, 2000), as well as other tectonic and climatic factors affecting both accommodation and sediment supply. Sedimentation rates in the offshore areas are low during periods of transgression and inter-glacial highstands of sea level, such that the resulting deposits are condensed. These condensed sections are generally regional marine shale markers or maximum flooding surfaces that form the basis of the genetic sequence (Galloway, 1989) and the regional chronostratigraphic framework. Periods of relative highstands of sea level tend to sequester sediments on the shelf, whereas periods of relative lowstands coinciding with glacial maxima see sands transported across the slope to the basin floor ([Figure 25](#)).

Early Cenozoic deposition in Upper Paleocene–Lower Eocene (Wilcox) time was in a warm greenhouse climate straddling the PETM ([Figure 25](#)), and the wet climate contributed to the large volumes of sediment weathered from Laramide uplifts ([Figure 20](#)) and delivered to shelf margin delta systems and basin-floor fans. Lignite coal is abundant in the Wilcox Formation in onshore areas, and organic rich terrestrial and marine source rocks were the sources for oils across much of the northern GOA shelf (Hood et al., 2002). Intermittent glaciation of Antarctica began in the Oligocene and was well established by late–middle Miocene time (Fillon and Lawless, 2000). Volcanism in the western U.S. and ongoing erosion of Laramide uplifts provided a large pulse of sediment to the basin margin in Oligocene (Frio) time ([Figure 25](#)), although sand fraction reaching the basin floor was limited to the western GOA (Fulthorpe et al., 2014).

Ongoing uplift in the western U.S. continued to source sediments to the GOA in Miocene time, as 3rd order depositional sequences associated with strong glacio-eustatic cyclicity prograded across a shelf and slope underlain by thick mobile salt. Salt withdrawal heavily influenced local accommodation in the north-central GOA and created a tortuous path around inflated and allochthonous salt through a network of intraslope minibasins and onto the basin floor.

Higher frequency (0.2–0.5 Myr) cyclicity in Pliocene and Pleistocene time correlates to the establishment of permanent ice sheets in North America, which delivered large volumes of sediment to the GOA through the Mississippi River drainage (Lawless et al., 1997). Pliocene and Pleistocene deltas prograded to the modern shelf-slope break and deposited a series of minibasin fills that advanced along with the Sigsbee Salt Canopy (Prather et al., 1998).

Major Cenozoic shelf-margin delta systems and their corresponding deepwater basin-floor fans are shown in [Figure 26](#) after Snedden and Galloway (2019). Note that the figure omits laterally equivalent shoreface, shelf, and slope facies that can also serve as hydrocarbon reservoirs. Also omitted are other

Paleogene units that have no established basin-floor fan facies. The shelf-margin deltas are seen to prograde basinward (dashed arrow) from locations well onshore in Texas and Louisiana in Paleocene (Wilcox) time to the modern offshore shelf-slope break by Pleistocene time. The locus of basin-floor sedimentation shifted eastward in Miocene time, back to the southwest in Pliocene time, and south to southwest in Pleistocene time, culminating in the deposition of the Mississippi Fan.

Within the greater GOA Basin, sediment fairways and depocenters influenced and were influenced by salt tectonic processes and accommodation space created by gravity sliding, rafting, and salt withdrawal. Allochthonous salt rose from depth to erupt onto the sea floor and flow glacially downslope coalescing to form extensive salt canopies (Figure 23) that generally young in toward the center of the basin (Peel et al., 1995). Loading of the salt by up to 50,000 ft of Cenozoic sediments mobilized the salt into a vast array of diapirs, salt tongues, and canopies along with associated extensional faults and salt welds (Figure 23). Early salt canopies that once covered much of the onshore and shelf have been evacuated farther downslope or lost to the sea. Shelf-margin growth fault trends are progressively younger into the basin and are generally linked to salt-withdrawal minibasins, which formed in the wake of ascending diapirs and salt ascension zones from which these canopies were sourced. Extension in updip areas was accompanied by contraction in downdip areas. A series of compressional fold belts formed at the downdip limit of the Mesozoic salt nappes to accommodate the extension in updip areas (Figure 23).

Across the Texas Gulf Coast in areas lacking thick salt, linear shelf-parallel fault trends formed above regional detachments in Paleogene strata (Figure 23). These growth fault trends are all subtly segmented across the underlying basement transfer fault trends (Stephens, 2009). Beneath the southwest Texas coast, large blocks of Wilcox section extending up to 100 miles along strike were rafted basinward creating depo-troughs for expanded Upper Wilcox and younger Paleogene section (Fiduk et al., 2004). Across the Texas shelf, the Lunker, Clemente-Tomas, Corsair, and Wanda growth fault systems are similarly segmented and can be linked downdip to salt withdrawal and elements of the Sigsbee Salt Canopy. Across the south Louisiana coastal zone and shelf where the Louann salt was thicker, fault systems are more highly segmented and arcuate and are closely linked to salt withdrawal minibasins and allochthonous salt systems. Counter-regional fault families (Rowan et al., 1999) situated downdip of major salt withdrawal basins are associated with salt feeders and vertical salt welds that sourced the south-leaning diapirs and tabular salt bodies and are linked to updip shelf-margin growth fault families (Stephens, 2013). These counter-regional fault systems and salt welds are important hydrocarbon migration pathways, and many accumulations are situated on structural highs associated with these features (Pilcher et al., 2011).

In the central and western GOA, a series of Cenozoic fold belts formed at the downdip limit of the allochthonous salt nappes (Figure 23) that had advanced onto oceanic crust in the Mesozoic. The Perdido, Keathley, Walker Ridge, and Mississippi Fan (Atwater) Fold Belts (Figure 23) consist of detachment folds overlying the ductile décollement layer of the Louann Salt. Contraction in the fold belts served to partially accommodate updip extension in shelf margin growth faults and detachments.

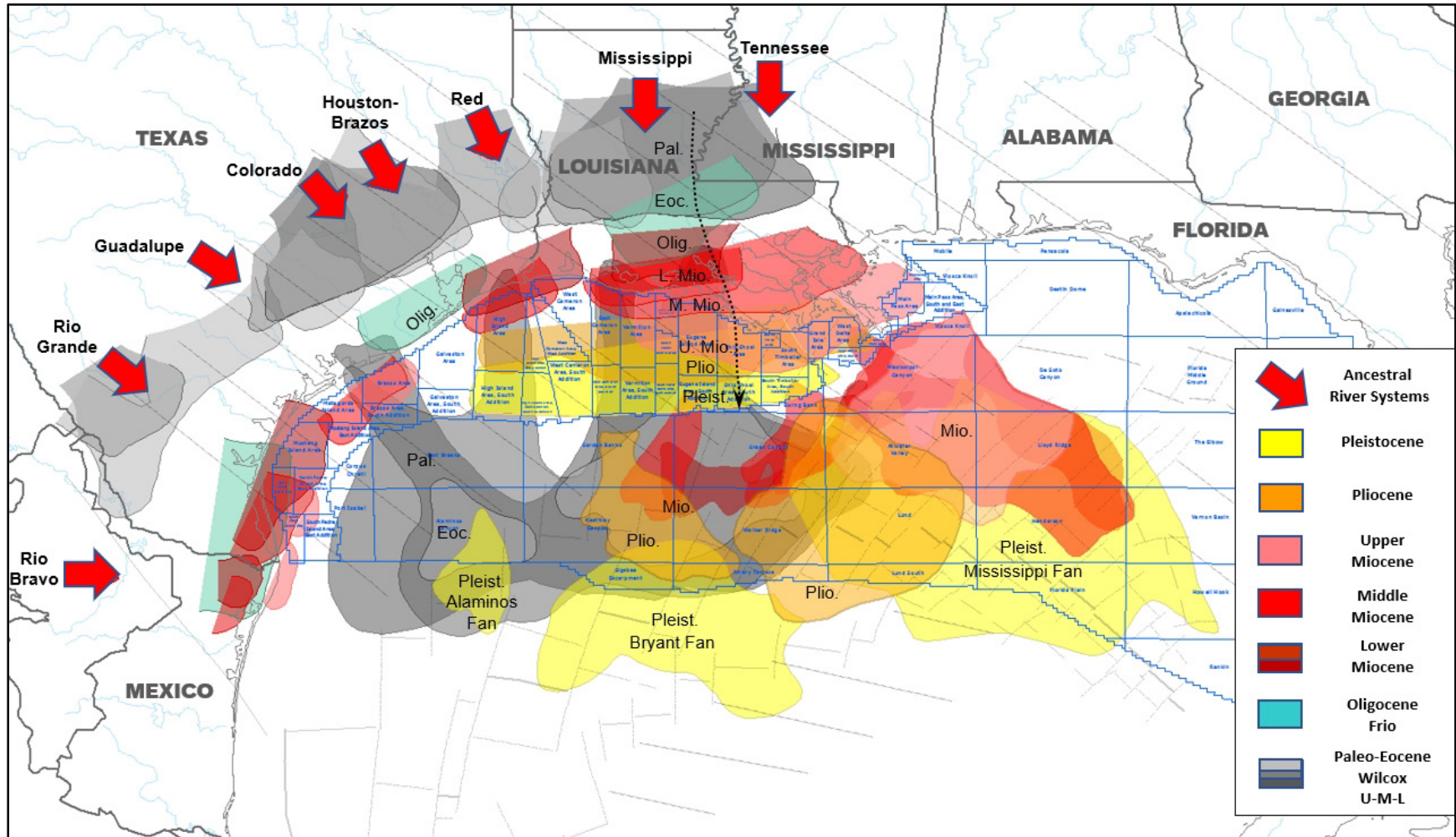


Figure 26. Major Cenozoic deltaic depocenters and equivalent basin-floor fans (after Snedden and Galloway, 2019).

The Perdido Fold Belt is composed of a series of elongate SWNE-trending salt-cored detachment folds that are bounded by kink bands (i.e., narrow zones of angularly folded strata) (Camerlo and Benson, 2006). The main stage of fold development involved stratigraphic section of Late Jurassic to Eocene age. Folding occurred primarily during the early Oligocene to possibly early Miocene in response to updip Paleogene sedimentary loading and accompanying extension.

Deformation of 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 produced 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 (Fiduk et al., 1999; Trudgill et al., 1999).

Structures of the Mississippi Fan Fold Belt consist of a series of ENE-SSW trending, subparallel, salt-cored folds. The folds are asymmetric, basinward-verging, 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 fold belt. 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 and 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.

The allochthonous salt sheets of the modern Sigsbee Salt Canopy can be more than 20,000 ft thick and pose great challenges for subsalt seismic imaging and exploration. Ongoing movement of the Sigsbee Salt Canopy beneath the continental slope in the deepwater GOA is apparent in modern seafloor bathymetry (**Figure 27**). The Sigsbee Escarpment (**Figure 22**) is coincident with the leading edge of the modern allochthonous salt beyond which lies the modern abyssal plain.

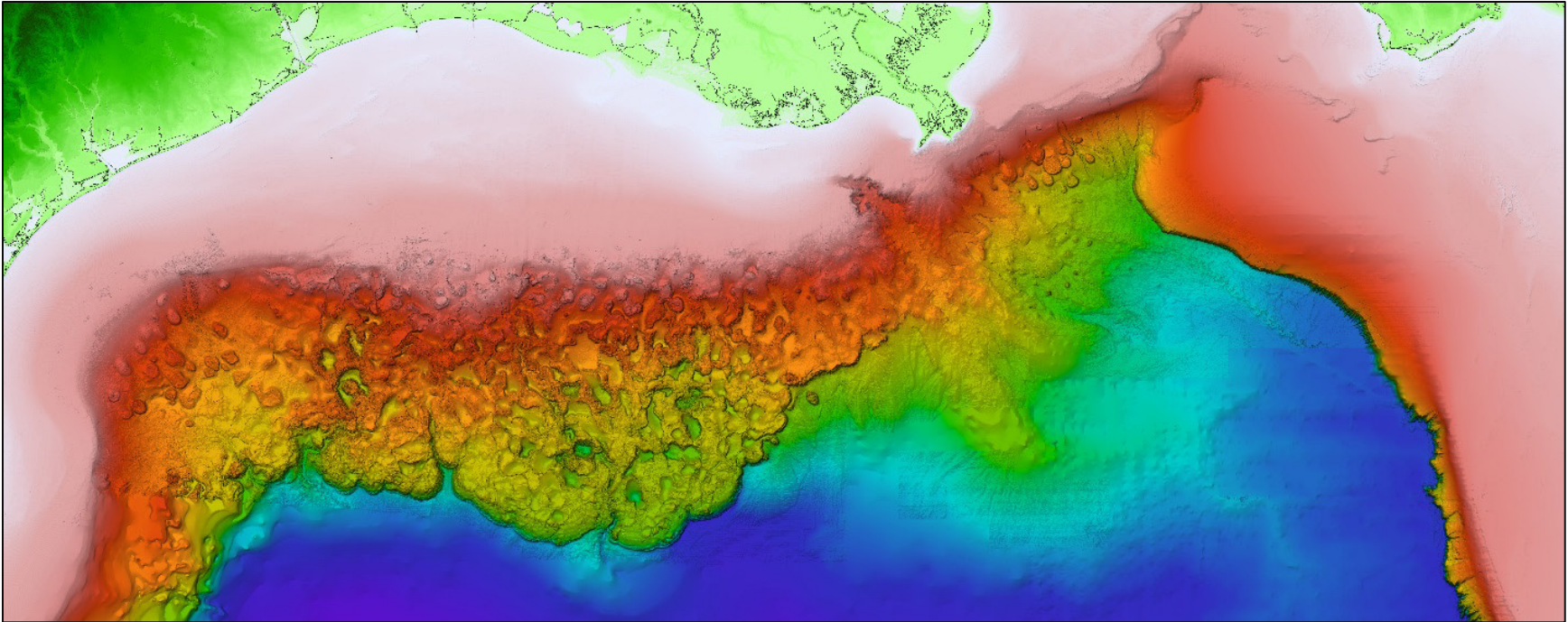


Figure 27. Modern seafloor bathymetry of the northern Gulf of America. Deepwater, high-resolution bathymetry (after Kramer and Shedd, 2017).

MESOZOIC ASSESSMENT UNITS

PRE-SALT OR EQUIVALENT

Geology

The Mesozoic (Triassic to Middle Jurassic) Pre-Salt or Equivalent Play has been identified in the northeast GOA extending from the Mississippi Canyon, De Soto Canyon, and Lloyd Ridge Areas eastward across the Florida shelf (Figure 28). The Pre-Salt or Equivalent section was deposited in rifts and grabens associated with the breakup of Pangea and opening of the GOA Basin. These objectives are now situated beneath the Louann Salt, or its equivalent autochthonous weld. In areas of the west Florida shelf beyond the depositional limit of the Louann Salt (Figure 21), the play is situated beneath a post-rift unconformity. The Louann Salt is estimated to be Middle Jurassic (Bajocian), or approximately 170 Ma in age, providing a minimum stratigraphic age for the play. The base of autochthonous salt in the De Soto Canyon and Lloyd Ridge Areas ranges in depth from 22,000 to 30,000 ft and deepens westward into Mississippi Canyon to over 40,000 ft.

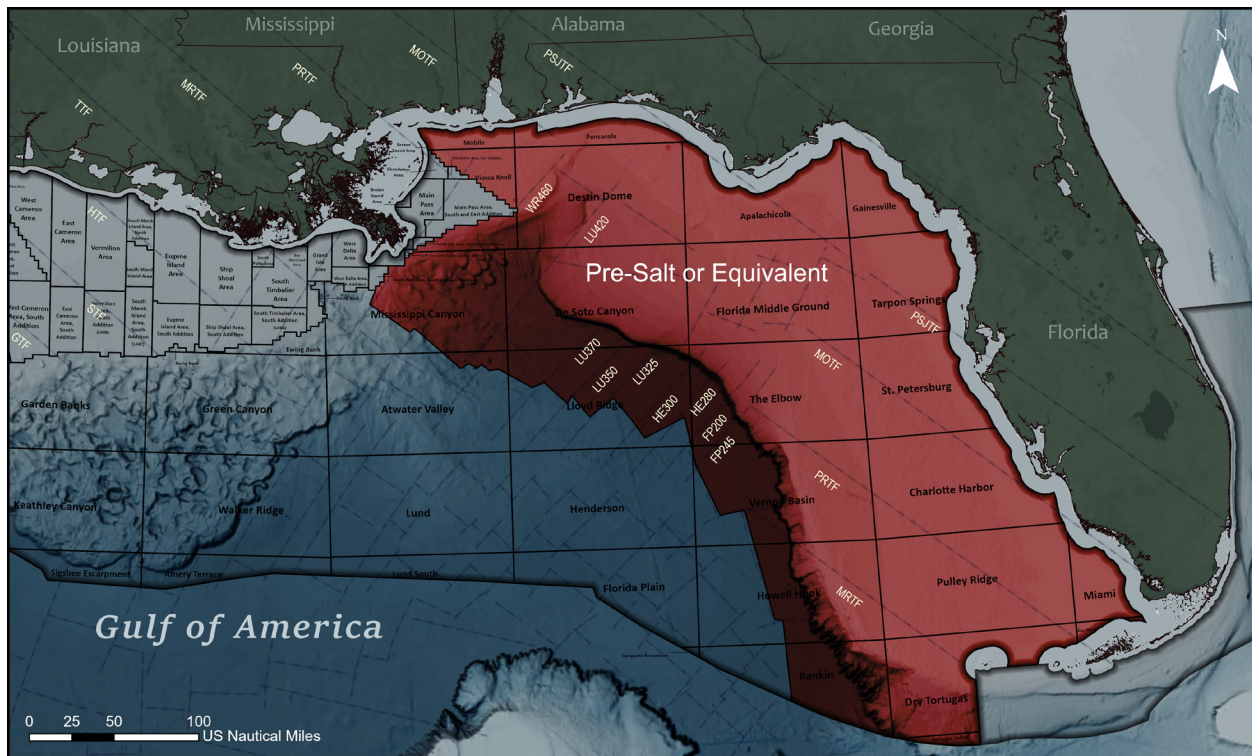


Figure 28. Pre-Salt or Equivalent location.

To the north and east, the play extends to state waters and can be considered an offshore extension of the South Georgia Basin and other Atlantic Margin Triassic Rift Basins. The western limit is at the boundary with younger Jurassic oceanic crust or the line where the top of the play (base of autochthonous salt) dives below 40,000 ft subsea, which generally coincides with a basement step associated with the Terrebonne Transfer Fault Zone (TTF, Figure 28). An analogous play has been described in the southern GOA beneath the Isthmian Salt Basin (ISB, Figure 21) (Williams-Rojas et al., 2012; Miranda-Peralta et al., 2014).

Two phases of rifting are recognized. The first phase is associated with crustal stretching in the NW-SE direction in the Triassic and may contain equivalents to the Eagle Mills Formation (210–195 Ma, [Table 5](#)) known from the onshore Gulf Coast and the Newark Group of the North Atlantic Margin. These rifts appear to be segmented by NW-SE trending basement lineaments—the Tallahassee, Port St. Joe, Mobile, Pearl River, Mississippi River, and Terrebonne Transfer Fault Zones ([Figure 20](#) and [Figure 22](#)). A second phase of crustal stretching and rifting from northeast to southwest preceded the emplacement of oceanic crust (Imbert and Philippe, 2005). These rifts are segmented by a series of transfer fault zones trending NE-SW that align with transform faults in the subsequently emplaced oceanic crust and appear to offset the earlier NW-SE trending lineaments ([Figure 21](#)). Phase 2 rifting was preceded or accompanied by the emplacement of seaward dipping reflectors (cross-hatched green polygons, [Figure 21](#)) thought to represent subaerial lava flows just prior to the formation of oceanic crust (Imbert, 2005). Restored cross sections from 2D and 3D seismic traverses show two pre-salt sequences spanning the eastern GOA and Yucatan conjugate margins (Curry et al., 2024). Filina and Beutel (2025) postulate that areas of thicker pre-salt section along the eastern GOA and Yucatan margins coincide with areas of thermal subsidence associated with the SDRs and CAMP-related volcanism. Reservoir objectives in the Phase 2 rifts are thought to be Lower to Middle Jurassic age, distinctly younger than the Eagle Mills Formation. Previous lease sale bidding in the De Soto Canyon (SW ¼) and Lloyd Ridge (NW ¼) Protraction Areas conform to areas of Phase 2 rifting. Storey (2020) shows a thin post-rift sag sequence beneath the Louann Salt in the Apalachicola Rift of the northeastern GOA.

With no Phase 2 well penetrations in the Gulf of America OCS, the identification of the Pre-Salt or Equivalent Play is based solely on the interpretation of 2D seismic lines and 3D seismic volumes. Resolution of both 2D and 3D seismic data is poor at the prospective interval due to its depth (locally greater than 30,000 ft), presence of salt in some of the area (De Soto Canyon and Lloyd Ridge), and processing of seismic data not focused on this particular play. The inferred objective section represents the filling of grabens or rift basins by alluvial fan, braided stream to fluvial-deltaic, and lacustrine shale paleo-environment deposits. Other possible rift deposits could include evaporites, carbonates, and volcanics. Lacustrine shale may provide the source rock for the play. Though detailed reservoir parameters are unknown, offshore Florida Platform wells in Phase 1 grabens with mud logs or cores from the interval record hundreds of feet of conglomeritic sandstones and siltstones similar to onshore Eagle Mills Formation samples. Two-dimensional seismic surveys and paleontological reports show that some of these wells are in grabens faulted into Paleozoic basement (Godo, 2025).

The eastern-GOA Pre-Salt or Equivalent Play is analogous to Atlantic Margin grabens and formed at similar Triassic-age latitudes (10 degrees to 23 degrees north) (Whiteside et al., 2011; Blakey, 2013). The eastern-GOA grabens today are structurally along strike from five Atlantic Margin grabens, which were assessed by the U.S. Geological Survey. The U.S. Geological Survey reported technically recoverable total undiscovered resources of 3.8 Tcf of gas and 135 million barrels of natural gas liquids (Milici et al, 2012). Source rocks in the Atlantic Margin grabens are interpreted as both lacustrine and terrestrial. Environments favorable to lacustrine and terrestrial organic matter accumulation and preservation are then also possible in grabens defined in the Pre-Salt or Equivalent Play.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 45% ([Figure 3](#))
- prospect-level: 18% ([Figure 4](#))
- exploration-level: 8% ([Figure 5](#))

The primary risk is the existence of source rocks that could generate hydrocarbons in sufficient quantities to be expelled into the proposed rifted section and preserved. No source rocks have been identified in wells inside the play; however, one well in Gainesville Block 707 drilled into interpreted Eagle Mills

Formation and recorded pollen and algal debris, indicating the precursors for type 3 source rock kerogens. Based on rift basins around the world, the probability of the presence of traps is high. These structures within the play are readily visible on 2D and 3D seismic surveys, and some have been confirmed by well penetrations on the Florida Platform. The overlying Louann Salt is present over some of the play area and could provide an excellent vertical seal for prospects. With an overall exploration chance of success of just 8%, this is one of the riskiest plays assessed in the OCS. See [Appendix A](#) for details.

Undiscovered Resources

This conceptual play could hold much potential based on global analogs. Pre-Salt Mesozoic discoveries of significant size occur in the offshore waters of Brazil, West Africa, and the North Sea. A press release indicates the Pemex Yaxtaab-1 well drilled offshore Ciudad del Carmen, Campeche, in 2018 was to test the pre-salt section, but no further details were provided.

Available 3D seismic data in the GOA were used to generate an inventory of 18 prospects over only a portion of the play. A prospect density was, therefore, calculated and extrapolated across all the remaining Phase 1 and Phase 2 rifts and grabens, which were interpreted from 2D seismic and potential field data, resulting in a maximum of 208 prospects. From this, the assessors determined that the number of prospects ranges from 150 to 200. Applying risk results in 0 to 60 undiscovered pools, with a mean of 14.

The pool-size distribution was modeled with 82 discoveries trapped in structural rifts and grabens from the North Sea (Viking and Central Grabens), Australia (Vulcan Basin), Newfoundland (Jeanne d'Arc Basin), and Argentina (Cuyo and San Jorge Basins). These discoveries range in size from 0.5 to 738 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 455 MMBOE.

The play was modeled as 100% oil. With no discoveries or definitive knowledge of the source rocks, gas-oil-ratios (GOR) were calculated from the analog volumes, with GRASP returning UTRR volumes for black oil and solution gas. Because there is play-level risk, only 45% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 2,552 MMbbl at the 5th percentile, with a mean of 808 MMbbl, and 2,609 Bcf at the 5th percentile, with a mean of 826 Bcf, respectively ([Table 8](#) and [Figure 29](#)). Of all 30 assessment units in this study, the Pre-Salt or Equivalent ranks 9th based on mean-level undiscovered BOE resources ([Figure 10](#)).

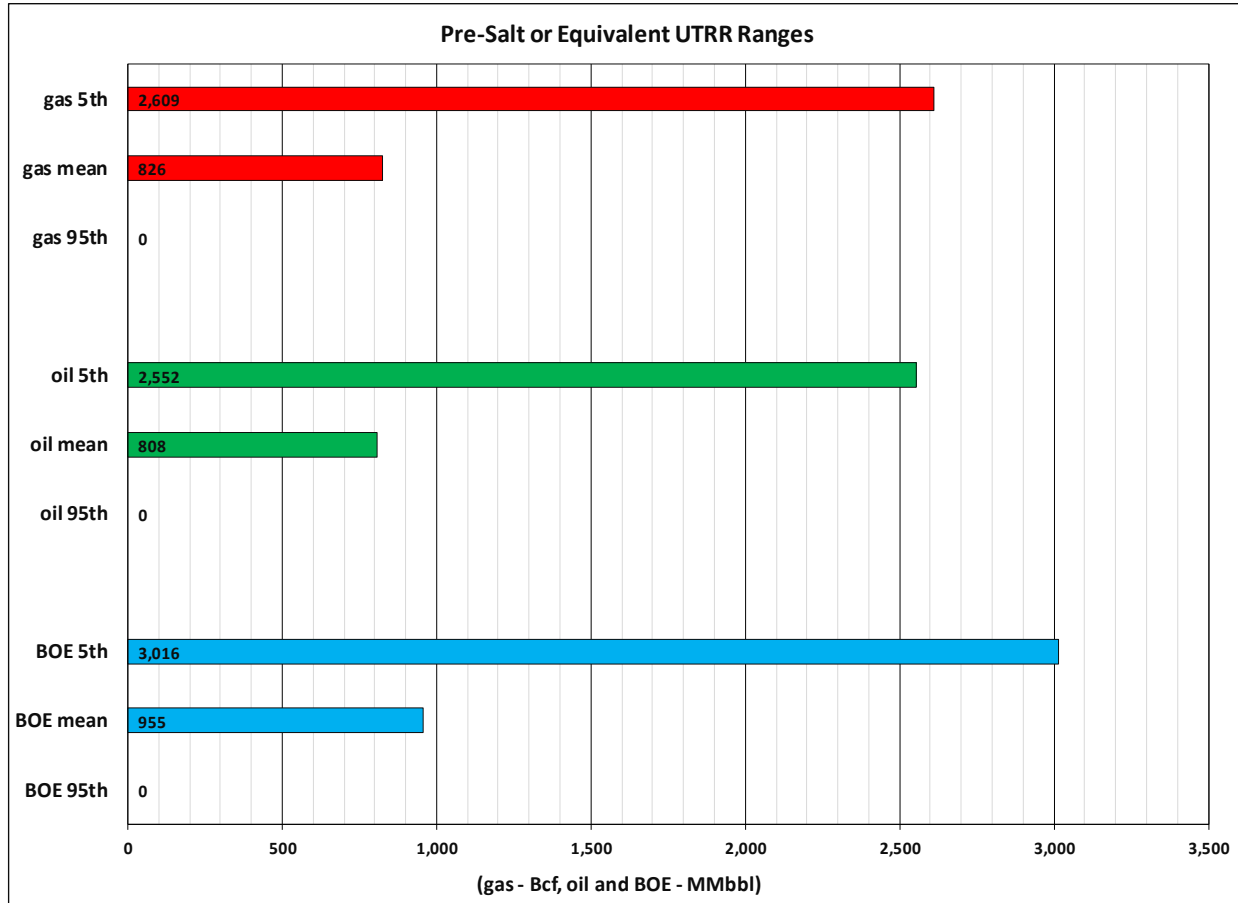


Figure 29. Pre-Salt or Equivalent gas, oil, and BOE UTRR ranges.

EXPANDED JURASSIC

Geology

An Expanded Jurassic (Middle to early Upper) Play has been identified across the northwest quadrant of the Lloyd Ridge Area and extends into southwest De Soto Canyon, southeast Mississippi Canyon, and northeast Atwater Valley (Figure 30). The expanded geologic section is positioned stratigraphically immediately above the Louann Salt of Middle Jurassic age (Bajocian) and below the basal Smackover Formation (Oxfordian) and is, therefore, postulated to be of Bathonian–Callovian to early Oxfordian age. The play area is within the footprint of underlying Phase 2 rifts, which are segmented by NE-SW trending transform faults that continue into the adjacent oceanic crust to the southwest (Figure 21). To the northwest, the play terminates abruptly at the transform fault designated “LU420,” and to the southeast, the play extends to the transform designated “HE300” (Figure 30). To the southwest, the play limit is the edge of the underlying Mesozoic salt nappes (Figure 23) that override oceanic crust. It is postulated that the process of outer margin collapse described by Pindell et al. (2014) caused the underlying Phase 2 rifts to subside and provided accommodation for an exceptional thickness of Louann Salt in this outer marginal trough, the “salt trough” of Imbert (2005). Subsequent withdrawal of this thick salt and mobilization down-dip into the Mesozoic salt nappes provided the accommodation for the exceptional thickness of post-Louann, pre-Smackover expanded Jurassic section.



Figure 30. Expanded Jurassic location.

The identification of this play is based on the interpretation in 3D seismic data of multiple prominent and continuous reflectors in the pre-Smackover section. Sediment loading and gravity spreading resulted in salt displacement and the formation of salt pillows, diapirs, vertical salt ridges, welds, and thrusts. Seismic reflector packages are as thick as 5,000 to 7,000 ft on depth surveys. The southern terminus of the Jurassic expansion is a counter-regional, down-to-the-north, normal fault that is first identifiable west of the Cheyenne Gas Field in Lloyd Ridge Block 399. The basement-involved fault proceeds generally southeastward until it intersects the Florida Escarpment in the south-central portion of The Elbow Area. Vertical salt movement is at its greatest immediately in front of this counter-regional normal fault.

The identified structural styles appear to involve expanded early Upper Jurassic section beneath the Smackover reflector. Trap types include three-way closures against salt and faults, and four-way closures (drape over underlying autochthonous salt features). Cycles of bright and dim reflectors over 5,000 ft of section indicate impedance contrasts, suggesting the presence of high density and lower density rocks, some of which could act as vertical seals.

Only one well tests the upper part of this interval, reaching a total depth of 24,613 ft (7,502 m). Drilled in 2013, it is likely that Shell's Swordfish well in De Soto Canyon Block 843 tested $\pm 1,000$ ft (± 305 m) of the upper portion of this play's section. The pre-Smackover section described on the mud log indicates this interval is primarily composed of sand, silt, and shale, possibly of fluvial origin. The well log shows the sand percentage increasing with depth, from 60%–75% of the total sample examined. A generalized description of the sand was brownish gray to red, partly consolidated to friable, very fine to fine grained, sub-angular to sub-rounded, poorly to moderately sorted, and either frosted, translucent, or coated. There were no references made regarding the presence of hydrocarbons. A well penetrating section directly above these reflectors is Appomattox in Mississippi Canyon Block 392, and the Norphlet Formation in this well is sandy. Adjacent to the trend is a second well—Cheyenne—in Lloyd Ridge Block 399 that shows the Norphlet Formation to have an interpreted marine limestone facies. No well has been drilled, however, that tests all reflectors associated with the play. In a publication by Rives et al. (2019),

Total Company geologists break these reflectors into third order cycles of basin-margin evaporites and proximal clastics.

Water depths within the play outline range from 8,000 to 10,000 ft. Wells drilled for the Expanded Jurassic Play will likely require drilling depths in the range of 20,000 to 28,000 ft depending on location.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 34% ([Figure 3](#))
- prospect-level: 21% ([Figure 4](#))
- exploration-level: 7% ([Figure 5](#))

The highest risks are the presence of mature source rocks and hydrocarbon migration from said source rocks to reservoir. However, the source bed potential of the overlying Smackover Formation is well known, maturity is within the oil window, and vertical migration from the Smackover downward into the section below has been demonstrated. Total's interpretation of basin-margin evaporites in their Sakarn domain (Rives et al., 2019) suggests the presence of anoxic basinal sediments within the reflector package capable of hydrocarbon generation. Lateral charging from source beds in Pennsylvanian–Permian successor basins (Nicholas and Waddell, 1989) or sag basins (Blakey, 2013) cannot be discounted. Because traps can be mapped with some confidence on 3D seismic data, the trapping component was designated the least risky. Reservoir rock presence and quality for this age are unclear due to very limited well data. With an overall exploration chance of success of just 7%, this is one of the riskiest plays assessed in the OCS. See [Appendix A](#) for details.

Undiscovered Resources

Available 3D seismic data in the GOA were used to generate an inventory of 42 prospects over a portion of the play. A prospect density was, therefore, calculated and extrapolated across all the play area, resulting in a maximum of 136 prospects. From this, the assessors determined that the number of prospects ranges from 70 to 140. Applying risk results in 0 to 50 undiscovered pools, with a mean of 7.

The pool-size distribution for this conceptual play was modeled with the nine [Norphlet Slope](#) discoveries in the deepwater OCS. These discoveries range in size from 10 to 309 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool in the play is 211 MMBOE.

The play was modeled as 100% oil. Based on GORs from the Norphlet Slope pools, GRASP returned UTRR volumes for black oil and solution gas. Because there is play-level risk, only 34% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 1,610 MMbbl at the 5th percentile, with a mean of 403 MMbbl, and 1,068 Bcf at the 5th percentile, with a mean of 267 Bcf, respectively ([Table 8](#) and [Figure 31](#)). Of all 30 assessment units in this study, the Expanded Jurassic ranks 13th based on mean-level undiscovered BOE resources ([Figure 10](#)).

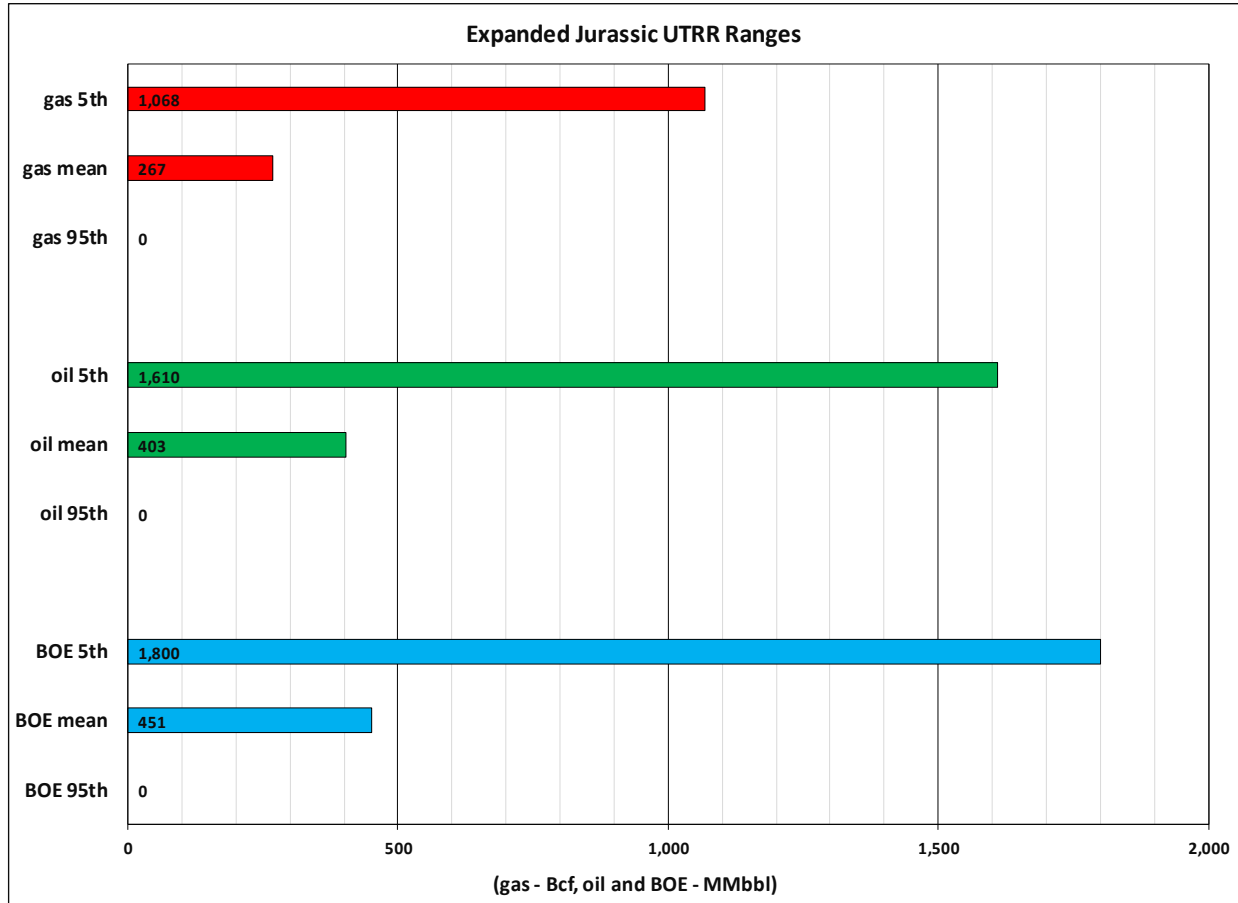


Figure 31. Expanded Jurassic gas, oil, and BOE UTRR ranges.

NORPHLET

The Upper Jurassic Norphlet Formation in the eastern GOA is defined by aeolian dune sediments deposited during the Oxfordian Stage (Table 5 and Figure 25). Productive Norphlet reservoirs consist of aeolian dunes that were deposited directly above the Middle Jurassic Louann Salt and less commonly above Norphlet fluvial facies. For this study, the Norphlet Formation is delineated by the modern shelf-slope break (Figure 32).

The Smackover-Norphlet (Figure 25) is a closed petroleum system. Laminated, algal-rich lime mudstones of the overlying lower Smackover Formation (Late Jurassic, Oxfordian) are geochemically typed as the source rocks for the Norphlet (Sassen, 1990) and provide the overlying top seal for Norphlet reservoirs (Mankiewicz et al., 2009). Except for a few onshore fields, the Norphlet is only productive where there is no porosity in the upper Smackover. Where there is porosity in the upper Smackover, the Norphlet is charged with commercial volumes of hydrocarbons only after all available Smackover porosity has been filled.

Whole core examinations from wells drilled in the De Soto Canyon and Mississippi Canyon Areas, used in conjunction with the analysis of their associated well logs, have established a dune type change in the aeolian deposits from the individual seif (longitudinal) and star dune setting in the north to an area with barchan (horned) dunes in a coalesced or erg type environment in the south (Godo et al., 2011). Additionally, the primary hydrocarbon also changes from north to south. The gas with associated liquids in the Norphlet Shelf Play changes to oil with associated gas in the deeper water Norphlet Slope Play.

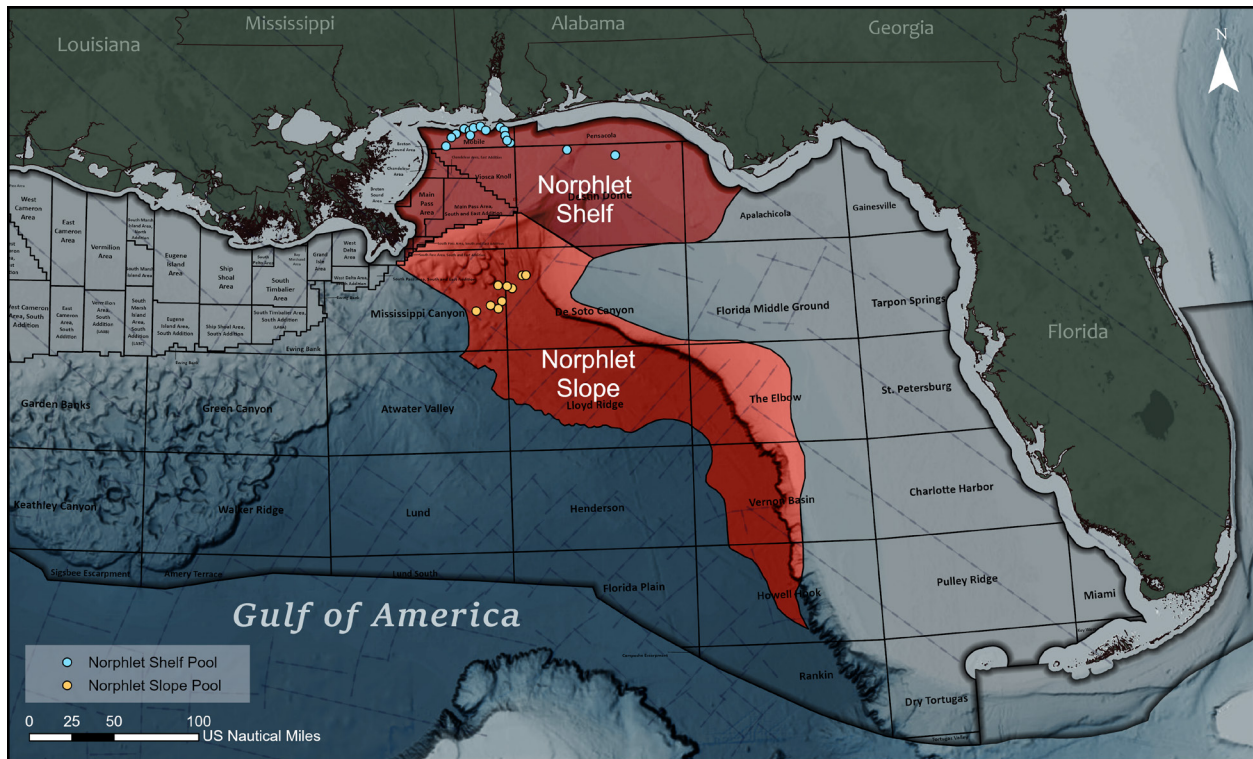


Figure 32. Norphlet Shelf and Slope locations and associated discovered pools.

Norphlet Shelf

Geology

The Norphlet Shelf Play references the modern shelf-slope break and is an offshore extension of an early onshore trend that was established around the northern GOA rim in Texas, Louisiana, Mississippi, Alabama, and Florida between 1967 and 1980. The trend continued into Alabama State waters off Mobile Bay with sour gas production in the 1980s and 1990s. Eventually, it reached the federal waters of the Destin Dome and Pensacola Areas, but small discoveries were not commercialized due to a federal drilling moratorium.

The play extends eastward across the Pensacola, Destin Dome, and western-most Apalachicola Areas, encompassing the De Soto Canyon Salt Basin (Figure 32). Wells define the eastern limit of Norphlet sand deposition as loosely coinciding with the updip limit of Jurassic Louann Salt, an irregular northwest trending onlap onto Triassic, Jurassic, and Paleozoic section of the southwest-plunging paleo-Appalachian Mountains. To the south, the section onlaps the Southern Platform. To the west, the Norphlet Shelf Play extends across the Mobile, Main Pass, Viosca Knoll, Breton Sound, and Viosca Knoll Areas and merges with the **Norphlet Slope Play** across the modern shelf-slope break, which generally aligns with the Pearl River Transfer Fault in the southwestern Destin Dome Area and is coincident with the geologically younger Cretaceous reef trend (Figure 22).

Sand-thickness isopachs, based on 3D seismic data proximate to the Mobile Area, show that Norphlet dune fields consist of NW-SE oriented, subparallel, elongate sand bodies up to 800 ft (244 m) thick, and 5,000 ft (1,524 m) across (Ajdukiewicz et al., 2010). These thicknesses are thought to be less than the original topography due to post-depositional sediment compaction (Ajdukiewicz et al., 2010). The generally elongate Norphlet dunes have a similar morphology and scale to modern linear dunes of the Namib Desert, where elongate dune complexes consisting of seif and star dunes are up to 1,060 ft (323 m) high (Mankiewicz et al., 2009). In the eastern GOA, dunes are separated from each other by areas with sand thickness less than the vertical seismic resolution of 300 ft (91 m) and are interpreted to be interdune

areas (Ajdukiewicz et al., 2010). Although post-depositional sediment compaction, structuring, and salt tectonics have distorted the original dune configuration, Story (1998) notes that overlying Smackover and lower Haynesville carbonates thin over Norphlet dune crests and thicken over interdune areas, indicating dune topography was present when the carbonates were deposited (Ajdukiewicz et al., 2010).

Discoveries

Pools within the Norphlet Shelf have been discovered in the Mobile and Destin Dome Areas (Figure 32). There are 16 total pools, and discovery dates range from 1983 to 2001 (Figure 33). The Norphlet Shelf is a gas play containing 3,385 Bcf, with minor amounts of condensate (Table 8). Discovered in 1983, Mobile 823 is the largest pool, containing an estimated 196 MMBOE (Figure 34). Pools have been discovered in water depths ranging from 39 ft in the Mobile Area to 389 ft in the Destin Dome Area. Subsea depths of these pools range from 18,339 to 22,948 ft.

Figure 35 illustrates cumulative resources for Shelf Play pool discoveries through time and the size of the discoveries. With the last pool discovery sized at over 100 MMBOE occurring in 1988, the present-day cumulative resources curve is flat, indicative of a mature play with little resources being added.

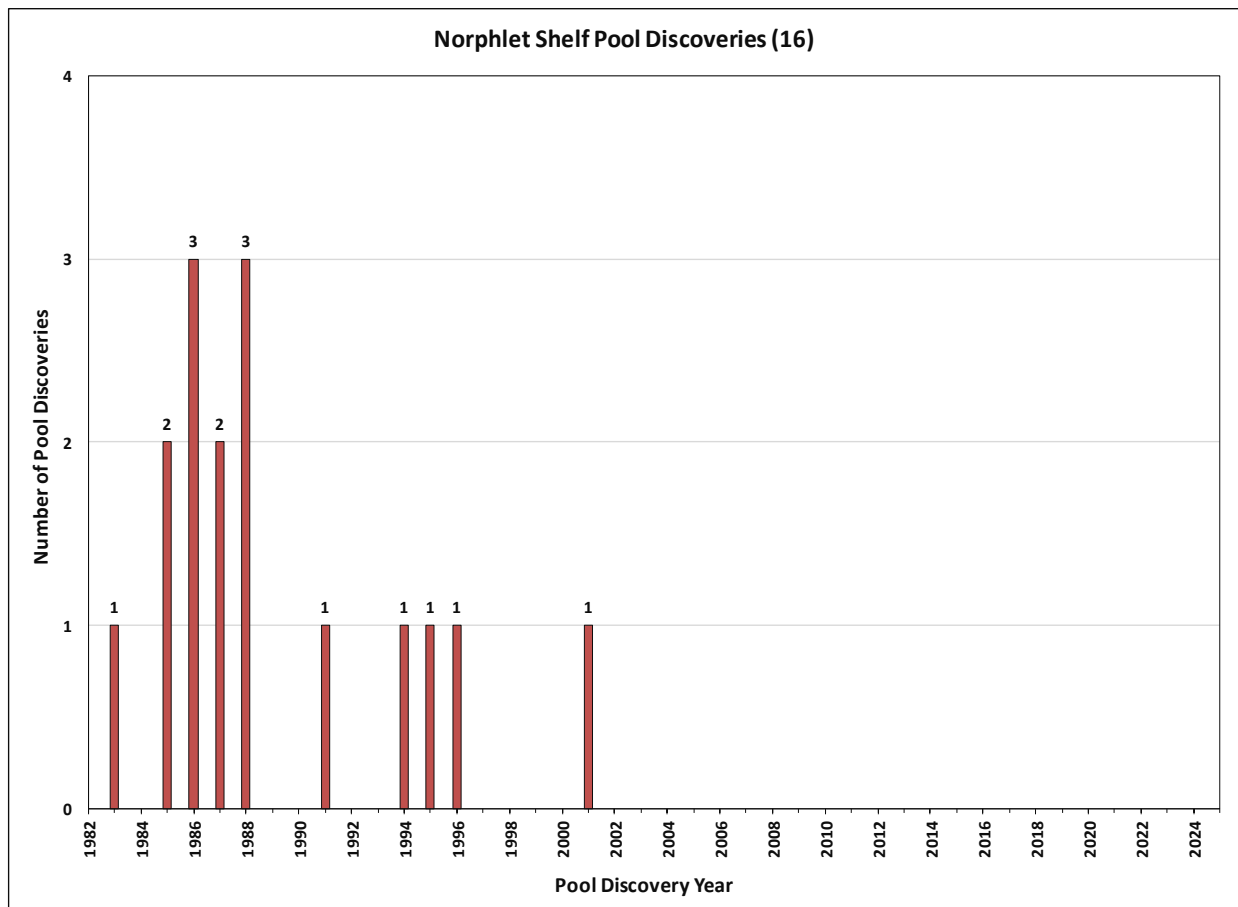


Figure 33. Norphlet Shelf pool discovery history.

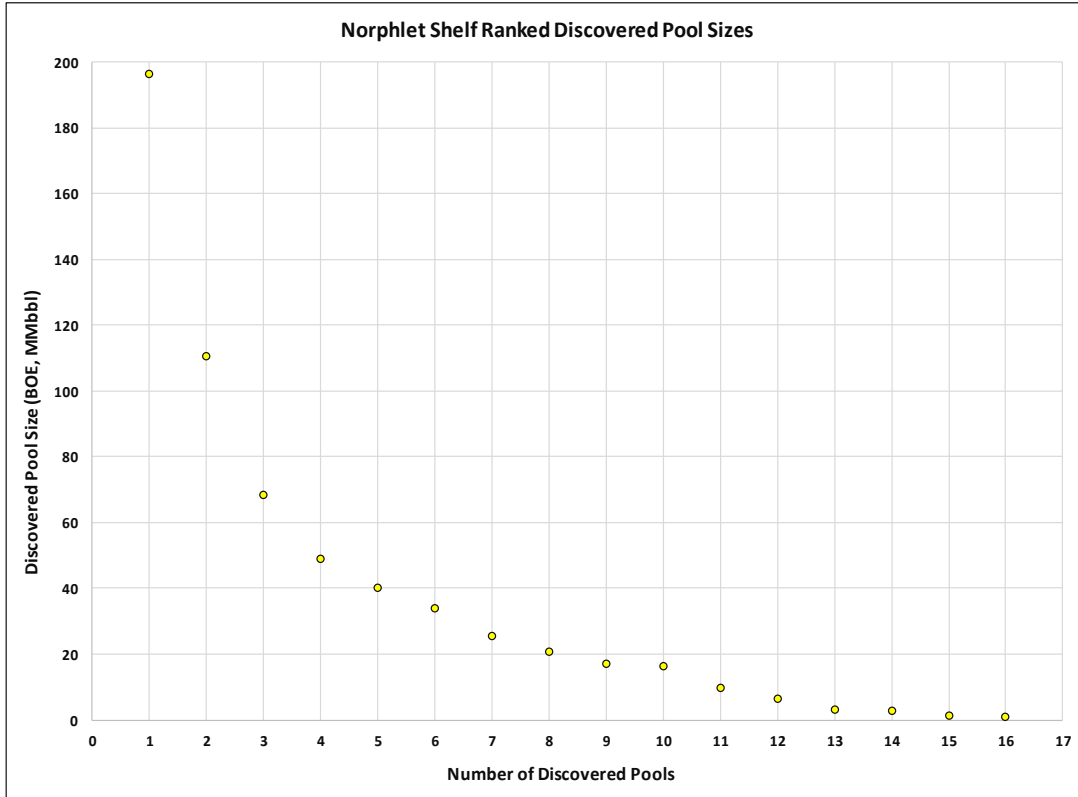


Figure 34. Norphlet Shelf discovered pool-rank plot.

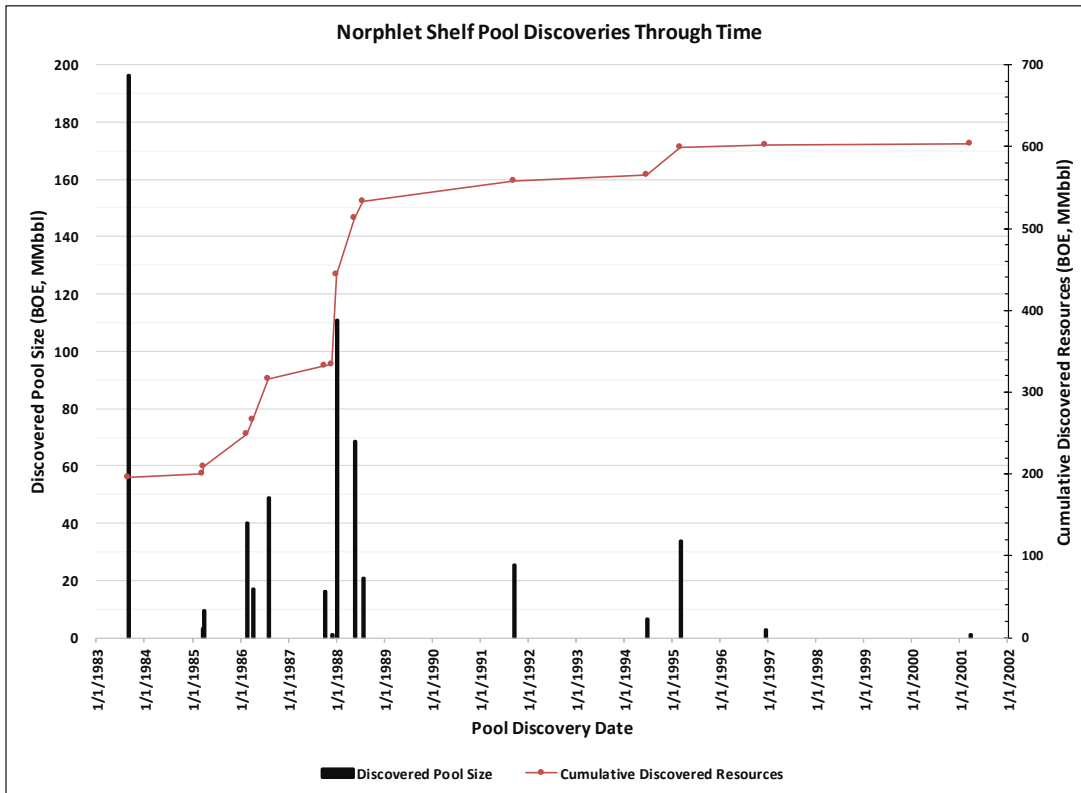


Figure 35. Norphlet Shelf pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% (Figure 3)
- prospect-level: 29% (Figure 4)
- exploration-level: 29% (Figure 5)

Because an active petroleum system has clearly been established, there is no play-level risk. At the prospect level, the highest risk is reservoir quality. See Appendix A for details.

Undiscovered Resources

The number of remaining prospects for this established play was estimated from legacy 2D seismic interpretation in the nearshore Pensacola and Destin Dome Areas, resulting in a portfolio of 269 closures, which were grouped into 89 prospects. These same structures were included in the assessment of the Smackover Play. From this, the assessors determined that the number of prospects ranges from 50 to 110. Applying risk results in 15 to 32 undiscovered pools, with a mean of 23.

The pool-size distribution was modeled with the 16 discoveries in the play. These pools range in size from approximately 1 to 200 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 113 MMBOE.

From the discovered data information, the play was modeled as 100% gas, with GRASP returning UTRR volumes for dry gas and small amounts of condensate. Assessment results indicate that undiscovered gas resources range from 1,143 to 5,283 Bcf at the 95th and 5th percentiles, respectively (Table 8 and Figure 36). Of all 30 assessment units in this study, the Norphlet Shelf ranks 12th based on mean-level undiscovered BOE resources (Figure 10).

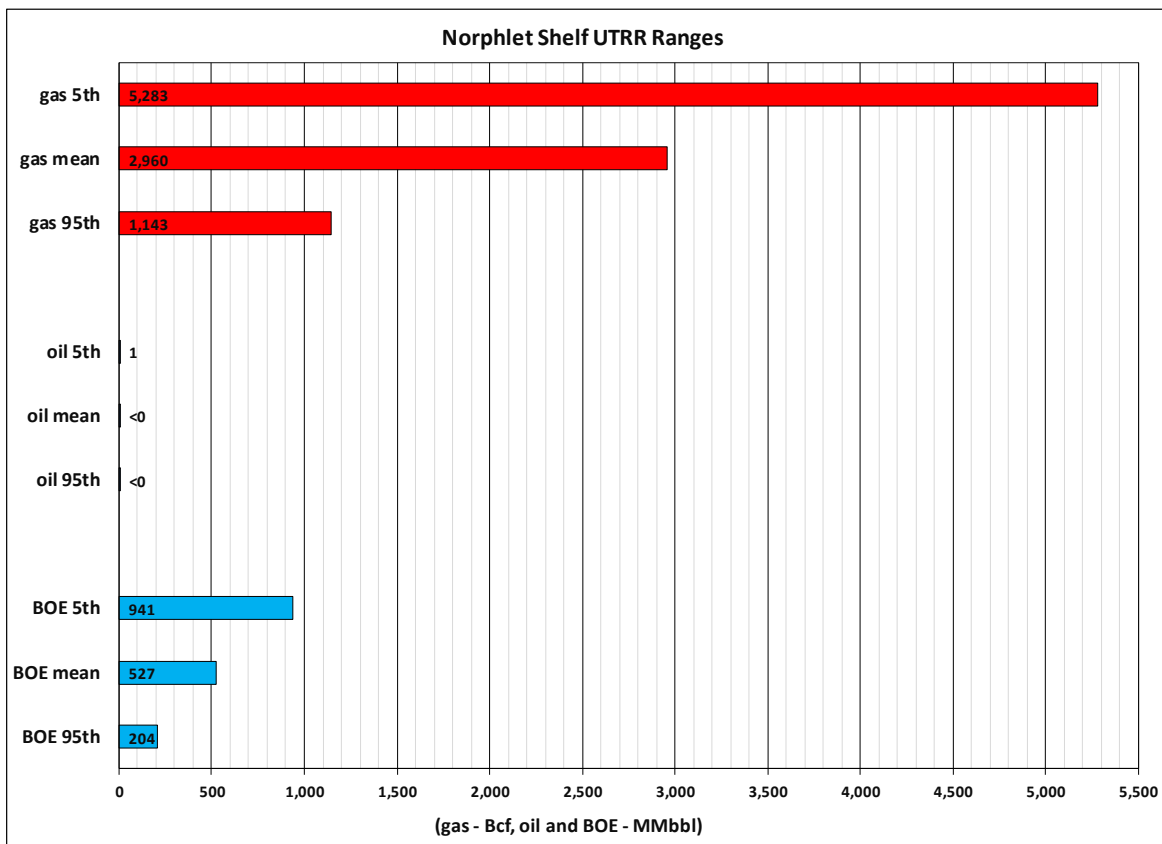


Figure 36. Norphlet Shelf gas, oil, and BOE UTRR ranges.

Norphlet Slope

Geology

The Norphlet Slope Play is located basinward of the modern shelf-slope break in the Eastern and Central GOA Planning Areas ([Figure 32](#)). The Slope Play merges to the north and east with the **Norphlet Shelf Play** across the modern shelf-slope break, which generally aligns with the Pearl River Transfer Fault in the southwestern Destin Dome Area and is coincident with the geologically younger Cretaceous reef trend ([Figure 22](#)). To the southeast, the Slope Play boundary generally parallels the modern Florida Escarpment, extending to stratigraphic pinchouts on the Southern Platform and Sarasota Arch with an excursion into the Tampa Embayment. To the southwest, the play boundary coincides with the limit of the Mesozoic salt nappes ([Figure 23](#)). The western boundary through the Mississippi Canyon Area is limited by depth and is aligned with salt features and an underlying basement step, the Mississippi River Transfer Fault, across which the Norphlet seismic reflector has not been recognized but would be anticipated below 35,000 ft. Notably, there have been discoveries in Mexican waters of the southernmost GOA in the Norphlet-equivalent Ek-Balam Formation that have been extrapolated north and eastward along the Campeche Escarpment (Steier and Mann, 2019). When rotated into their paleogeographic position prior to Middle Jurassic seafloor spreading, this trend is juxtaposed across the salt separation line to the Norphlet Slope Play in Mississippi Canyon and De Soto Canyon.

The play is based on the identification of Norphlet section in the deepwater wells of De Soto Canyon, Mississippi Canyon, and Lloyd Ridge. Here, the defined facies of the Norphlet Formation include aeolian dune and interdune environments. With current well information, the depositional environment becomes fluvial to the east and southeast. Further east on the Florida Platform, the section is characterized by alluvial fans deposited basinward of the highlands of the paleo-Appalachian Mountains (Godo, 2019, page 108). A paleo-environmental interpretation of continental sediments spread around the margins of a broad flat salt pan of Louann Salt is the currently accepted model.

Prediction of paleo-environments and reservoir facies distribution is complicated by the existence of numerous rafted blocks produced by downslope horizontal sliding or gravity gliding on a Louann décollement surface from Oxfordian into Cretaceous time (Pilcher et al., 2014). These blocks of Norphlet to Cotton Valley section, clearly visible on 2D and 3D seismic surveys, have horizontal displacements of over 15 miles (25 kilometers) (Pilcher et al., 2014). These raft blocks radiate west to southwest to south from a break away zone along the western edge of the Southern Platform in the De Soto Canyon Area. The trend of rafts and associated Jurassic faults appears to be segmented by the projections of NE-SW trending transform faults of the Jurassic oceanic crust to the west. The definition of these blocks of self-contained Norphlet reservoir and Smackover source bed have been critical in planning new well locations. Traps include faulted three-way and four-way closures.

A published compilation of Norphlet wells in deep water by Godo (2019) shows that the three essential play components required for substantial hydrocarbon accumulations are (1) the presence of permeable aeolian dune facies of sufficient lateral continuity to provide a less-pressured environment for oil to migrate into, (2) a threshold level of Smackover source rock maturity of 0.9 vitrinite reflectance equivalence, and (3) a narrow window (not older than 15–20 my) for trap creation relative to hydrocarbon expulsion and migration.

Discoveries

Pools within the Norphlet Slope have been discovered in the Mississippi Canyon and De Soto Canyon Areas ([Figure 32](#)). BOEM has estimated sizes of nine discoveries ([Figure 37](#)). The Norphlet Slope is an oil play containing 1,108 MMbbl of oil and 735 Bcf of solution gas (total BOE of 1,239 MMbbl) ([Table 8](#)). The largest discoveries—Mississippi Canyon 651 (Ballymore) and Mississippi Canyon 392 (Appomattox)—are both estimated to contain more than 300 MMBOE ([Figure 38](#)). Pools have been discovered in water

depths ranging from 6,540 ft in the Mississippi Canyon Area to 7,579 ft in the De Soto Canyon Area. Subsea depths of the discovered pools range from 23,210 to 28,529 ft.

Figure 39 illustrates cumulative resources for Slope Play pool discoveries through time and the size of the discoveries. Only nine BOEM-designated discoveries so far and a climbing cumulative volume are indicative of an immature play in exploration phase.

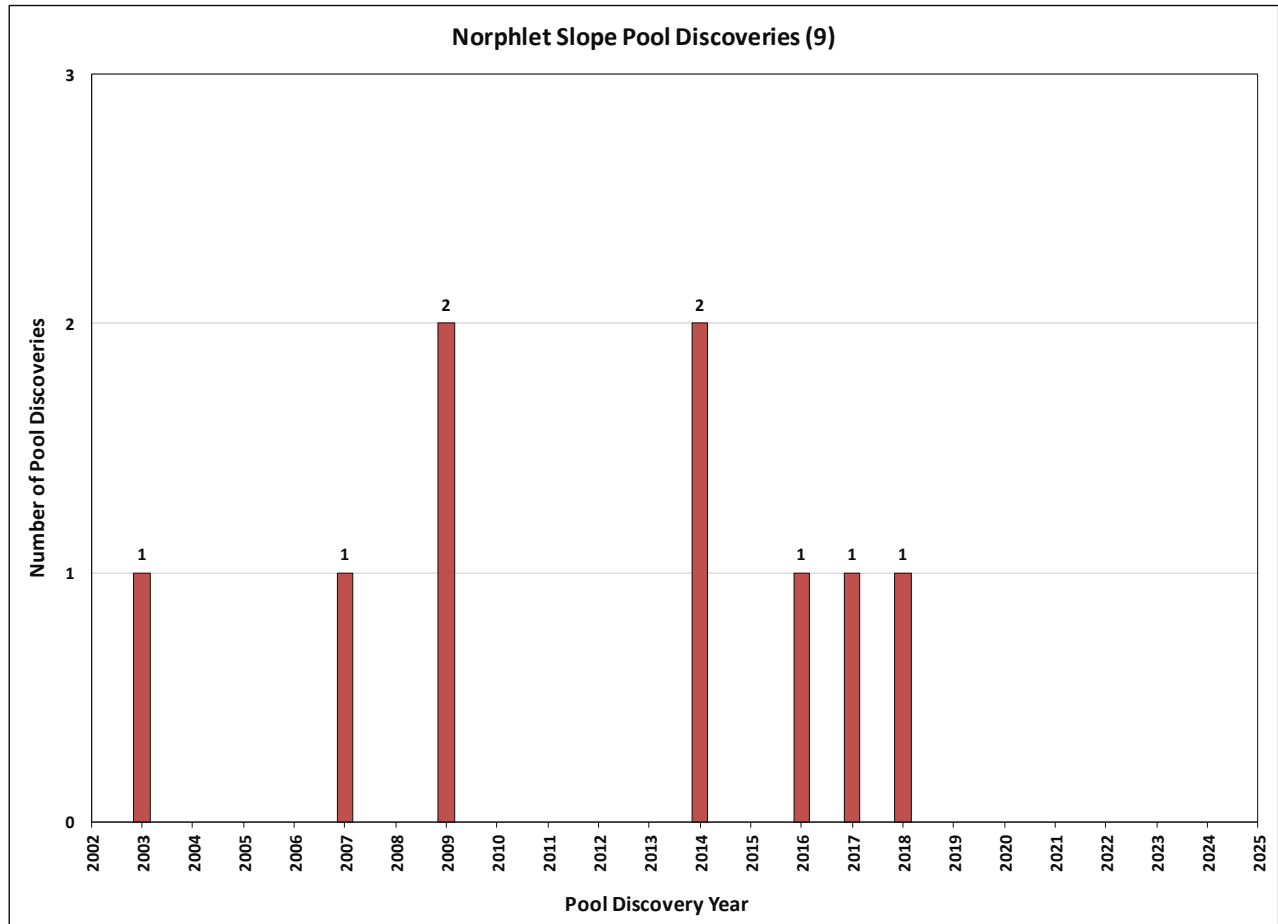


Figure 37. Norphlet Slope pool discovery history.

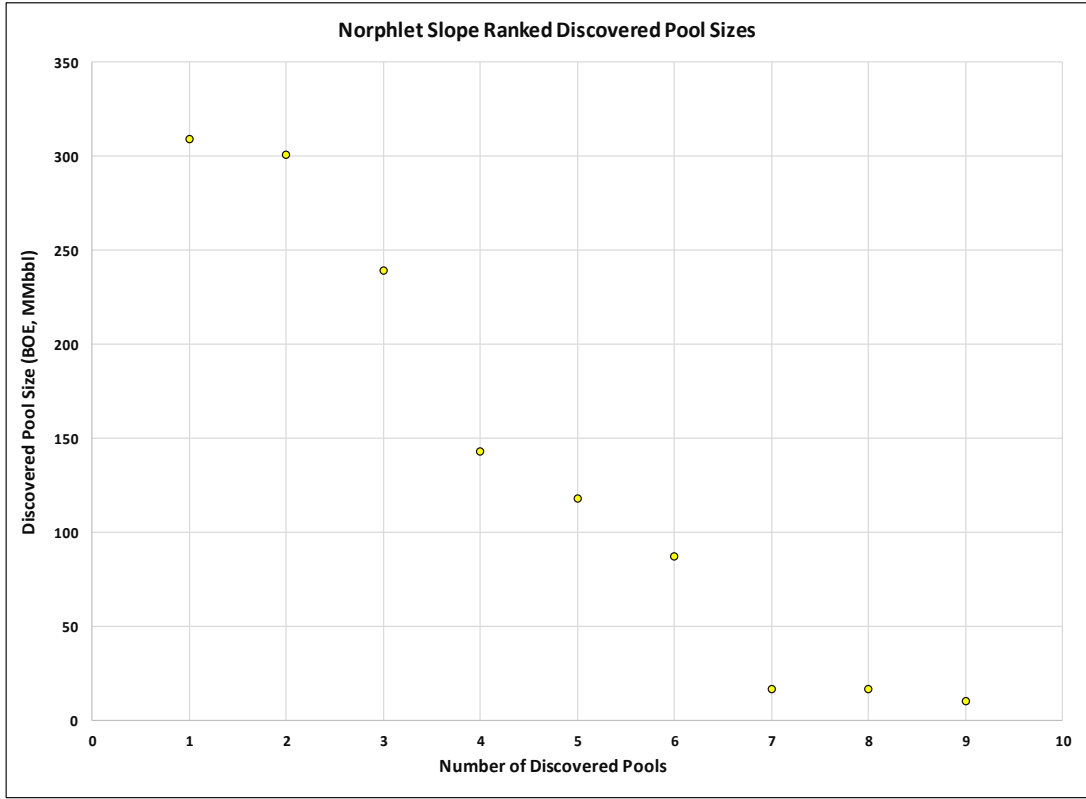


Figure 38. Norphlet Slope discovered pool-rank plot.

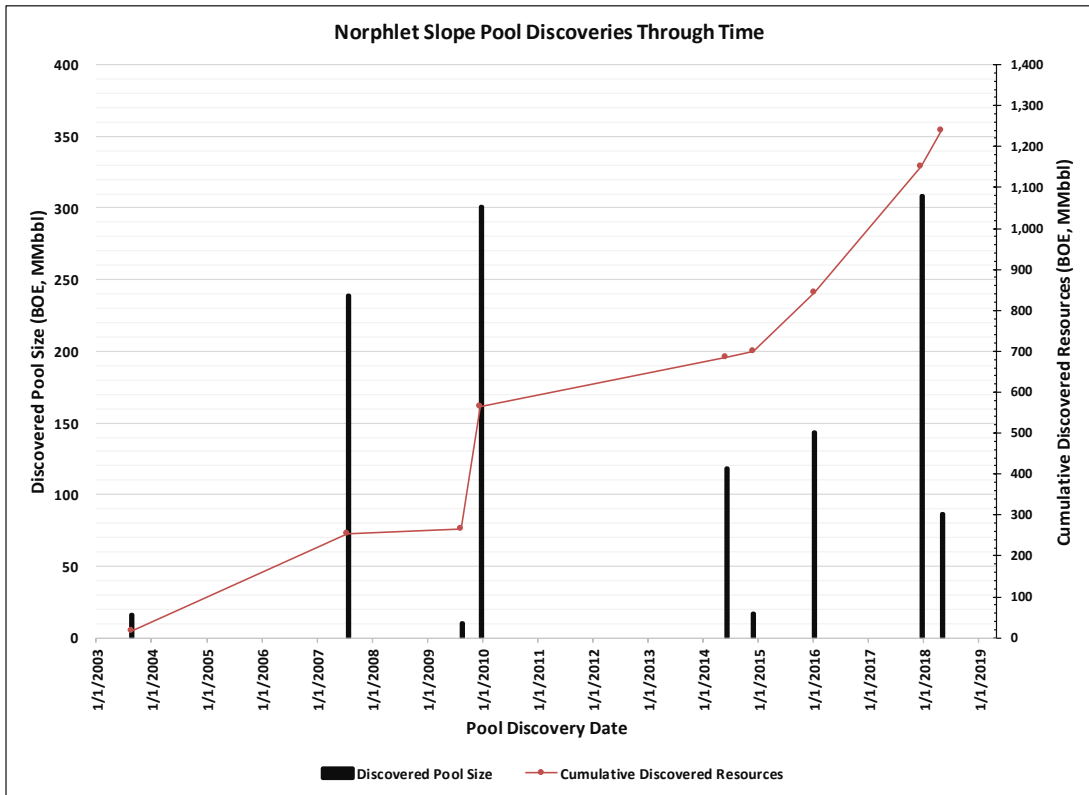


Figure 39. Norphlet Slope pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 17% ([Figure 4](#))
- exploration-level: 17% ([Figure 5](#))

Because an active petroleum system has clearly been established, there is no play-level risk. At the prospect level, the highest risk is reservoir presence. The reservoir component chance of success was reduced from 50% in the [2021 assessment report](#) (U.S. DOI, 2021b) to 40% in this assessment to reflect an emerging consensus that the reservoir facies is trending toward more fluvial environments to the southeast in well penetrations (Godo, 2019) and paleogeographic reconstructions (Snedden and Galloway, 2019; Peel and Apps, 2021). See [Appendix A](#) for details.

Undiscovered Resources

The number of remaining prospects for this established play was estimated from a portfolio of 1,190 traps mapped from available 3D seismic data across portions of the Mississippi Canyon, De Soto Canyon, Lloyd Ridge, and The Elbow Areas. Traps were grouped into prospects from which a prospect density was calculated and applied to the play area. From this, the assessors determined the mean number of prospects to be 390. Applying risk resulted in a mean of 66 undiscovered pools.

The pool-size distribution was modeled with the nine discoveries in the play. These pools range in size from approximately 10 to 310 MMBOE. From this pool-size distribution, the lognormal GRASP model indicates the largest undiscovered pool is 156 MMBOE ([Figure 38](#)).

From the discovered data information, the play was modeled as 100% oil, with GRASP returning UTRR volumes for black oil and solution gas. Assessment results indicate that undiscovered oil resources range from 1,086 to 5,180 MMbbl, and undiscovered gas resources range from 720 to 3,435 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 40](#)). Of all 30 assessment units in this study, the Norphlet Slope ranks 4th based on mean-level undiscovered BOE resources ([Figure 10](#)) and is the highest ranking Mesozoic play in the GOA.

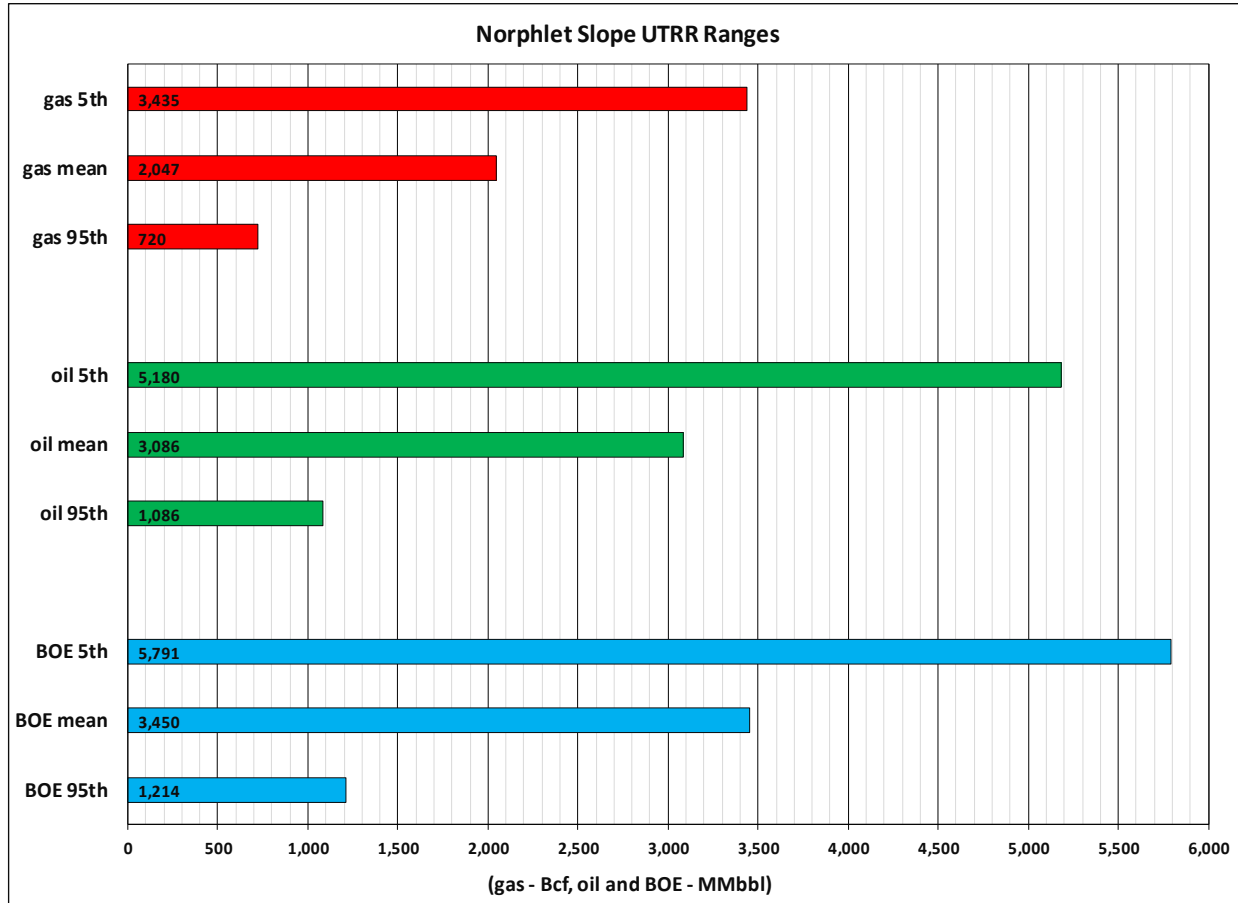


Figure 40. Norphet Slope gas, oil, and BOE UTRR ranges.

SMACKOVER

Geology

The Upper Jurassic (Oxfordian) Smackover Formation (Table 5 and Figure 25), named after the Smackover Oil Field in southern Arkansas, is a carbonate unit deposited during a major marine transgression and sea-level highstand across the northern rim of the GOA. Producing reservoirs extend around the margin of the basin in Texas, Louisiana, Arkansas, Mississippi, Alabama, and Florida. In federal waters, to date, wells drilled that specifically target Smackover are located primarily in the Pensacola, Apalachicola, Destin Dome, De Soto Canyon, Florida Middle Ground, and The Elbow Areas (Figure 41). The play consists of (1) algal buildups or “thrombolite” reservoirs over positive basement highs on the nearshore shelf and across the Southern Platform (Petty, 2010) and (2) grainstone shoals situated above salt rollers and raft blocks (Pashin et al., 2016). Some 2D seismic lines show irregular “pitted” or “pock-marked” reflectors at the top of the Smackover that resemble lines over the onshore Appleton Field of southwest Alabama (Petty, 2010). These reflectors are interpreted as thrombolite buildups. Some 2D seismic lines in the Destin Dome Area and more recent 3D seismic surveys from the Lloyd Ridge Area show shingled bright reflectors between the interpreted Smackover top and the lower Smackover reflector and could represent grainstone facies similar to onshore reservoirs such as the Jay Field of Florida and Alabama. These reflectors occur over salt pillows. Wells nearby record oolites in mud logs. No Smackover fields have been declared in federal waters. However, the Pensacola Block 996 number 1 well flowed a calculated 43 barrels of oil per day from 22 ft of oil, proving the existence of an active petroleum system. We also include within the Smackover Play the grainstone reservoirs of Kimmeridgian age referred to as

the Haynesville Limestone (Figure 25) or Gilmer Limestone as described by Godo and Landry (2024). A well in De Soto Canyon Block 535 encountered over 100 ft of oil pay in a high-quality oolitic grainstone reservoir, confirming both the hydrocarbon system and reservoir in the deepwater portion of the play. The western boundary of the play is coincident with the primary breakaway fault zone for Jurassic rafting, generally paralleling the NWSE-trending Mobile Transfer Fault (MOTF, Figure 23) in the Mobile and Destin Dome Areas, then skirting the northern flank of the Southern Platform and continuing southeast along the break-away zone generally coincident with the modern Florida Escarpment.

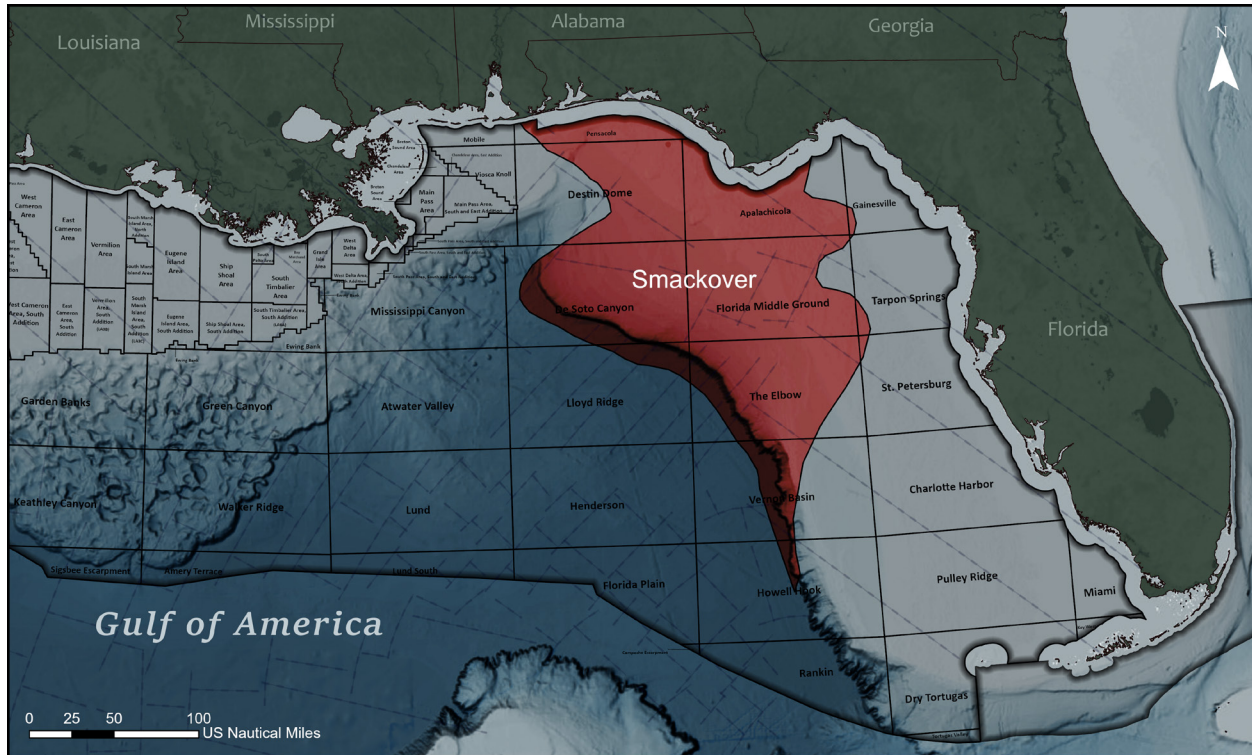


Figure 41. Smackover location.

Onshore, reservoirs in the upper Smackover section consist of inner ramp, high-energy, oolitic grainstones alternating with carbonate mudstones. Localized thrombolitic reefs and grainstone shoals developed over basement highs, salt pillow structures, and topographic highs related to dunes of the underlying Norphlet Erg. 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 paleo-structural highs that favored reef and grainstone shoal development are drilling objectives. Similar features have been documented offshore (Petty, 2010; Pashin et al., 2016). A Kimmeridgian-aged oolite bank play has been documented in onshore Sureste Basin and extending into the southern GOA by Shann et al. (2020).

The Smackover is self-sourcing, with hydrocarbons derived from the low-energy, algal-rich, laminated carbonate mudstones located near the base of the section. For a detailed discussion, see Petty (2010). The underlying Norphlet sand reservoirs are proven to be charged with Smackover-sourced oils (Sassen, 1990). Oil in a Kimmeridgian oolitic reservoir in De Soto Canyon block 535 is reportedly typed to a Smackover source rock (Godo and Landry, 2024).

Structural traps include anticlinal and faulted three-way closures associated with salt pillows and rafts formed by gravity spreading along the Louann Salt, which served as a detachment layer (Pilcher, 2014; Pashin et al., 2016). Since reservoir quality is related to positive topography conducive to thrombolite

growth and/or presence of high-energy grainstone facies, most Smackover traps possess a strong stratigraphic component. Basal anhydrites of the overlying Buckner Formation create seals at the top of the Smackover section, while laminated carbonate mudstones, anhydrites, and shales form seals within the formation.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% (Figure 3)
- prospect-level: 25% (Figure 4)
- exploration level: 25% (Figure 5)

Because (1) of a long history of onshore production from Smackover reservoir facies and examples of these facies in OCS wells, (2) structural traps within the play are readily identifiable on seismic data, and (3) the Pensacola Block 996 number 1 well flowed 43 barrels of oil per day from the Smackover Formation, an active petroleum system has been established, and there is no play-level risk (Figure 3). At the prospect level, the highest risk is reservoir quality. See Appendix A for details.

Undiscovered Resources

Two sub-populations of prospects—grainstone shoals and thrombolite buildups—were modeled for this play. A portfolio of 27 thrombolite prospects was gleaned from legacy 2D seismic interpretation in the nearshore Pensacola Area. Additional prospective thrombolite areas were identified from seismic facies in the De Soto Canyon, Florida Middle Ground, and The Elbow Areas. A pool density calculated from the onshore Alabama analog area on the Conecuh Arch was applied to the prospective OCS area to forecast a maximum of 450 undiscovered thrombolite prospects.

For the grainstone prospects, a portfolio of 269 closures grouped into 89 prospects was assembled from legacy 2D seismic interpretation in the nearshore Pensacola and Destin Dome Areas. These same structures are utilized in the assessment of the **Norphlet Shelf Play**. An additional 90 traps were identified from recent mapping of available 3D seismic data on the flanks of the Southern Platform in the De Soto Canyon and The Elbow Areas, and another 135 were forecast by analogy in unmapped areas, resulting in a maximum of 314 grainstone prospects. Combining the number of thrombolite and grainstone prospects results in a total of 764 prospects. From this the assessors determined that the number of prospects ranges from 200 to 750. Applying risk results in 27 to 229 undiscovered pools, with a mean of 117.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 106 onshore Gulf Coast Smackover discoveries (Figure 42). These discoveries range in size from 0.007 to 518 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 512 MMBOE.

The play was modeled as 50% oil and 50% gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR values for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 349 to 2,274 MMbbl, and undiscovered gas resources range from 808 to 7,835 Bcf at the 95th and 5th percentiles, respectively (Table 8 and Figure 43). Of all 30 assessment units in this study, the Smackover ranks 6th based on mean-level undiscovered BOE resources (Figure 10).

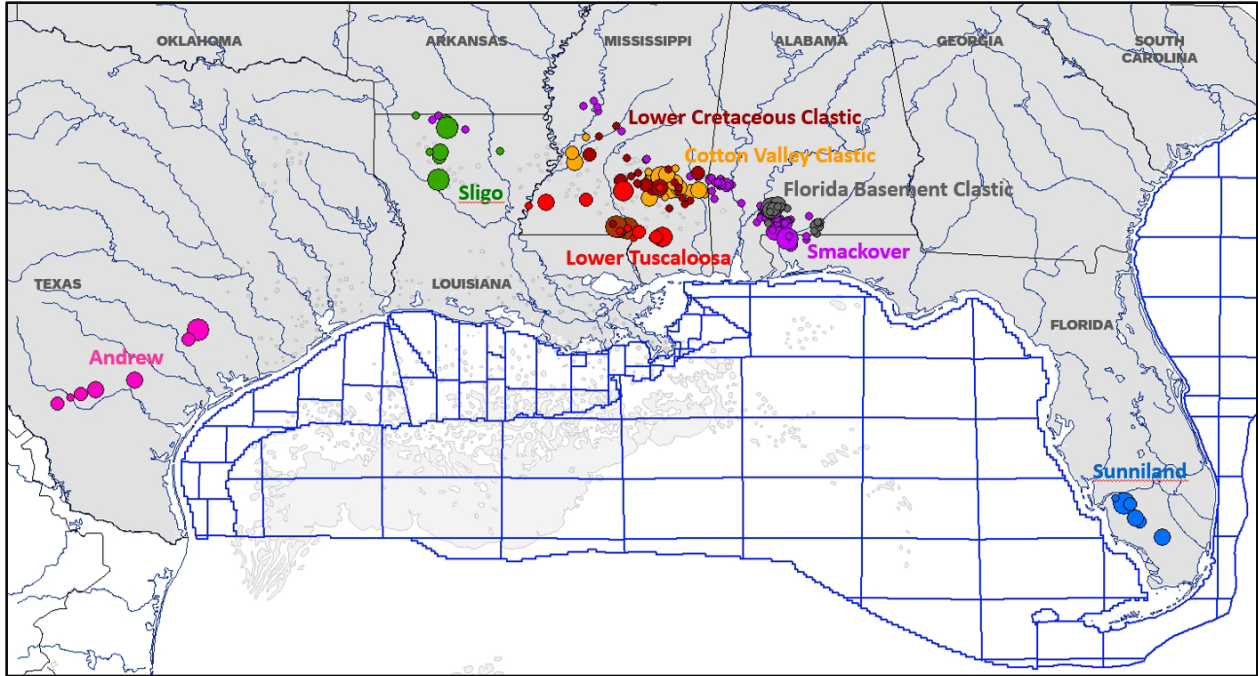


Figure 42. Onshore Gulf Coast discoveries used for analog pool sizes in undiscovered Mesozoic OCS plays.

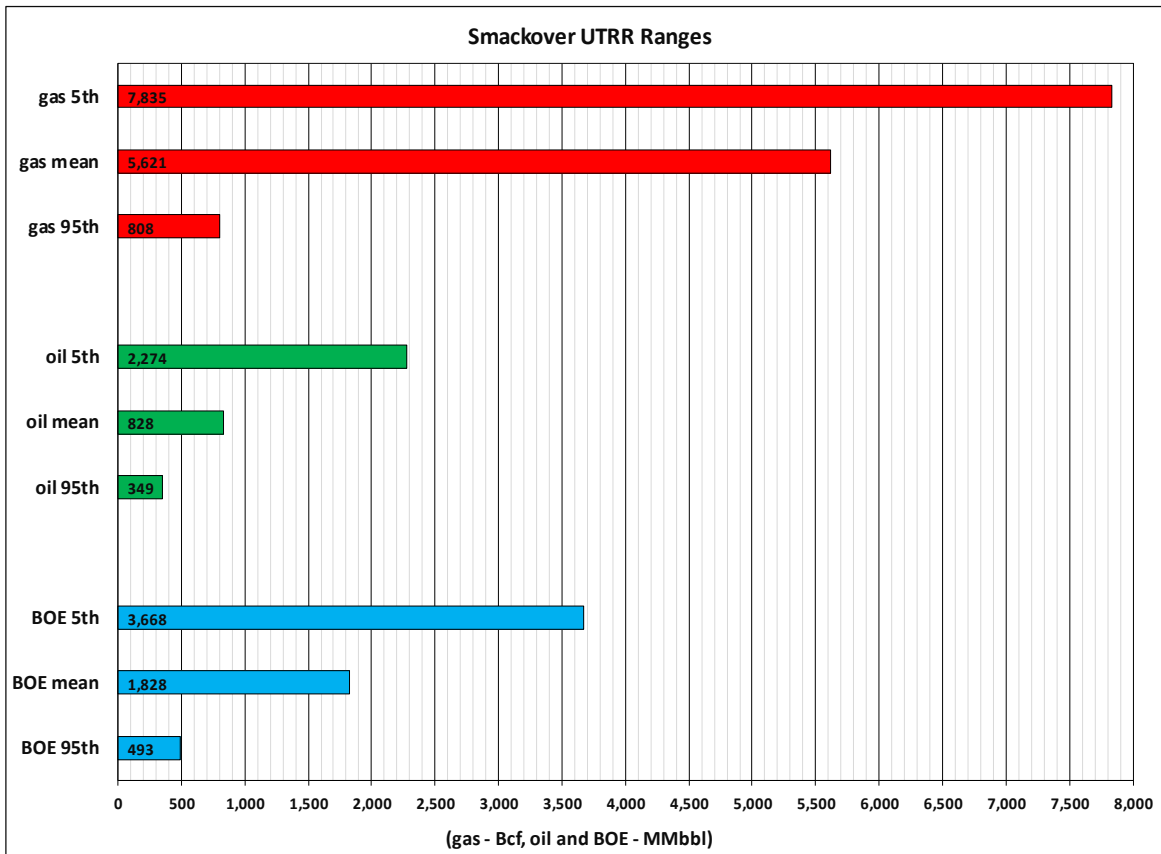


Figure 43. Smackover gas, oil, and BOE UTRR ranges.

FLORIDA BASEMENT CLASTIC

Geology

The Florida Basement Clastic Play (Figure 44) consists of clastic wedges eroded from structurally positive basement rocks exposed on the Sarasota Arch (SA, Figure 22) mainly in Middle and Upper Jurassic time (see Godo, 2025, Figure 4). The play is limited to the north by the Tampa Embayment (TE, Figure 22) and extends southward beneath the South Florida Basin (SFB, Figure 22) to basement highs south of Key West and the Dry Tortugas Areas. Eastward, the play extends to state waters and may continue onshore. To the west, the play is limited by oceanic crust.

Potential reservoirs were deposited as alluvial fans, barrier island-beach systems, and fan deltas immediately overlying basement rocks. Basement clastic sands penetrated to date have been as thick as 150 ft (46 m) and are rich in mica and feldspar. Several different “halos” of eroded Jurassic and Cretaceous rocks should exist around each basement high, and some formations, possibly eroded Norphlet or Haynesville equivalents, could have reservoir-quality, conglomeratic, quartz sandstones. Because of recurrent uplift of these blocks, the resultant eroded section originates from section as old as the Triassic Eagle Mills Formation to as young as the Lower Cretaceous Hosston Formation (Table 5). The onshore Clarksville Field (10 million barrels of oil) in Bowie County, Texas, is a good example of conglomerate fan deltas that exist along the entire expanse of an eroded upthrown block (Reed, 1991).

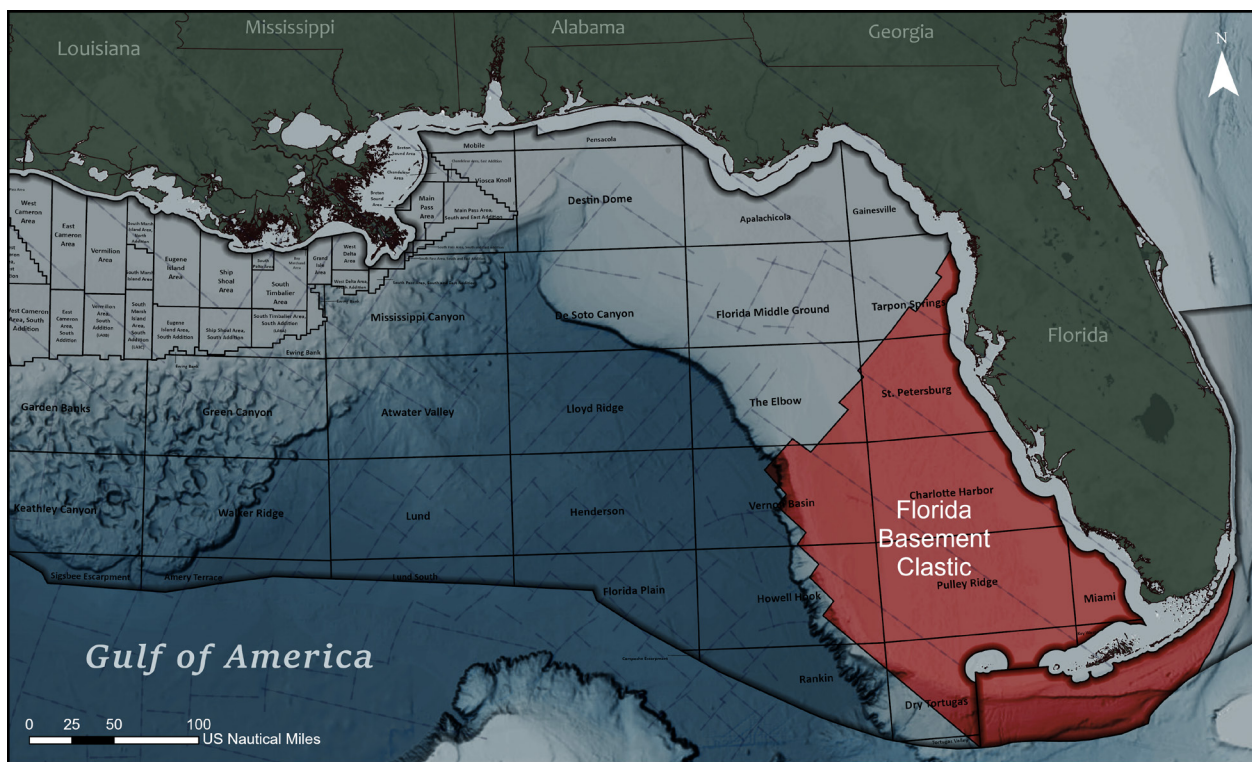


Figure 44. Florida Basement Clastic location.

Hydrocarbon systems may include Jurassic and Cretaceous source rocks from the Tithonian Bossier Shale (A148, Figure 25) to the Aptian Glen Rose Shale (A110, Figure 25) not present on the basement highs, but which may be present downdip from and surrounding these perched reservoirs. Oil production in the South Florida Basin confirms source rock maturity, but maturity likely decreases onto the Sarasota Arch due to shallower burial depths.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 34% ([Figure 3](#))
- prospect-level: 22% ([Figure 4](#))
- exploration level: 7% ([Figure 5](#))

Because of the inability to predict the origin of a reservoir facies, reservoir presence and quality were deemed quite risky. Based on the ability to define the structural component of prospects in the play with interpretations from the depth-to-magnetic basement surveys and conventional 2D and 3D seismic surveys, the presence of traps carries the least risk. The weakest element of the trap is the presence of a top seal. With an overall exploration chance of success of just 7%, this is one of the riskiest plays assessed in the OCS. See [Appendix A](#) for details.

Undiscovered Resources

A nearby analog for this play occurs in the Bahamas Basin, on the east side of the Peninsular Arch (PA, [Figure 22](#)), where the Great Isaac number 1 well encountered live oil in clastic sediments near the basement at 17,800 ft measured depth (information from an investor presentation by the Bahamas Petroleum Company).

Available 2D seismic coverage was insufficient to delineate a portfolio of prospects, so a proprietary interpretation of the basement structure from commercial magnetic field data was used to identify positive features most likely associated with traps. From this, the assessors determined that the number of prospects ranges from 60 to 180. Applying risk results in 0 to 61 undiscovered pools, with a mean of 9.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 21 onshore Frisco City Trend discoveries in southern Alabama ([Figure 42](#)). These discoveries range in size from 0.004 to 20 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 23 MMBOE.

The play was modeled as 100% oil. With no discoveries or definitive knowledge of the source rocks in the play, GORs were calculated from the onshore analog pool volumes, with GRASP returning UTRR volumes for black oil and solution gas. Because there is play-level risk, only 34% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 95 MMbbl at the 5th percentile, with a mean of 21 MMbbl, and 117 Bcf at the 5th percentile, with a mean of 26 Bcf, respectively ([Table 8](#) and [Figure 45](#)). Of all 30 assessment units in this study, the Florida Basement Clastic ranks last based on mean-level undiscovered BOE resources ([Figure 10](#)).

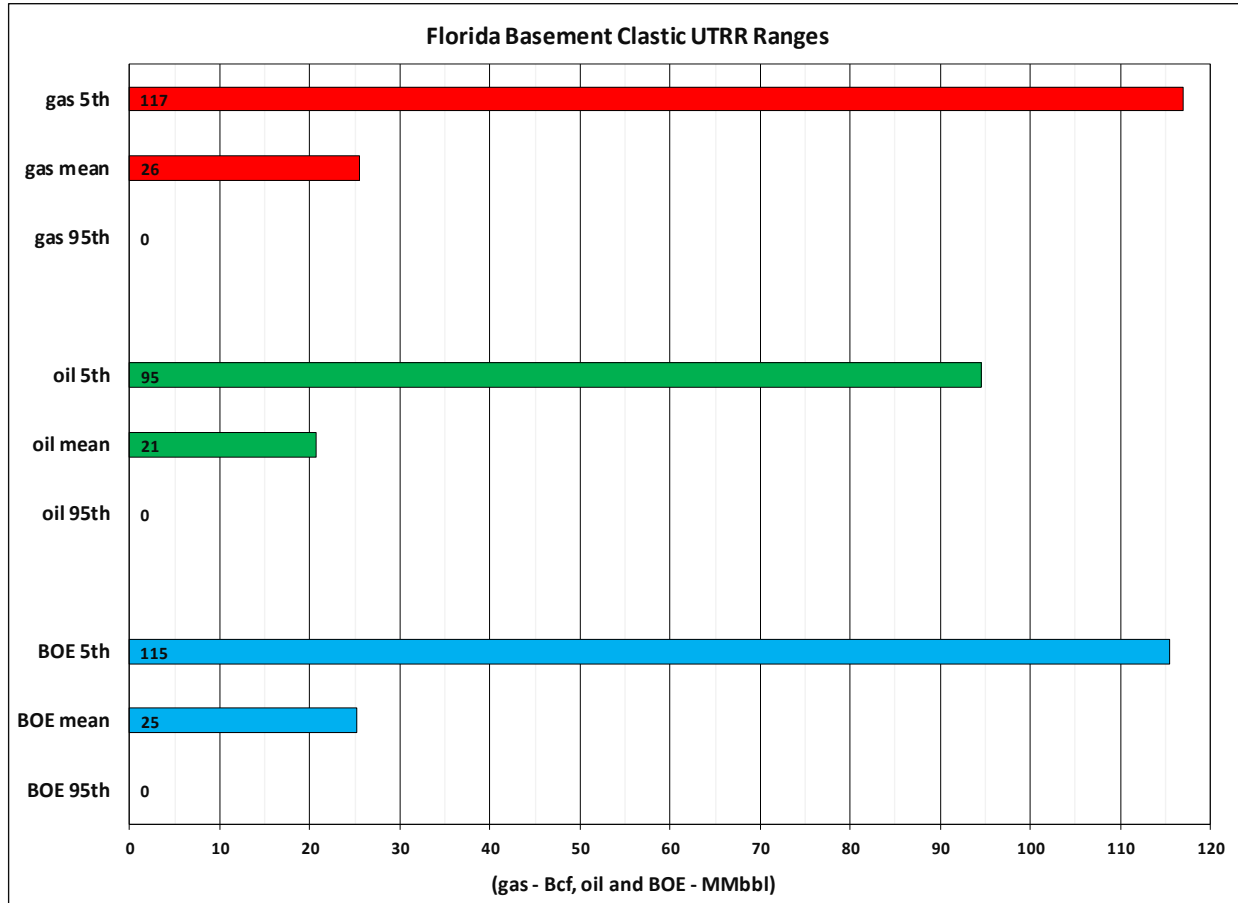


Figure 45. Florida Basement Clastic gas, oil, and BOE UTRR ranges.

COTTON VALLEY CLASTIC

The Cotton Valley Clastic Shelf and Slope Plays target the Upper Jurassic (Tithonian) to Lower Cretaceous (Berriasian) Cotton Valley Group (Table 5 and Figure 25), which includes sands, shales, and siltstones that were deposited, from landward to basinward, in fan delta-delta plain, prodelta, restricted lagoonal, barrier island, open- to marginal-marine conditions, and slope turbidites, and underlies much of the northern coastal plain of the GOA from east Texas to Alabama. The Shelf and Slope Plays are delineated by the modern shelf-slope break (Figure 46).

The Cotton Valley Group produces from numerous onshore fields in eastern Texas, southern Arkansas, northern Louisiana, and southern Mississippi, with the nearest onshore production to the offshore Cotton Valley from the Catahoula Creek Field in Hancock County, Mississippi. Reservoir sands at the Catahoula Creek Field were deposited in a barrier island environment that can be traced offshore into the Destin Dome Area (Ericksen and Thieling, 1993). Even though there are no commercial discoveries thus far in the OCS, two wells demonstrate that there is a working hydrocarbon system in place, and that additional hydrocarbon exploration in the OCS within the Cotton Valley Clastic Plays is warranted.

Because of the widely accepted interfingering relationship with the Tithonian Bossier Shale (A148, Figure 25), a basin-wide unit with total organic carbon averaging 6.5% (Cunningham et al., 2016), there is a high probability of the presence of source rocks for the Cotton Valley Clastic Plays in the OCS.

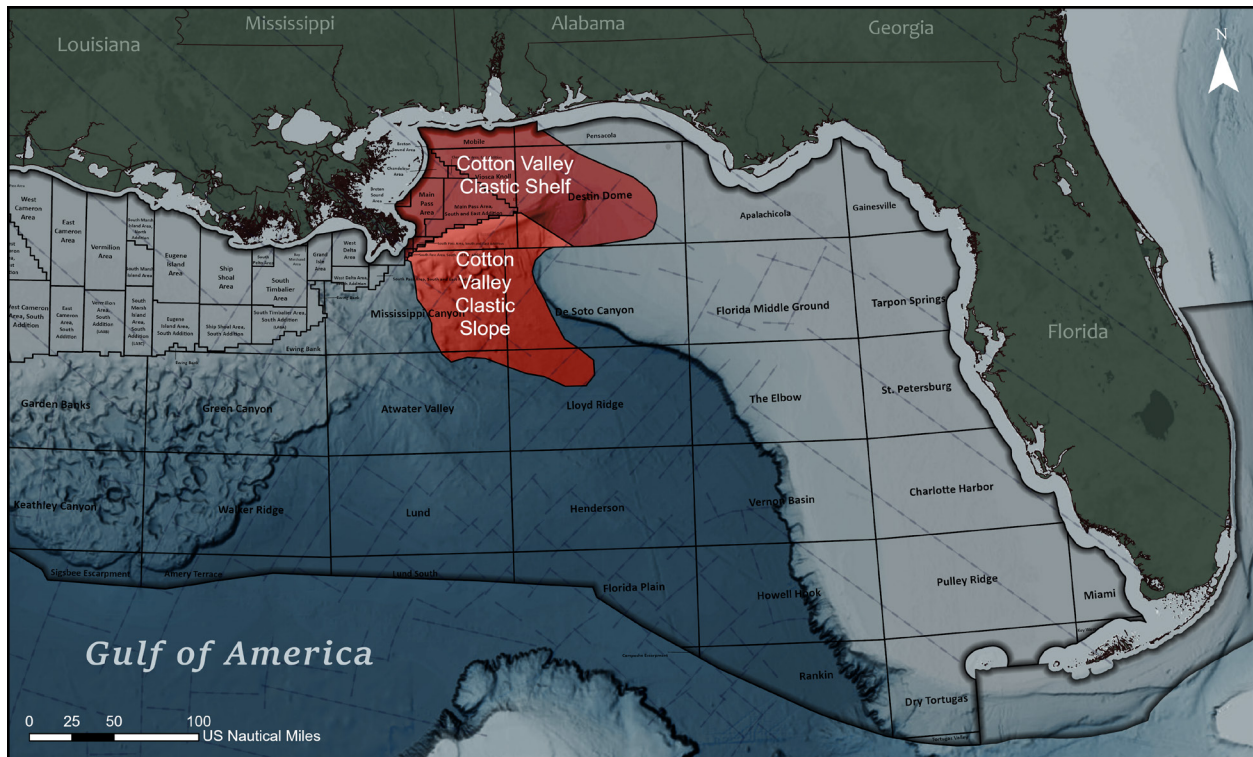


Figure 46. Cotton Valley Clastic Shelf and Slope locations.

Cotton Valley Clastic Shelf

Geology

The Cotton Valley Clastic Shelf Play covers portions of the Mobile, Pensacola, Viosca Knoll, and Destin Dome Areas encompassing the De Soto Canyon Salt Basin in a swath between the underlying Mobile and Pearl River Transfer Fault Zones (Figure 22 and Figure 23) and extends westward across the Chandeleur, Main Pass, and Breton Sound Areas, inboard of the modern shelf-slope break (Figure 46).

In onshore Texas, Louisiana, and Mississippi, an arc of wave-reworked sandstones representing the Jurassic shore zone roughly parallels the Lower Cretaceous shelf edge but is positioned 50 miles north. This Jurassic shore zone turns south and passes beneath modern-day Mobile Bay and on to the Florida shelf, passing over the Southern Platform (Thomas et al., 2005) and as far south as the Sarasota Arch (SA, Figure 22). Rivers eroding the southeastern Appalachians brought sediment to this shore zone (Ewing, 2001). This sediment was then transported basinward across a muddy to grain-rich carbonate platform into OCS waters of the Shelf Play to be reworked in a shallow shelf-edge environment.

These clastics were reworked into elongate sand bodies trending subparallel to the shoreline. Finer clay-size particles in these barrier clastics were removed by wave action, resulting in reservoir-quality rock surrounded by seals from marine and lagoonal shales. Sandstones in the barrier bar system are clear to white and well sorted; whereas sands deposited in updip delta plain areas are red to brown with traces of lignite and red shale. Downdip on the marine side of the barrier bar system, shales are dark gray, silty, and calcareous. Interbedded with the shales are minor, hard, brown limestone and calcareous, fine-to-medium grained, gray sandstone. The barrier bar system consists of three facies: (1) an aeolian section where barrier tops were exposed, (2) a sand-rich shoreface in the center of the barrier, and (3) siltstones on the outer flanks interbedded with shales. Adjacent to the landward side are lagoonal shales indicating the barrier system is a regressive system.

Structural traps include anticlinal and faulted three-way closures associated with salt pillows and rafts formed by gravity spreading along the Louann Salt, which served as a detachment layer (Pilcher et al., 2014; Pashin et al., 2016), as well as traps against diapirs in the De Soto Canyon Salt Basin (Figure 23).

The Main Pass Block 154 well number 1 penetrated 500 ft (152 m) of marine gray shale and small sand stringers. To the east, Destin Dome Block 529 well number 1 penetrated the toe portion of the barrier island system, where the clastics coarsen upward and have a well log signature that suggests a high energy environment and consequently reservoir rock development. Updip, the Viosca Knoll Block 251 well number 1 penetrated 1,450 ft (442 m) of sand-rich barrier islands (Petty, 2008). These sands are blockier in spontaneous potential development on well logs than sands in delta plain regions and are in seismically well-defined stratified regions of the De Soto Canyon Salt Basin. Recorded reservoir properties from cores in this well at 20,000 ft show porosity of 1%–6.7% (Thomas et al., 2005). Viosca Knoll Block 117 well number 1 penetrated a complete section of Cotton Valley clastics deposited on the edge of the De Soto Canyon Salt Basin, with a thickness of 1,950 ft (594 m). The sands in this section are interbedded with marine carbonates and shales. Gas shows from mud logs in this well occur in interpreted barrier bar sandstone at 20,300 to 21,200 ft. Farther eastward and updip in Mobile Block 991 well number 2, a wide variety of environments is displayed as defined by kerogen type, ranging from nonmarine, fluvial, lagoonal, marginal marine to marine. This area represents a transitional zone between the barrier island system and the lagoonal-delta plain areas. Cotton Valley Formation lithologies are described as silty, fine-to-coarse grained quartz sandstones with porosity values of 13%–18% and permeability values of 2–34 millidarcies (Petty, 2008). Also, metamorphic rock fragments, muscovite, and biotite are present that upon dissolution provide chlorite coatings and porosity preservation below 20,000 ft.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% (Figure 3)
- prospect-level: 21% (Figure 4)
- exploration-level: 21% (Figure 5)

Because Cotton Valley sands exhibit hydrocarbon shows by mud log in wells located in the Viosca Knoll and Mobile Areas, the presence of an active hydrocarbon system has been established, and there is no play-level risk. At the prospect level, the highest risk is associated with reservoir quality. See Appendix A for details.

Undiscovered Resources

Possible prospects include 12 untested four-way anticlinal closures identified from 2D seismic data, and possible traps on 29 diapiric structures and 45 faults. From this, the assessors determined that the number of grouped prospects ranges from 25 to 75. Applying risk results in 0 to 32 undiscovered pools, with a mean of 11.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 43 Cotton Valley discoveries in onshore Mississippi (Figure 42). These discoveries range in size from 0.011 to 36 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 19 MMBOE.

The play was modeled as 50% oil and 50% gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR values for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 4 to 42 MMbbl, and undiscovered gas resources range from 3 to 506 Bcf at the 95th and 5th percentiles, respectively (Table 8 and Figure 47). Of all 30 assessment units in this study, the Cotton Valley Clastic Shelf ranks 28th based on mean-level undiscovered BOE resources (Figure 10).

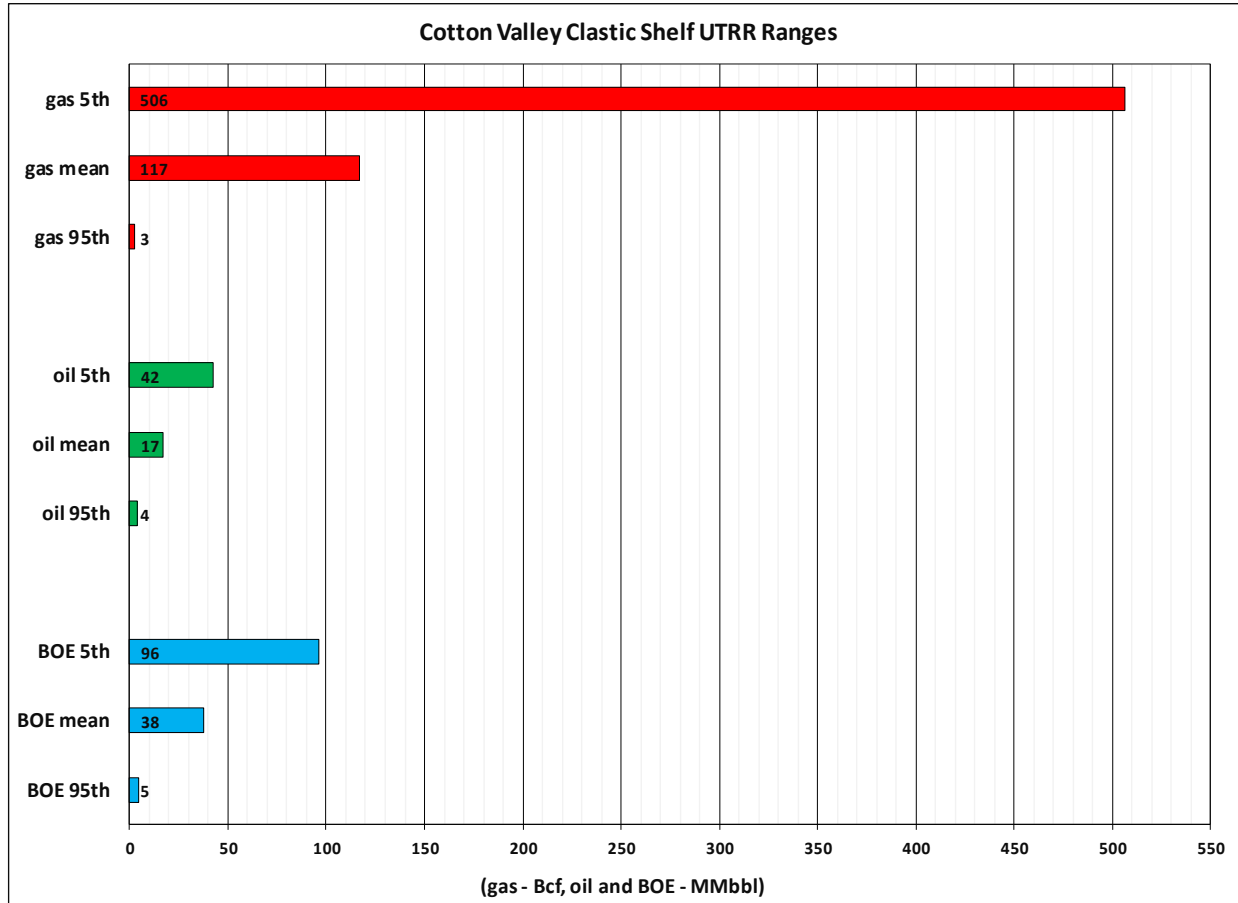


Figure 47. Cotton Valley Clastic Shelf gas, oil, and BOE UTRR ranges.

Cotton Valley Clastic Slope

Geology

The Cotton Valley Clastic Slope Play extends southwestward from the shelf across portions of the Viosca Knoll, Mississippi Canyon, De Soto Canyon, Atwater Valley, and Lloyd Ridge Areas (Figure 46). The downdip extent of the play is limited by a seismically defined Cotton Valley interval thickness that shows downdip thinning onto the back of the Mesozoic salt nappes (Figure 23).

Penetrations in the play have encountered less than 200 ft of net sand. However, a penetration of the whole Cotton Valley sand interval near the paleo shelf-slope break in Viosca Knoll Block 251 shows a 200 ft sand channel beneath three channel splays that were all deposited on a mud-rich carbonate platform. Discrete sediment fairways may exist within the syn-kinematic wedges of thickened Cotton Valley section between the Smackover and Haynesville rafts in similar fashion to the scenario postulated for the Lower Tuscaloosa (Upper Cretaceous) section by Harding et al. (2016).

Peak rafting was coincident with deposition of the Cotton Valley Formation (Pilcher et al., 2014) resulting in a variety of syn-kinematic wedges, anticlines, turtle structures, and fault traps associated with expulsion rollover systems. Updip extension was accommodated in part by the advancement of an allochthonous salt nappe onto newly formed oceanic crust, and the Cotton Valley interval thins downdip onto this region of inflated salt. Down-to-the-basin and counter-regional fault systems associated with the Jurassic rafts appear to be segmented by the shelf-ward projections of the transform faults of the adjacent oceanic crust, suggesting that rafting was coupled with seafloor spreading.

Traps have a stratigraphic component, as potential reservoirs occur in shelf-edge barrier bars or slope turbidite fans and channel fill sands. The structural component involves draping over or pinching out against salt rollers or basement blocks. Cotton Valley sands traveling down slope into the central Cretaceous basin in the play would be the earliest Cretaceous regressive unit trapped in expulsion rollover systems, displacing thick autochthonous Louann Salt (Harding et al., 2016).

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 43% ([Figure 3](#))
- prospect-level: 21% ([Figure 4](#))
- exploration-level: 9% ([Figure 5](#))

The riskiest components at the play and prospect levels are the presence and quality of the reservoir facies. With an overall exploration chance of success of just 9%, this is one of the riskiest plays assessed in the OCS. See [Appendix A](#) for details.

Undiscovered Resources

An inventory of 365 traps grouped into 173 prospects were identified from 3D seismic data across portions of the Mississippi Canyon, De Soto Canyon, Lloyd Ridge, and The Elbow Areas. However, the prospective area was limited by downdip thinning and contained only 108 prospects. From this, the assessors determined that the number of prospects ranges from 60 to 110. Applying risk results in 0 to 42 undiscovered pools, with a mean of 8.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 23 Lower Tuscaloosa Formation discoveries in onshore Mississippi ([Figure 42](#)). Instead of using onshore Cotton Valley Formation discoveries, the assessors felt that larger pool sizes of onshore Lower Tuscaloosa Formation discoveries were more representative of pools to be found in the OCS. These Lower Tuscaloosa discoveries range in size from 1.6 to 242 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 268 MMBOE.

The play was modeled as 100% oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Because there is play-level risk, only 43% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 1,134 MMbbl at the 5th percentile, with a mean of 299 MMbbl, and 753 Bcf at the 5th percentile, with a mean of 199 Bcf, respectively ([Table 8](#) and [Figure 48](#)). Of all 30 assessment units in this study, the Cotton Valley Clastic Slope ranks 17th based on mean-level undiscovered BOE resources ([Figure 10](#)).

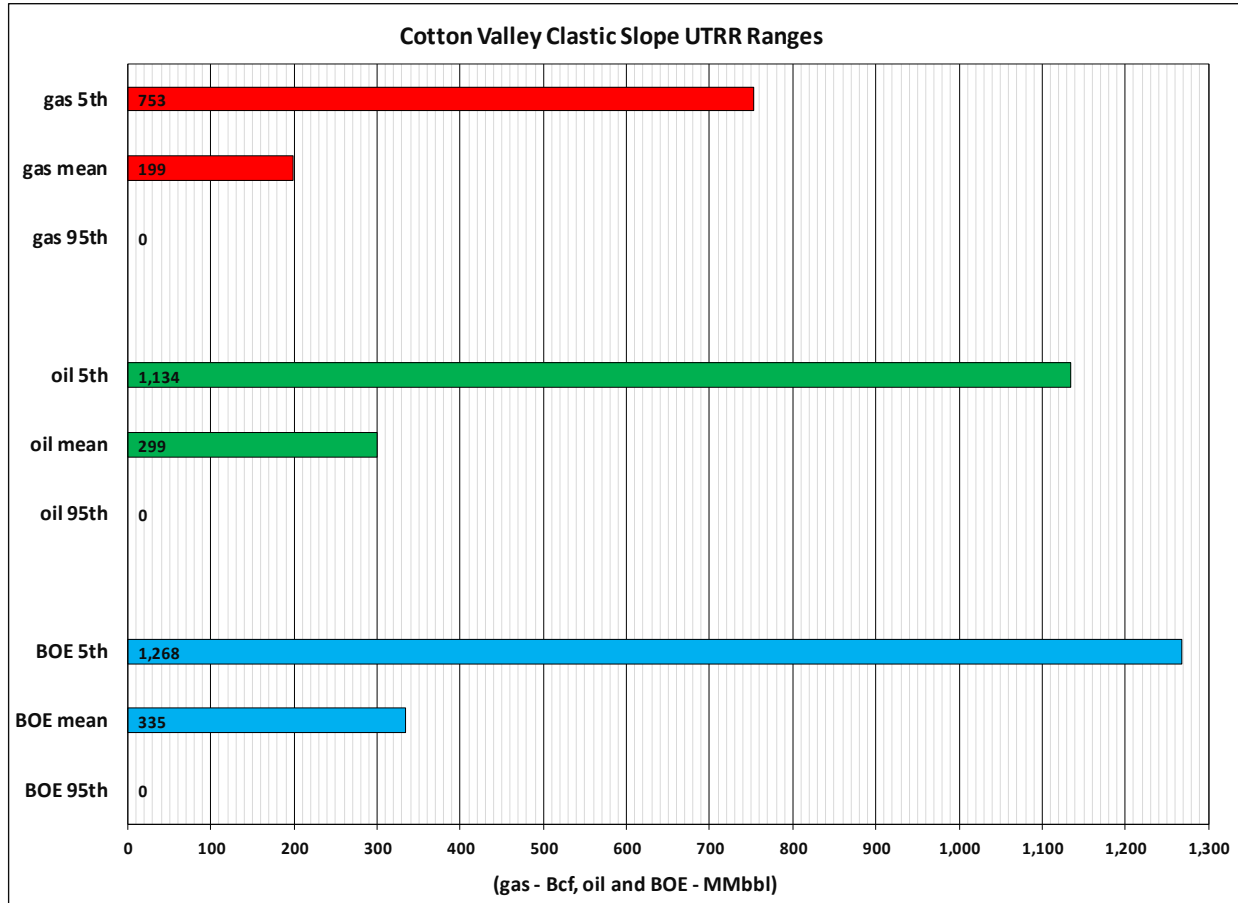


Figure 48. Cotton Valley Clastic Slope gas, oil, and BOE UTRR ranges.

KNOWLES CARBONATE (UNASSESSED)

Geology

The unassessed Knowles Carbonate Play is composed of Berriasian–Valanginian platforms that cap the underlying **Cotton Valley Clastic Play** (Table 5 and Figure 25). In the eastern GOA, the play extends southeastward from Mississippi State waters across the Mobile, Viosca Knoll, and Destin Dome Areas and across the Southern Platform in the De Soto Canyon Area (Figure 49). The play continues across the western flank of the Tampa Embayment and terminates at the northwestern flank of the Sarasota Arch in the Vernon Basin Area, where the Knowles is absent due to non-deposition or erosion.

Carbonate development initiated along the Tithonian shelf edge. Three carbonate platforms developed over the seaward prograding clastic wedge during the early Valanginian, with the uppermost platform extending 100 miles (161 kilometers) landward of the shelf edge (Petty, 2008). The Berriasian reefal buildup is clearly visible on 2D seismic lines in the De Soto Canyon, Vernon Basin, and The Elbow Areas. Some Knowles reflectors exhibit the appearance of clinofolds, suggesting reef migration during progradational episodes. Two recent wells, Saki and Perseus, in the De Soto Canyon Area drilled multiple Knowles carbonate units, each with sections showing porosity greater than 15%. Methane shows were recorded throughout the Knowles interval in the Sake well, but any hydrocarbon accumulations possibly leaked up-section due to absence of or less than adequate top seal in the Hosston section. This carbonate, associated with a distinctive positive-amplitude seismic reflector and clean gamma-ray signature in well logs, was possibly subaerially exposed and karsted. The packstones and grainstones of the three platforms

are separated by intra-platform gray shales and gray mudstones. Each ramp and platform is thicker along the prograding shelf edge and interfingers landward with delta-plain clastics.

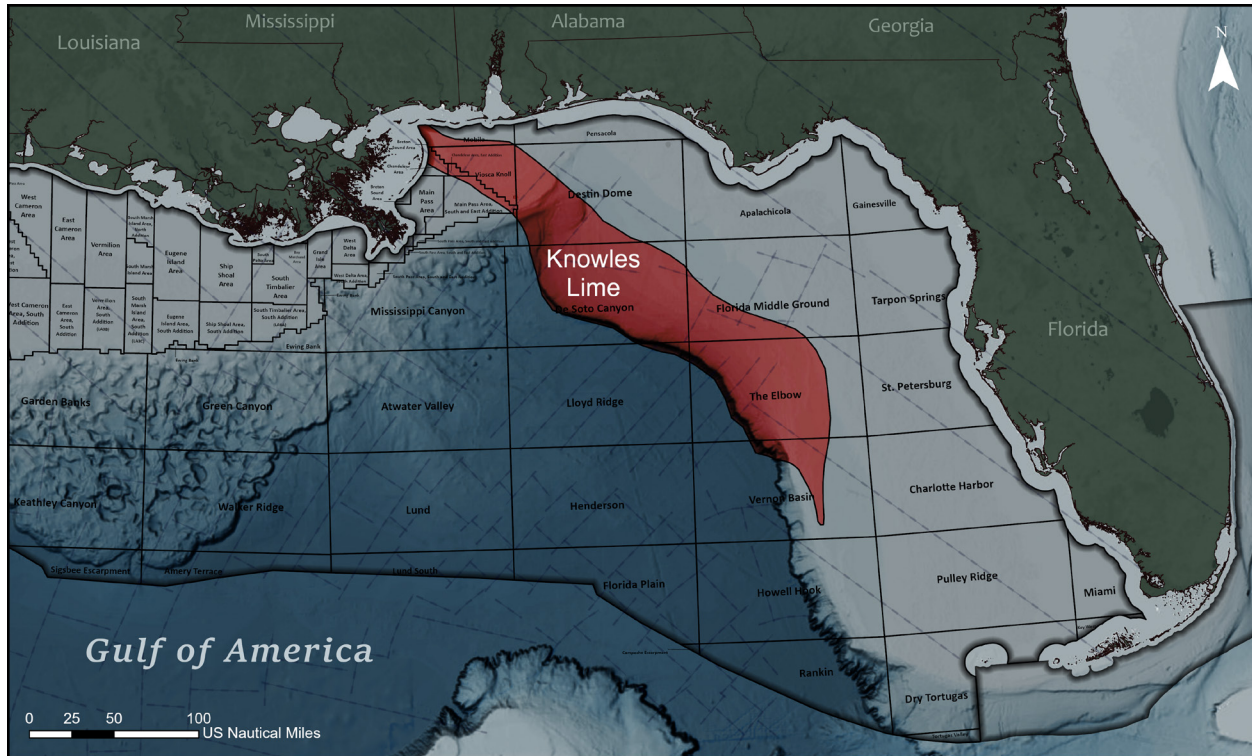


Figure 49. Knowles Carbonate location.

Combined thickness of the carbonates ranges from 2,200 ft (670 m) at the shelf edge to 0 over the Destin Dome (DD, [Figure 23](#)). Shoreward, carbonates have less-developed spontaneous potential well log signatures in all inner ramps and platforms, reflecting a change from the better-developed outer ramp and platform bioclasts to less-developed inner ramp and platform mudstones (Cregg and Ahr, 1983; Finneran et al., 1984). The best development of the outer ramp and platform bioclasts is in the Viosca Knoll and western Destin Dome Areas.

There has been no production from the Knowles Carbonate in the OCS. The nearest production to the OCS extends onshore from the southern Arkansas-northern Louisiana area to the southwestern edge of the East Texas Basin (Cregg and Ahr, 1983). Even though there have been no commercial discoveries thus far in the OCS, gas shows have been encountered (e.g., Main Pass Block 154 well number 1 and Viosca Knoll Block 202 well number 1).

Due to extensive OCS exploration with no significant oil and gas discoveries and a limited inventory of prospects, the play was not assessed for undiscovered resources.

SUNNILAND

Geology

The Lower Cretaceous (Albian) Sunniland Play ([Table 5](#) and [Figure 25](#)) begins onshore on the eastern flank of the South Florida Basin (SFB, [Figure 22](#)). The play extends offshore encompassing the remainder of the South Florida Basin, the Sarasota Arch (SA), high-standing basement areas around the eastern flank of the Tampa Embayment (TE), and the Middle Ground Arch (MG) ([Figure 22](#) and [Figure 50](#)). The Sunniland carbonate platform is situated within a 12-mile-wide fairway between the Lower Cretaceous reef trend

on the west and the Florida Peninsular Arch (PA, [Figure 22](#)) on the east. Reservoirs consist of dolomitized grainstones, rudistid patch reefs, and grainstones from debris halos in backreef areas.

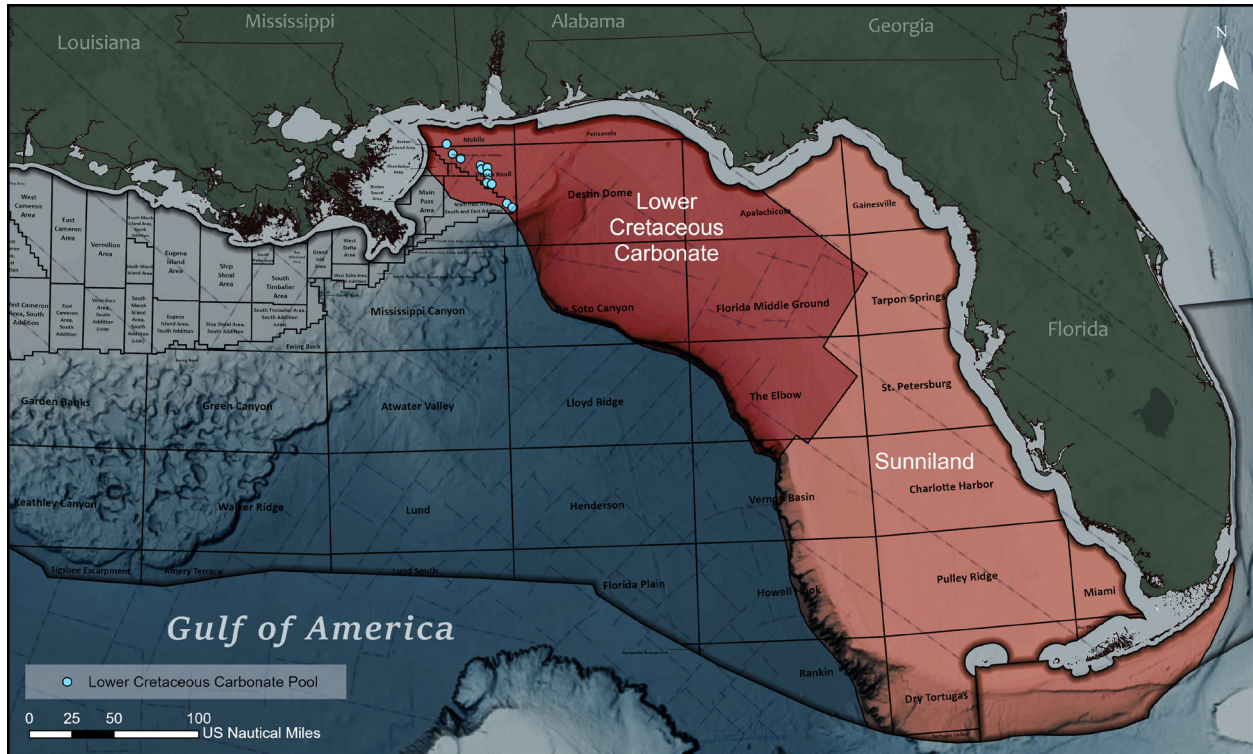


Figure 50. Sunniland and Lower Cretaceous Carbonate locations and associated discovered pools.

Interpretations from proprietary depth-to-magnetic-basement maps show a positive relationship between existing onshore fields and basement high trends. Based on the presence of similar structural elements, defined readily by interpretations of depth to magnetic basement and 2D and 3D seismic surveys northwest along the trend of the play outline, structural closures over reefal buildups are possible, but many traps could have a stratigraphic component.

Average Sunniland permeabilities from onshore fields are 80–100 md with an average porosity of 20% (Mitchell-Tapping, 2003). Because of the proximity to onshore fields and the presence of similarly situated basement highs throughout the trend, the chance of the presence and quality of a reservoir in the OCS is good.

Potential source rocks are from back reef organic-rich lagoonal and marine mudstones that interfinger along this shelf interior environment. A lime mudstone—the “Black Shale” directly beneath the Sunniland carbonates—has been identified as one likely onshore-field source rock (Applegate and Pontigo, 1984) and correlates to the Ferry Lake-Glen Rose of Olson et al. (2015) and OAE 1b and organic matter acme A110 ([Figure 25](#)) of Pepper (2016). Based on similar geologic histories of the onshore and offshore Sunniland areas, hydrocarbon expulsion and migration chances are high in the OCS.

Top and bottom seal are based on existing stratigraphic relationships. The Sunniland Formation occurs between two extensive anhydrite formations, the Ferry Lake below and Lake Trafford above, providing top and basal seals (Liu, 2015). The Lake Trafford Anhydrite, the top seal, has been interpreted as an evaporite filling shallow restricted lagoons, the extent being at least 5 miles northwest to southeast over the Felda trends (Halley, 1985). Published cross sections (Petty, 1995) show numerous anhydrites in the Ferry Lake and Rodessa section. The Ferry Lake Anhydrite is present in the Mobile Area and is present in

wells south to the South Florida Basin ([Figure 22](#)), where it is correlated with the Punta Gorda Formation. The Lake Trafford Formation could be just as extensive in area.

Sunniland Formation production has been established in 14 onshore fields along the northwest trending Felda and West Felda areas in Collier, Lee, and Hendry Counties, Florida. The West Felda Field has produced 48 million barrels of oil, and fields in the trend have a cumulative production of 122 million barrels of oil. Production is mostly oil with an API gravity of 26 degrees (Mitchell-Tapping, 2000).

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 50% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 13% ([Figure 5](#))

The highest risk factor associated with the Sunniland play in the OCS is deemed to be associated with the trap component. See [Appendix A](#) for details.

Undiscovered Resources

Available 2D seismic coverage was insufficient to delineate a portfolio of prospects. To determine the possible number of prospects in the play, a proprietary interpretation of the basement structure from commercial magnetic field data was used to identify approximately 71 positive features most likely associated with traps. Additionally, 9 areas of possible grainstone shoals based on seismic facies were gleaned from published sources. Multiple prospects were anticipated within each paleo-topographic area and possible grainstone shoal. From this, the assessors determined that the number of prospects ranges from 100 to 180. Applying risk results in 0 to 70 undiscovered pools, with a mean of 18.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 14 Sunniland discoveries in onshore Florida ([Figure 42](#)). These discoveries range in size from 0.002 to 49 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 50 MMBOE.

With onshore discoveries producing very little gas, the Sunniland play was modeled as 100% black oil. Because there is play-level risk, only 51% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil resources are 346 MMbbl at the 5th percentile, with a mean of 115 MMbbl ([Table 8](#) and [Figure 51](#)). Of all 30 assessment units in this study, Sunniland ranks 25th based on mean-level undiscovered BOE resources ([Figure 10](#)).

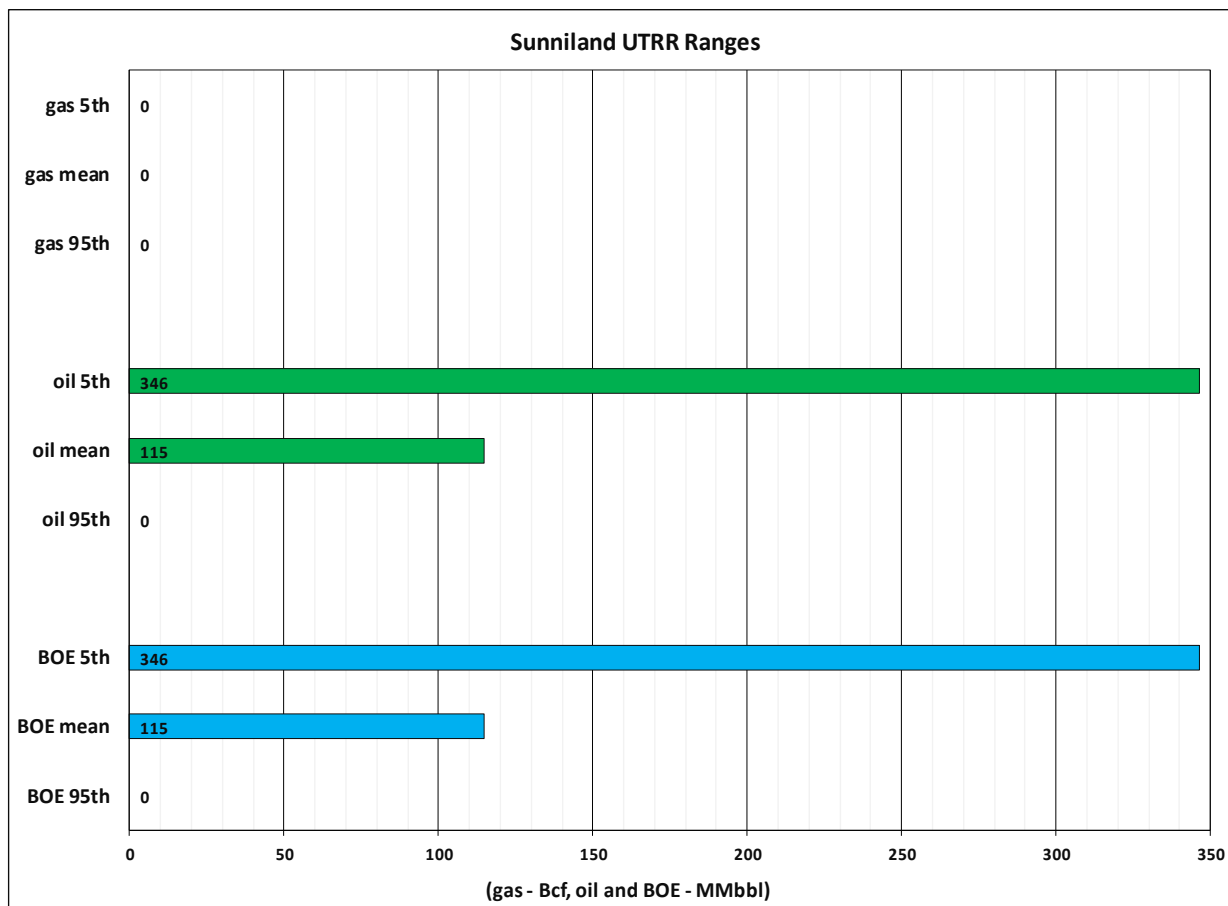


Figure 51. Sunniland oil UTRR ranges.

LOWER CRETACEOUS CARBONATE

Geology

The Aptian Sligo Formation and James Limestone and the Albian Andrew Formation of the eastern GOA have been aggregated into a single AU—the Lower Cretaceous Carbonate. Each of these three stratigraphic intervals is characterized by narrow shelf-margin reef trends (LK, [Figure 20](#) and [Figure 22](#)), which are geographically coincident with one-another and in onshore areas are similarly situated above a basement hinge, the Toledo Bend Flexure (TBF, [Figure 22](#)), which is generally aligned with the boundary between continental and transitional crust. These reef trends circumscribe the perimeter of the entire GOA Basin and outlying basement highs. In the eastern GOA, the aggregated AU extends along strike from Mississippi, Alabama, and Florida State waters southeastward across the De Soto Canyon Salt Basin, the Southern Platform, and Tampa Embayment ([Figure 22](#) and [Figure 50](#)). The AU transitions to the southeast into the partially coeval [Sunniland Play](#) at a boundary coincident with the step up onto the Sarasota Arch (SA, [Figure 22](#)). Along depositional dip to the west, the Lower Cretaceous Carbonate AU is limited by basinal facies and extends from the shelf-margin reef trends eastward to include areas of the carbonate shelf with nearshore siliciclastics and restricted mud-rich platform interior carbonates with patch reefs and grainstone buildups on paleo-highs.

Carbonate depositional environments were widespread throughout the Lower Cretaceous in the eastern GOA. Although barrier reef complexes are important stratigraphic features along the shelf edge, more prolific oil and gas fields have been discovered in patch reefs and debris mounds behind the shelf-edge reef trend and, therefore, are more attractive targets for hydrocarbon exploration (Sams, 1982).

Recognized continuity of the Lower Cretaceous reef suggests back reef environments and favorable reservoir characteristics are present along the entire trend.

Trap components involve stratigraphic traps, which are predicted by the preference of these patch reef and debris mound facies for positive structural features and basement blocks readily identified by magnetic surveys and 2D and 3D seismic surveys. Lateral and vertical seals are provided by back-reef muddy carbonates and anhydrites found in the section.

Potential source rock Acmes A120, A110, and A98 ([Figure 25](#)) include Cretaceous shales deposited during oceanic anoxic events (Olson et al., 2015; Pepper, 2016). Other potential source rocks are contained within the Oxfordian-A157 basal Smackover Formation, Kimmeridgian-A154 Haynesville Shale, and Tithonian-A148 Bossier Shale. Existing OCS fields in the Viosca Knoll, Main Pass, and Mobile Areas indicate timing and migration are favorable.

Sligo Formation (Aptian age, [Table 5](#) and [Figure 25](#)) objectives include narrow shelf-margin reef trends of 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. During Sligo highstands in onshore Louisiana behind the reef trend, there are three examples of Sligo back reef-inner platform high energy shoal to reef facies on paleo-highs that occur 80 to over 100 miles shoreward of the platform-margin reef trend. These paleo-highs occur on salt-supported positive features in the North Louisiana Salt Basin (NLSB, [Figure 22](#)). One of these inner platform fields (Black Lake) is a large caprinid-rudistid mound complex (Yurowicz et al., 1993). Reservoir permeability and porosity are controlled by a combination of primary fabric, diagenetic leaching, and dolomitizations defined by reefs and reef talus. There are no declared Sligo fields in the OCS.

The **James Limestone** (Aptian age, [Table 5](#) and [Figure 25](#)) 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-ft thick Bexar Shale member is found in the OCS. The Pine Island Shale member found onshore in the Pearsall Formation is a carbonate in the OCS that is lithologically indistinguishable from the James Limestone. In the OCS, the James Limestone and Pine Island Shale members are commonly identified by operators as the Upper and Lower James Limestone ([Table 5](#)).

Ten James pools have been discovered in the OCS. These pools are part of a patch reef trend, oriented northwest to southeast and aligned with onshore Mississippi and Louisiana fields along the Hancock Ridge and Wiggins Arch (Montgomery et al., 2002). The patch reefs favor preexisting structural highs and are typically elliptical, with 3–5 mile (4.8–8 kilometer) long axes oriented 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. The grainstone-packstone bioclastic debris facies and the reworked interior platform grainstone facies hold the greatest exploration potential.

Patch reef well log signatures are characterized by erratic spontaneous potential and high resistivity curves. Pay zone thicknesses in the 10 discoveries range from approximately 10 to 100 ft (3 to 30 m) on well logs, with most discoveries 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. For a detailed discussion, see Petty (1999) and Bascle et al., (2001).

“Andrew Limestone” is a term used by drilling operators to describe undifferentiated carbonates of late Lower Cretaceous Washita-Fredericksburg (Albian) age ([Table 5](#) and [Figure 25](#)). In the OCS, Andrew

Formation stratigraphy consists of an upper, middle, and lower carbonate platform. The upper platform is Washita age, while the middle and lower platforms are Fredericksburg age. These carbonate platforms are composed of interbedded carbonates, shales, and anhydrites and are approximately 9,000 ft (2,743 m) thick and 125 miles (201 kilometers) wide. They are separated by gray carbonate mudstones, minor sandstones, and shelf shales (Petty, 1999).

The established Andrew Play is defined by a narrow shelf-edge reef facies. Generally, for the Lower Cretaceous, a well-defined rudist reef crests the shelf edge and foreslope leading into open marine environments (Yurewicz et al., 1993). Flanking the rudist reefs are oolitic packstones and shelf grainstones adjacent and trending subparallel to shelf-edge boundstones and packstones. Updip to the northeast are lagoonal, nonporous wackestones and mudstones interbedded with basin-wide shales representing transgressive units (Yurewicz et al., 1993; Petty, 1999). Anhydrites were deposited in the highly restrictive backreef platform that was cut off from open circulation (Petty, 1995). Downdip to the southwest, the Andrew Limestone is bound by a forereef facies of dark shales and carbonate muds.

Two Andrew pools have been discovered in the AU. However, hydrocarbons have been encountered within several biostrome shoals that have come in contact with hydrocarbon migration routes from Lower Cretaceous source beds (Wagner et al., 1994). Reservoir porosity and permeability are controlled by a combination of primary fabric, diagenetic leaching, and dolomitization. Hydrocarbons are trapped in small anticlines located within the porous and permeable facies. Marine shales, micrites, and anhydrites provide hydrocarbon seals. For a detailed discussion, see Petty (1999) and Bascle et al., (2001).

Discoveries

Ten James gas pools in the Viosca Knoll and Mobile Areas and two Andrew oil pools in the Main Pass Area have been discovered within the Lower Cretaceous Carbonate AU ([Figure 50](#) and [Figure 52](#)). No Sligo discoveries lie within the OCS to date. The small oil pools in the Andrew Formation were discovered in the early 1970s, while the gas pools in the James Formation were discovered from 1993 to 2001 ([Figure 52](#)). Combined, all 12 pools contain 0.453 MMbbl of oil and 595 Bcf of gas (total BOE of 106 MMbbl) ([Table 8](#)). The Andrew carbonate platform discoveries lie in an average water depth of approximately 268 ft, and the James patch reef discoveries are in an average water depth of approximately 118 ft. Subsea depths for the Andrew pools have an average of 8,848 ft subsea, and the older James pools range from 14,312 to 15,138 ft subsea.

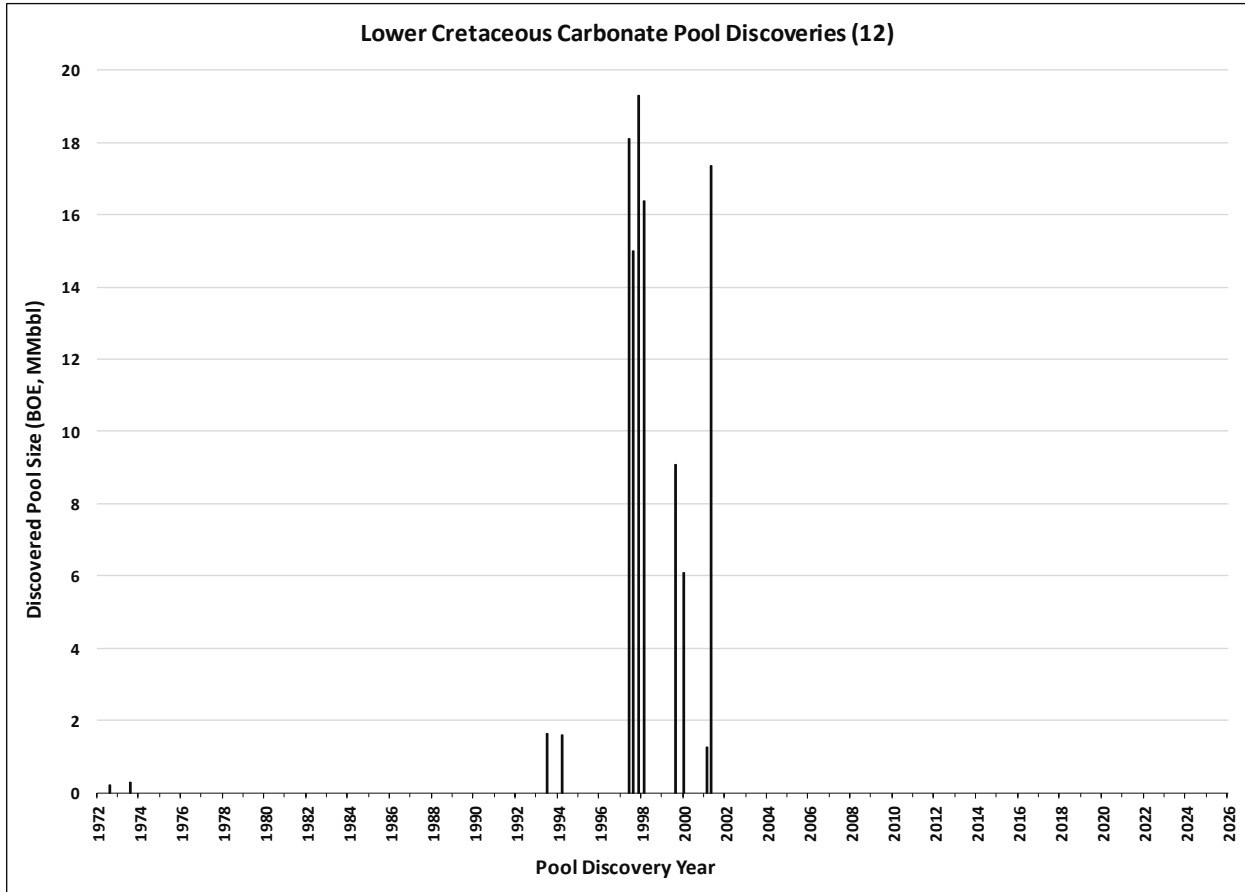


Figure 52. Lower Cretaceous Carbonate pool discovery history.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% (Figure 3)
- prospect-level: 21% (Figure 4)
- exploration-level: 21% (Figure 5)

Because an active petroleum system has clearly been established by the 12 OCS discoveries, there is no play-level risk. At the prospect level, the highest risk is associated with trapping mechanisms. See Appendix A for details.

Undiscovered Resources

A mapped prospect inventory was not available for the AU, so a prospect density was calculated from Lower Cretaceous analog areas of onshore Texas. From this, the assessors determined that the number of prospects ranges from 100 to 300. Applying risk results in 6 to 93 undiscovered pools, with a mean of 42.

The pool-size distribution was modeled with the 12 BOEM-designated James and Andrew discoveries in the OCS, 12 Andrew discoveries in onshore Texas, and 18 Sligo discoveries in onshore Louisiana (Figure 39). These discoveries range in size from 0.1 to 160 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 159 MMBOE.

The AU was modeled as 50% oil and 50% gas. Using the discovered OCS data, GRASP returned UTRR values for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 104 to 544 MMbbl, and undiscovered gas

resources range 266 to 3,518 Bcf at the 95th and 5th percentiles, respectively (Table 8 and Figure 53. Of all 30 assessment units in this study, the Lower Cretaceous Carbonate ranks 11th based on mean-level undiscovered BOE resources (Figure 10).

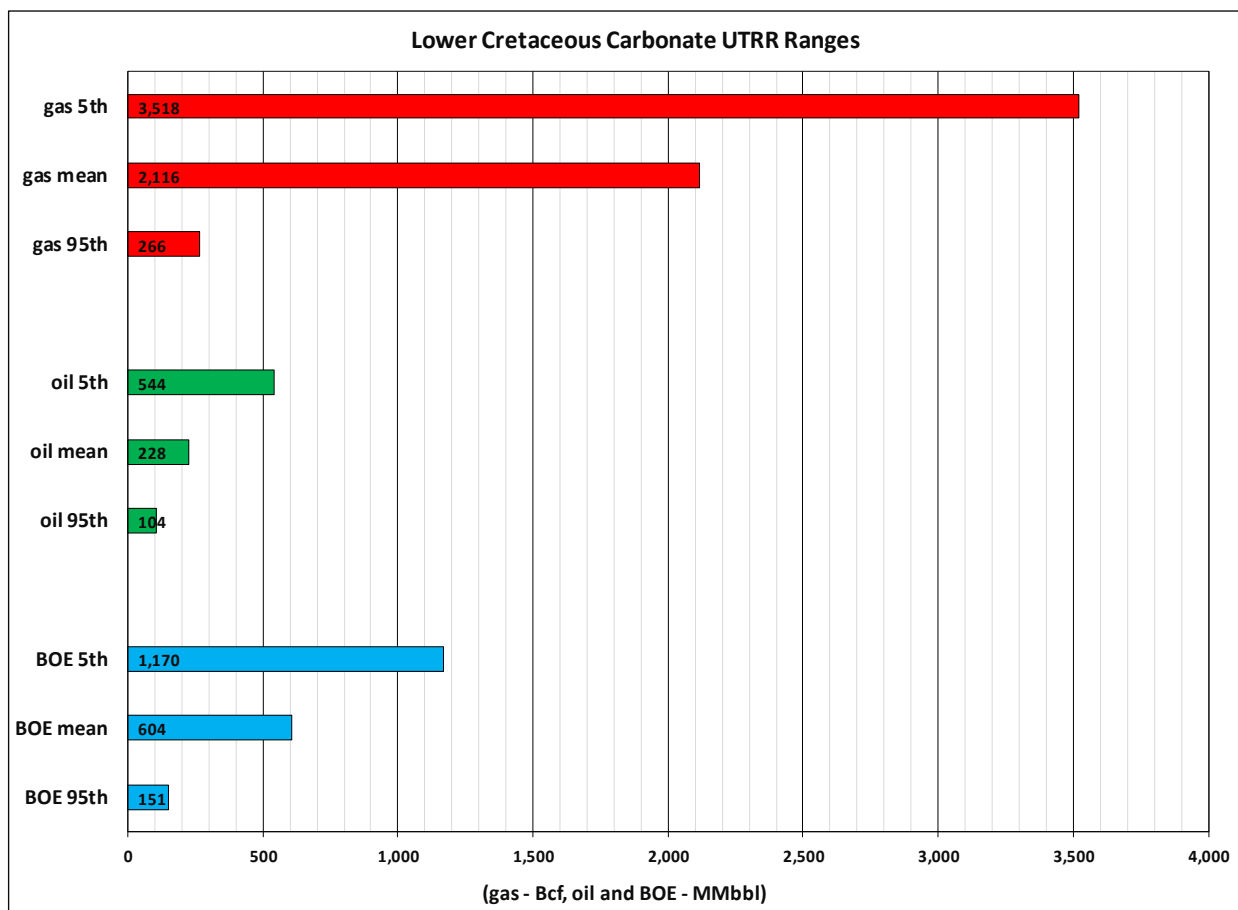


Figure 53. Lower Cretaceous Carbonate gas, oil, and BOE UTRR ranges.

LOWER CRETACEOUS CLASTIC

Siliciclastic rocks of Lower Cretaceous age have been aggregated into two AUs—the Lower Cretaceous Clastic Shelf and the Lower Cretaceous Clastic Slope. The objectives in these AUs are sediments of the Hosston (Valanginian–Barremian), Paluxy (Albian), and Dantzler (Albian–Cenomanian) Formations (Table 5 and Figure 25).

These rock formations are delineated into a shelf and slope component by the modern shelf-slope break (Figure 54). The downdip limit is located where Lower Cretaceous clastic sands either pond against an extensive shelf margin reef or lap out against the Middle Ground Arch (MG, Figure 22). Of the OCS wells that penetrated these AUs, all were dry; however, the clastic objectives in question were probably not the primary exploration target for these wells.

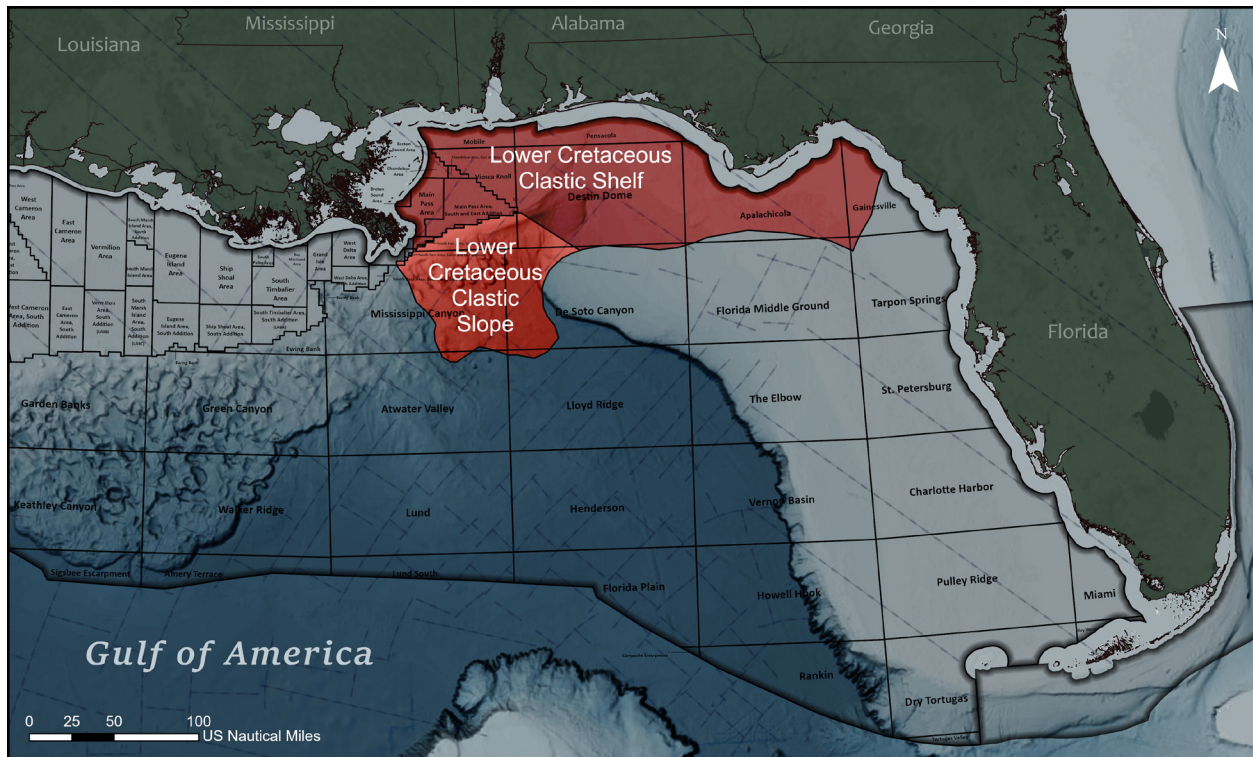


Figure 54. Lower Cretaceous Clastic Shelf and Slope locations.

Reservoir characteristics in the Shelf and Slope AUs are largely unknown, but due to common provenance of the Paluxy and Dantzler Formations (Merill, 2016) originating in the southern Arkansas peridotite belt of the ancestral Ouachita Mountains (Thompson, 1979) or from metamorphic rocks in the Appalachian mountains (Thomas et al., 2005), it can be assumed that quartz framework grains similar to those described in the **Lower Tuscaloosa Plays** can be expected. Because the ancestral Ouachita Mountains were in the drainage basin, the presence of porosity enhancing authigenic chlorite cannot be discounted. Hosston reservoir provenance, however, involved terrains of the Penninsular and Ocala Arches in the east, with less opportunity for volcanics or metamorphic clasts and authigenic chlorite. Carbonate cements are probable due to the close association with carbonate shelf and slope limestones.

Each formation in these AUs is stratigraphically associated with a nearby potential Mesozoic source rock acme. The Hosston Formation can be charged from underlying Oxfordian (A157) or Tithonian (A148) source rocks (Figure 25). However, Oxfordian source rocks are absent over much of the Shelf and Slope AU areas due to rafting and gravity gliding. Furthermore, areas underlain by thick a Jurassic section, such as the raft blocks of the **Norphlet Slope Play**, are typically areas of thin Cretaceous overburden that were skirted by Cretaceous depositional fairways. The Hosston also immediately overlies potential source rocks associated with the Valanginian A138 (Figure 25). The Paluxy Formation is situated above the Pine Island Shale, equivalent to oceanic anoxic event OAE 1a-A120 and erodes into the Glen Rose Shale and Ferry Lake maximum flooding surface associated with OAE 1b-A110 (Olsen et al., 2015; Pepper, 2016) (Figure 25). The Dantzler Formation is situated above OAE 1d-A98 and beneath the Lower Tuscaloosa Formation and Tuscaloosa Marine Shale associated with OAE 2-A94 (Figure 25).

Lower Cretaceous Clastic Shelf

Geology

The Shelf AU extends eastward from the Mississippi Delta across offshore Mississippi, Alabama, and Florida, including the northern portions of the Viosca Knoll, Destin Dome, Apalachicola, and Gainesville

Areas ([Figure 54](#)). In these protraction areas, each rock formation shows an east-west thickening trend of sand that probably represents reworking of northern-sourced fluvial sediments by wave and tidal energy, spreading the bedload across a carbonate shelf. To the south, these formations onlap the northern flanks of the Southern Platform (SP) and Middle Ground Arch (MG, [Figure 22](#)). Basinward, clastic sediments are ponded behind the extensive platform margin reef systems coincident with the underlying Knowles shelf margin. It is presumed that there were breaks in the shelf margin reefs through which clastic sediments prograded across the slope and into the deep basin.

Within the Shelf AU, examples of thick sandstone-bearing intervals exist in all three formations. Structural traps include anticlinal and faulted three-way closures associated with salt pillows and rafts formed by gravity spreading along the Louann Salt, which served as a detachment layer (Pilcher et al., 2014; Pashin et al., 2016), as well as traps against diapirs in the De Soto Canyon Salt Basin (DCSB, [Figure 22](#)).

The **Hosston Formation** (Valanginian–Barremian, [Table 5](#) and [Figure 25](#)) has a gross interval thickness of 2,000 ft (610 m) in the Mobile Area and 2,700 ft (823 m) in the Destin Dome Area. Fluvial bedload in the Hosston results from south Appalachian, Ocala, and Peninsular uplifts landward of a modern Great Barrier Reef-sized rimmed shelf reef (Snedden et al., 2016).

The **Paluxy Formation** (Albian, [Table 5](#) and [Figure 25](#)) is widespread in the OCS and locally has high porosity in barrier bars and stream channels, with gross interval thicknesses ranging from 900 ft (274 m) in the Mobile Area to over 2,200 ft (671 m) in the Destin Dome Area. Albian clastics of the Paluxy were sourced primarily by Appalachian and Ouachita-Ar buckle Mountains (Merrill, 2016).

The **Dantzler Formation** (Albian–Cenomanian, [Table 5](#) and [Figure 25](#)) is truncated by the prominent Mid-Cretaceous Unconformity (MCU). Thick sandy sections exist in fluvial facies that prograded from source areas in the ancestral Appalachian Mountains of central Alabama and southern Georgia across the modern Pensacola, Destin Dome, and Apalachicola Areas. The distal fluvial facies changes to a shore zone facies in the Viosca Knoll, Mobile, Pensacola, northwest Destin Dome, and southern Apalachicola Areas. The Dantzler Formation is thickest over the Destin Anticline (DD, [Figure 22](#)) but thins to the south away from its source area.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 58% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 15% ([Figure 5](#))

The riskiest play-level components are associated with the hydrocarbon fill and trapping mechanisms. At the prospect level, the highest risks are associated with the reservoir and trap components. See [Appendix A](#) for details.

Undiscovered Resources

A mapped prospect portfolio was not available, so the number of possible traps was estimated from an inventory of 38 faulted, salt-cored anticlines and 29 salt diapirs. From this, the assessors determined that the number of prospects ranges from 10 to 70. Applying risk results in 0 to 33 undiscovered pools, with a mean of 6.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 35 Lower Cretaceous clastic discoveries in onshore Mississippi ([Figure 42](#)). These discoveries range in size from 0.01 to 28 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 33 MMBOE.

The Shelf AU was modeled as 50% oil and 50% gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP

returning UTRR values for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Because there is play-level risk, only 57% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 44 MMbbl at the 5th percentile, with a mean of 13 MMbbl, and 417 Bcf at the 5th percentile, with a mean of 89 Bcf, respectively (Table 8 and Figure 55). Total undiscovered BOE resources are 118 MMbbl at the 5th percentile, with a mean of 29 MMbbl. Of all 30 assessment units in this study, the Lower Cretaceous Clastic Shelf ranks 29th based on mean-level undiscovered BOE resources (Figure 10).

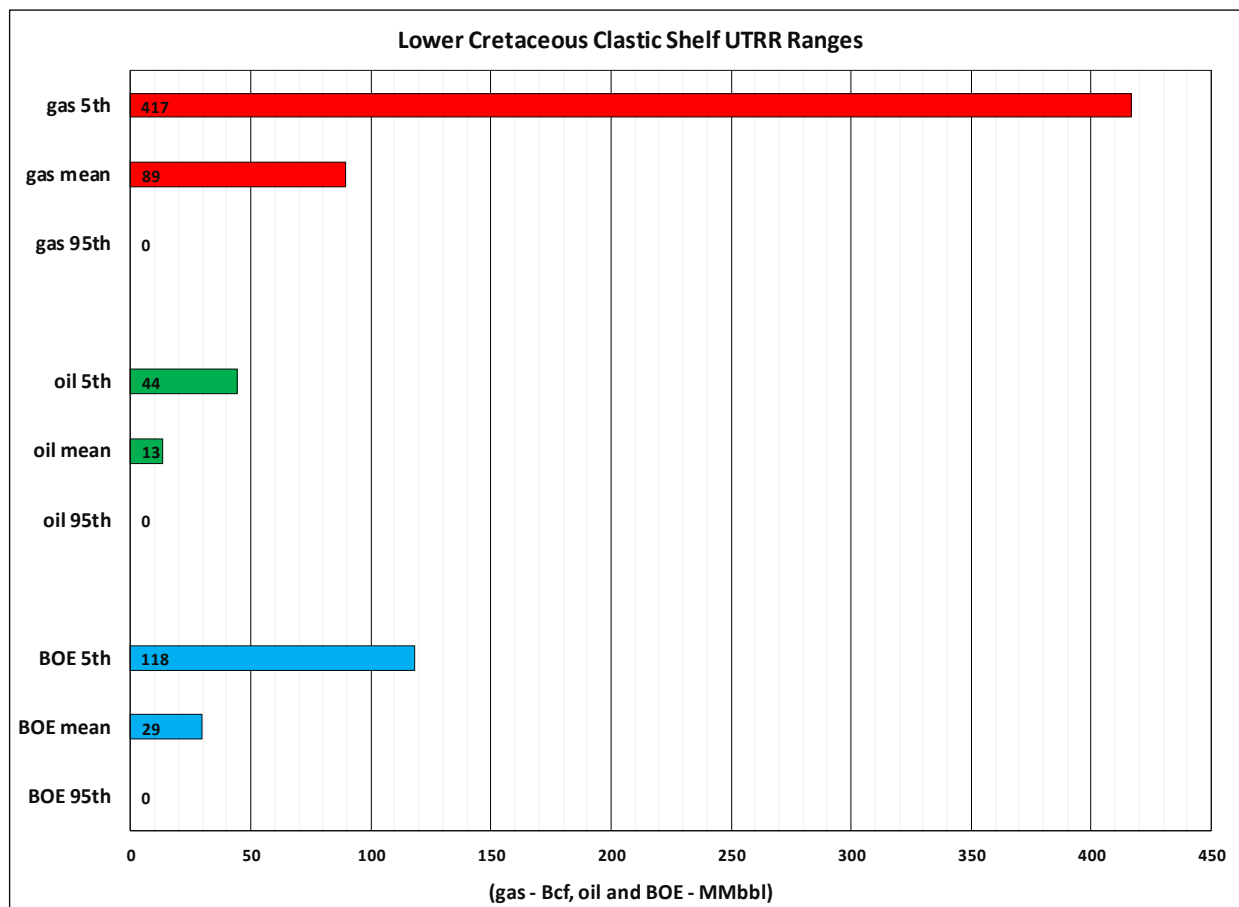


Figure 55. Lower Cretaceous Clastic Shelf gas, oil, and BOE UTRR ranges.

Lower Cretaceous Clastic Slope

Geology

The Slope AU extends downdip from the Cretaceous shelf margin into deep water in the Viosca Knoll, western De Soto Canyon, and eastern Mississippi Canyon Areas (Figure 54). To the north, the Slope AU abuts the Lower Cretaceous Clastic Shelf AU along the modern shelf-slope break. To the southeast, the Lower Cretaceous Clastic Slope AU onlaps the Southern Platform (SP, Figure 22) and to the southwest, onlaps inflated salt of the Mesozoic salt nappes. To the west, the Slope AU abuts the Mesozoic Shelf Play along a northwest-southeast trending line of salt stocks and vertical welds that are the remnants of a collapsed salt wall, beyond which the Mesozoic stratigraphy is poorly imaged due to increasing depth, structural complexity, and extensive allochthonous salt.

The Slope AU is characterized by large turtle-structure anticlines and asymmetrical expulsion rollovers related to salt evacuation in the eastern Mississippi Canyon Area (Harding et al., 2016). Seven Lower and

Upper Cretaceous wedges prograde from northeast to southwest within a depositional fairway bounded by large NNW-SSE trending salt walls and diapirs, which may be aligned with steps in the underlying basement.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 18% ([Figure 4](#))
- exploration-level: 18% ([Figure 5](#))

Geochemical modeling predicts a favorable oil generation window for the Tithonian shale beneath the Slope AU (Cunningham et al., 2016; Harding et al., 2016). In fact, the discovery well for the Norphlet Appomattox Field in Mississippi Canyon Block 392 logged oil in the Paluxy Formation; therefore, a working petroleum system has been established. At the prospect level, the highest risks are associated with the reservoir and trap components. See [Appendix A](#) for details.

Undiscovered Resources

The number of prospects was estimated from a portfolio of 57 Cretaceous structural closures mapped from recent vintage 3D seismic data. From this, the assessors determined that the number of prospects ranges from 20 to 60. Applying risk results in 0 to 25 undiscovered pools, with a mean of 7.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 23 Lower Tuscaloosa Formation discoveries in onshore Mississippi ([Figure 42](#)). Instead of using onshore Lower Cretaceous clastic discoveries, the assessors felt that larger pool sizes of onshore Lower Tuscaloosa Formation discoveries were more representative of pools to be found in the OCS. These Lower Tuscaloosa discoveries range in size from 2 to 242 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 163 MMBOE.

The Slope AU was modeled as 100% oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Assessment results indicate that undiscovered oil resources range from 24 to 730 MMbbl, and undiscovered gas resources range from 16 to 484 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 56](#)). Of all 30 assessment units in this study, the Lower Cretaceous Clastic Slope ranks 18th based on mean-level undiscovered BOE resources ([Figure 10](#)).

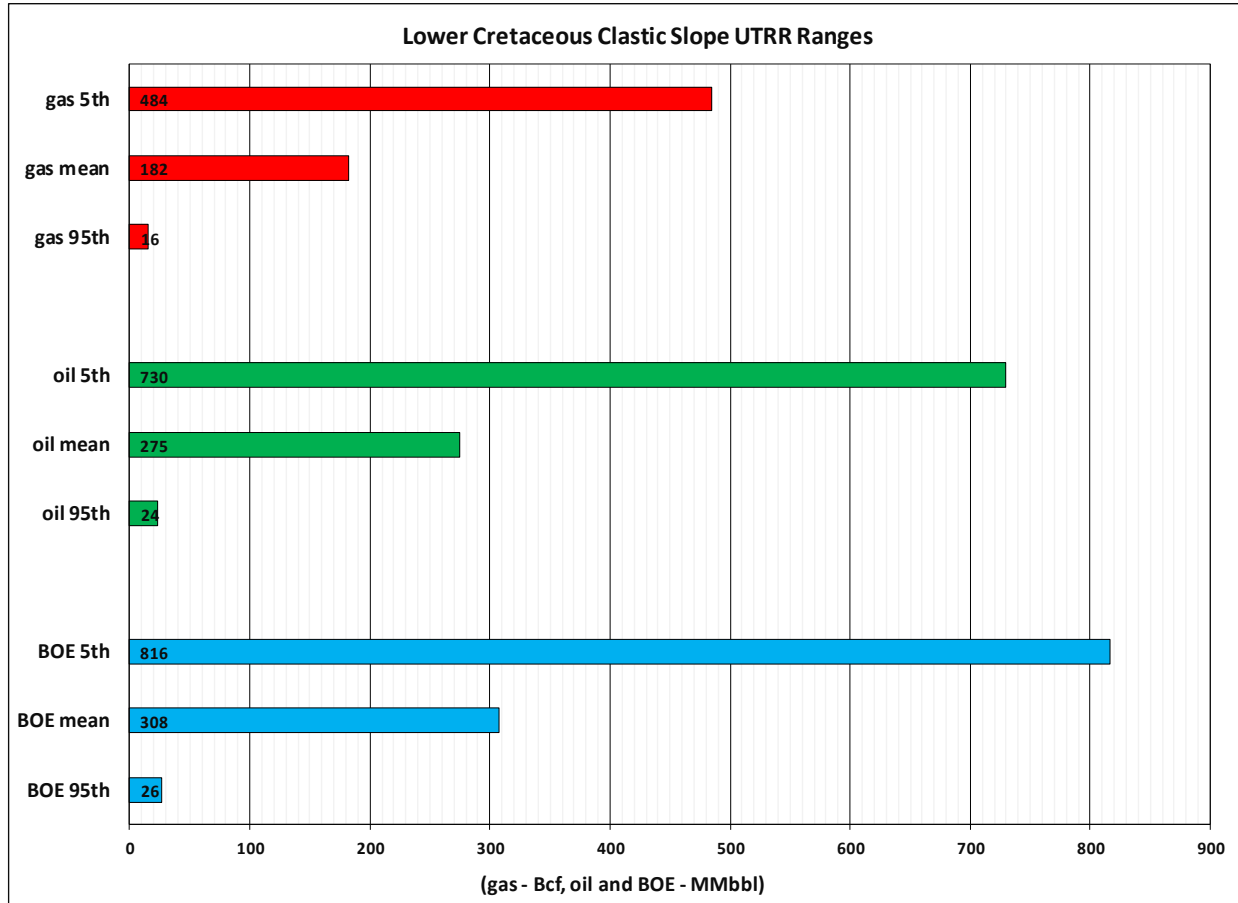


Figure 56. Lower Cretaceous Clastic Slope gas, oil, and BOE UTRR ranges.

LOWER TUSCALOOSA (EASTERN GOA)

The Upper Cretaceous Tuscaloosa Group (Cenomanian–Turonian) is subdivided into sands and shales of the Lower Tuscaloosa Formation, the Tuscaloosa Marine Shale, and sands and shales of the Upper Tuscaloosa Formation (Table 5 and Figure 25). The updip, onshore Tuscaloosa section has a long history of production in Louisiana, Mississippi, and Alabama, and from the stratigraphically equivalent Woodbine Formation in Texas. The **Tuscaloosa Marine Shale** is being developed as an unconventional resource play in onshore Louisiana and is the subject of its own unassessed play in the eastern GOA. Reservoirs of the productive, onshore Lower Tuscaloosa Trend consist of braided stream channel sands, progradational deltaic sands, aggradational stacked barrier bar and channel sands, and reworked retrogradational sands.

Two regional Tuscaloosa depositional axes trending into the deep GOA Basin have been interpreted (Snedden et al., 2016). The eastern Mississippi Canyon axis trends into the eastern Mississippi Canyon Area from entry points to the east and/or north-northwest through the Main Pass or Viosca Knoll Areas (Harding et al., 2016; Snedden et al., 2016). This fairway is associated with the Lower Tuscaloosa Shelf and Slope Plays. The second depositional fairway trends through south-central Louisiana across the central Louisiana shelf and into the deepwater subsalt region of Garden Banks, Green Canyon, Alaminos Canyon, and Keathley Canyon. This Keathley Canyon axis (Snedden et al., 2016) is addressed in the undifferentiated **Mesozoic Shelf** and **Mesozoic Slope** Plays.

Lower Tuscaloosa objectives in the Shelf and Slope Play areas (Figure 57) were deposited in the full range of shelf-to-basin environments from their source areas, across the shelf margin, and into the deep basin.

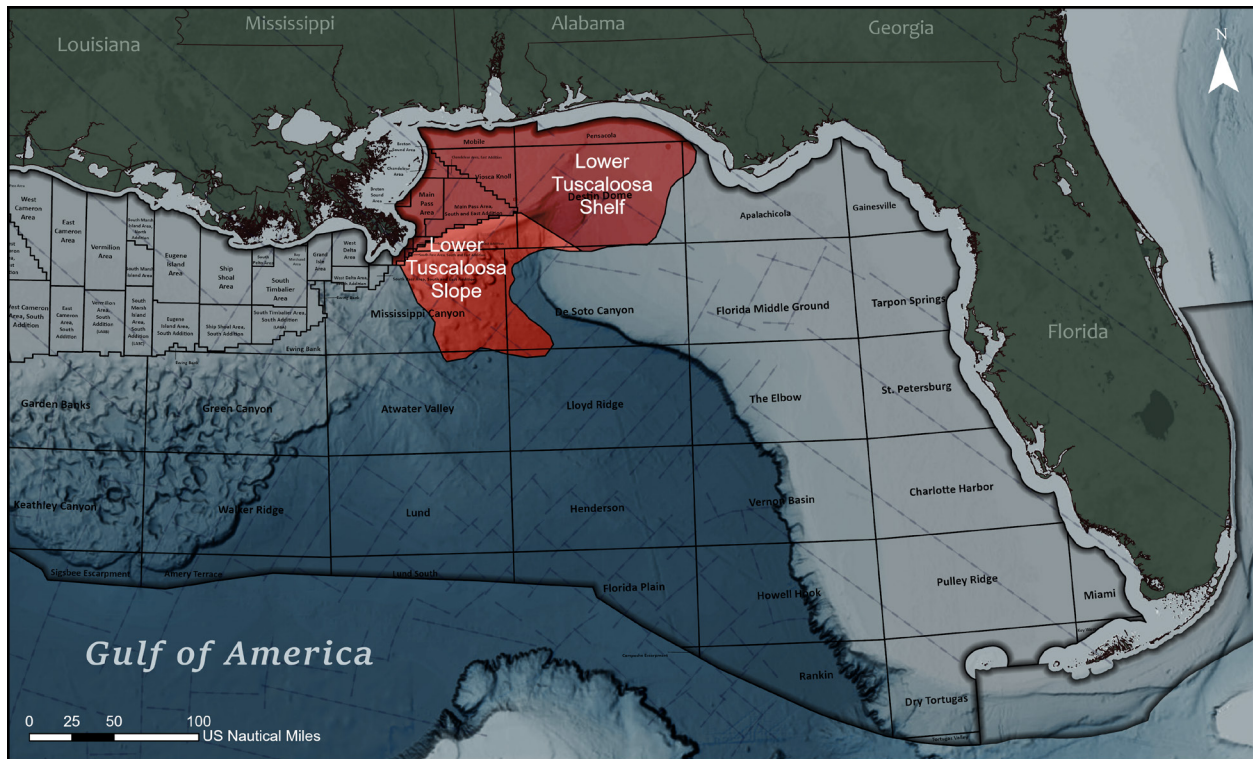


Figure 57. Lower Tuscaloosa Shelf and Slope locations.

Drainages of the paleo-Mississippi, -Pearl, -Mobile, -Tensas, and -Apalachicola Rivers could have supplied the bed load for the Lower Tuscaloosa objectives. Broad northeast-to-southwest trending depositional fairways of fluvial and estuarine environments extend from sediment source areas in the Appalachian Mountains to deltas immediately north of the Lower Cretaceous shelf in Louisiana, Mississippi, Alabama, and Florida (Woolf, 2012). The maximum thickness of sand at the paleo-shelf edge is 152 m (500 ft) (Woolf, 2012). Depositional fairways and deltas of the Tuscaloosa system appear to skirt the Lasalle Arch, Wiggins Arch, and Baldwin High (Figure 22), suggesting that these were paleo-topographic features. Entry points into the deep basin appear to coincide with gaps between the underlying basement highs, where they are offset by the NW-SE trending Mississippi River, Pearl River, and Mobile Transfer Fault Zones (Stephens, 2009; Woolf, 2012) (Figure 22 and Figure 23).

Petrology of Lower Tuscaloosa sequences from proximal to distal environments can be characterized as coarse to fine grained, laminated to massive quartz sandstones and sublitharenites, with varying degrees of shale or siltstone depending on proximity to estuarine, prodelta, or nearshore environments. In all instances, the percentage of sand is high. Onshore in the Tuscaloosa Trend of Louisiana and Texas, porosities of 20%–29% from 16,000 to 23,000 ft and permeabilities of hundreds of millidarcies are reported (Dubiel and Pitman, 2004). Often noted is the presence of framework-coating chlorite that serves to inhibit quartz overgrowths, enhancing porosity (Thomson, 1979). The source of chlorite is traced to the peridotite belt of south Arkansas (Thomson, 1979). Biotite and muscovite from eroded metamorphic rocks of the ancestral Appalachians were also diagenetically converted to chlorite (Thomas et al., 2005).

Potential petroleum source rocks include the entire Mesozoic suite (Cole et al., 2001). Because the Lower Tuscaloosa represents multiple sequences interpreted as regressive sands alternating with finer-grained marine sediments, the chance for intra-formational hydrocarbon sourcing is high. Onshore, shales within the Tuscaloosa Formation, the Tuscaloosa Marine Shale, and the Smackover Formation have all been considered as possible source beds in studies of the downdip Tuscaloosa-Woodbine Trend (Dubiel and Pitman, 2004) and are likely hydrocarbon sources for the plays.

Lower Tuscaloosa Shelf

Geology

The Lower Tuscaloosa Shelf Play is an extension of the productive onshore trend and continues eastward from the Mississippi Delta across offshore Mississippi, Alabama, and Florida, including the northern portions of the Viosca Knoll and Destin Dome Areas ([Figure 57](#)). West of the Mississippi Delta, the Lower Tuscaloosa Shelf Play abuts the undifferentiated [Mesozoic Shelf Play](#). Downdip, the Lower Tuscaloosa Shelf Play overlaps the Southern Platform (SP, [Figure 22](#)) in the east, and in the southwest it meets the Lower Tuscaloosa Slope environment along the modern shelf-slope break near the Lower Cretaceous shelf edge trend in the Viosca Knoll Area.

Lower Tuscaloosa Shelf objectives are channel, strandplain, and stacked barrier bar sands (Petty, 1997). The structural setting is similar to that of the underlying [Lower Cretaceous Clastic Shelf AU](#). Structural traps include anticlinal and faulted three-way closures associated with salt pillows and rafts formed by gravity spreading along the Louann Salt, which served as a detachment layer (Pilcher et al., 2014), as well as traps against diapirs in the De Soto Canyon Salt Basin (DCSB, [Figure 22](#)), which experienced growth through the Cretaceous (Pashin et al., 2016). Likely source rocks are Oxfordian (A157) or Tithonian (A148) ([Figure 25](#)).

One OCS well in Main Pass Block 254 has flowed hydrocarbons from the Lower Tuscaloosa sand. The Lower Tuscaloosa was perforated, probably based on the mud log show, and the recorded test is a calculated open flow of 2,525 barrels of oil per day. The well was ultimately abandoned, but this test proves that there is an active petroleum system in place.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 25% ([Figure 5](#))

Because an active petroleum system has been established by the Main Pass Block 254 well, there is no play-level risk. At the prospect level, the highest risks are associated with the reservoir and trap components. See [Appendix A](#) for details.

Undiscovered Resources

A mapped prospect portfolio was not available, so possible traps were estimated from an inventory of 38 faulted, salt-cored anticlines and 29 salt diapirs, in a similar fashion to the [Lower Cretaceous Clastic Shelf AU](#). From this, the assessors determined that the number of prospects ranges from 10 to 70. Applying risk results in 0 to 34 undiscovered pools, with a mean of 10.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 23 Lower Tuscaloosa Formation discoveries in onshore Mississippi ([Figure 42](#)). These discoveries range in size from 1.6 to 242. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 59 MMBOE.

The Shelf Play was modeled as 50% oil and 50% gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR values for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 12 to 133 MMbbl, and undiscovered gas resources range from 95 to 1,569 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 58](#)). Of all 30 assessment units in this study, the Lower Tuscaloosa Shelf Slope ranks 23rd based on mean-level undiscovered BOE resources ([Figure 10](#)).

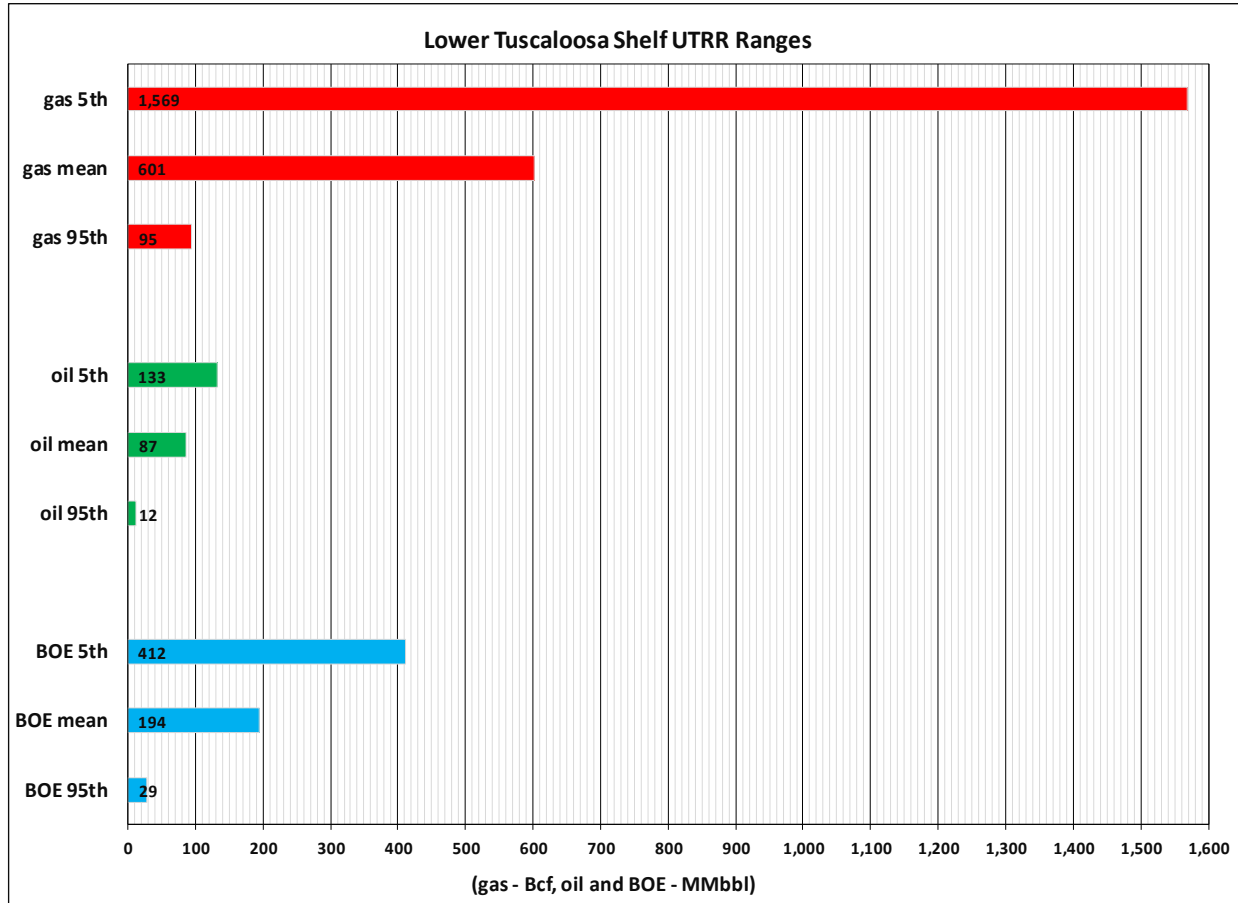


Figure 58. Lower Tuscaloosa Shelf gas, oil, and BOE UTRR ranges.

Lower Tuscaloosa Slope

Geology

The Lower Tuscaloosa Slope Play extends downdip from the Cretaceous shelf margin into deep water in the Viosca Knoll, western De Soto Canyon, and eastern Mississippi Canyon Areas (Figure 57). To the north, the Lower Tuscaloosa Slope Play abuts the Lower Tuscaloosa Shelf Play along the modern shelf-slope break. To the southeast, the Lower Tuscaloosa Slope Play onlaps the Southern Platform (SP, Figure 22), and to the southwest, it onlaps inflated salt of the Mesozoic salt nappes (Figure 23). To the west, the Lower Tuscaloosa Slope Play abuts the undifferentiated Mesozoic Slope Play along a NW-SE trending line of salt stocks and vertical welds that are the remnants of a collapsed salt wall beyond which Mesozoic stratigraphy is poorly imaged due to increasing depth, structural complexity, and extensive allochthonous salt.

Potential reservoirs are submarine fans sourced through breaks in the reef margin to the east or from the north-northwest through structurally controlled fairways linked to shelf-margin deltas in onshore areas (Woolf, 2012; Snedden et al., 2016).

The structural setting is similar to that of the underlying Lower Cretaceous Clastic Slope AU. The Lower Tuscaloosa Slope Play is characterized by large turtle-structure anticlines and asymmetrical expulsion rollovers related to salt evacuation in the eastern Mississippi Canyon Area (Harding et al., 2016). Lower and Upper Cretaceous sediment wedges prograded from northeast to southwest within depositional fairways bounded by large NNW-SSE trending salt walls and diapirs, which may be aligned with steps in

the underlying basement. A large portfolio of structures is identifiable on numerous depth-migrated 3D seismic surveys that illuminate the play.

Published geochemical modeling studies indicate that the Tithonian (A148) and the Lower Cretaceous (A120) sources ([Figure 25](#)) are mature within the play area (Harding et al., 2016; Weimer et al., 2016).

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 54% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 13% ([Figure 5](#))

The riskiest components at the play and prospect levels are the presence and quality of a reservoir facies. See [Appendix A](#) for details.

Undiscovered Resources

The number of prospects was estimated from a portfolio of 57 Cretaceous structural closures mapped from recent vintage 3D seismic data, the same structures used for the [Lower Cretaceous Clastic Slope AU](#). From this, the assessors determined that the number of prospects ranges from 25 to 75. Applying risk results in 0 to 35 undiscovered pools, with a mean of 7.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 23 Lower Tuscaloosa Formation discoveries in onshore Mississippi ([Figure 42](#)). These Lower Tuscaloosa discoveries range in size from 1.6 to 242 MMBOE, with a mean size of 36 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 222 MMBOE.

The play was modeled as 100% oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Because there is play-level risk, only 54% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 916 MMbbl at the 5th percentile, with a mean of 260 MMbbl, and 607 Bcf at the 5th percentile, with a mean of 172 Bcf, respectively ([Table 8](#) and [Figure 59](#)). Of all 30 assessment units in this study, the Lower Tuscaloosa Slope ranks 19th based on mean-level undiscovered BOE resources ([Figure 10](#)).

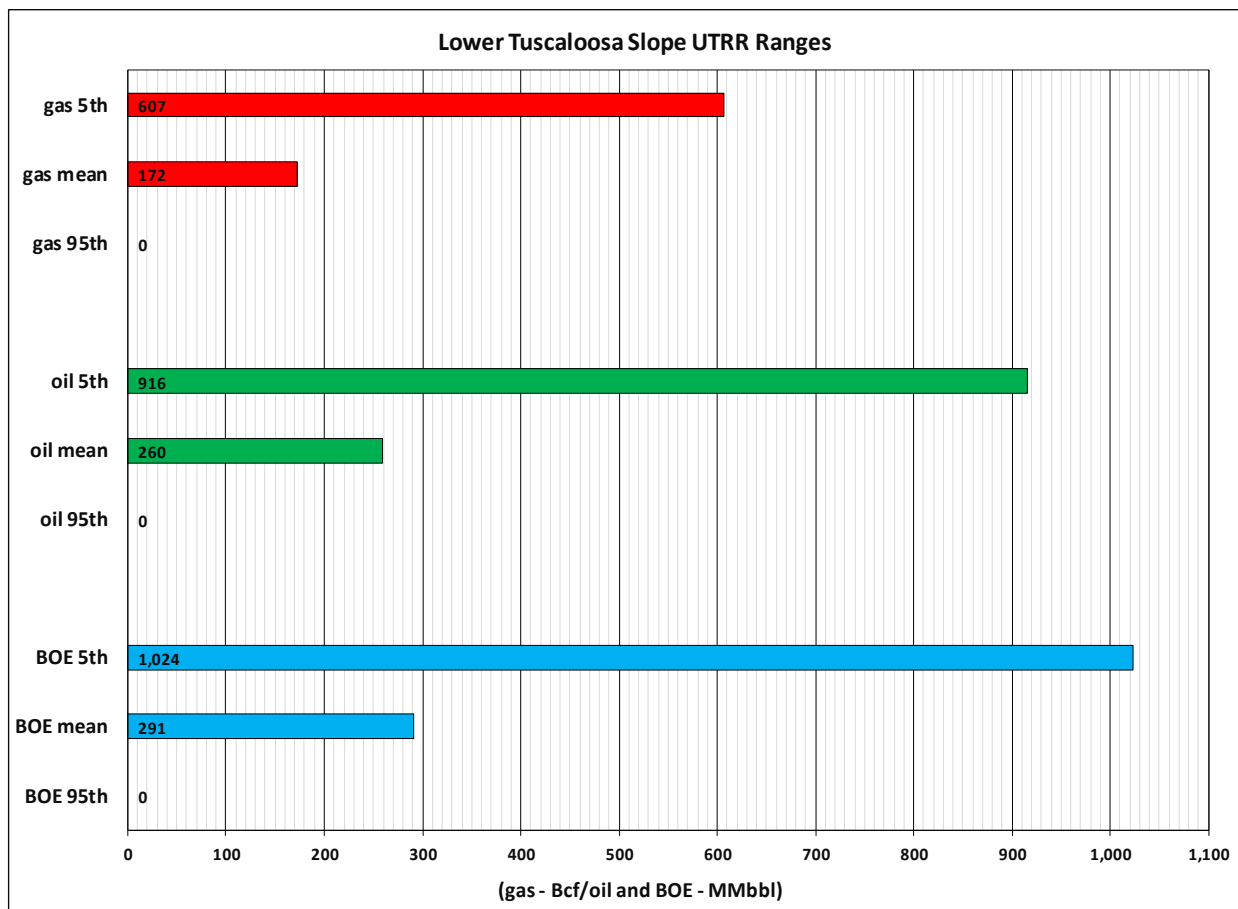


Figure 59. Lower Tuscaloosa Slope gas, oil, and BOE UTRR ranges.

TUSCALOOSA MARINE SHALE (UNASSESSED)

Geology

The Tuscaloosa Marine Shale (TMS) of southern Louisiana and Mississippi and the Eagle Ford Shale (Figure 25) of Texas are Upper Cretaceous shale units located behind and parallel to the underlying Lower Cretaceous shelf edge. The TMS is depositionally younger than the sandstones of the Lower Tuscaloosa Plays (Table 5 and Figure 25). The TMS is coincident with organic matter acme A94 (Figure 25) deposited during a major sea level rise in the Turonian and is slightly younger than the Cenomanian–Turonian oceanic anoxic event (OAE 2) (Lowery et al., 2017). Between 2007 and 2016, the play produced 9.4 million barrels of oil and 5.5 billion cubic feet of gas from 80 horizontal wells in south-central Louisiana and southwest Mississippi (Enomoto et al., 2017). Helis Oil and Gas attempted to extend the play eastward in 2016 with a well in St. Tammany Parish, Louisiana, that was determined to be non-commercial and abandoned. The U.S. Geological Survey released an assessment of the TMS in 2018 covering portions of Louisiana, Mississippi, Alabama, and Florida, including state waters (Hackley et al., 2018). Mean undiscovered resources were 1,537 million barrels of oil and 4,614 billion cubic feet of gas.

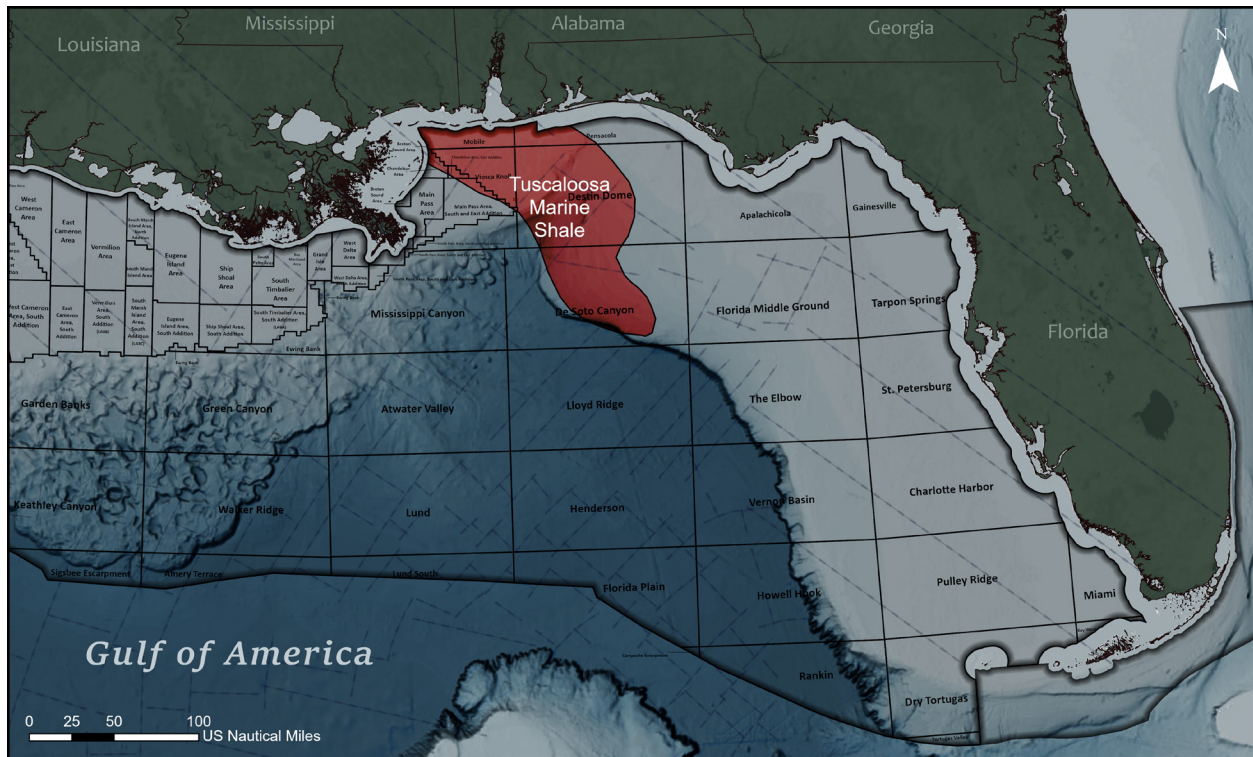


Figure 60. Tuscaloosa Marine Shale location.

The TMS Play in the OCS tentatively follows the underlying Lower Cretaceous shelf-margin reef trend southeastward from the modern Mississippi River Delta to the Southern Platform at depths of approximately 12,000 to 14,000 ft. The trend then turns north, then northeast across the northern flank of the Southern Platform before turning northwest, paralleling structural contours at depths of 6,000 to 8,000 ft to intersect the U.S. Geological Survey play outline at state waters (Figure 60).

In general, resource plays are hydrocarbon source rocks that have reached maturity, but from which significant volumes of oil and/or gas have not been expelled and remain in place. The TMS and other Cenomanian–Turonian shale units associated with organic matter acme A94 (Figure 25) are likely hydrocarbon source rocks for conventional reservoirs located farther basinward in Louisiana, Mississippi, and the OCS, including portions of the Mississippi Canyon and Viosca Knoll Areas where burial depths are greater. Offshore wells penetrating the TMS show similar total organic carbon content to onshore wells as calculated by the Passey-Creaney delta log R method (Passey et al., 1980). Mud log shows from the De Soto Canyon Block 512 well near the TMS indicate an active hydrocarbon system. However, TMS wells in federal waters show lower resistivities than the 5 ohm-meter cutoff identified by John et al. (1997) for the productive high-resistivity zone (HRZ) of the onshore play.

The TMS is an unconventional reservoir and must be hydraulically fractured (“fracked”) to create a reservoir to liberate hydrocarbons for production. In onshore settings, such reservoirs (resource plays) employ dense arrays of horizontal wellbores to achieve commercial rates of hydrocarbon production and recovery. Such technologies have not been employed in offshore settings and would not likely be economically viable at foreseeable price scenarios. Although the geologic trend may extend into federal waters, no attempt was made to quantitatively assess the TMS, but its possible extent is noted.

MESOZOIC SHELF, SLOPE, AND BASIN FLOOR (CENTRAL-WESTERN GOA)

The undifferentiated Mesozoic Shelf, Slope, and Basin Floor Plays (Figure 61) conceptually include all potential Mesozoic objectives recognized to the east of the modern Mississippi River Delta. However, for

the purpose of this assessment, these central-western GOA Mesozoic Plays were modeled with Lower Tuscaloosa objectives analogous to the eastern GOA **Lower Tuscaloosa Plays**. The shelf, slope, and basin floor designations of the central-western GOA Mesozoic Plays refer to modern bathymetry. Depositionally, the areas of all three Mesozoic Plays would have been in a slope to basinal setting at Lower Tuscaloosa time.

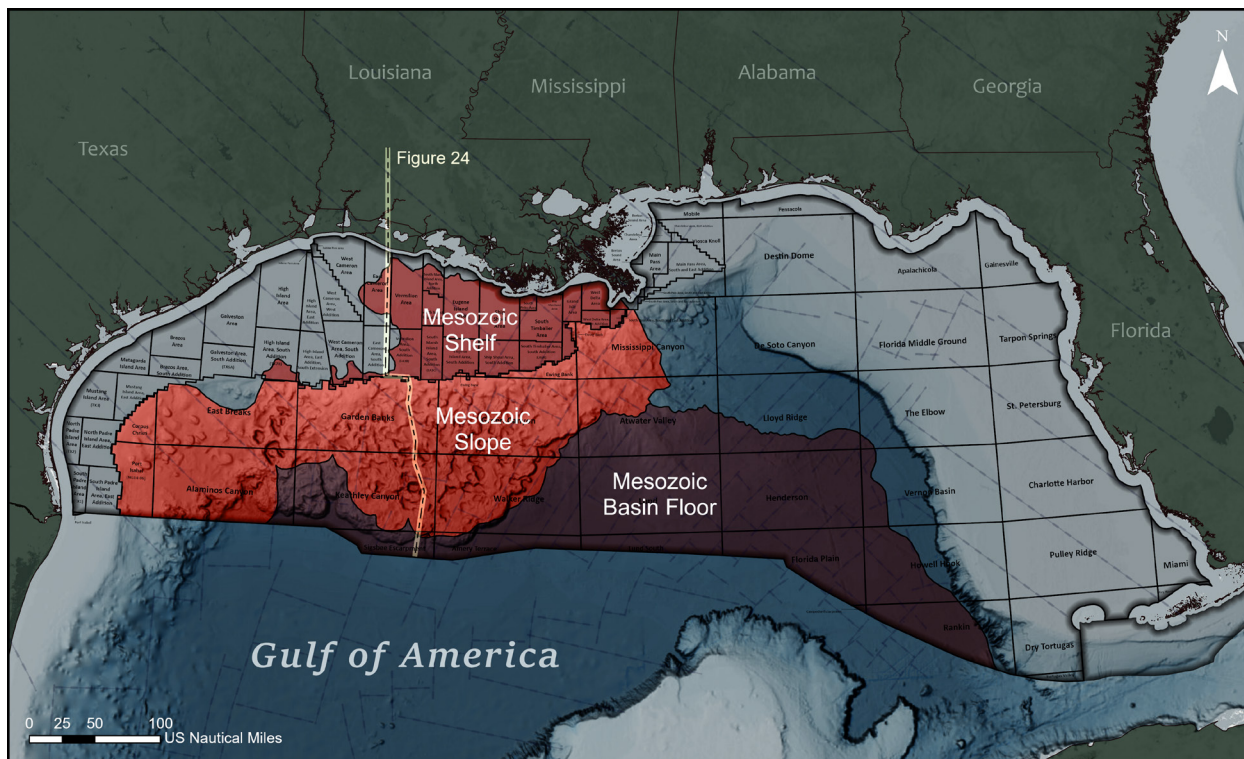


Figure 61. Mesozoic Shelf, Slope, and Basin Floor locations.

Potential Tuscaloosa reservoirs are slope channels and basin-floor fans sourced from shelf margin deltas in onshore areas to the north or from the northeast (Woolf, 2012; Snedden et al., 2016). A western Tuscaloosa sediment fairway, the Keathley Canyon axis, trends through south-central Louisiana across the central Louisiana shelf and into the deepwater subsalt region of Garden Banks, Green Canyon, Alaminos Canyon, Keathley Canyon and western Walker Ridge (Snedden et al., 2016). The Davy Jones well (South Marsh Island Block 234) encountered amalgamated, sand-rich, mid-slope channels. The Tiber (Keathley Canyon Block 102) and BAHA II (Alaminos Canyon Block 557) prospects encountered multiple basin-floor fan lobes (Snedden et al., 2016).

Mesozoic Shelf

Geology

The Mesozoic Shelf Play extends from state waters to the modern shelf-slope break (Figure 61). The Texas shelf and portions of the western-most Louisiana shelf are excluded from the play due to high subsurface temperatures and pressures that pose risks for hydrocarbon stability, reservoir diagenesis, and operations. The Will K (High Island Block A119) and Davy Jones (South Marsh Island Block 230) Prospects both reached bottom-hole temperatures of 460 °F (238 °C). A published map of subsurface temperature trends (Forrest et al., 2005) was used to delineate areas with anticipated temperatures that are hotter than these locations. The remaining prospective area includes a portion of the East Cameron Area and

extends eastward to the West Delta Area, where it is juxtaposed across the modern Mississippi Delta to the **Lower Tuscaloosa Shelf Play**.

The Mesozoic section of the Mesozoic Shelf Play is situated beneath Paleogene and Neogene detachments, horizontal salt welds, and thick, complexly faulted Miocene, Pliocene, and Pleistocene sediments filling salt-withdrawal minibasins (Diegel et al., 1995). Prospective structures include anticlinal closures above remnant autochthonous salt pillows and folds (Philippe et al., 2005; Dooley et al., 2013) and upthrown three-way closures against the counter-regional salt feeders and welds (**Figure 23**) that sourced the mostly evacuated paleo-salt canopy now represented by Roho systems (Jamieson et al., 2000).

Reservoir characteristics derived from the study of onshore Lower Tuscaloosa wells reveal primarily fining-upward sandstones (sublitharenites) with anomalously high porosities (26%) resulting from detrital grain-rimming chlorite grains. This relationship has been used to explain high porosities and permeabilities in updip Tuscaloosa reservoirs deeper than 20,000 ft (Thomson, 1979). Uncertainties remain in how these favorable characteristics might persist in deep slope to basinal environments. Publicly available information from the Tiber well (Keathley Canyon Block 102) shows that Tuscaloosa sands at depths of 33,000 to 34,000 ft have moderate to low concentrations of chlorite grain coatings, measured porosities averaging 8%, and measured permeabilities averaging less than 0.1 millidarcies.

Most likely source rocks are Lower and Middle Cretaceous in age, which are in or beyond the gas window, with possible contributions from sub-canopy Tithonian sources along the southern margins of the trend that could still be in the oil window. One OCS well in Main Pass Block 254 has flowed hydrocarbons from the Lower Tuscaloosa in the stratigraphically equivalent **Lower Tuscaloosa Shelf Play**. Overlying tertiary reservoirs are charged predominantly by Tertiary source rocks (Hood et al., 2002).

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 50% (**Figure 3**)
- prospect-level: 18% (**Figure 4**)
- exploration-level: 9% (**Figure 5**)

The riskiest play and prospect component is the quality of a reservoir facies. With an overall exploration chance of success of just 9%, this is one of the riskiest plays assessed in the OCS. See **Appendix A** for details.

Undiscovered Resources

The number of prospects was estimated based on a portfolio of mapped closures and proxy structures associated with autochthonous salt pillows, salt feeders, and vertical welds. From this, the assessors determined that the number of prospects ranges from 20 to 100. Applying risk resulted in 0 to 35 undiscovered pools, with a mean of 5.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 23 Lower Tuscaloosa Formation discoveries in onshore Mississippi (**Figure 42**). These discoveries range in size from 1.6 to 242 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 61 MMBOE.

The play was modeled as 100% gas. With no information on yields from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR values for dry gas and condensate liquids (oil herein). Because there is play-level risk, only 50% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 11 MMbbl at the 5th percentile, with a mean of 40 MMbbl, and 1,828 Bcf at the 5th percentile, with a mean of 510 Bcf, respectively (**Table 8** and **Figure 62**). Of all 30 assessment units in this study, the Mesozoic Shelf ranks 25th based on mean-level undiscovered BOE resources (**Figure 10**).

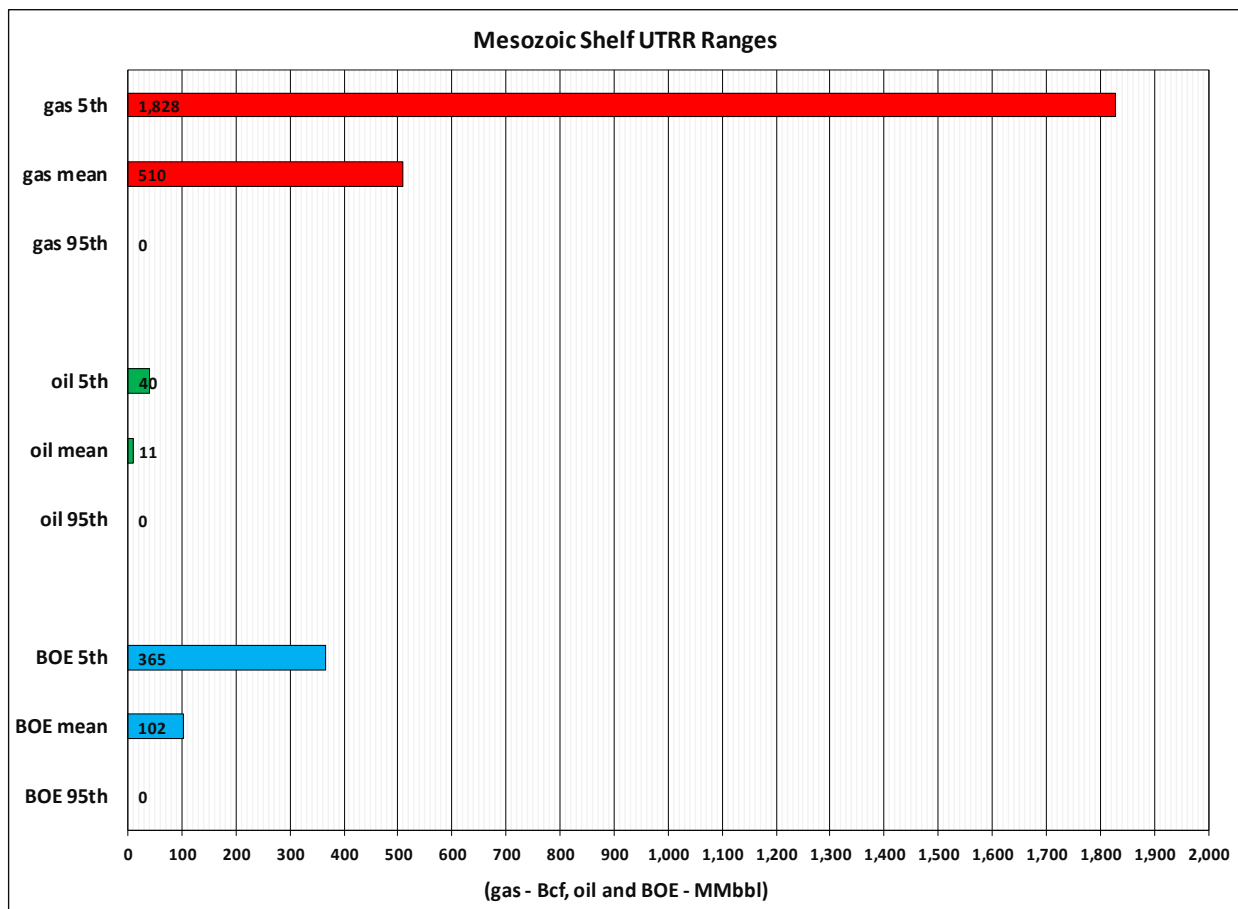


Figure 62. Mesozoic Shelf gas, oil, and BOE UTRR ranges.

Mesozoic Slope

Geology

The Mesozoic Slope Play extends from the modern shelf-slope break downdip to the limit of the allochthonous Mesozoic salt nappes (Figure 23) that override oceanic crust and provide the detachment for the Perdido, Keathley, Walker Ridge, and Mississippi Fan (Atwater) Fold Belts (Figure 23 and Figure 61). The Mesozoic Slope Play abuts the Lower Tuscaloosa Slope Play along a generally NNW-SSE trending line of salt diapirs and vertical welds that are aligned with an underlying basement lineament between the NW-SE trending Terrebonne and Mississippi River Transfer Fault Zones (TTF and MRTF, Figure 23). West of this lineament, depth to basement increases and there was additional accommodation from withdrawal of thicker autochthonous salt. The Mesozoic stratigraphy is poorly imaged due to increasing depth, structural complexity, and extensive allochthonous salt. Well penetrations of the Mesozoic section are sparse.

The Mesozoic Slope Play is located mostly subsalt, and subsurface temperatures are cooler relative to the Mesozoic Shelf Play due to (1) the heat-wicking effect of the allochthonous salt canopy, which efficiently transfers heat from the deep subsurface to the sea floor and (2) increasing water depth and less overburden. Only a small portion of the northern East Breaks Area was excluded due to anticipated high temperature. Because the Slope Play is situated in a cooler subsalt environment, Jurassic and Cretaceous source rocks remain in the oil-to-gas window, as evidenced by (1) oil shows at 34,000 ft in the Tiber well (Keathley Canyon Block 102) and (2) numerous oil reservoirs in the overlying Wilcox Slope Play, which share common fetch areas and migration pathways with deeper Tuscaloosa structures.

Traps outboard of the Sigsbee Salt Canopy ([Figure 22](#)) and just beneath its distal limit include four-way anticlinal closures above remnant pillows of the Mesozoic allochthonous salt nappes and thrust, salt-cored folds of the Perdido, Keathley, Walker Ridge, and Atwater Fold Belts ([Figure 23](#)). Further inboard, traps are three-way closures against salt feeders, counter-regional welds, and bucket welds—the collapsed remnants of earlier inflated stocks that sourced the Sigsbee Salt Canopy (Pilcher et al., 2011). Mesozoic section that once formed the carapaces of these earlier diapirs has been rafted basinward on top of the modern canopy (Fiduk et al., 2014) so that some bucket weld basins are devoid of potential Mesozoic reservoirs or source rocks.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 60% ([Figure 3](#))
- prospect-level: 18% ([Figure 4](#))
- exploration-level: 11% ([Figure 5](#))

Because of the portfolio of seismically defined, subsalt structures and oil shows at the Tiber well (Keathley Canyon Block 102), the hydrocarbon fill and trap components of the risk matrix at the play level carry no risk. Reservoir quality is the riskiest component, resulting in a petroleum system chance of success of 60%. See [Appendix A](#) for details.

Undiscovered Resources

The estimated number of prospects is based on regional geologic trends and a portfolio of 76 Cretaceous closures mapped from recent vintage depth-migrated 3D seismic data. From this, the assessors determined that the number of prospects ranges from 25 to 125. Applying risk results in 0 to 40 undiscovered pools, with a mean of 8.

With no BOEM-designated discoveries in the OCS, the pool-size distribution was modeled with 23 Lower Tuscaloosa Formation discoveries in onshore Mississippi ([Figure 42](#)). These Lower Tuscaloosa discoveries range in size from 1.6 to 242 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 226 MMBOE.

The play was modeled as 100% oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOA discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Because there is play-level risk, only 60% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 962 MMbbl at the 5th percentile, with a mean of 281 MMbbl, and 1,180 Bcf at the 5th percentile, with a mean of 345 Bcf, respectively ([Table 8](#) and [Figure 63](#)). Of all 30 assessment units in this study, the Mesozoic Slope ranks 16th based on mean-level undiscovered BOE resources ([Figure 10](#)).

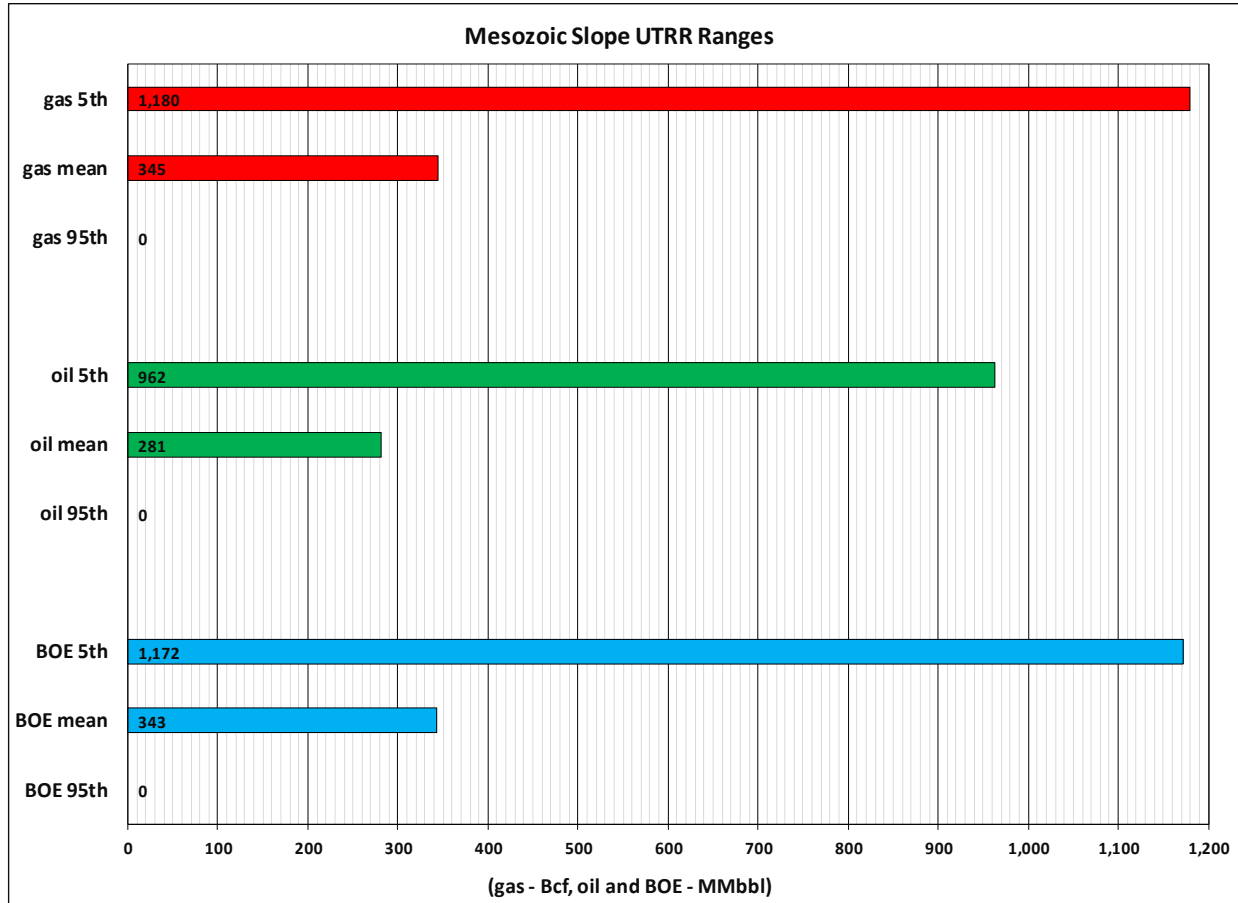


Figure 63. Mesozoic Slope gas, oil, and BOE UTRR ranges.

Mesozoic Basin Floor (unassessed)

Geology

The unassessed Mesozoic Basin Floor Play extends from the downdip limit of the Mesozoic allochthonous salt nappes across the modern abyssal plain to the limit of U.S. waters and along strike from the Perdido Fold Belt to the West Florida Salt Basin (Figure 23 and Figure 61).

BOEM resource assessments prior to the 2021 report included the region of the Mesozoic Basin Floor Play in the Buried Hills Structural, Stratigraphic, and Drape Plays. The premise of these plays was that they were underlain by fractured and weathered blocks of continental crust with flanking detrital wedges and drape closures in the overlying sedimentary cover (Lore et al., 2001). The current consensus is that the play sits astride a Jurassic mid-ocean ridge (Sandwell et al., 2014; Snedden et al., 2014; Pindell et al., 2016), and the underlying crust is most likely oceanic basalt, ultramafic lithologies of exhumed mantle, or other volcanic lithologies. Furthermore, collapse of the margin at the rift-to-drift transition was probably quite rapid, without subaerial exposure or time to develop extensive weathering profiles or sedimentary wedges (Pindell and Kennan, 2007; Pindell et al., 2014). Many of the large basement structures that underpinned the Buried Hills are areas where both Oxfordian and Tithonian source rocks are demonstrably absent (Pepper, 2016) through seismic correlation, and Cretaceous source rocks are likely to be immature. Although remnant blocks of hyper-extended continental crust are possible, the foregoing observations and concerns have raised the Buried Hills risks sufficiently to warrant withdrawal of the Buried Hills Structural and Stratigraphic Plays from the appraisal, and a reallocation of the Buried Hills Drape Play.

No seismic evidence suggesting the presence of reservoir facies of the Tuscaloosa Formation or older Mesozoic units has been recognized in the Mesozoic Basin Floor Play. Subsequent well tests and regional seismic correlation confirm that the unit originally identified as the Mid-Cretaceous Sequence Boundary was the Chicxulub debrite unit at the Cretaceous-Paleogene boundary (K-Pg) (Scott et al., 2014). Thus, some strata of the previously assessed Buried Hill Drape Play that was thought to be Mesozoic, possibly Lower Tuscaloosa, age is now known to be stratigraphically equivalent to the Wilcox Formation and is addressed in the [Lower Tertiary Basin Floor Play](#).

OTHER MESOZOIC OBJECTIVES

Other unassessed conceptual objectives of the Mesozoic Plays include breccias associated with the Chicxulub meteorite impact that form the reservoirs for the Giant Cantarell and neighboring fields in Mexican waters of the southern GOA (Grajales-Nishimura et al., 2009). This play could extend eastward along the Campeche slope (Williams-Rojas et al., 2012). Similar deposits have been identified seismically (Snedden et al., 2014) in the abyssal plain of the central GOA. Numerous penetrations in the deepwater areas of the northern GOA have penetrated the Chicxulub debrite layer (Scott et al., 2014), but none have yet encountered reservoir-quality rock. Other Cretaceous forereef breccias and talus not associated with the Chicxulub impact but rather deposited through normal shelf margin and slope processes may be present on the slope in front of the reef margins of the [Lower Cretaceous Carbonate AU](#) and could be analogous to the Tamabra Formation reservoirs of the Poza Rica Field of eastern Mexico. Although a small portfolio of these talus prospects has been identified, a high degree of uncertainty and perceived geologic risk precluded assessment.

Expansion of the Norphlet Play westward is problematic due to structural complexity, subsalt imaging, and anticipated depths generally greater than 40,000 ft beneath much of the shelf and slope. Areas of the Keathley, Walker Ridge, and Atwater Fold Belts are underlain by younger oceanic crust, so the only avenue for the Norphlet section to be present would be as rafts above the para-autochthonous salt nappes. There are areas west of the Brazos Transfer Fault (BTF, [Figure 23](#)) in the Perdido Fold Belt where the Norphlet Formation, if present, could be situated atop inflated salt at drillable depths. Discoveries in the Ek-Balam Play 500 miles to the south in Mexican waters of the southern GOA may be stratigraphically equivalent to the Norphlet Formation. Plate reconstructions place these discoveries only 150 miles southeast of the Perdido Fold Belt after removal of post-Oxfordian oceanic crust. Seismic correlations are difficult, and the prospective interval is relatively thin on available seismic data.

Also of note is the Southeast Florida Platform-Puerto Rico Trench Play situated in the Straits of Florida Planning Area, including portions of the Dry Tortugas and Tortugas Valley Protraction Areas. The play is situated at the extreme south edge of the South Florida Platform and slope. Potential reservoirs are Cretaceous and Jurassic carbonates adjacent to and south of the [Suniland Play](#), but sourced by long-distance migration from the Cuban thrust zone. The Cuban thrust zone is part of the subduction complex that stretches from the Puerto Rico Trench in the east and continues west to Yucatan forming the north boundary of the Caribbean plate, which is overriding the North American plate. An evaluation of the petroleum system of the Cuban Northwest Offshore Zone suggests that long distance lateral migration can occur due to regional unconformities and the continuity of the evaporites in the section (Moretti et al., 2003). Reserves of 4.6 billion barrels of oil have been assessed for the North Cuba Basin (Shenk, 2010), but long-distance lateral migration of up to 100 miles would be necessary to charge carbonates of the South Florida Platform and slope in the OCS. Additionally, Bahamas Petroleum Company announced that their Perseverance well in The Bahamas that drilled into the play did not find commercial volumes of oil, but it did prove the existence of reservoir, seal, and oil (Oilfield Technology, 2021). The location of this well is along strike and downdip from six OCS protraction areas along the south end of the South Florida Platform. Three industry and Deep Sea Drilling Project (Bouma et al., 1986) wells south of the platform area record oil shows. However, because it is considered high risk, this play was not assessed in the OCS.

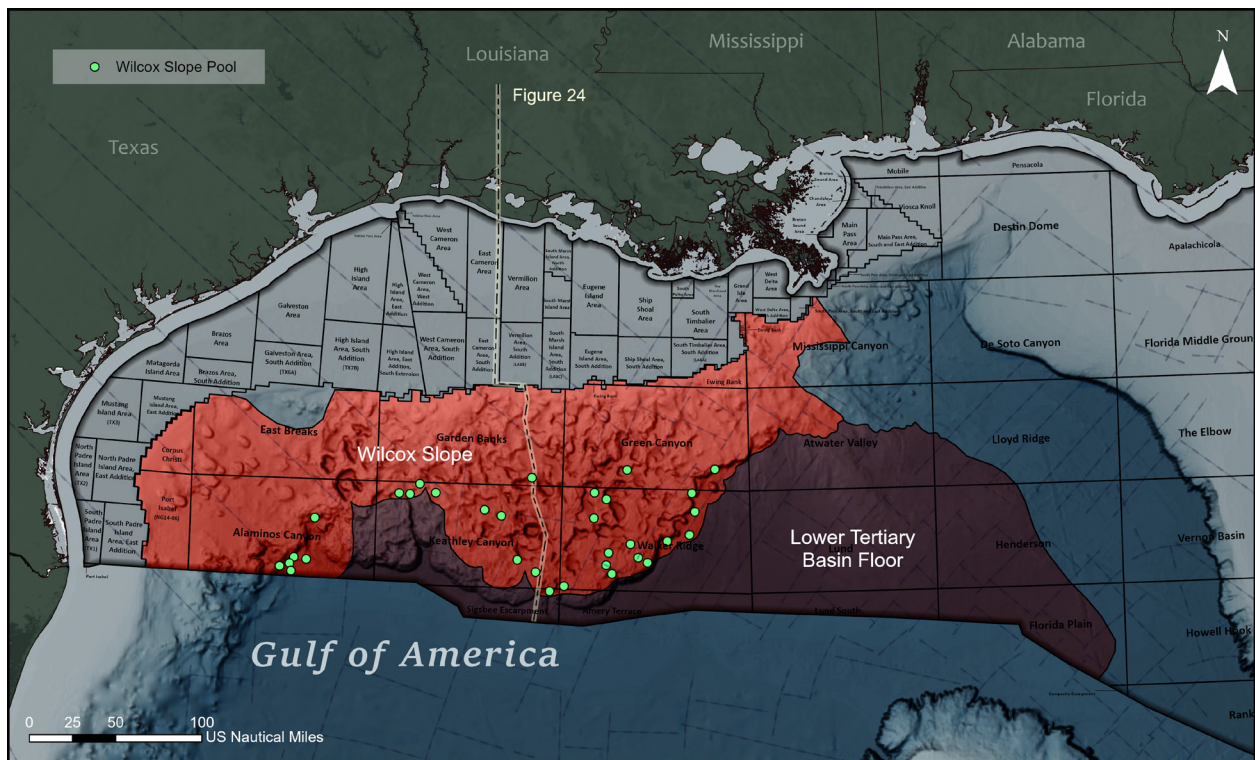
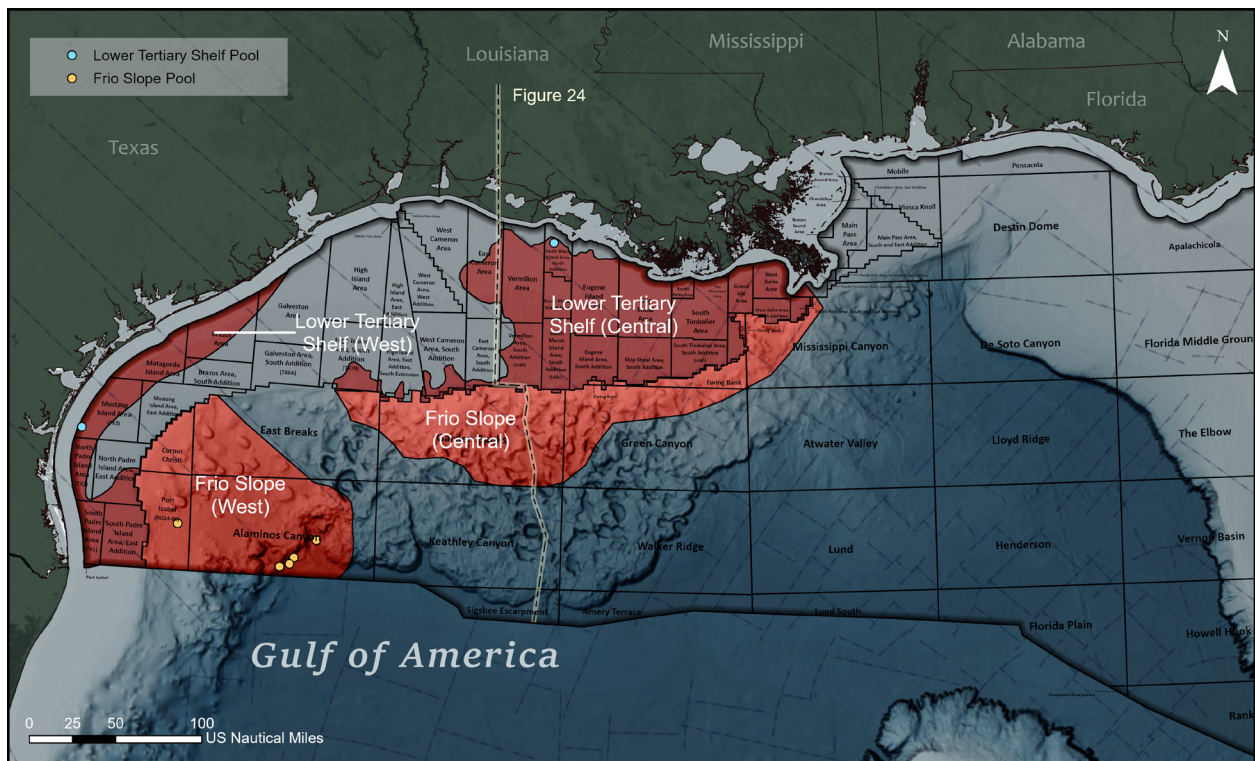
CENOZOIC ASSESSMENT UNITS

LOWER TERTIARY (PALEOGENE)

The Lower Tertiary Shelf, Frio Slope, Wilcox Slope, and Lower Tertiary Basin Floor Plays reference their modern bathymetric, rather than depositional setting (Figure 64 and Figure 65). All plays were deposited in slope or basin-floor environments. Lower Tertiary units include the Upper Paleocene–Lower Eocene Wilcox Formation, the Middle Eocene Queen City, Sparta, and Yegua Formations, the Upper Eocene–Lower Oligocene Jackson Group, and the Oligocene Frio Formation (Figure 25).

The Wilcox and Frio Formations are productive along shelf-margin growth fault trends across the Texas and Louisiana coasts. These sediments were deposited in deltaic and coastal environments. Submarine fans and channels of the Wilcox have been a primary objective of deepwater subsalt exploration for the past two decades. No candidate reservoirs have been encountered in Queen City, Sparta, Yegua, or Jackson sediments in the OCS, and they are not included in this assessment. Production has been established from the Frio Formation in the deepwater GOA in the Perdido Fold Belt. In Mexican waters just across the international boundary from the Perdido Fold Belt, four discoveries—Exploratus, Trion, Maximino, and Supremus—have been announced on analogous structures in Paleogene reservoirs.

The Paleocene is known for thick deposits of sediment in the central and western GOA. The Paleocene–Eocene Thermal Maximum (PETM, Figure 25) was characterized by the highest global temperatures during the Cenozoic. This event is hypothesized to have contributed to the high sediment supply and long run-out distance for Paleocene deposition (Sharman et al., 2017). During Cenozoic time, the grain volume rate of supply had the most predominant shift during Paleocene deposition of the shales that dominate the Midway Group to the sand rich facies of the Wilcox Formation (Figure 25). The rate of sediment supply was three times the average rate for the Cenozoic, resulting in a major progradation of the shoreline and a large volume of sand reaching the basin floor (Galloway et al., 2011). The PETM may have aided in the catchment of the California river drainage, which increased sediment influx by 20% during the Paleocene (Sharman et al., 2017).



Lower Tertiary Shelf (Wilcox and Frio)

Geology

The undifferentiated Lower Tertiary Shelf includes all Paleocene, Eocene, and Oligocene Strata (Table 4 and Figure 25), of which the prospective Upper Paleocene–Lower Eocene Wilcox and Oligocene Frio Formations were assessed. The play includes western and central GOA sectors (Figure 64) likely sourced by different depositional fairways and separated by high-temperature areas that were excluded from the assessment in the same fashion as the underlying **Mesozoic Shelf Play**. Wilcox sediments of the Lower Tertiary Shelf were deposited in slope canyons (McDonnell et al., 2008), intra-slope basins, and basin-floor fans. Frio-aged sediments of the Lower Tertiary Shelf were also deposited in slope and basin-floor settings.

The **western sector** of the Lower Tertiary Shelf Play extends along the Texas coast from the South Padre Island Area adjacent to Mexican waters and into the Galveston Area (Figure 64). The western sector is anchored by a single discovery in the Frio Formation in the Mustang Island 859 Field. Wilcox sediments were likely sourced from the north through the paleo-Colorado or -Brazos axis (Figure 26). Wilcox traps include salt-cored anticlines and folds beneath a regional Eocene salt weld and detachment surface. Deltas of the ancestral Rio Grande or Rio Bravo axis (Figure 26) are likely sediment sources for the Frio reservoirs of the western sector. Potential Frio structures include rollover anticlines and fault traps associated with an array of coast parallel growth faults that sole out into the Eocene detachment. Due to large scale salt withdrawal causing the shelf margin to collapse between the Houston and Norias deltas, there is also the likelihood of mass transport deposits during late Frio time (Ogiesoba and Hammes, 2012).

The **central sector** of the Lower Tertiary Shelf Play encompasses most of the central Louisiana shelf from the East Cameron Area eastward to the modern Mississippi River Delta (Figure 64). The central sector is anchored by a single discovery in the Wilcox Formation in the South Marsh Island 243 Field (Davy Jones Prospect). The Davy Jones well encountered 63 ft true vertical depth thickness of gas in the Lower Eocene Wilcox 1 sandstone, as well as 70 ft true vertical depth thickness of gas in the Upper Paleocene Wilcox 2 and Wilcox 3 sandstones combined. In the central sector, Wilcox sediments were sourced from the north and northwest through ancestral Colorado, Brazos, Red, and Mississippi River fluvial axes, and Frio reservoirs were likely sourced from the north through an ancestral Mississippi River axis (Figure 26). Frio-aged sediments were deposited in slope and basin-floor settings sourced from the paleo-Mississippi fluvial axis (Figure 26). Structurally, the Lower Tertiary Shelf Play is similarly situated to the **Mesozoic Shelf Play** beneath Paleogene and Neogene detachments, horizontal salt welds, and thick, complexly faulted Miocene, Pliocene, and Pleistocene sediments filling salt-withdrawal minibasins (Diegel et al., 1995). Prospective structures of the central sector are situated above many of the same features as the **Mesozoic Shelf Play** and include anticlinal closures above remnant autochthonous salt pillows and folds (Philippe et al., 2005; Dooley et al., 2013) and upthrown three-way closures against the counter-regional salt feeders and welds (Figure 23) that sourced the mostly evacuated paleo-salt canopy now represented by Roho systems (Jamieson et al., 2000).

Discoveries

Discovered resources for the Lower Tertiary Shelf are contained in two BOEM-designated fields—Mustang Island 859 (Frio age) and South Marsh Island 243 (Davy Jones Prospect—Wilcox age). Together, the two pools contain 0.572 MMbbl of oil and 46.404 Bcf of gas (total BOE of 8.829 MMbbl) (Table 8 and Figure 66). Subsea depths for the two discovered pools are 12,648 ft in Mustang Island and 26,789 ft in South Marsh Island, and water depths of the two pools are less than 100 ft.

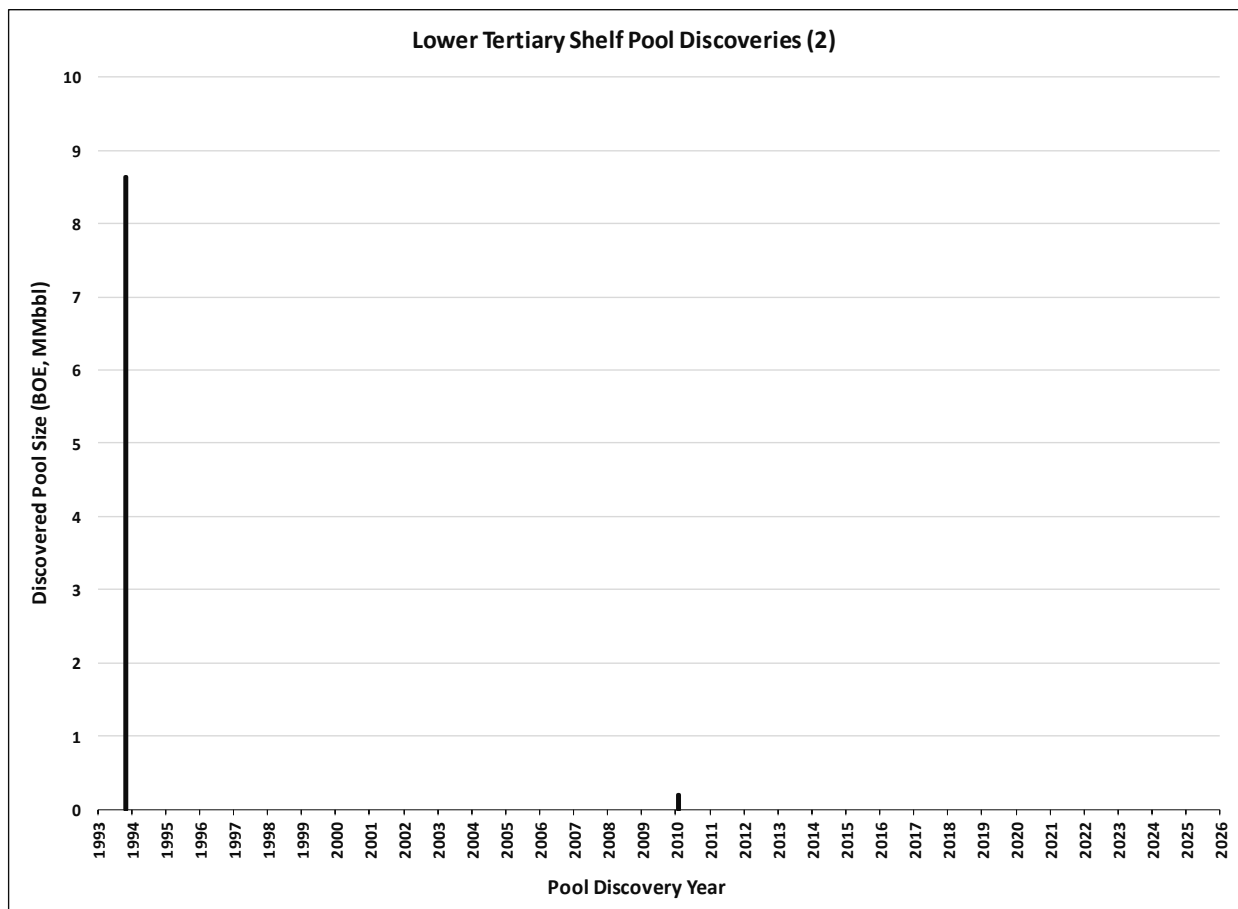


Figure 66. Lower Tertiary Shelf pool discovery history.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% (Figure 3)
- prospect-level: 18% (Figure 4)
- exploration-level: 18% (Figure 5)

Most of the Galveston, High Island, West Cameron, and East Cameron Areas were excluded (Figure 64) from prospectivity due to high anticipated subsurface temperatures in excess of 460 °F (238 °C), as seen in the Will K (High Island Block A119) and Davy Jones (South Marsh Island Block 230) Prospects. Such high temperatures pose risks for hydrocarbon stability, reservoir diagenesis, and operations. “Tight” reservoirs due to the diagenetic effects of high pressures and temperatures have led to failed flow rate tests. Even though a working petroleum system has been established for both Wilcox and Frio rocks in the OCS, the high pressure and temperature environments encountered condemn the prospect-level reservoir-quality component of risk analysis. See Appendix B for details.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and a portfolio of mapped closures and proxy structures associated with autochthonous salt pillows, salt feeders, and vertical welds. Many of these structures are coincident with traps used for the Mesozoic Shelf Play. From this, the assessors determined that the number of prospects ranges from 60 to 140. Applying risk results in 11 to 25 undiscovered pools, with a mean of 18.

The pool-size distribution was modeled with the discoveries and mapped prospects in the play. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest six pools are undiscovered, with the largest being approximately 57 MMBOE.

From the discovered data information, the play was modeled as 100% gas, with GRASP returning UTRR volumes for dry gas and condensate liquids (oil herein). Assessment results indicate that undiscovered oil resources range from 5 to 23 MMbbl, and undiscovered gas resources range from 432 to 1,877 Bcf at the 95th and 5th percentiles, respectively (Table 8 and Figure 67). Of all 30 assessment units in this study, the Lower Tertiary Shelf ranks 22nd based on mean-level undiscovered BOE resources (Figure 10).

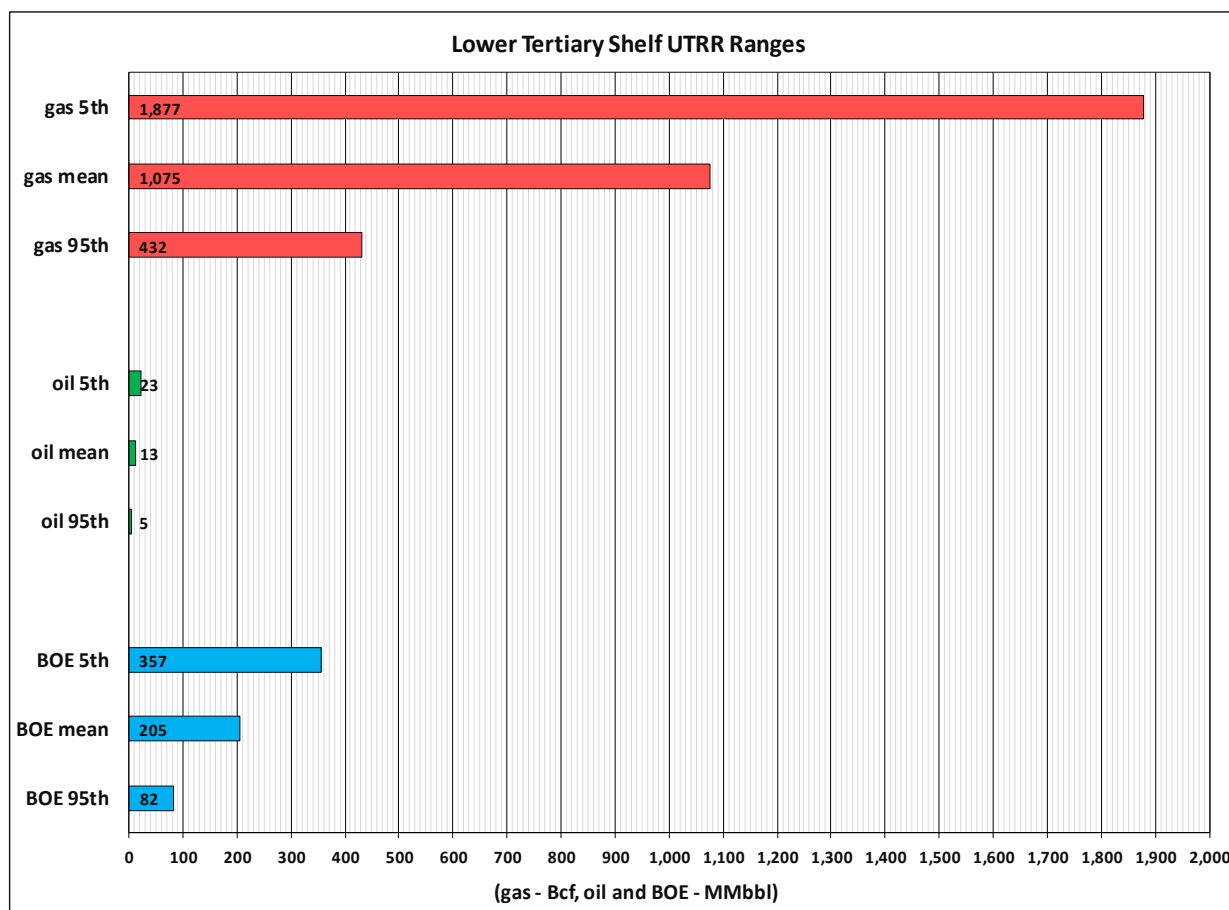


Figure 67. Lower Tertiary Shelf gas, oil, and BOE UTRR ranges.

Frio Slope

Geology

The Frio Slope Play is split into western and central GOA sectors (Figure 64) that are downdip equivalents of the Lower Tertiary Shelf Play sectors. Onshore and beneath the modern shelf, large volumes of Frio sediments were sequestered behind rotated fault blocks above regional detachment surfaces linked to gravity gliding and salt evacuation in downdip areas (Brown et al., 2004). Furthermore, large areas of the Texas and Louisiana shelf were also occupied by a paleo-salt canopy formed in Eocene time that may have further obstructed Frio sediments from reaching the deep basin (Peel et al., 1995; Snedden and Galloway, 2019, their Figure 5.17). However, some Frio sediments were able to negotiate pathways through salt-induced depositional topography of the slope into slope minibasins and onto the basin floor.

The **western sector** of the Frio Slope Play traverses the Port Isabel and Perdido Fold Belts (**Figure 64**), which are the structures the Frio discoveries are associated with. Frio reservoirs are amplitude-associated on seismic data and generally exhibit higher porosities and permeabilities than those in the Wilcox, but contain low gravity, biodegraded oils. Deltas of the ancestral Rio Grande or Rio Bravo axis (**Figure 26**) are likely sediment sources for the Frio reservoirs of the western sector.

The **central sector** of the Frio Slope Play includes the Garden Banks Area east of the Brazos Transfer Fault (BTF, **Figure 23**), northern Green Canyon, Ewing Bank, and northwestern Mississippi Canyon Areas. Along depositional dip, the central sector extends from the modern shelf-slope break downdip to the limit of negative well control. Oligocene section in the central sector has been penetrated by numerous wells drilled to test deeper Wilcox objectives, and no appreciable Frio reservoirs have been encountered. However, the possibility remains that Frio deepwater systems may have traversed the slope through discrete fairways, perhaps ponding behind inflated salt of the outer marginal trough that would evolve into the roots and feeders of the Sigsbee Salt Canopy. A similar setup has been observed in the **Lower Miocene Slope AU**. Frio reservoirs of the central sector were likely sourced from the north through an ancestral Mississippi River axis (**Figure 26**).

Discoveries

As of this study, there are no discoveries in the central sector. Frio pools in the western sector are contained in five BOEM-designated pools, with the first two discovered in 1996 (**Figure 68**). Together they contain 349 MMbbl of oil and 247 Bcf of gas (total BOE of 393 MMbbl) (**Table 8**). Alaminos Canyon 857 and 859 are the only pools of Frio-age in the slope with volumes greater than 50 MMBOE (**Figure 68**). For the discovered Frio pools in the western sector, water depths range from 3,381 ft in Port Isabel to 9,373 ft in Alaminos Canyon, and subsea depths average around 11,000 ft.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% (**Figure 3**)
- prospect-level: 15% (**Figure 4**)
- exploration-level: 15% (**Figure 5**)

With a proven Frio petroleum system on the OCS slope, there is no play-level risk. However, the reservoir quality and effective seal mechanisms of these Frio rocks were deemed the riskiest aspect at the prospect level. See **Appendix B** for details.

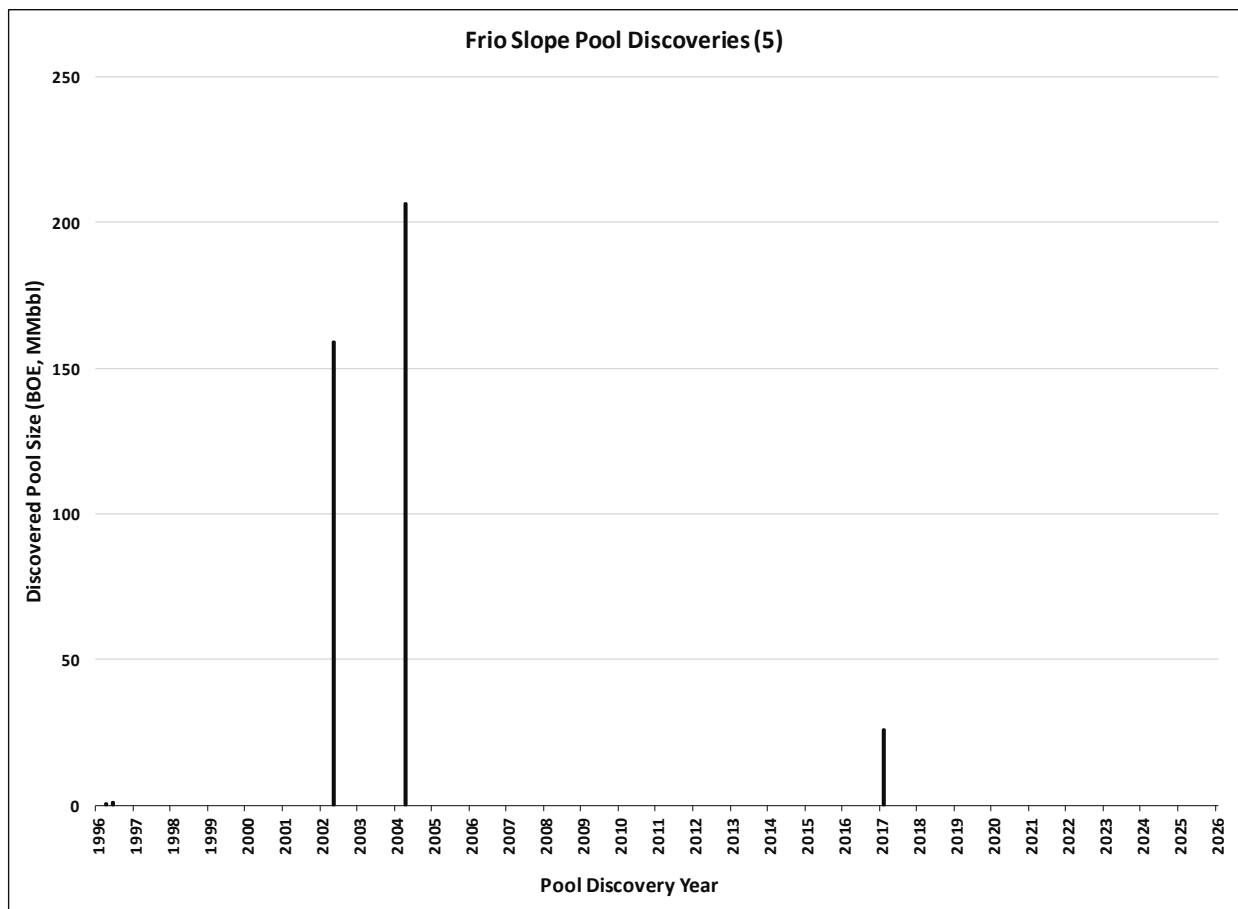


Figure 68. Frio Slope pool discovery history.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and a portfolio of mapped closures and proxy structures associated with autochthonous salt pillows, salt feeders, and vertical welds. From this, the assessors determined that the number of prospects ranges from 73 to 189. Applying risk results in 11 to 28 undiscovered pools, with a mean of 20.

The pool-size distribution was modeled with the discoveries and mapped prospects in the play. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 51 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 61 to 388 MMbbl, and undiscovered gas resources range from 42 to 268 Bcf at the 95th and 5th percentiles, respectively (Table 8 and Figure 69). Of all 30 assessment units in this study, the Frio Slope ranks 21st based on mean-level undiscovered BOE resources (Figure 10).

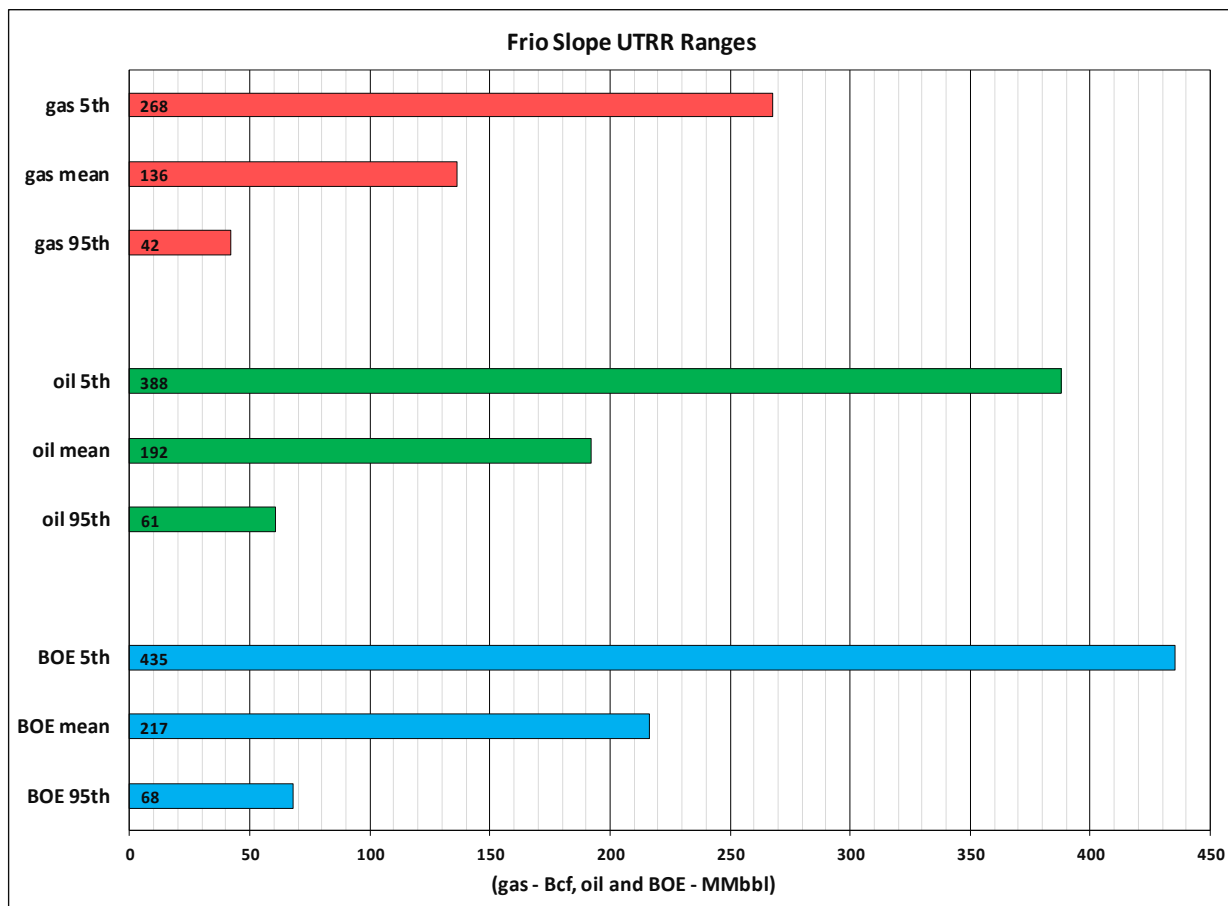


Figure 69. Frio Slope gas, oil, and BOE UTRR ranges.

Wilcox Slope

Geology

The Wilcox Slope Play extends from the modern shelf-slope break downdip to the basinward limit of the Mesozoic salt nappes that advanced onto oceanic crust beneath the modern abyssal plain (Figure 23 and Figure 65). The play extends from Mexican waters westward encompassing the Perdido, Keathley, Walker Ridge, and western Atwater Fold Belts and terminates at a NW-SE trending boundary associated with vertical salt welds and feeders generally aligned with the underlying Mississippi River Transfer Fault (MRTF, Figure 23). The play generally sits astride the region of uncertain crustal type at the continent-ocean transition (Figure 20). Basement structure and crustal variations in this region have influenced patterns of subsequent salt deposition and allochthonous deformation, source rock distribution, burial history, and sediment fairways.

Structural traps in the Perdido Fold Belt are anticlines and thrusts above a series of elongate SW-NE trending, salt-cored detachment folds that terminate to the northeast along the underlying Keathley Transfer Fault (KTF, Figure 23). Salt serving as the basal detachment layer for the Perdido Fold Belt was sourced from a NE-SW trending autochthonous thick in the region of the Bravo Trough (BT, Figure 21) and was buttressed to the south against a positive basement feature termed the “Baha High” (Hudec et al., 2020). The Bravo Trough is believed to have been occupied by a large, inflated salt diapir from Mesozoic to Oligocene time. Increased sediment supply associated with Cordilleran uplift provided a large volume of eroded sediment from Oligocene to Miocene time which evacuated the Bravo Diapir into the segments of the allochthonous Sigsbee Salt Canopy (Figure 22) overriding the Perdido Fold Belt (Figure 23) and filled

the accommodation space created in the Bravo Trough. Updip extension and translation was accomplished along Oligocene-to-Cretaceous aged shale detachments.

Paleogene reservoirs of the Perdido Fold Belt are generally shallower (less than 20,000 ft, with an average depth of approximately 14,000 ft) than in the central GOA (25,000 to greater than 35,000 ft) (U.S. DOI, 2021a). In spite of the shallower depths, subsurface temperatures are higher due to heat-wicking effects of the allochthonous salt canopy that has reduced the geothermal gradient in the central GOA and perhaps in part due to differences in basement geology, crustal type, and basal heat flow west of the Brazos Transfer Fault (BTF, [Figure 23](#)).

There is a more diverse suite of trapping styles in the Wilcox Slope Play in the central GOA (see Hart and Albertin, 2001). At the basinward limit of the trend are four-way anticlinal closures above deep allochthonous salt pillows, which are remnants of the Mesozoic salt nappes ([Figure 23](#)). Some of these structures are basinward of the Sigsbee Salt Canopy (i.e., not subsalt) and have been referred to by industry as the “Outboard” Lower Tertiary Trend. Moving “inboard” beneath the salt, the salt-cored folds and thrusts of the Keathley, Walker Ridge, and western Atwater Fold Belts are encountered ([Figure 23](#)). Progressing farther inboard or shelf-ward are increasingly complex structures related to salt withdrawal. Traps are typically three-way closures against salt feeders or vertical salt welds. Of note are “bucket-weld basins” ([Figure 24](#)), which are minibasins filled with younger Neogene sediments and enclosed by vertical salt welds (Pilcher et al., 2011). These basins are the remnants of collapsed salt diapirs, feeders, and inflated pillows that sourced the modern Sigsbee Salt Canopy. The salt-cored paleo-highs that once occupied the footprints of these relict bucket-weld basins may have influenced depositional fairways across the paleo-slope and onto the basin floor. Mesozoic source rocks and the Paleogene section are typically absent within the bucket-weld basins, either from nondeposition or rafting and downdip translation of the carapaces above the inflated salt bodies onto the basinward spreading salt canopy (Fiduk et al., 2014). Three-way traps against the vertical welds on the exterior of the bucket-weld basins and major counter-regional salt welds and feeders of the Sigsbee Salt Canopy are predominant in the northern-most reaches of the play.

Wilcox sediments were deposited as deepwater basin-floor fans under the influence of salt-induced depositional topography. Reservoir facies include amalgamated sheets and channels. Submarine-fan systems to the west in the East Breaks and Alaminos Canyon Areas, including the Perdido Fold Belt, were likely sourced from Colorado and Brazos fluvio-deltaic axes ([Figure 26](#)). Fan systems in the Garden Banks, Green Canyon, Keathley Canyon, and Walker Ridge Areas were likely sourced from a paleo-Mississippi River axis ([Figure 26](#)). The Wilcox of the deepwater subsalt region thins from west to east (Zarra, 2007) and is generally condensed across the Atwater Valley and Mississippi Canyon Areas, presumably because inflated salt diverted sediment fairways and limited available accommodation space.

Discoveries

BOEM-designated discoveries occur in the Alaminos Canyon, Garden Banks, Keathley Canyon, Walker Ridge, Green Canyon, and Sigsbee Escarpment Areas ([Figure 65](#)). BOEM has estimated sizes of 32 pools, with discovery dates ranging from 2001 to 2020 ([Figure 70](#)). The play contains 4,643 MMbbl of oil and 2,826 Bcf of gas (total BOE of 5,146 MMbbl) ([Table 8](#)). Discovered in 2008, Keathley Canyon 872 (Buckskin) is the largest pool, containing an estimated 748 MMBOE ([Figure 71](#)). Other sizeable, discovered pools include Alaminos Canyon 857 (Great White), Walker Ridge 678 (St. Malo), Green Canyon 807 (Anchor), and Walker Ridge 759 (Jack), all estimated to contain more than 300 MMBOE ([Figure 71](#)). Pools have been discovered in water depths ranging from 3,910 to 9,693 ft, and subsea depths of these pools range from 12,750 to 32,219 ft.

[Figure 72](#) illustrates cumulative resources for Wilcox Slope pool discoveries through time and the size of the discoveries. Generally, the curve for the Wilcox Slope is still in an ascending phase, with pool

discoveries at Walker Ridge 272 (Monument), Alaminos Canyon 380 (Blacktip), and Alaminos Canyon 772 (Whale) adding significant resources since 2016.

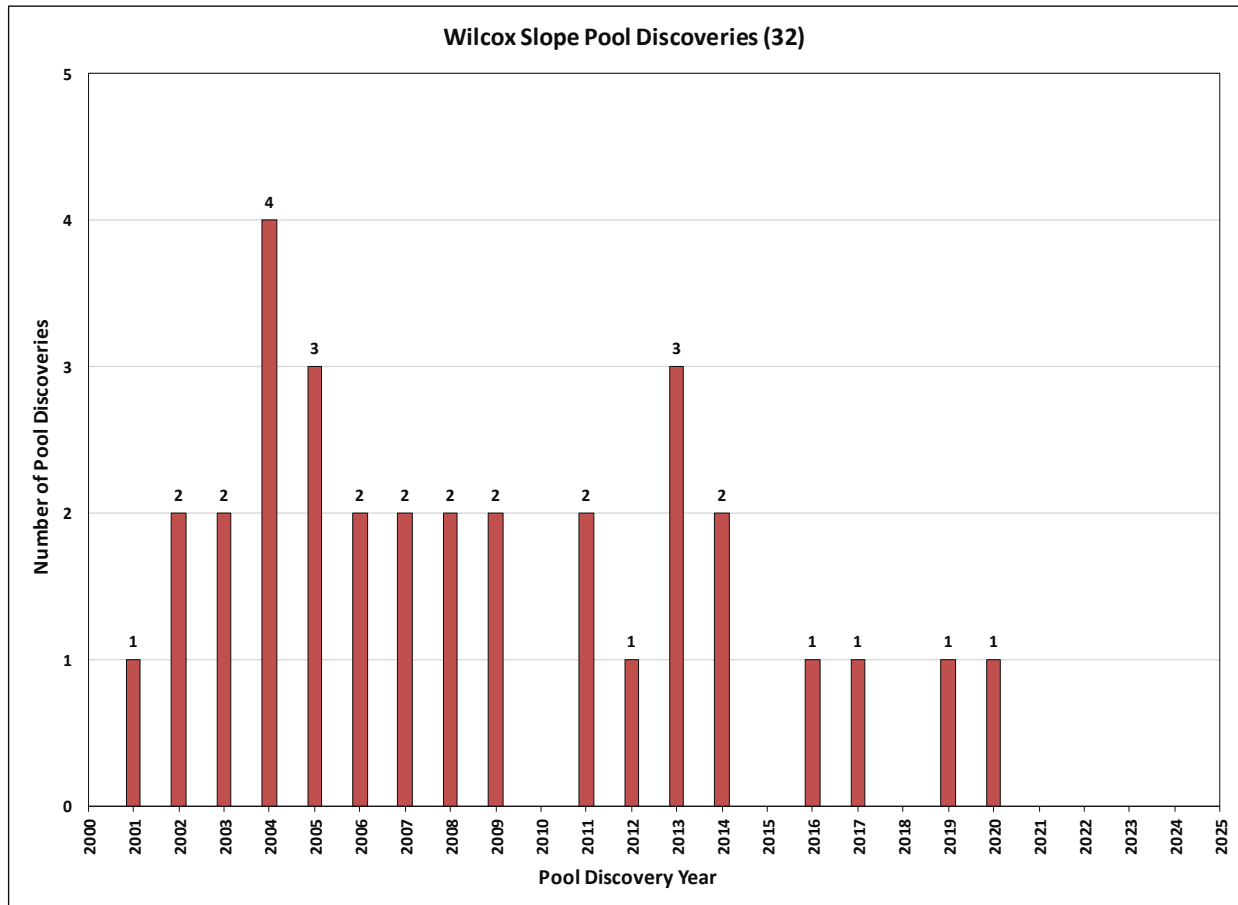


Figure 70. Wilcox Slope pool discovery history.

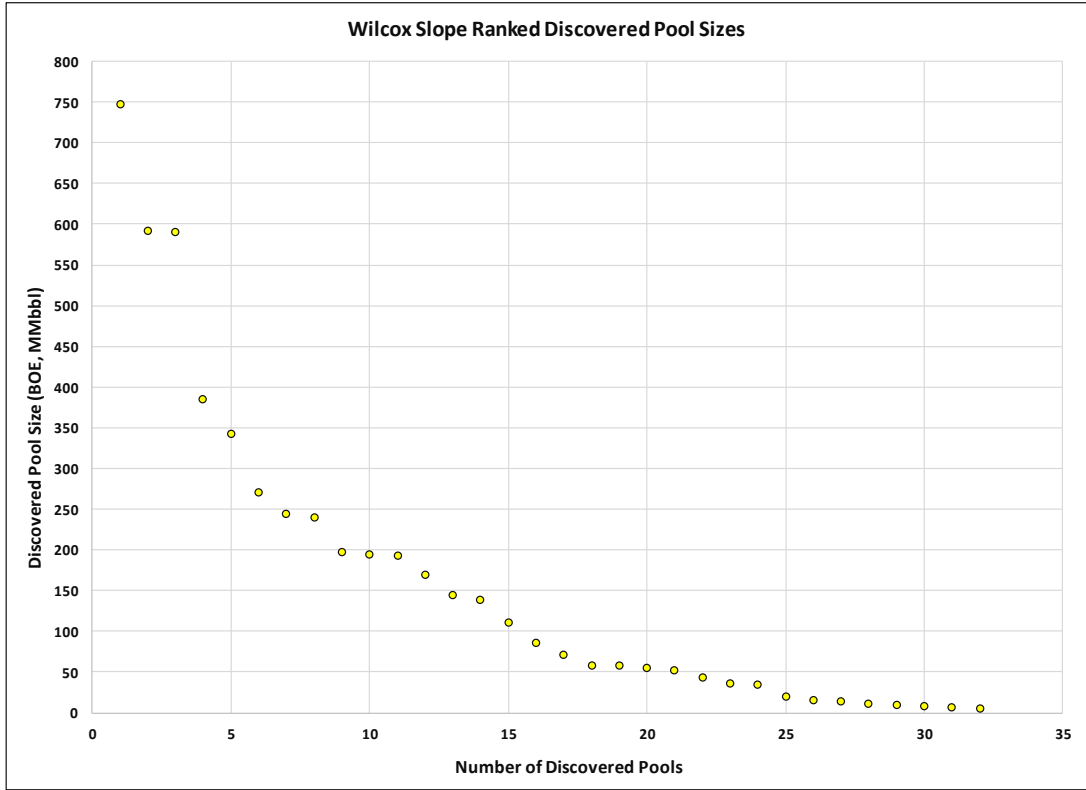


Figure 71. Wilcox Slope discovered pool-rank plot.

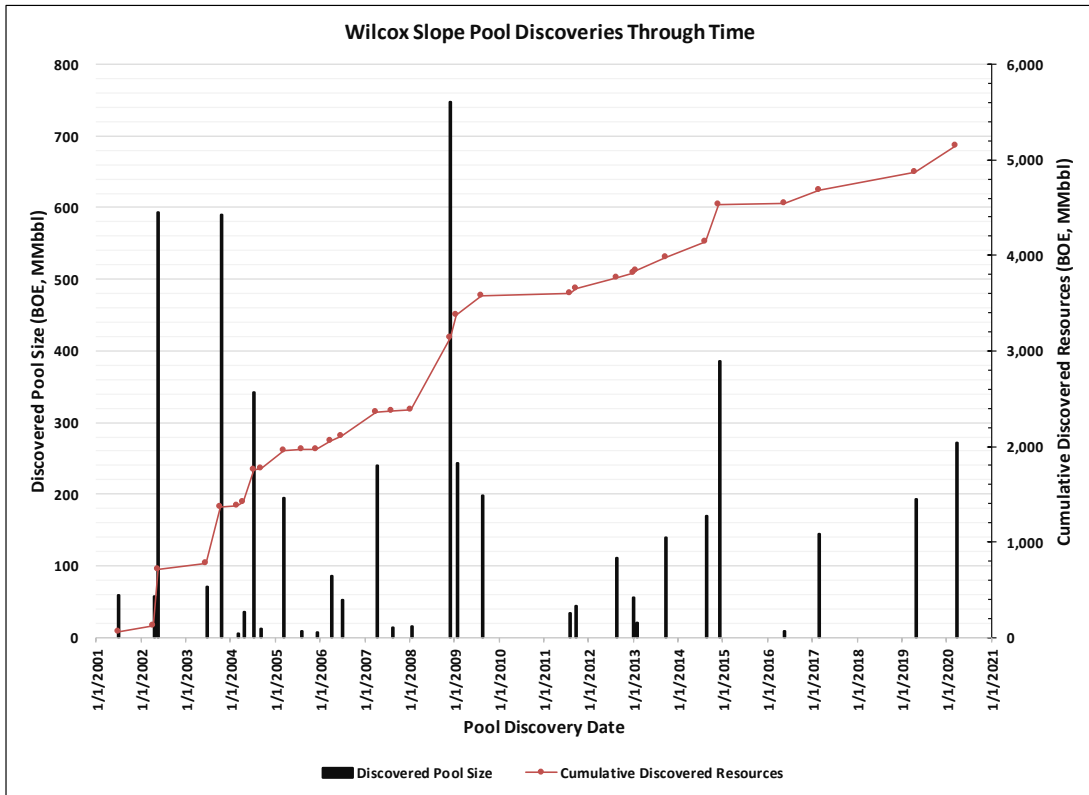


Figure 72. Wilcox Slope pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 25% ([Figure 5](#))

With numerous commercial discoveries and hydrocarbon encounters in the play, there is no play-level risk, as a working petroleum system has been well established for the Wilcox Formation in the deepwater OCS. At the average conditional prospect-level, it was deemed that the reservoir quality and effective seals were the most problematic. Wilcox reservoirs are often referred to as “tight,” because more diagenesis has occurred than within younger Cenozoic rocks (e.g., the prolific reservoirs of Miocene age), decreasing the porosity and permeability. However, based on its discovery history, the Wilcox Slope is one of the least risky plays in the GOA, with an overall exploration chance of success of 25%. See [Appendix B](#) for details.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and a portfolio of mapped closures and proxy structures associated with autochthonous salt pillows, salt feeders, and vertical welds. From this, the assessors determined that the number of prospects ranges from 175 to 525. Applying risk results in 44 to 132 undiscovered pools, with a mean of 88.

The pool-size distribution was modeled with the discoveries in the play, which range in size from 6 to 748 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 584 MMBOE.

From the discovered data information, the play was modeled as 100% oil, with GRASP returning UTRR volumes for black oil and solution gas. Assessment results for the Wilcox Slope indicate that undiscovered oil resources range from 4,329 to 13,853 MMbbl, and undiscovered gas resources range from 2,636 to 8,436 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 73](#)). Based on mean-level undiscovered BOE resources, the Wilcox Slope is forecast to contain the most potential of all 30 GOA assessment units ([Figure 10](#)).

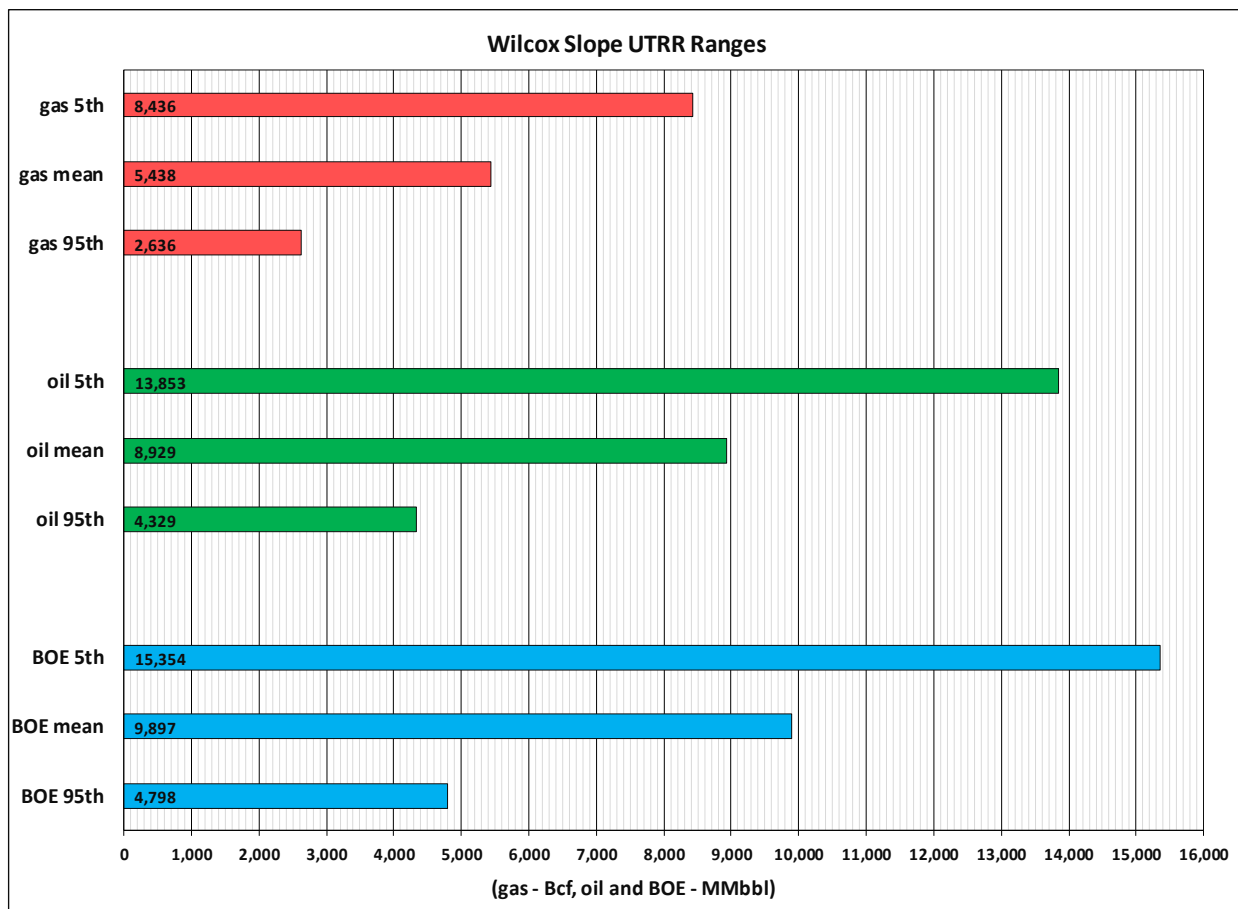


Figure 73. Wilcox Slope gas, oil, and BOE UTRR ranges.

Lower Tertiary Basin Floor

Geology

The undifferentiated Lower Tertiary Basin Floor Play contains no discoveries and conceptually includes all Paleocene, Eocene, and Oligocene strata. The play is situated outboard of the Perdido, Keathley, Walker Ridge, and Atwater Fold Belts and extends from the distal edge of the Mesozoic salt nappes (Figure 23) downdip to the limits of U.S. waters (Figure 64). The play generally coincides with the modern abyssal plain but does extend inboard of the Sigsbee Escarpment, beneath the canopy in eastern-most Alaminos Canyon, western Keathley Canyon, Sigsbee Escarpment, Amery Terrace, and Walker Ridge Areas.

The Lower Tertiary section beneath the abyssal plain has not been penetrated by wells and is known only from seismic facies and structural mapping. Structurally, the Lower Tertiary section climbs from approximately 30,000 ft just outboard of the Sigsbee Escarpment to approximately 24,000 ft as it approaches the Campeche Escarpment to the south. Prospects in the play include (1) an inventory of subtle compactional drape closures associated with underlying basement structures that had been included in the Buried Hills Drift Play of previous BOEM assessments (e.g., Lore et al., 2001), and (2) a portfolio of large stratigraphic traps inferred from seismic facies that are syncline-separated from discoveries in the outboard Wilcox Slope Play.

Likely source rocks are Tithonian, with lesser contributions from the Cretaceous and Lower Tertiary sections. However, through seismic correlation to well control, Tithonian source rocks are demonstrably absent above the crests of the high-standing basement features along the Jurassic spreading center. Thermal maturity of Cretaceous and Lower Tertiary source rocks is also a concern due to lesser burial

depths and lower heat flow from oceanic crust. Attribute extractions from recently acquired 3D seismic surveys have demonstrated intricate networks of Wilcox channels traversing the distal reaches of the Lower Tertiary Basin Floor Play, increasing the likelihood of sandstone reservoirs in the distal fan.

The Oligocene section is relatively condensed and is characterized by an intricate network of strata-bound polygonal faults interpreted as fluid escape structures (Loneragan and Cartwright, 1999). Along the front of the Sigsbee Escarpment, the Oligocene section also serves as a detachment layer for the frontal lobes of the Sigsbee Salt Canopy (Fiduk et al., 2016). Base of salt keels pass downward into listric faults that parallel the front of the canopy and sole out into an Oligocene detachment (Fiduk et al., 2016).

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 56% ([Figure 3](#))
- prospect-level: 18% ([Figure 4](#))
- exploration-level: 10% ([Figure 5](#))

With no proven petroleum system, the Lower Tertiary Basin Floor Play is one of the riskiest in the OCS. See [Appendix B](#) for details.

Undiscovered Resources

The number of prospects was estimated from an inventory of 301 drape closures mapped on a regional grid of 2D seismic data. However, only 122 closures of greater than 1,000 acres were considered. Additionally, four very large (45,000–160,000 acres) stratigraphic traps were included. From this, the assessors determined that the number of prospects ranges from 40 to 120. Applying risk results in 0 to 40 undiscovered pools, with a mean of 8.

The pool-size distribution for this conceptual play was modeled with 14 outboard [Wilcox Slope](#) discoveries in the deepwater OCS. These pools range in size from 9 to 748 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is approximately 478 MMBOE.

The play was modeled as 100% oil. Based on GORs from the 14 Wilcox Slope pool volumes, GRASP returned UTRR volumes for black oil and solution gas. Because there is play-level risk, only 56% of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 3,042 MMbbl at the 5th percentile, with a mean of 1,004 MMbbl, and 876 Bcf at the 5th percentile, with a mean of 289 Bcf, respectively ([Table 8](#) and [Figure 74](#)). Of all 30 assessment units in this study, the Lower Tertiary Basin Floor ranks 8th based on mean-level undiscovered BOE resources ([Figure 10](#)).

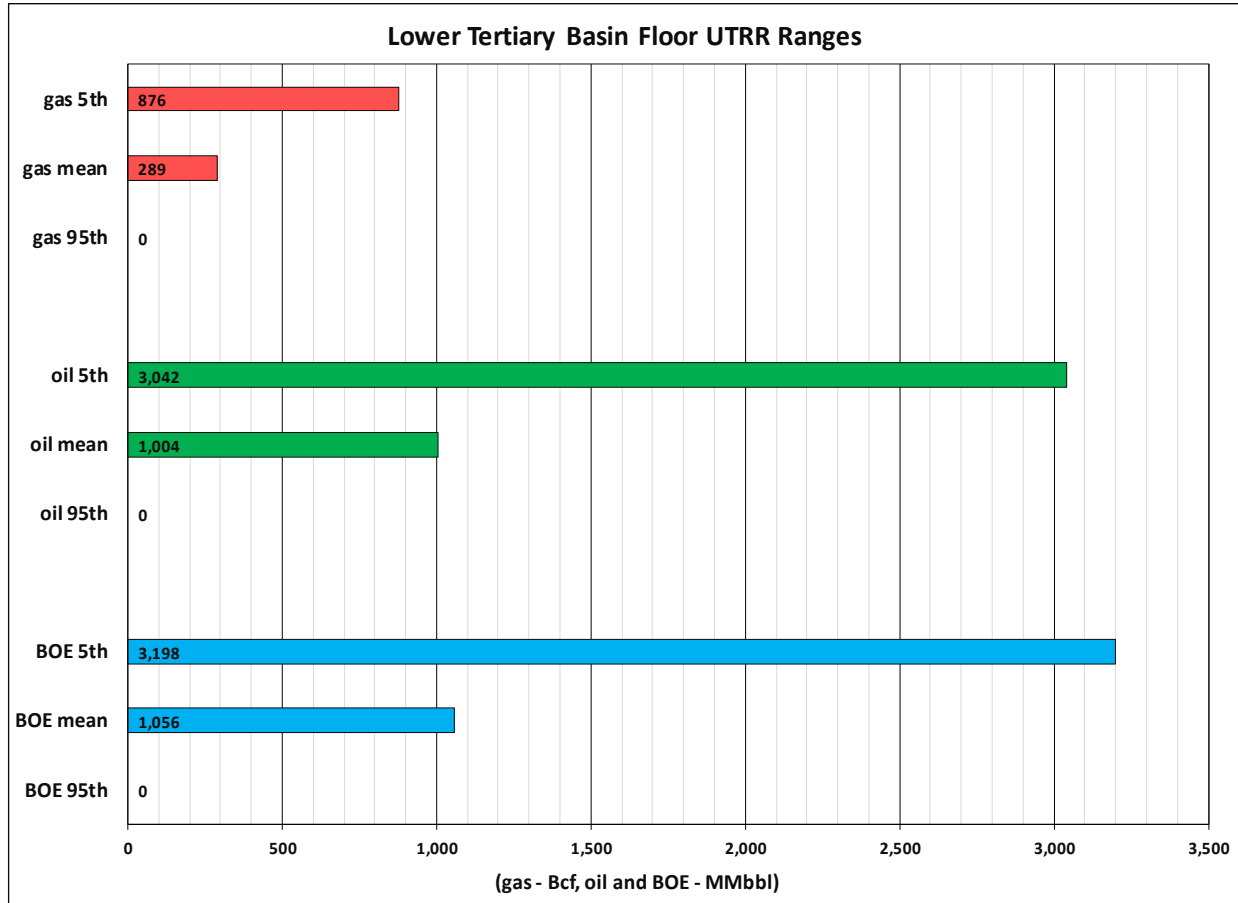


Figure 74. Lower Tertiary Basin Floor gas, oil, and BOE UTRR ranges.

NEOGENE AND QUATERNARY

The Neogene and Quaternary Shelf, Slope, and Basin Floor AU locations reference modern GOA bathymetric, rather than depositional setting and are identical for Miocene, Pliocene, and Pleistocene AUs (Figure 2).

The **Miocene, Pliocene, and Pleistocene Shelf AUs** extend along strike from Mexican waters in the west and onlap the Cretaceous shelf margin in the east. In the dip direction, they extend from State waters to the modern shelf-slope break at a water depth of 656 ft (200 m). Along the Texas coast, Neogene and Quaternary structures include rollover anticlines and fault traps associated with an array of coast parallel growth faults, including the Clemente-Tomas, Lunker, Corsair, and Wanda Fault Systems (Figure 23). Beneath the distal reaches of the eastern Texas shelf and the entirety of the Louisiana shelf is a diverse array of allochthonous salt bodies and associated feeders and welds as well as related faults, fault traps, and rollover anticlines (Figure 23).

The **Miocene, Pliocene, and Pleistocene Slope AUs** extend along strike from Mexican waters in the west and onlap the Cretaceous shelf margin in the east. In the dip direction, they extend from the modern shelf-slope break to the basinward limit of the Sigsbee Salt Canopy (Figure 22). Beyond the eastward limit of the Sigsbee Salt Canopy, the distal limit of the Slope AUs follows the basinward limit of the Mesozoic salt nappes (Figure 23). The Slope AUs encompass the entire area of the Sigsbee Salt Canopy and are underlain by numerous salt diapirs, tabular salt bodies, salt stocks, welds, and feeders. Reservoirs are in both subsalt primary basins and suprasalt secondary basins (Figure 24). Traps include salt flanks, salt welds, subsalt truncations, base of salt closures, and four-way turtle structure anticlines. The Slope AUs

also include the Perdido, Keathley, Walker Ridge, and western Atwater Fold Belts, which are situated just inboard of the distal reaches of the overlying Sigsbee Salt Canopy and include thrust and anticlinal closures.

The unassessed **Neogene–Quaternary Basin Floor AU** extends basinward from the distal edge of the Sigsbee Salt Canopy or the Mesozoic salt nappes (Figure 23) and encompasses the modern abyssal plain to the limit of U.S. waters (Figure 2). Salt is absent and structures are limited to drape closures above deep basement highs and subtle stratigraphic and compactional drape closures.

Lower Miocene Shelf

Geology

The Lower Miocene Shelf AU is defined by sediments deposited in the Aquitanian and Burdigalian Stages (Table 4) within the modern GOA shelf. The stratigraphic framework within the GOA Basin for Lower Miocene rocks is illustrated in Figure 25. The Shelf AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east, and in the dip direction, it extends from state waters to the modern shelf-slope break at a water depth of 656 ft (200 m) (Figure 75).

The Lower Miocene shelf margin was situated just beyond and parallel to the modern shoreline from south Texas to the central Louisiana coast where it passes onshore and re-emerges east of the modern Mississippi Delta (Snedden and Galloway, 2019). Deltas were fed from the Rio Grande, Red River, and Mississippi River Systems (Figure 26). Representative depositional facies include (1) distributary mouth bars, delta fringes, marine bars, channel-levee complexes, and crevasse splays in Lower Miocene shelf environments and (2) deepwater turbidites deposited basinward of Lower Miocene shelf margins on the upper and lower slopes in topographically low areas between salt structure highs and on the abyssal plain.

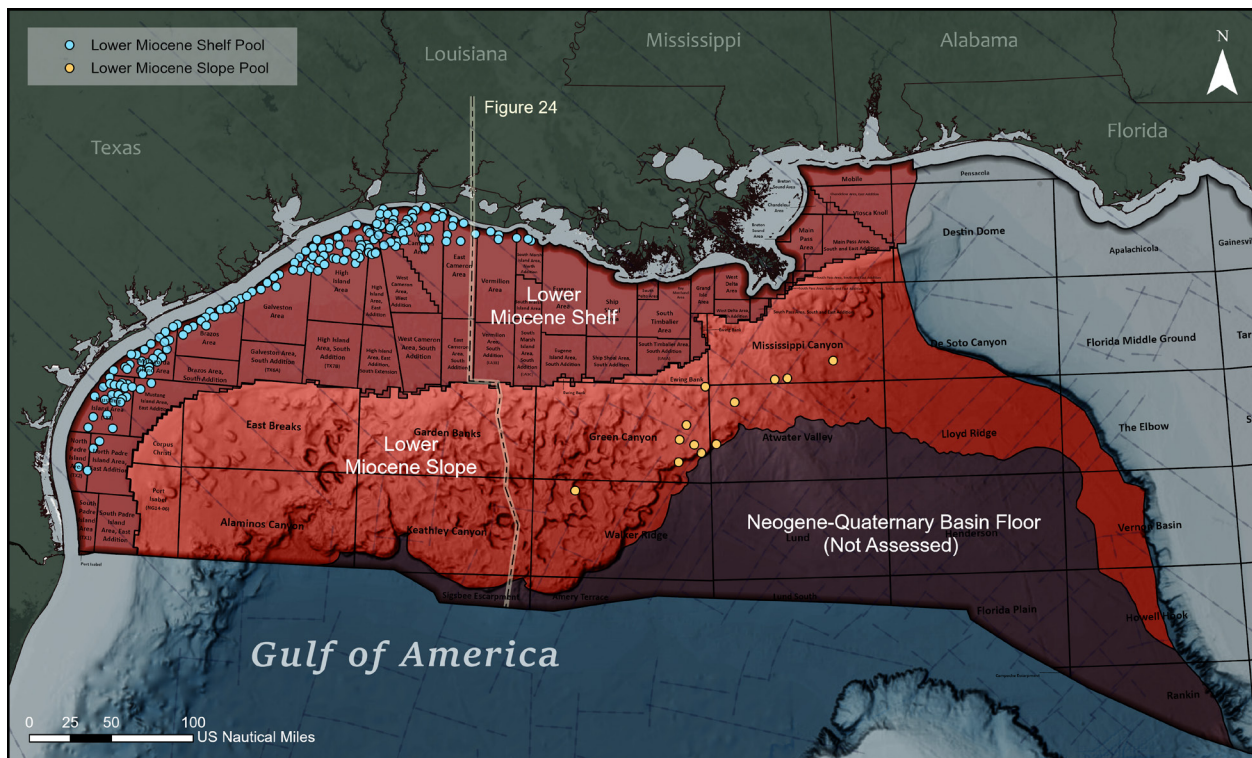


Figure 75. Lower Miocene Shelf and Slope locations and associated discovered pools.

The Shelf AU in the western GOA includes upthrown three-way fault closures and downthrown rollover anticlines along down-to-the-basin growth faults (Figure 22) associated with regional shale detachments and shale diapirs. Across the Louisiana shelf, the AU is characterized by traps against and above remnant allochthonous salt bodies and upthrown three-way fault closures or downthrown rollover anticlines along growth faults associated with salt-withdrawal minibasins (Figure 24). The proven portion of the Shelf AU passes onshore across the central Louisiana coast. Potential traps on the distal shelf include subsalt or subweld closures upthrown to counter-regional salt feeders or welds.

Discoveries

BOEM-designated hydrocarbon discoveries lie in shallow OCS waters of offshore Texas and the southwest Louisiana coast (Figure 75). There are 168 total pools, and discovery dates range from 1949 to 2013 (Figure 76). The Shelf AU contains 307 MMbbl of oil and 22,801 Bcf of gas (total BOE of 4,364 MMbbl) (Table 8). Discovered in 1980, Matagorda Island 623 is the largest pool, containing an estimated 304 MMBOE (Figure 77). Other sizeable, discovered pools include Vermilion 14, West Cameron 45, and West Cameron 71, all estimated to contain more than 200 MMBOE (Figure 77). Pools have been discovered in water depths ranging from 13 to 213 ft, and subsea depths of these pools range from 4,717 to 19,632 ft.

Figure 78 illustrates cumulative resources for Shelf AU pool discoveries through time and the size of the discoveries. Most of the largest pools were found in the early history of exploration, with relatively little resources being added present day. The most recent OCS pool was found in 2013 (Figure 76).

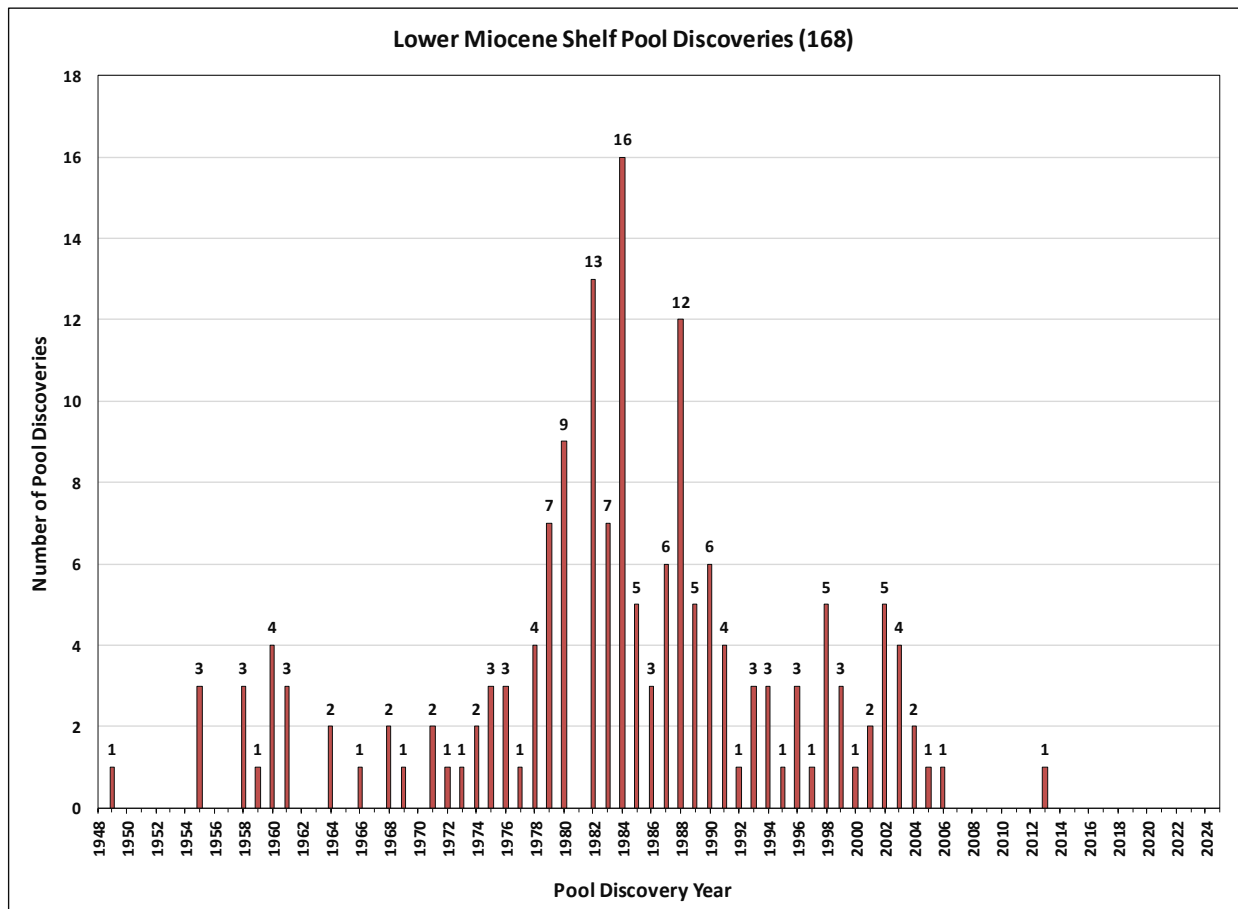


Figure 76. Lower Miocene Shelf pool discovery history.

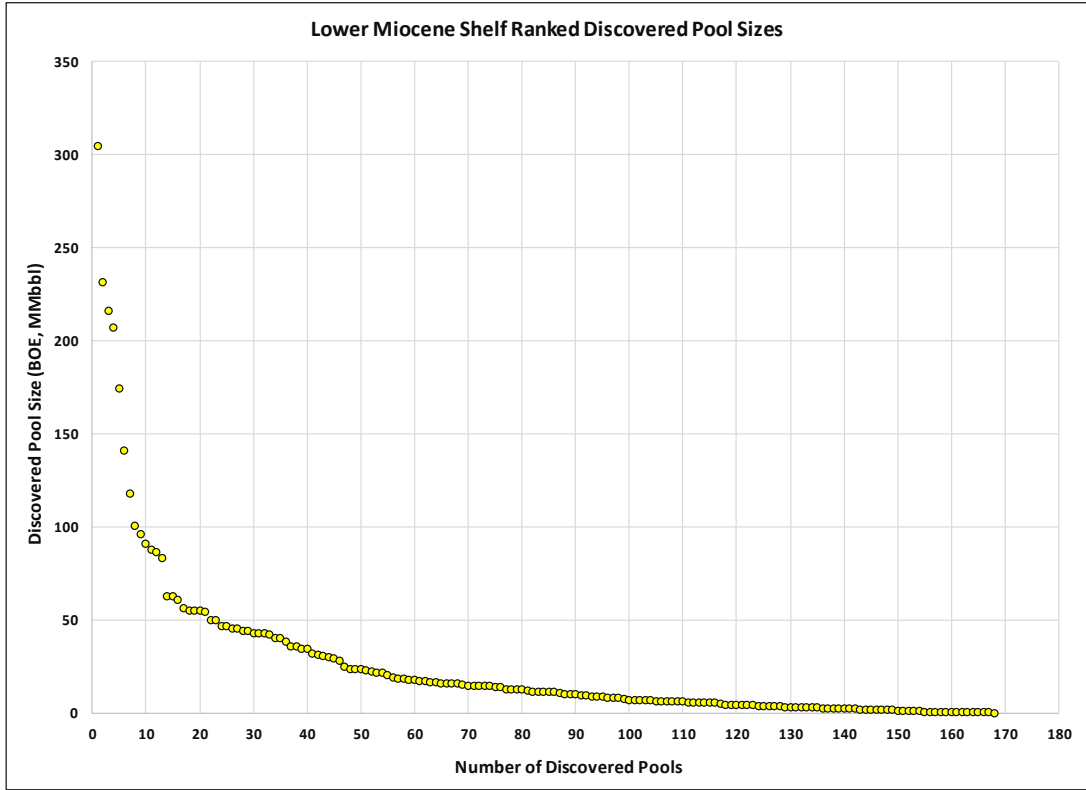


Figure 77. Lower Miocene Shelf discovered pool-rank plot.

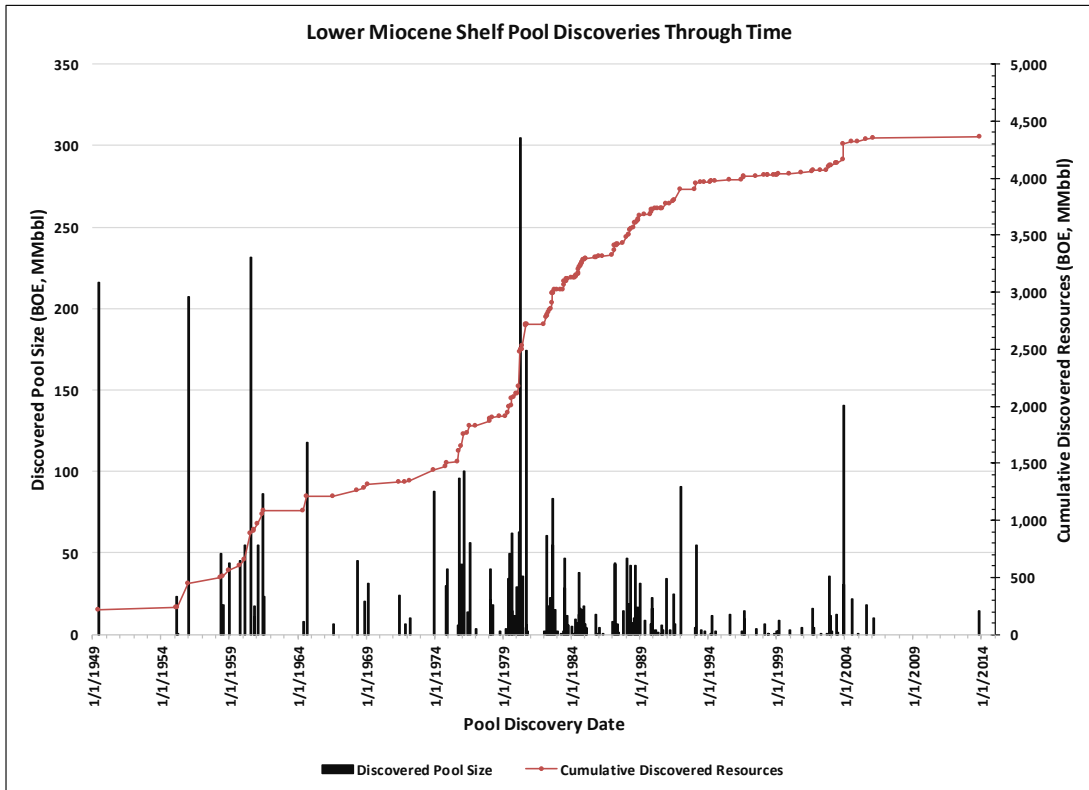


Figure 78. Lower Miocene Shelf discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 21% ([Figure 4](#))
- exploration-level: 21% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 48 to 286. Applying risk results in 10 to 60 undiscovered pools, with a mean of 35.

The pool-size distribution was modeled with the 168 discoveries in the AU. These pools range in size from 0.03 to 304 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 28 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 1 to 186 MMbbl, and undiscovered gas resources range from 93 to 6,327 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 79](#)). Of all 30 assessment units in this study, the Lower Miocene Shelf ranks 13th based on mean-level undiscovered BOE resources ([Figure 10](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values have decreased from 581 to 361 MMBOE ([Figure 79](#)). The discovered area within the Lower Miocene Shelf AU has been extensively explored and is even more geographically limited than the Middle Miocene, constrained by deeper sections that often present high-temperature conditions. Although some hydrocarbons have been encountered in deeper wells within these high-temperature zones, the results have generally been discouraging.

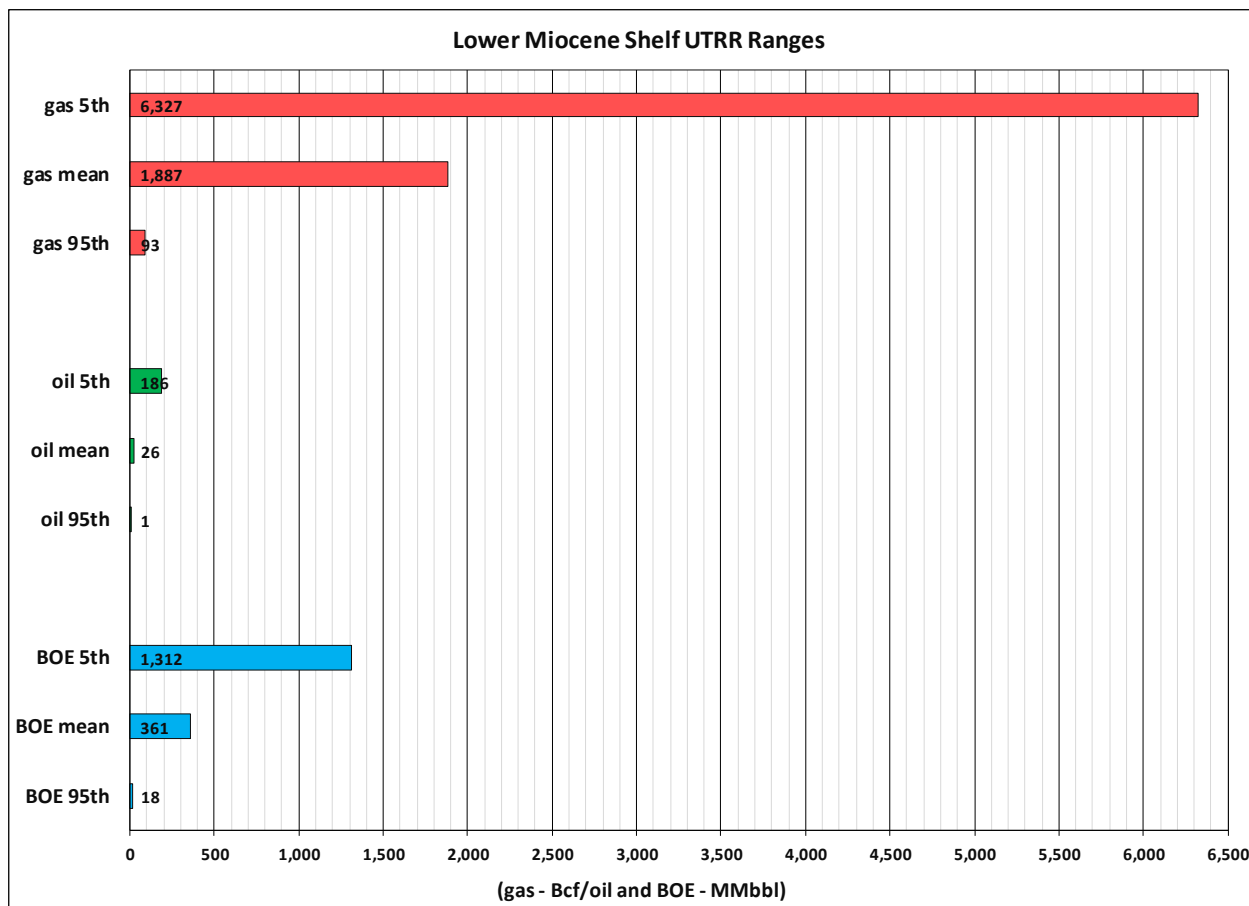


Figure 79. Lower Miocene Shelf gas, oil, and BOE UTRR ranges.

Lower Miocene Slope

Geology

The Lower Miocene Slope AU is defined by sediments deposited in the Aquitanian and Burdigalian Stages (Table 4) located on the modern GOA slope. The stratigraphic framework for Lower Miocene rocks is illustrated in Figure 25. The Slope AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east (Figure 75). In the dip direction, it extends from the modern shelf-slope break to the basinward limit of the Sigsbee Salt Canopy. Beyond the eastward limit of the Sigsbee Salt Canopy, the distal limit of the Slope AU follows the basinward limit of the Mesozoic salt nappes (Figure 23).

Lower Miocene Slope reservoirs are characterized by submarine fans deposited under the influence of salt-related depositional topography. A sandy basin floor apron prograded into the north-central GOA from the Red and Mississippi Rivers, and sandy basin-floor fans from Tennessee River sources ponded behind salt canopy elements in the Mississippi Canyon, Atwater Valley, Green Canyon, and Walker Ridge Areas, and also parallel to the Florida Escarpment (Figure 26). Typical depositional facies include channel-levee complexes and sheet-sand lobes.

The Slope AU includes structural and stratigraphic traps above remnant autochthonous salt highs and salt-cored anticlines and fold belts which are remnants of the Mesozoic salt nappes beneath the leading edge of the Sigsbee Escarpment (Figure 22 and Figure 23). Other potential subsalt traps are upthrown closures to major counter-regional salt feeders and welds (Figure 24).

Discoveries

BOEM-designated hydrocarbon discoveries occur in the Walker Ridge, Green Canyon, Atwater Valley, and Mississippi Canyon Areas (Figure 75). There are 12 total pools, and discovery dates range from 1998 to 2014 (Figure 80). The Slope AU contains 3,989 MMbbl of oil and 1,923 Bcf of gas (total BOE of 4,331 MMbbl) (Table 8). Discovered in 1998, Green Canyon 826 (Mad Dog) is the largest pool, containing an estimated 1,495 MMBOE (Figure 81). Other sizeable, discovered pools include Mississippi Canyon 940 (Vito), Mississippi Canyon 778 (Thunder Horse), and Green Canyon 654 (Shenzi), all estimated to contain more than 600 MMBOE (Figure 81). Pools have been discovered in water depths ranging from 1,971 to 6,362 ft, and subsea depths of these pools range from 16,396 to 31,463 ft.

Figure 82 illustrates cumulative resources for Slope AU pool discoveries through time and the size of the discoveries. With only 12 discovered pools so far, the curve stairsteps through time, rising with each relatively large discovery. The most recent OCS pools were found in 2014 (Figure 80).

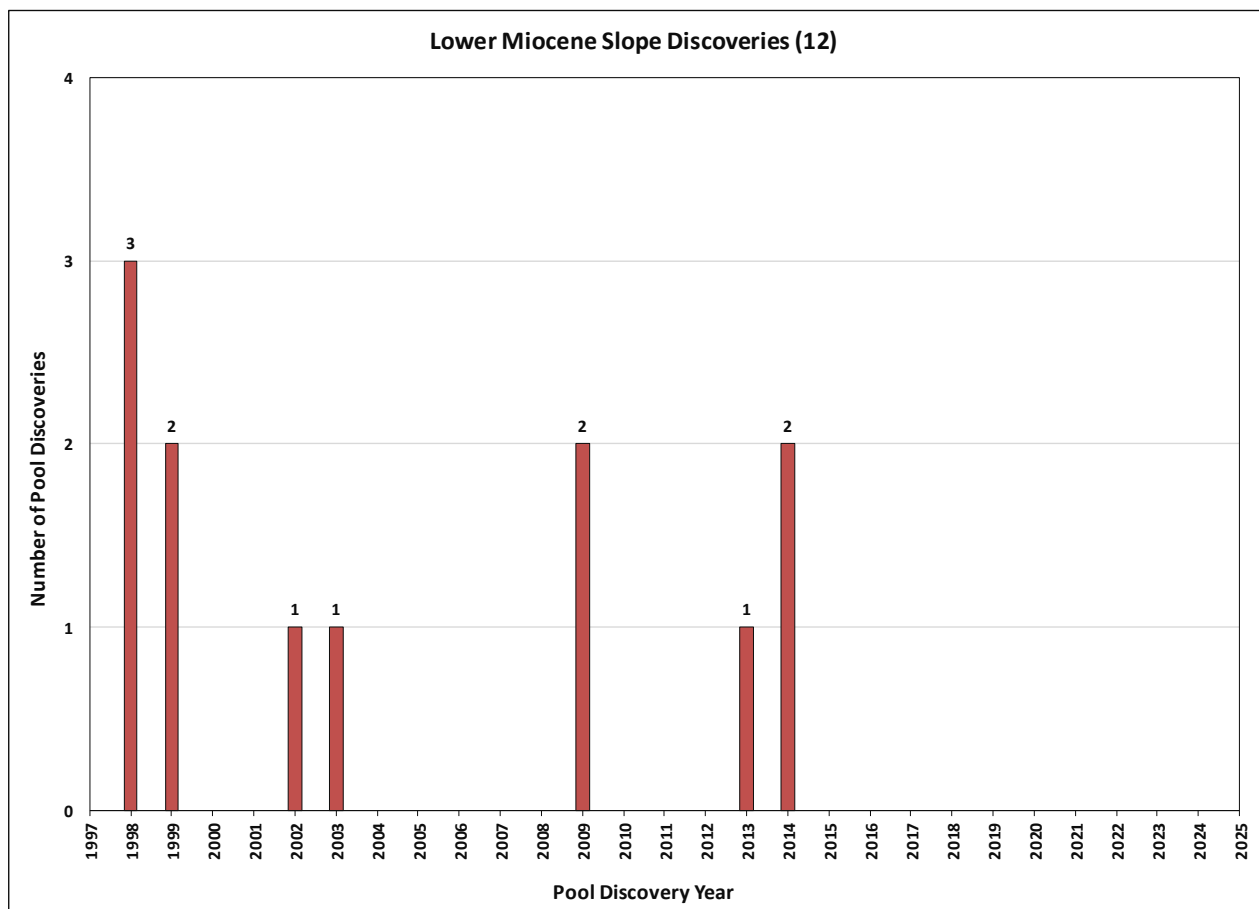


Figure 80. Lower Miocene Slope pool discovery history.

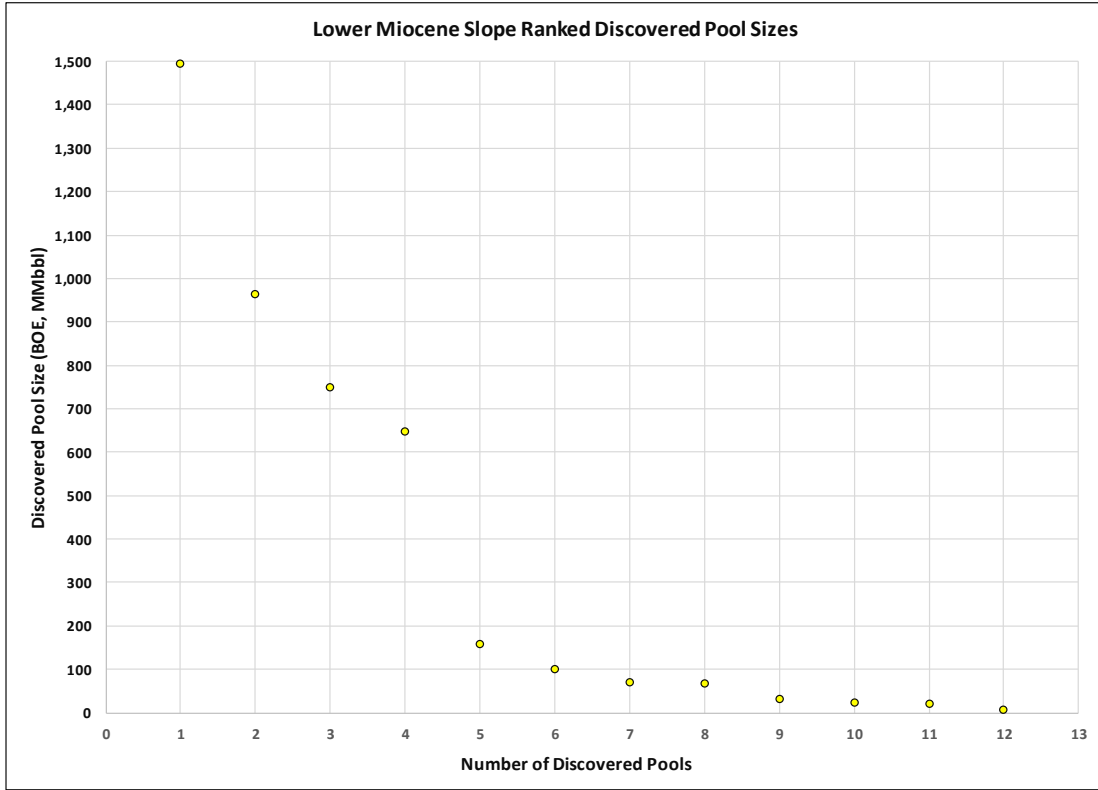


Figure 81. Lower Miocene Slope discovered pool-rank plot.

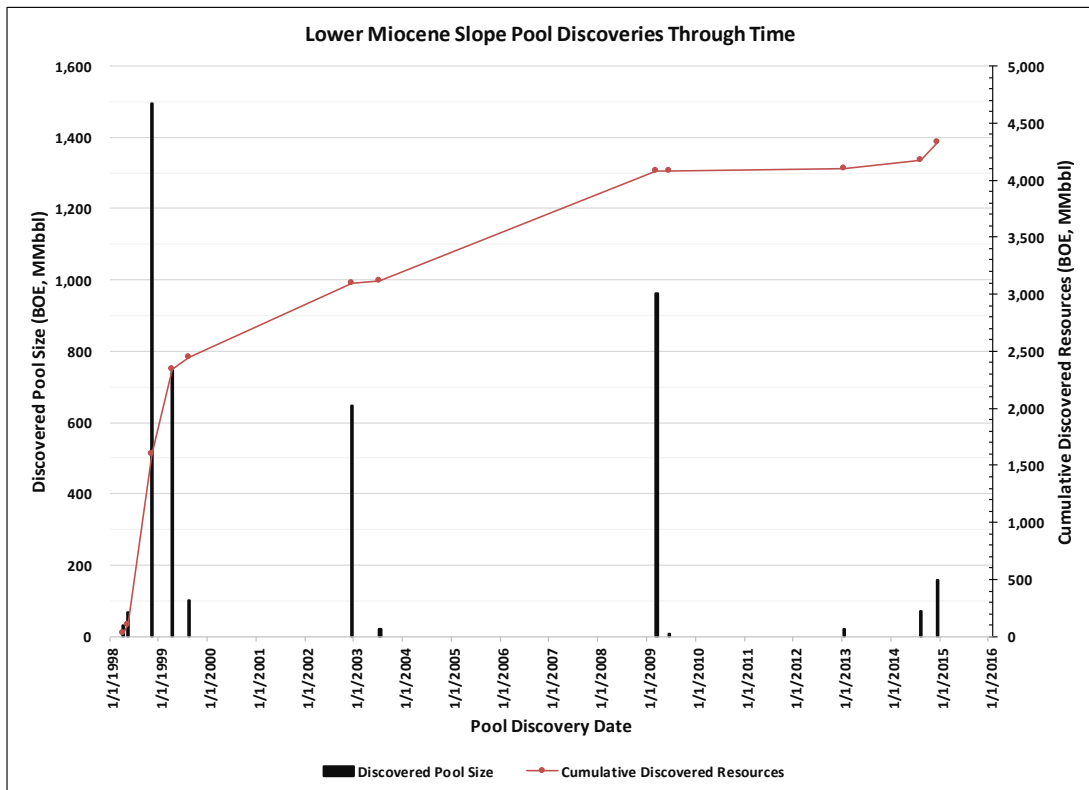


Figure 82. Lower Miocene Slope pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 21% ([Figure 4](#))
- exploration-level: 21% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The Slope AU was modeled with high undiscovered potential based on a vast exploration area with numerous, untested, positive structures where deep-sea fan sediments could have ponded behind inflated salt.

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 95 to 476. Applying risk results in 20 to 100 undiscovered pools, with a mean of 60.

The pool-size distribution was modeled with the 12 discoveries in the AU. These pools range in size from 6 to 1,495 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 623 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for black oil and solution gas. Assessment results indicate that undiscovered oil resources range from 653 to 7,336 MMbbl, and undiscovered gas resources range from 315 to 3,536 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 83](#)). Of all 30 assessment units in this study, the Lower Miocene Slope ranks 4th based on mean-level undiscovered BOE resources ([Figure 10](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values have decreased from 4,725 to 3,807 MMBOE ([Figure 83](#)). Exploration continues to target deeper waters in this area, with the Lower Miocene requiring wells that often exceed 28,000 ft in depth. While this interval is generally considered higher risk, it has the potential for larger discoveries. The Green Canyon and Mississippi Canyon Areas remain active for Lower Miocene exploration, with multiple sale prospects submitted to BOEM. However, recent wells have largely been deemed unsuccessful, despite encountering significant sand packages—although an encouraging sign for future potential. The current prospective depositional area is limited, but significant interest has been shown by companies as they continue to expand from the core depositional area and strive to find the next newsworthy discovery.

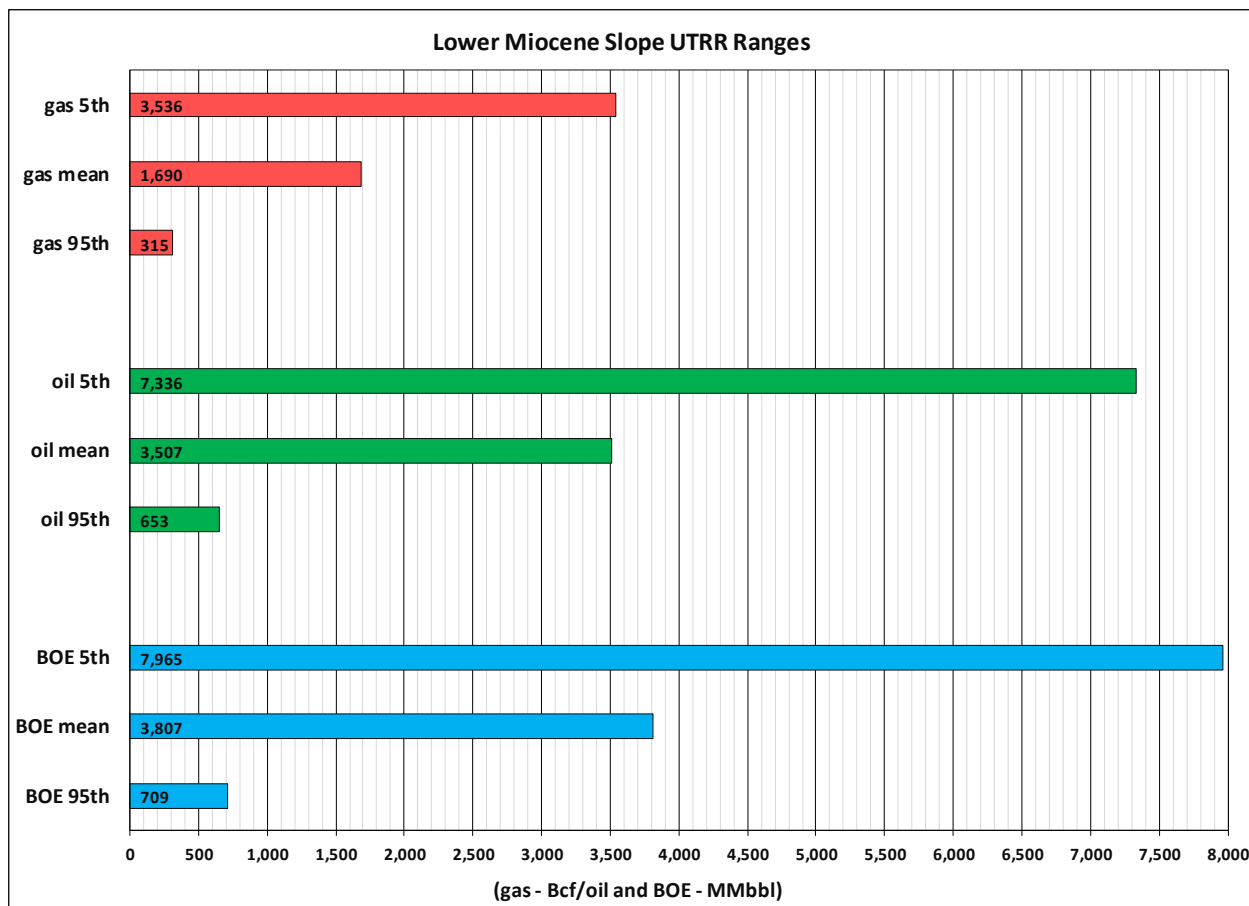


Figure 83. Lower Miocene Slope gas, oil, and BOE UTRR ranges.

Middle Miocene Shelf

Geology

The Middle Miocene Shelf AU is defined by sediments deposited in the Langhian and Serravallian Stages (Table 4) within the modern GOA shelf. The stratigraphic framework within the GOA Basin for Middle Miocene rocks is illustrated in Figure 25. The AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east, and in the dip direction, it extends from state waters to the modern shelf-slope break at a water depth of 656 ft (200 m) (Figure 84).

The Middle Miocene shelf margin advanced beyond and in similar fashion to the Lower Miocene, just outboard of the modern shoreline from south Texas to central Louisiana. Deltas fed by the ancestral Guadalupe River were deposited beneath the modern central Texas shelf, while deltas of the Mississippi and Tennessee Rivers were deposited across much of south Louisiana and near-shore areas (Figure 26) and represent major regressive episodes of outbuilding of both the shelf and slope. The thickest sand dominated intervals likely represent multiple episodes of delta-lobe switching and progradation. Representative depositional facies include (1) distributary mouth bars, delta fringes, marine bars, channel-levee complexes, and crevasse splays in Middle Miocene shelf environments and (2) deepwater turbidites deposited basinward of Middle Miocene shelf margins on the upper and lower slopes in topographically low areas between salt structure highs and on the abyssal plain.

The Shelf AU in the western GOA includes upthrown three-way fault closures and downthrown rollover anticlines along down-to-the-basin growth faults (Figure 22) associated with regional shale detachments and shale diapirs. Across the Louisiana shelf, the AU is characterized by traps against and above salt diapirs

and remnant allochthonous salt bodies along Roho welds (Figure 24), the remnants of earlier salt canopies. Subsalt traps beneath tabular salt bodies and upthrown to counter-regional faults and salt feeders are also possible. Other traps are upthrown three-way fault closures or downthrown rollover anticlines along growth faults associated with salt-withdrawal minibasins.

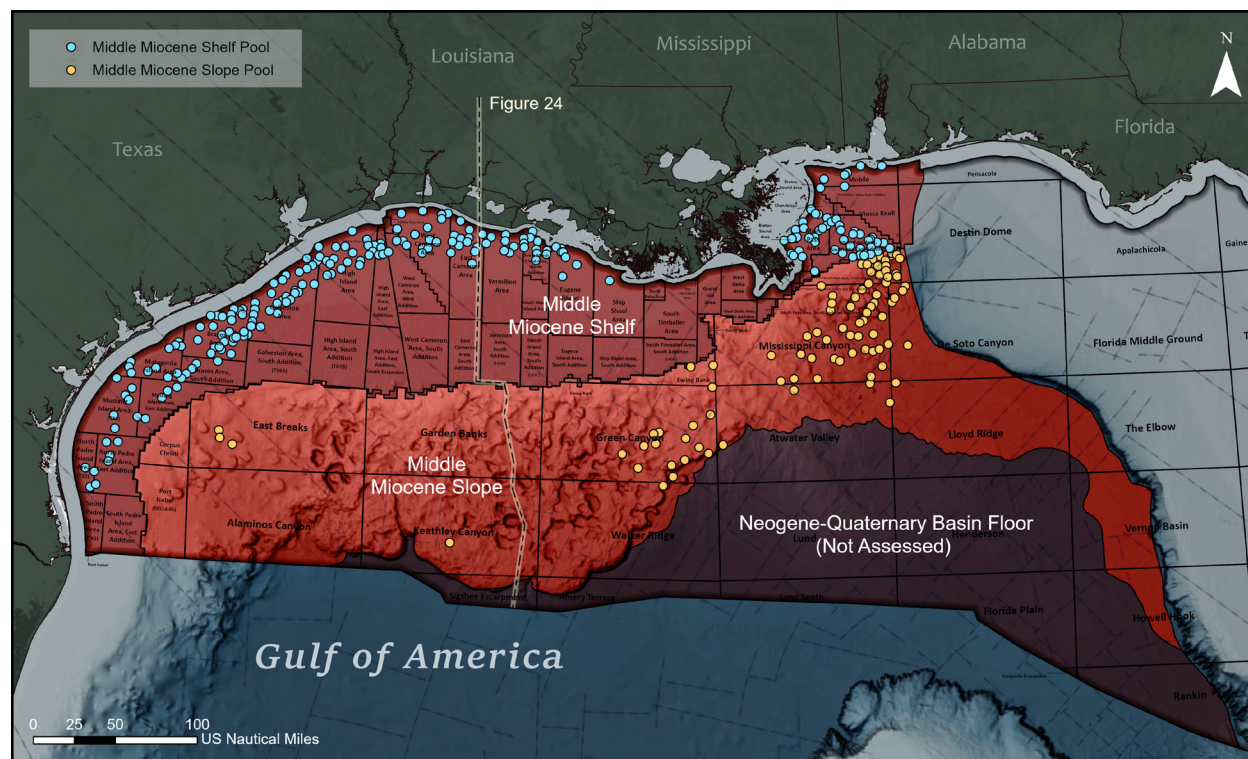


Figure 84. Middle Miocene Shelf and Slope locations and associated discovered pools.

Discoveries

BOEM-designated hydrocarbon discoveries occur in shallow OCS waters from the North Padre Island Area of offshore Texas to the Ship Shoal Area of offshore Louisiana and east of the modern Mississippi River Delta south of Mississippi and Alabama (Figure 84). There are 225 total pools, and discovery dates range from 1948 to 2017 (Figure 85). The AU contains 671 MMbbl of oil and 27,493 Bcf of gas (total BOE of 5,563 MMbbl) (Table 8). Discovered in 1958, the Tiger Shoal discovery in the South Marsh Island Area is the largest, containing an estimated 552 MMBOE in Middle Miocene rocks (Figure 86). Other sizeable, discovered pools include Vermilion 39, Vermilion 14, West Cameron 180, and East Cameron 64, all estimated to contain more than 250 MMBOE (Figure 86). Pools have been discovered in water depths ranging from 10 to 588 ft, and subsea depths of these pools range from 1,892 to 18,445 ft.

Figure 87 illustrates cumulative resources for Shelf AU pool discoveries through time and the size of the discoveries. The largest pools were found in the early history of exploration, with little resources being added present day. The most recent OCS pool was found in 2017 (Figure 85).

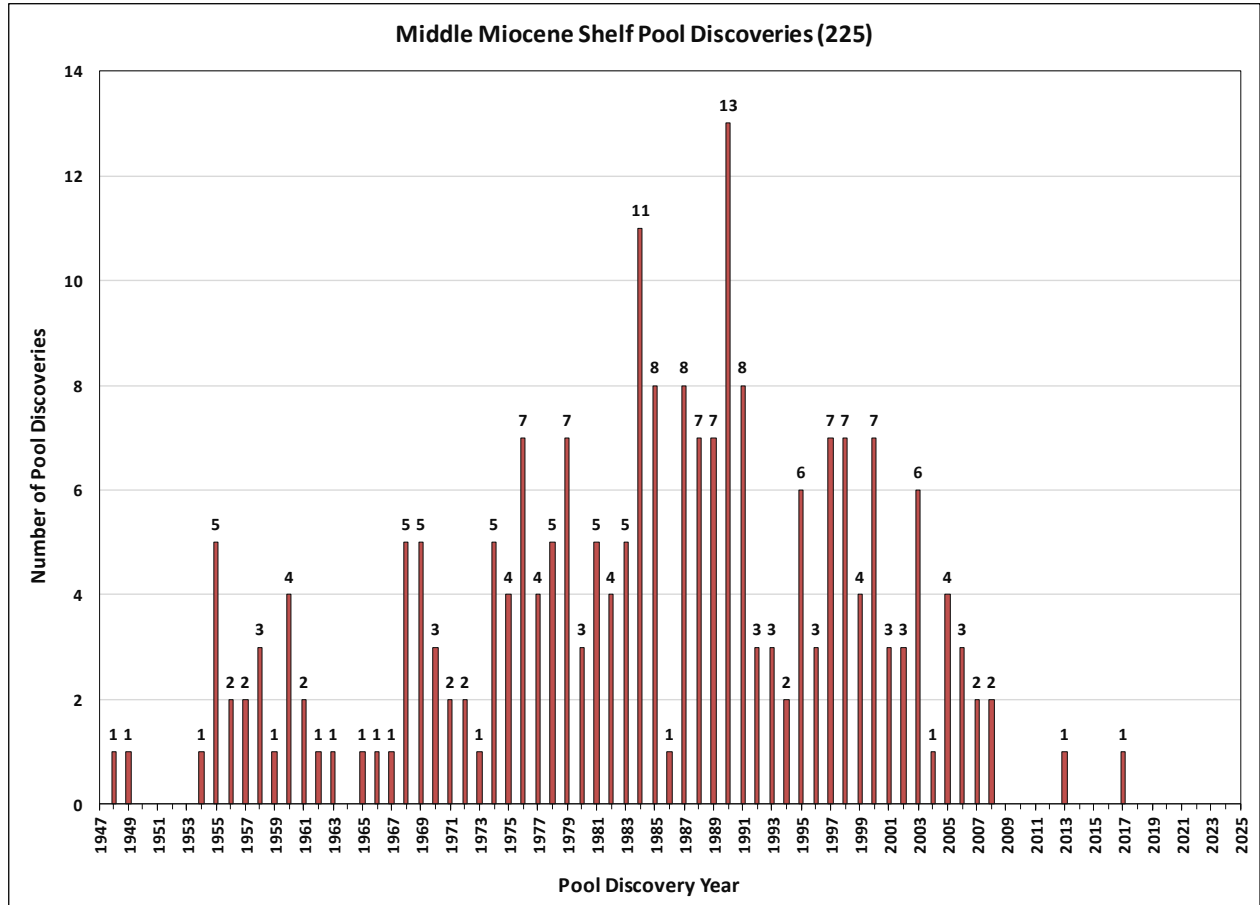


Figure 85. Middle Miocene Shelf pool discovery history.

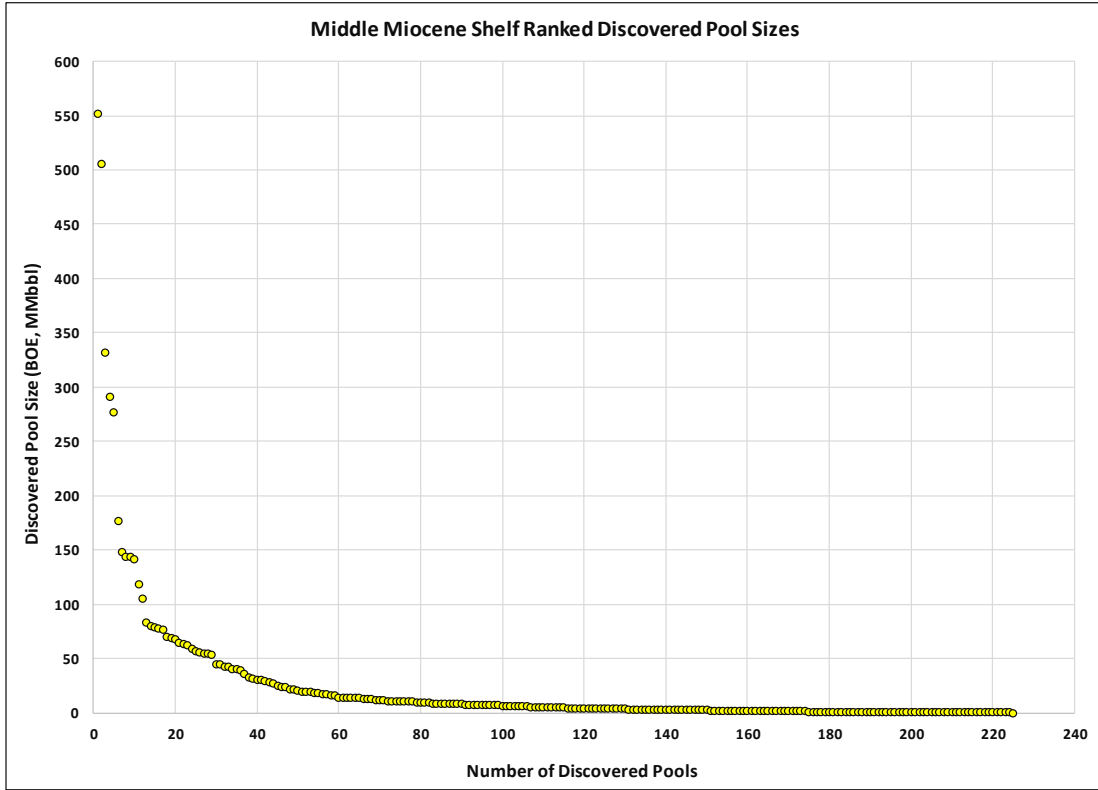


Figure 86. Middle Miocene Shelf discovered pool-rank plot.

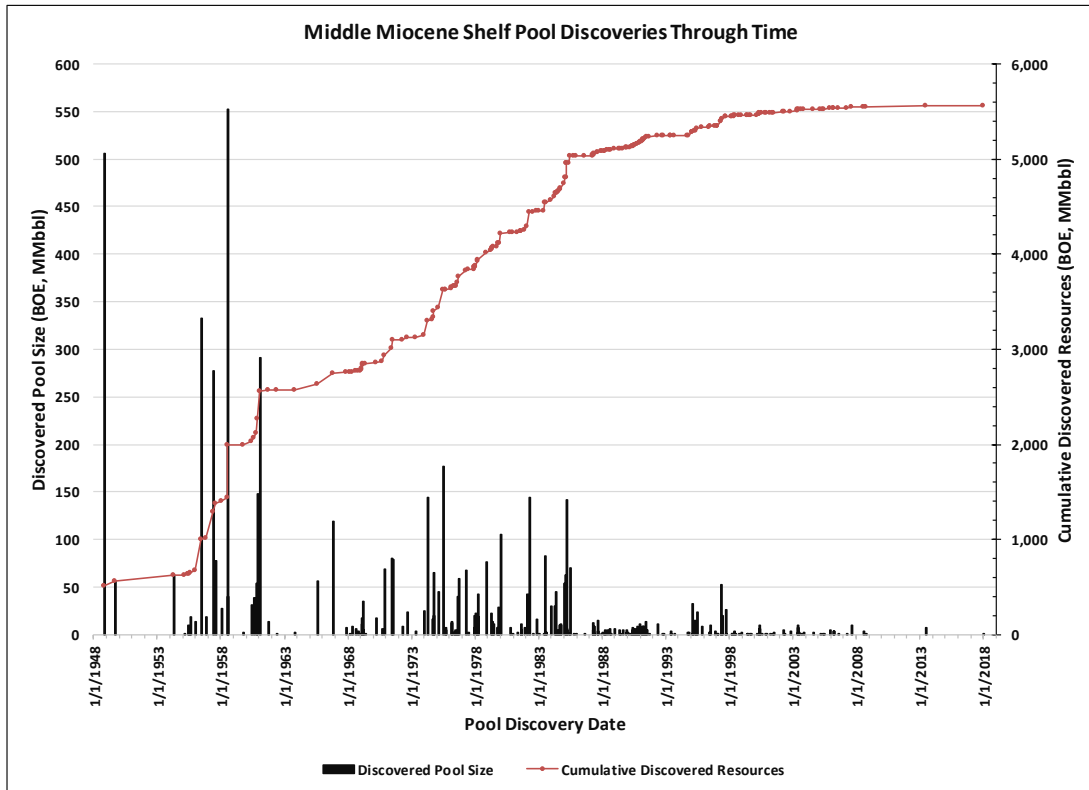


Figure 87. Middle Miocene Shelf Pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 25% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 82 to 490. Applying risk results in 20 to 120 undiscovered pools, with a mean of 70.

The pool-size distribution was modeled with the 225 discoveries in the AU. These pools range in size from 0.04 to 552 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 29 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 1 to 224 MMbbl, and undiscovered gas resources range from 18 to 8,464 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 88](#)). Of all 30 assessment units in this study, the Middle Miocene Shelf ranks 14th based on mean-level undiscovered BOE resources ([Figure 10](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values have decreased from 906 to 447 MMBOE ([Figure 88](#)). The discovered area within the Middle Miocene Shelf AU has been extensively explored and is even more geographically limited than the Upper Miocene, constrained by deeper sections that often present higher temperature challenges. While smaller accumulations are possible, they are typically associated with deeper targets and elevated thermal conditions, which can preclude economic viability.

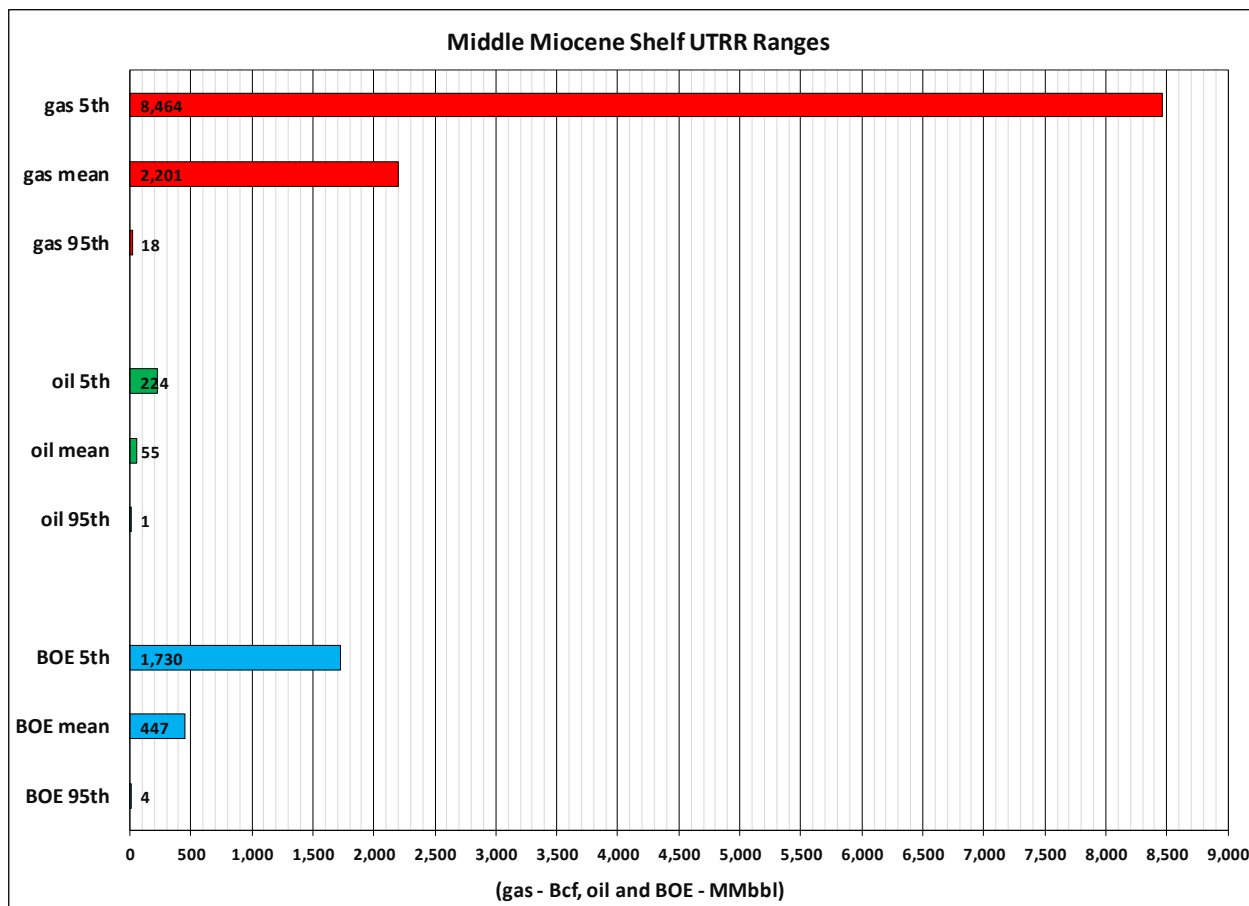


Figure 88. Middle Miocene Shelf gas, oil, and BOE UTRR ranges.

Middle Miocene Slope

Geology

The Middle Miocene Slope AU is defined by sediments deposited in the Langhian and Serravallian Stages (Table 4) within the modern GOA slope. The stratigraphic framework within the GOA Basin for Middle Miocene rocks is illustrated in Figure 25. The AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east (Figure 84). In the dip direction, it extends from the modern shelf-slope break to the basinward limit of the Sigsbee Salt Canopy. Beyond the eastward limit of the Sigsbee Salt Canopy, the distal limit of the Slope AU follows the basinward limit of the Mesozoic salt nappes (Figure 23).

Reservoirs are in extensive sandy basin-floor fans and aprons sourced from the Mississippi River and Tennessee River systems and reaching into the Garden Banks, Green Canyon, Mississippi Canyon, and Atwater Valley Areas (Figure 26). Typical depositional facies include channel-levee complexes and sheet-sand lobes.

The Slope AU includes structural and stratigraphic traps above the flanks of tabular salt bodies and sheets around the periphery of salt-withdrawal minibasins (Figure 24). Subsalt traps are present beneath the Sigsbee Salt Canopy as base-of-salt closures and against salt stocks, feeders, and vertical welds above autochthonous salt structures (Figure 24). Traps are also present above the salt cored anticlines and fold belts, which are remnants of the Mesozoic salt nappes beneath the leading edge of the Sigsbee Escarpment (Figure 22 and Figure 23). A few small accumulations in the East breaks Area are associated with anticlinal closures above shale ridges.

Discoveries

BOEM-designated hydrocarbon discoveries occur from the East Breaks Area to the De Soto Canyon Area (Figure 84). There are 87 total pools, and discovery dates range from 1984 to 2018 (Figure 89). The Slope AU contains 6,553 MMbbl of oil and 10,655 Bcf of gas (total BOE of 8,449 MMbbl) (Table 8). The two largest pools—Green Canyon 640 (Tahiti) and Green Canyon 743 (Atlantis)—both contain more than 1,000 MMBOE (Figure 90). Other large, discovered pools include Mississippi Canyon 776 (North Thunderhorse), Mississippi Canyon 84 (King and Horn Mountain), and Green Canyon 468 (Stampede), all estimated to contain more than 300 MMBOE (Figure 90). Pools have been discovered in water depths ranging from 689 to 8,351 ft, and subsea depths of these pools range from 8,288 to 29,678 ft.

Figure 91 illustrates cumulative resources for Slope AU pool discoveries through time and the size of the discoveries. The last discovery over 150 MMBOE occurred with Mississippi Canyon 300 (Marmalard) in 2012. The most recent OCS pool was found in 2018 (Figure 89).

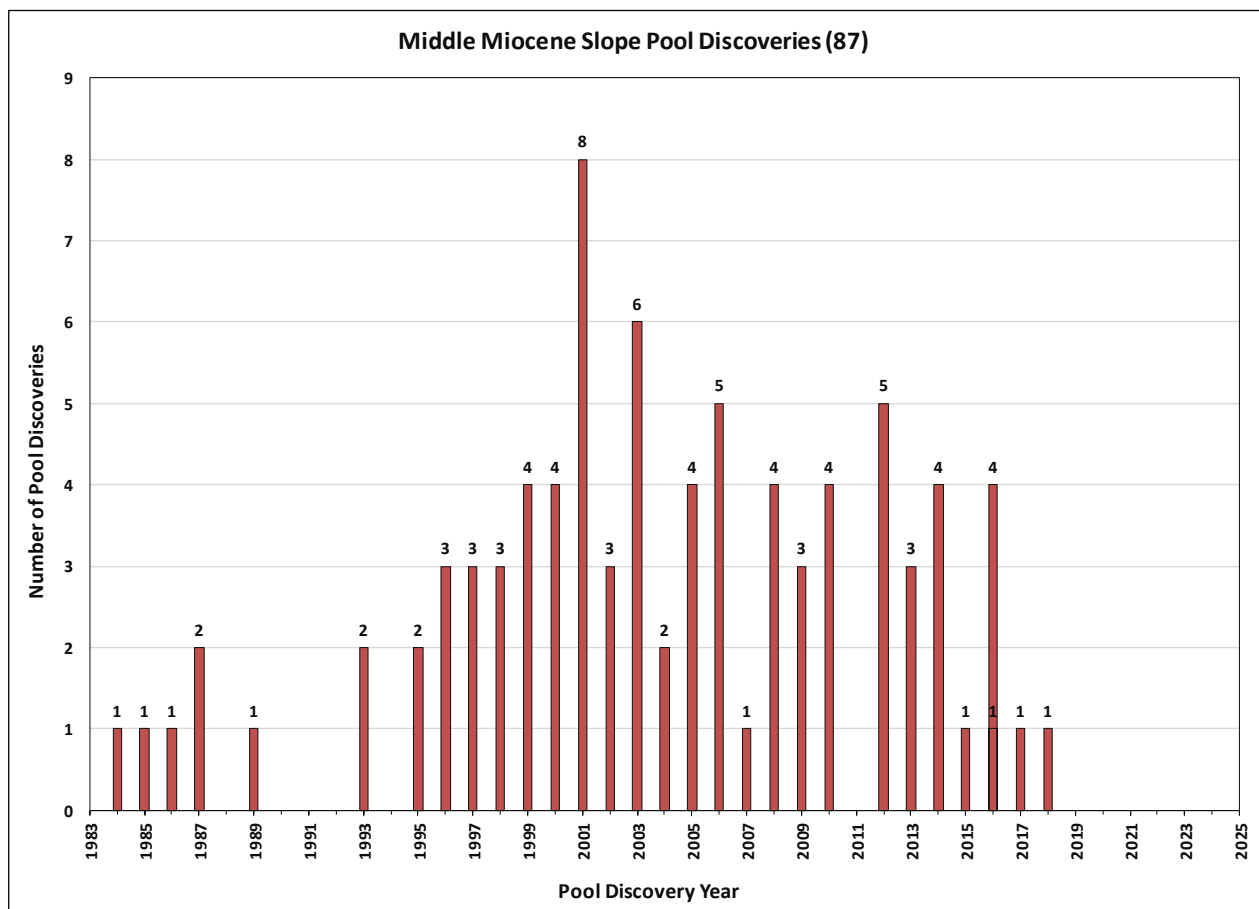


Figure 89. Middle Miocene Slope pool discovery history.

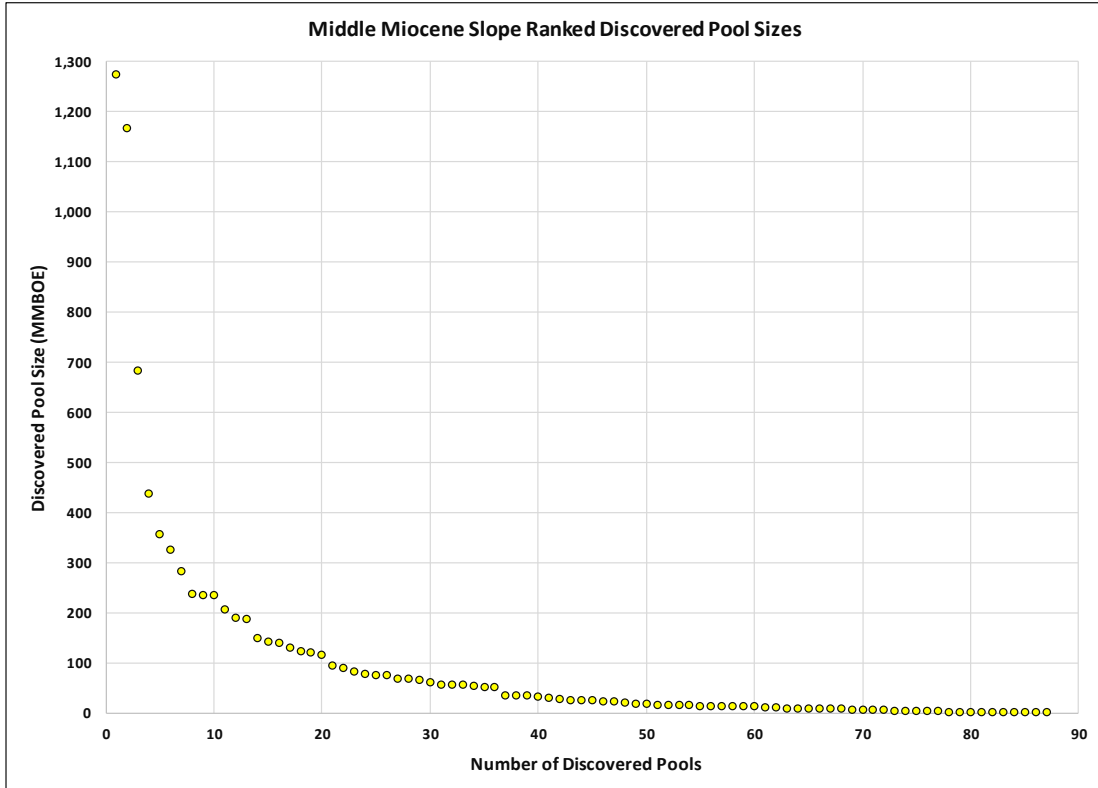


Figure 90. Middle Miocene Slope discovered pool-rank plot.

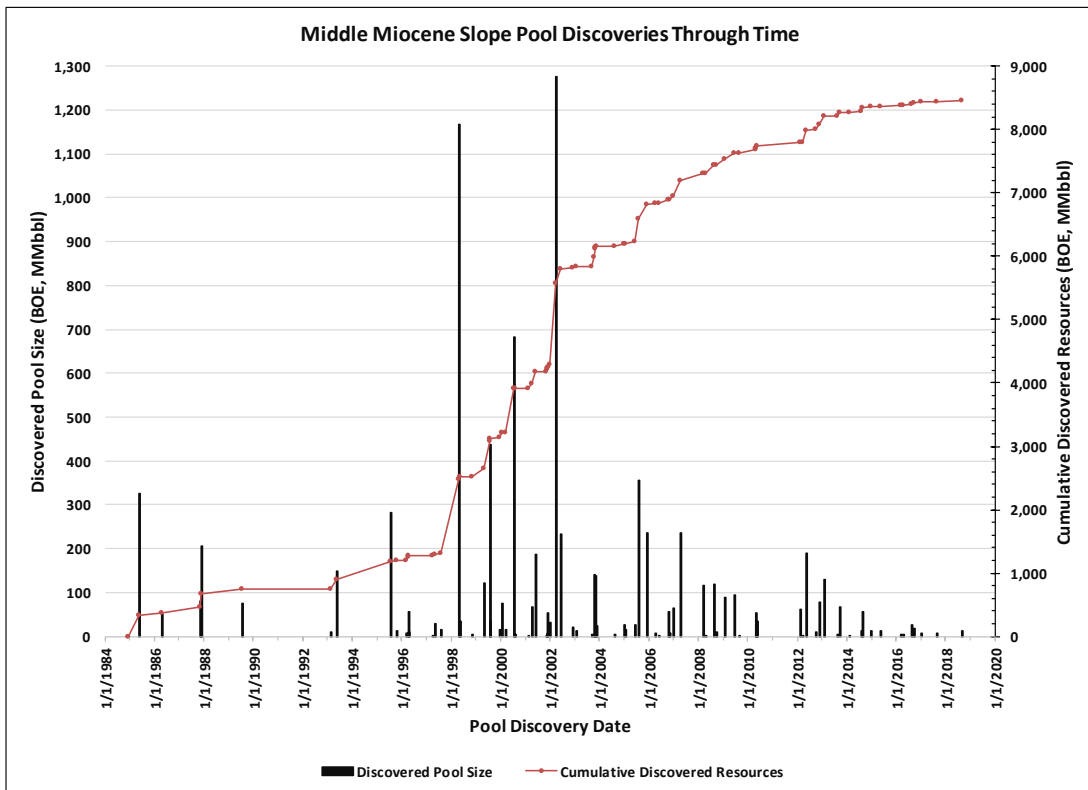


Figure 91. Middle Miocene Slope pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 25% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 204 to 776. Applying risk results in 50 to 190 undiscovered pools, with a mean of 120.

The pool-size distribution was modeled with the 87 discoveries in the AU. These pools range in size from 0.31 to 1,275 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 331 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 492 to 5,921 MMbbl, and undiscovered gas resources range from 588 to 8,698 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 92](#)). Of all 30 assessment units in this study, the Middle Miocene Slope ranks 5th based on mean-level undiscovered BOE resources ([Figure 10](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values have decreased from 5,101 to 3,388 MMBOE ([Figure 92](#)). Exploration in this area continues to progress into deeper waters, necessitating increasingly deep wells to test emerging prospects. Although the Middle Miocene has been thoroughly explored in both the Mississippi Canyon and Green Canyon areas, it remains a key target—yielding larger new discoveries extending the core exploration areas and smaller finds in the mature areas with existing infrastructure. The AU continues to attract exploration interest, with recent discoveries offering encouraging results. Seismic imaging still faces some challenges in areas with complex salt structures, suggesting that additional significant prospects may remain undetected.

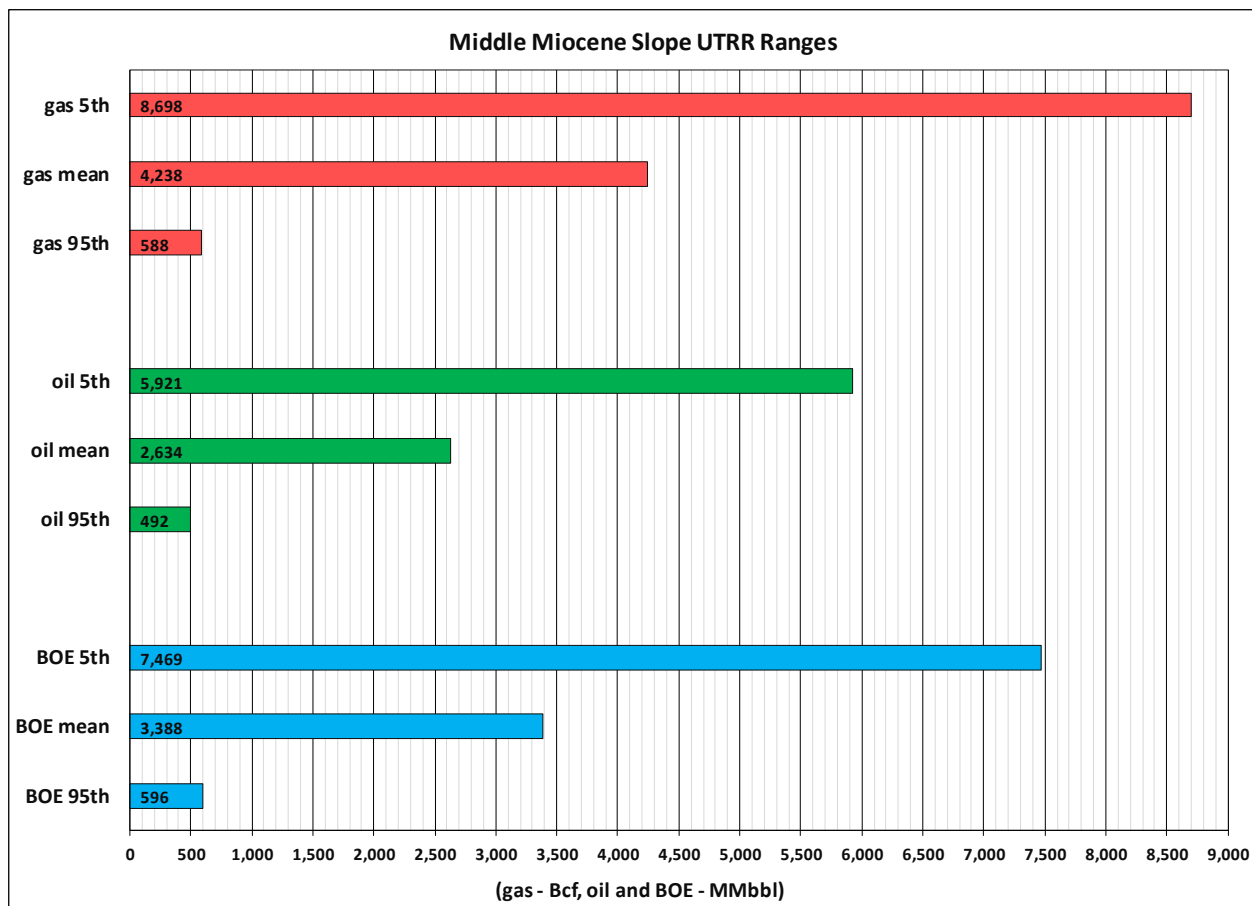


Figure 92. Middle Miocene Slope gas, oil, and BOE UTRR ranges.

Upper Miocene Shelf

Geology

The Upper Miocene Shelf AU is defined by sediments deposited in the Tortonian and Messinian Stages (Table 4) within the modern GOA shelf. The stratigraphic framework within the GOA Basin for Upper Miocene rocks is illustrated in Figure 25. The Shelf AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east, and in the dip direction, it extends from state waters to the modern shelf-slope break at a water depth of 656 ft (200 m) (Figure 93).

The Upper Miocene shelf margin advanced beyond the modern coastline from Texas to Florida. Extensive fluvial-dominated delta systems sourced from the ancestral Mississippi and Tennessee Rivers prograded across the modern Louisiana shelf (Figure 16). Sediment loading of the Sigsbee Salt Canopy was accompanied by extensive salt tectonism and remobilization. Smaller wave-dominated delta systems sourced from the Rio Grande and Guadalupe Rivers prograded across the Texas shelf (Figure 26). Representative depositional facies include (1) distributary mouth bars, delta fringes, marine bars, channel-levee complexes, and crevasse splays in Lower Miocene shelf environments and (2) deepwater turbidites deposited basinward of the Upper Miocene shelf margin on the upper and lower slopes and in topographically low areas between salt highs and onto the abyssal plain.

The Shelf AU in the western GOA includes upthrown three-way fault closures and downthrown rollover anticlines along down-to-the-basin growth faults (Figure 22) associated with regional shale detachments and shale diapirs. Across the Louisiana shelf, the AU is characterized by traps against and above salt diapirs and remnant allochthonous salt bodies along Roho welds (Figure 24), the remnants of earlier salt

canopies. Other traps are upthrown three-way fault closures or downthrown rollover anticlines along growth faults associated with salt-withdrawal minibasins.

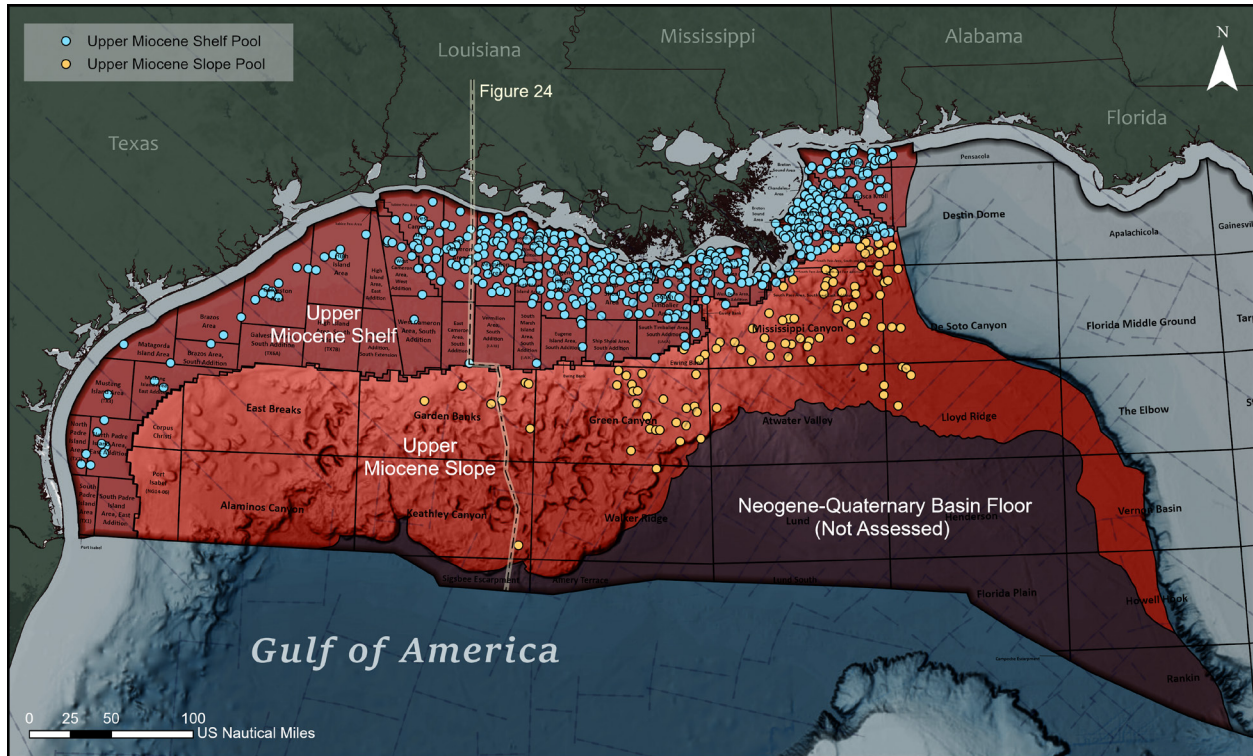


Figure 93. Upper Miocene Shelf and Slope locations and associated discovered pools.

Discoveries

Upper Miocene Shelf deposition has been extensively studied, and exploration and development go back to 1947 with the first shelf discovery in federal waters in Vermilion Block 71. There are 471 total pools, and discovery dates range from 1947 to 2018 (Figure 94). The pools contain 7,405 MMbbl of oil and 51,655 Bcf of gas (total BOE of 16,596 MMbbl) (Table 8). Discovered in 1956, Grand Isle 43 is the largest pool, containing an estimated 771 MMBOE (Figure 95). Other sizable, discovered pools include Bay Marchand 2, West Delta 30, and Main Pass 41, all estimated to contain more than 450 MMBOE (Figure 95). Pools have been discovered in water depths ranging from 9 to 625 ft, and subsea depths of these pools range from 1,286 to 21,247 ft.

Figure 96 illustrates cumulative resources for Shelf AU pool discoveries through time and the size of the discoveries. A present-day flat cumulative resources curve and decreasing discovery sizes through time reflect a well-established, highly explored AU, where the largest discoveries were found early in its exploration history. The most recent OCS pool was found in 2018 (Figure 94).

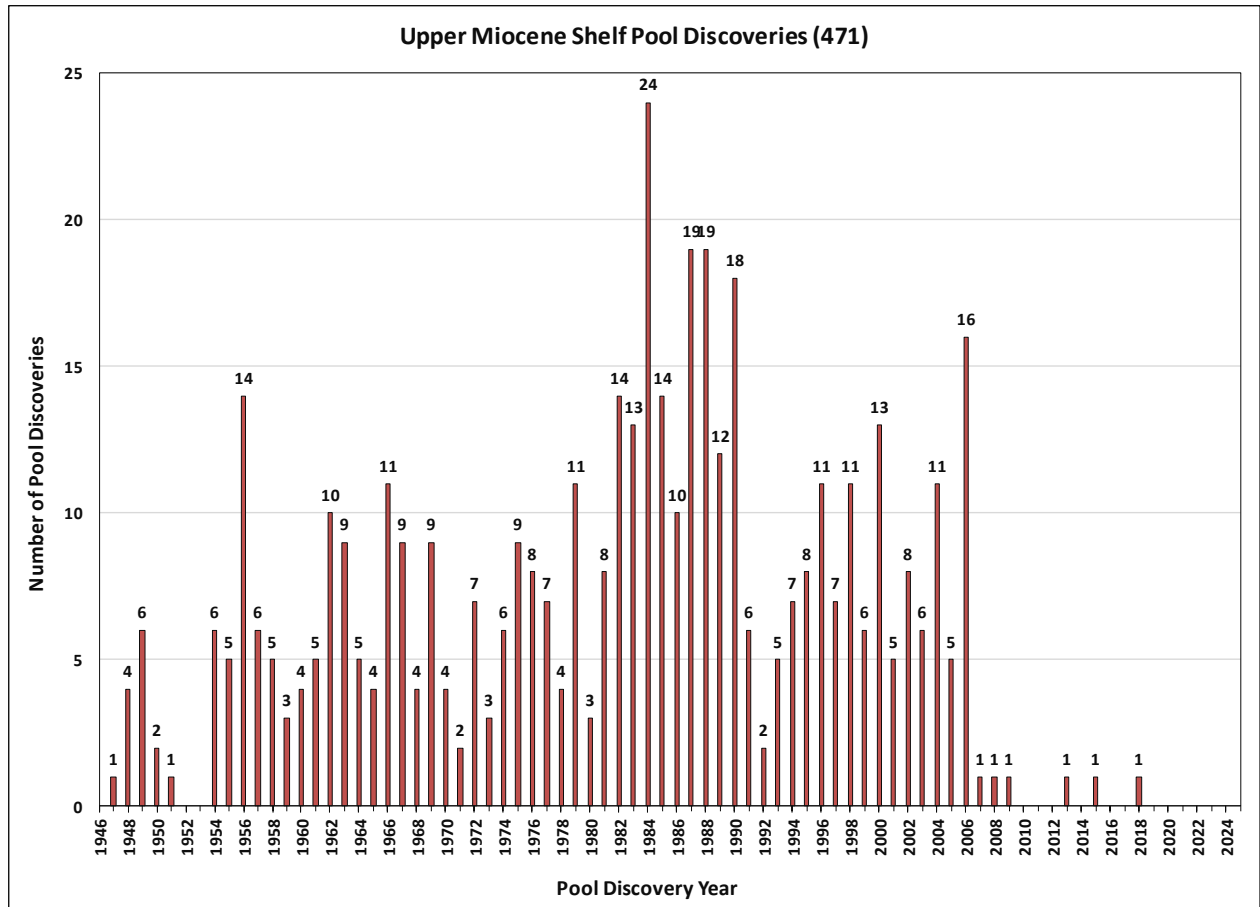


Figure 94. Upper Miocene Shelf pool discovery history.

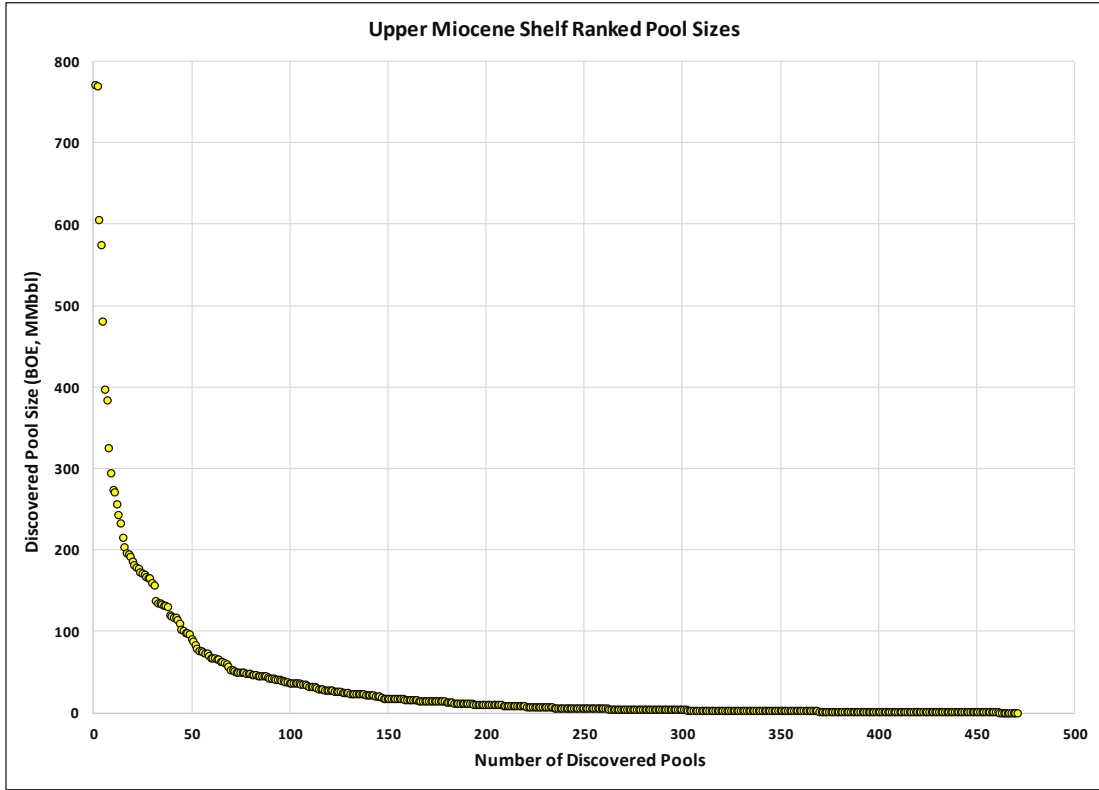


Figure 95. Upper Miocene Shelf discovered pool-rank plot.

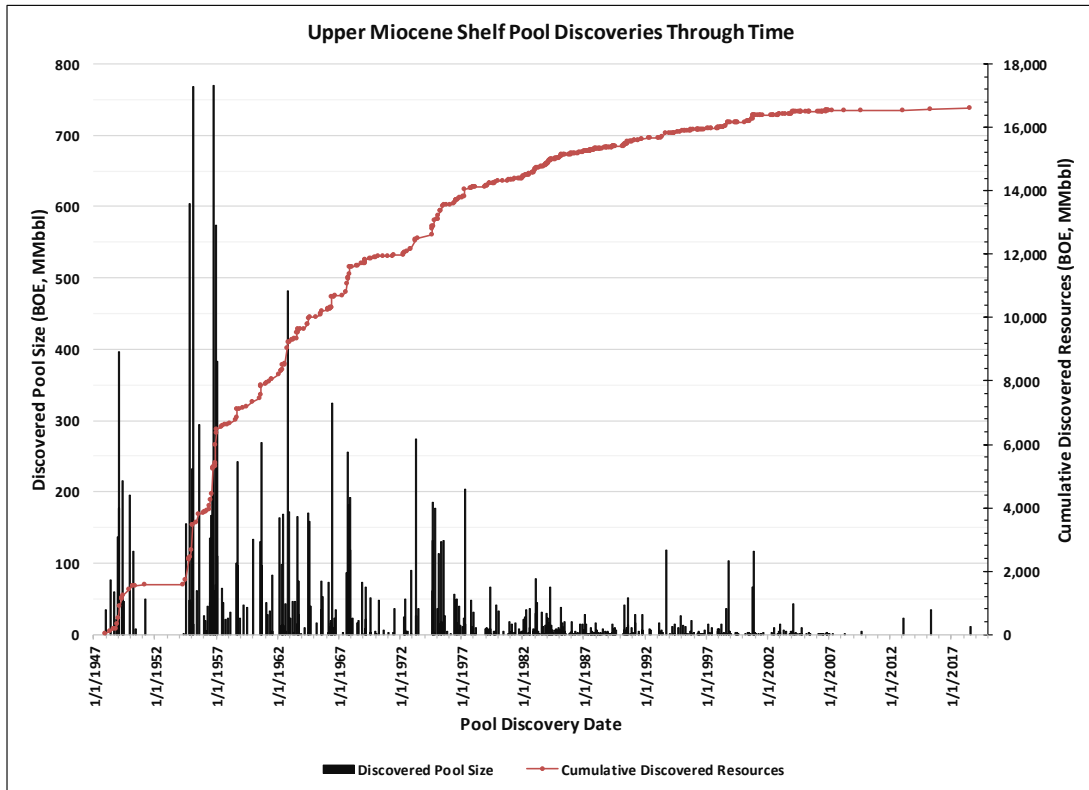


Figure 96. Upper Miocene Shelf pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 29% ([Figure 4](#))
- exploration-level: 29% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 136 to 408. Applying risk results in 40 to 120 undiscovered pools, with a mean of 80.

The pool-size distribution was modeled with the 471 discoveries in the AU. These pools range in size from 0.001 to 771 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 31 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 60 to 1,364 MMbbl, and undiscovered gas resources range from 430 to 7,189 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 97](#)). Of all 30 assessment units in this study, the Upper Miocene Shelf ranks 10th based on mean-level undiscovered BOE resources ([Figure 10](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values have decreased from 1,046 to 866 MMBOE ([Figure 97](#)). The Upper Miocene Shelf area has been extensively explored and has had significant development and production for about 70 years. Only smaller, likely uneconomic accumulations remain—unless they are near existing infrastructure. Overall, industry bidding interest in the Shelf AU continues to decline.

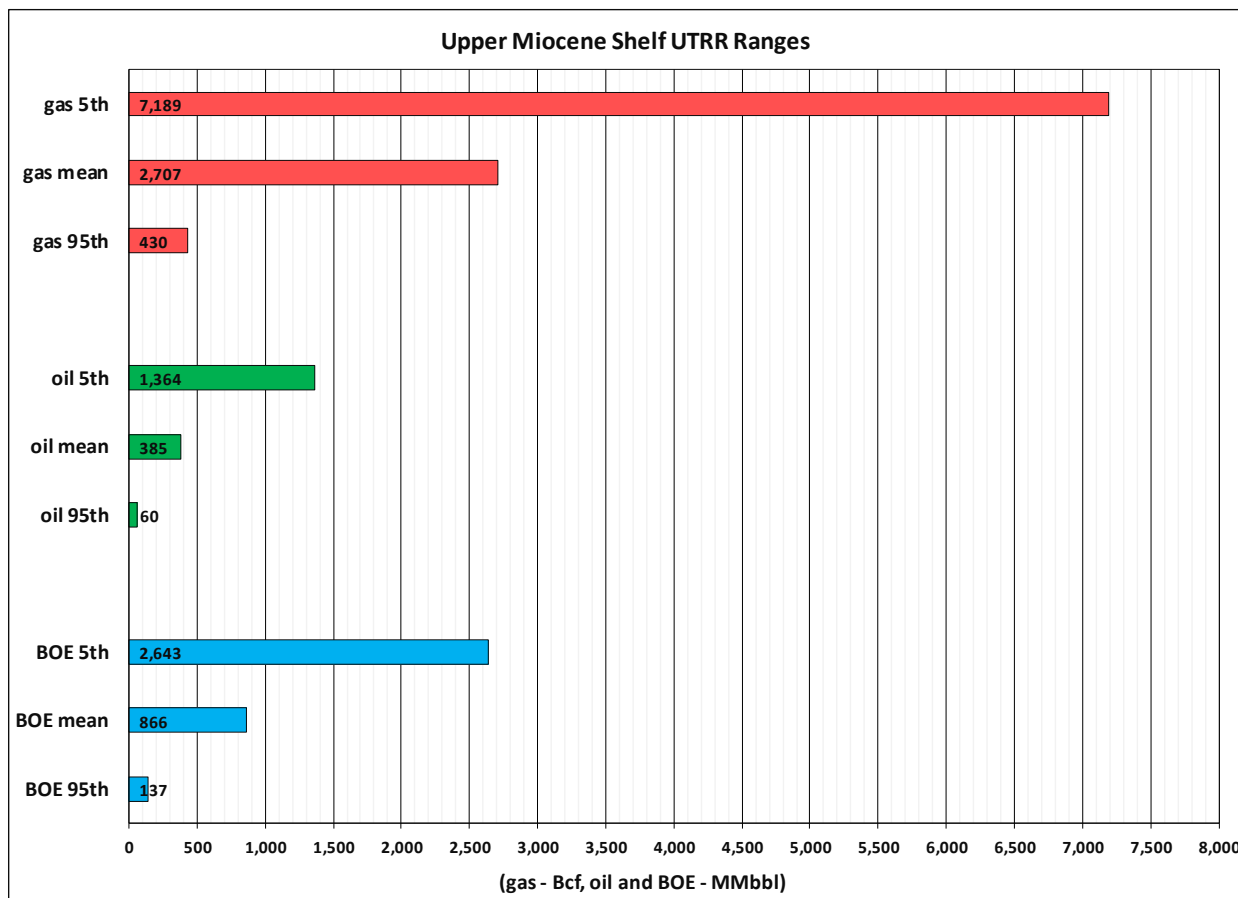


Figure 97. Upper Miocene Shelf gas, oil, and BOE UTRR ranges.

Upper Miocene Slope

Geology

The Upper Miocene Slope AU is defined by sediments deposited in the Tortonian and Messinian Stages (Table 4) within the modern GOA slope. The stratigraphic framework within the GOA Basin for Upper Miocene rocks is illustrated in Figure 25. The Slope AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east (Figure 93). In the dip direction, it extends from the modern shelf-slope break to the basinward limit of the Sigsbee Salt Canopy. Beyond the eastward limit of the Sigsbee Salt Canopy, the distal limit of the Slope AU follows the basinward limit of the Mesozoic salt nappes (Figure 23).

The Slope AU includes extensive submarine fans and basin floor aprons sourced from the ancestral Mississippi and Tennessee Rivers and deposited across portions of the Garden Banks, Green Canyon, Atwater Valley, Lund, De Soto Canyon, and Lloyd Ridge Areas (Figure 26). Reservoir facies include channel-levee complexes and sheet-sand lobes.

The Slope AU includes structural and stratigraphic traps above the flanks of tabular salt bodies and sheets around the periphery of salt-withdrawal minibasins (Figure 24). Subsalt traps are present beneath the Sigsbee Salt Canopy as base-of-salt closures and against salt stocks, feeders, and vertical welds above autochthonous salt structures (Figure 24). Traps are also possible above the salt cored anticlines and fold belts which are remnants of the Mesozoic salt nappes beneath the leading edge of the Sigsbee Escarpment (Figure 22 and Figure 23).

Discoveries

Deposition on the Upper Miocene Slope has been extensively studied, and the strata have been explored and developed back to 1980 with the discovery of the first Upper Miocene pool on the slope in the Mississippi Canyon 194 Field (Cognac). Discoveries within the complex structural setting of the Slope AU occur from the Garden Banks and Keathley Canyon Areas in its western extent to the De Soto Canyon and Lloyd Ridge Areas in its eastern extent (Figure 93). There are 106 total pools, and discovery dates range from 1980 to 2022 (Figure 98). The Slope AU contains some of the largest pools ever discovered in the deepwater OCS, including the discoveries associated with the Mars-Ursa geologic complex in the Mississippi Canyon Area (Figure 99). Upper Miocene Slope discoveries account for 5,550 MMbbl of oil and 14,776 Bcf of gas (total BOE of 8,179 MMbbl) (Table 8). Pools have been discovered in water depths ranging from 697 to 9,112 ft, and subsea depths of these pools range from 4,943 to 25,912 ft.

Figure 100 illustrates cumulative resources for Slope AU pool discoveries through time and the size of the discoveries. Numerous large pool discoveries have resulted in sharp upticks in volumes added to the AU through time. The most recent example is the Mississippi Canyon 768 discovery (Kaikias) in 2014, which added 226 MMBOE to the discovered resource base in the AU. The most recent OCS pool was found in 2022 (Figure 98).

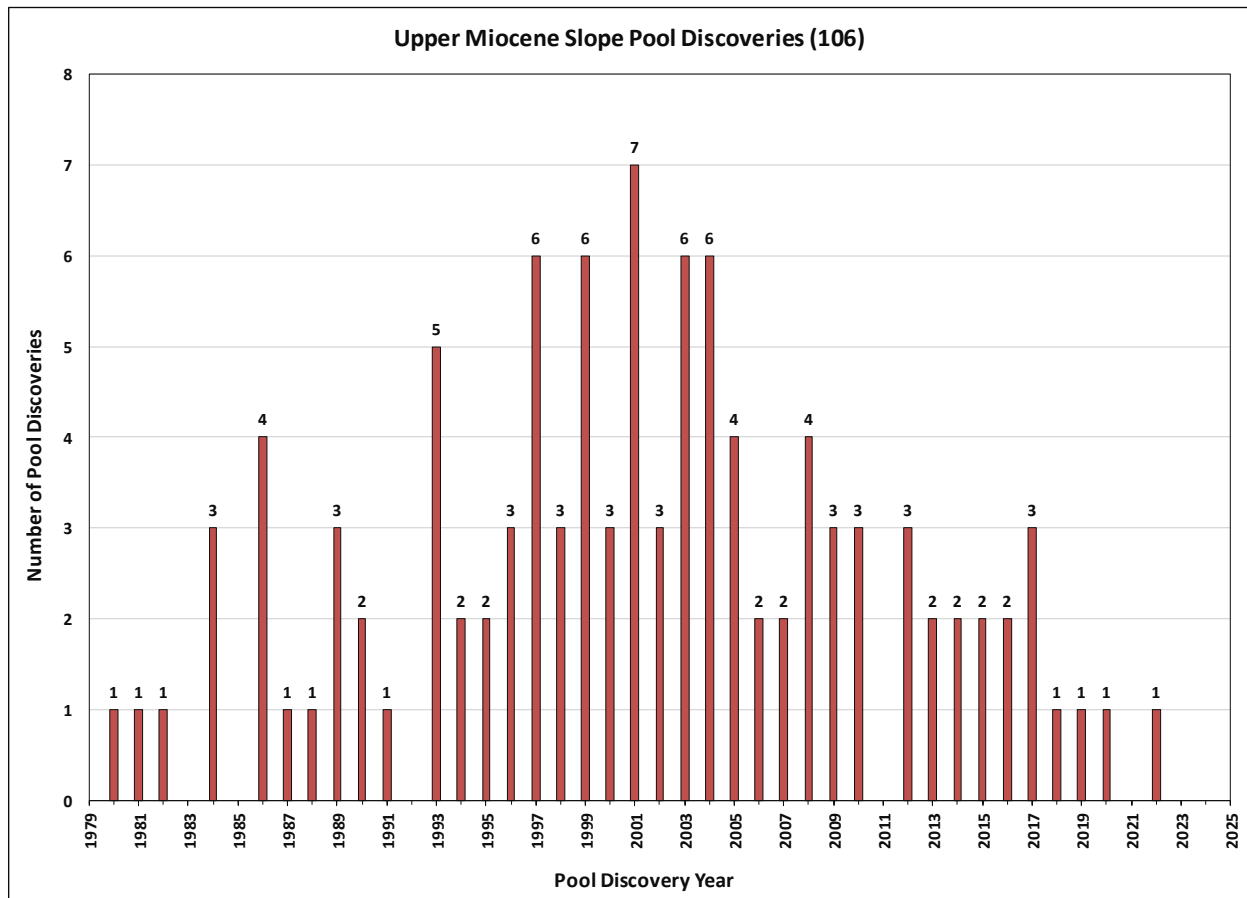


Figure 98. Upper Miocene Slope pool discovery history.

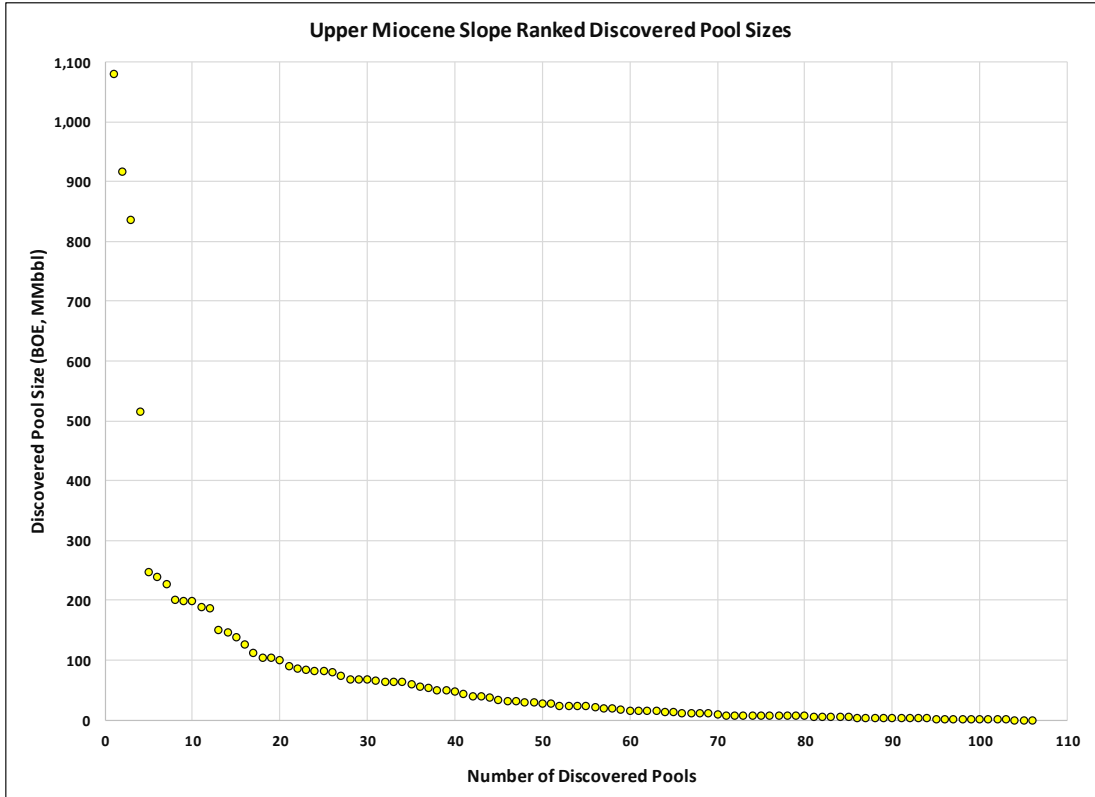


Figure 99. Upper Miocene Slope discovered pool-rank plot.

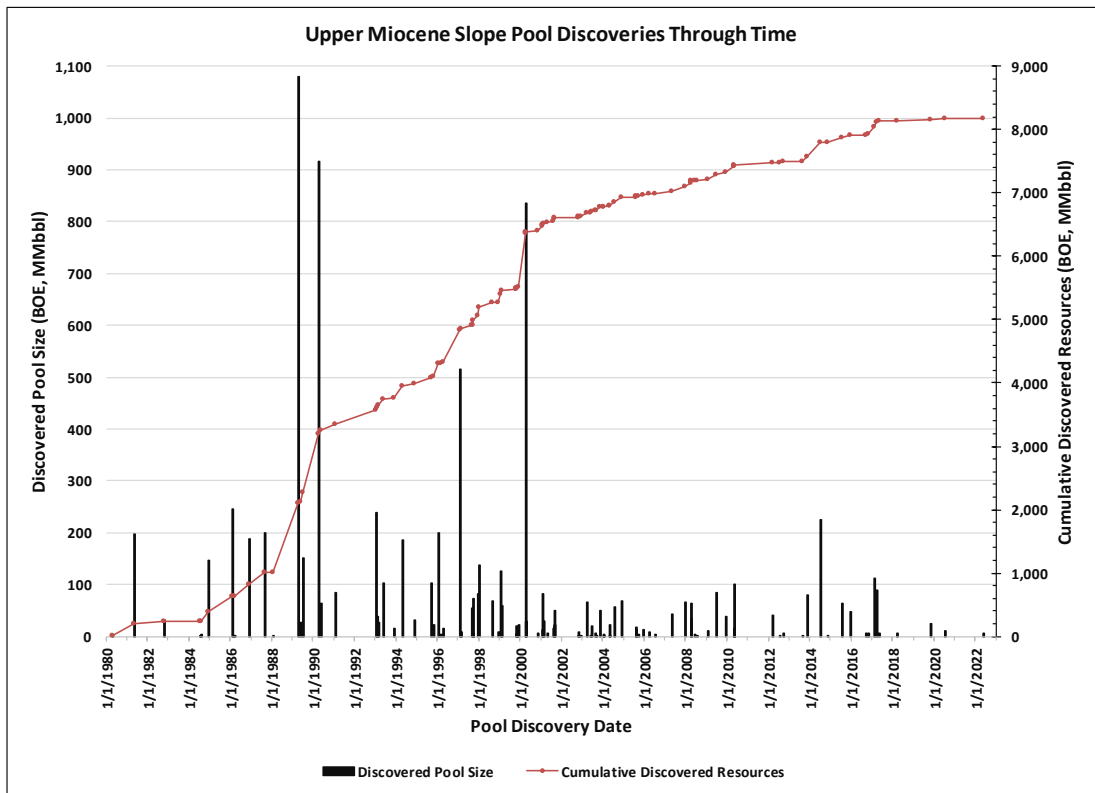


Figure 100. Upper Miocene Slope pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 29% ([Figure 4](#))
- exploration level: 29% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 170 to 714. Applying risk results in 50 to 210 undiscovered pools, with a mean of 130.

The pool-size distribution was modeled with the 106 discoveries in the AU. These pools range in size from 0.024 to 1,080 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 485 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 277 to 4,736 MMbbl, and undiscovered gas resources range from 801 to 17,711 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 101](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values have decreased from 5,625 to 3,620 MMBOE ([Figure 101](#)). Exploration in this area continues to push into deeper waters, with many prospects identified through amplitude anomalies visible in the latest seismic data. While these discoveries are typically modest—often under 100 MMBOE—they highlight ongoing interest in the AU. Additionally, several regions remain underexplored, largely due to the absence of infrastructure, which renders even significant but sub-stand-alone platform discoveries economically unviable. Despite these challenges, the AU still holds considerable potential. Advances in seismic imaging, particularly in resolving traps just beneath the base of salt, are making these features increasingly apparent. As a result, economics—not imaging capability—is becoming the primary limiting factor. Of all 30 assessment units in this study, the AU ranks 3rd based on mean-level undiscovered BOE resources ([Figure 10](#)).

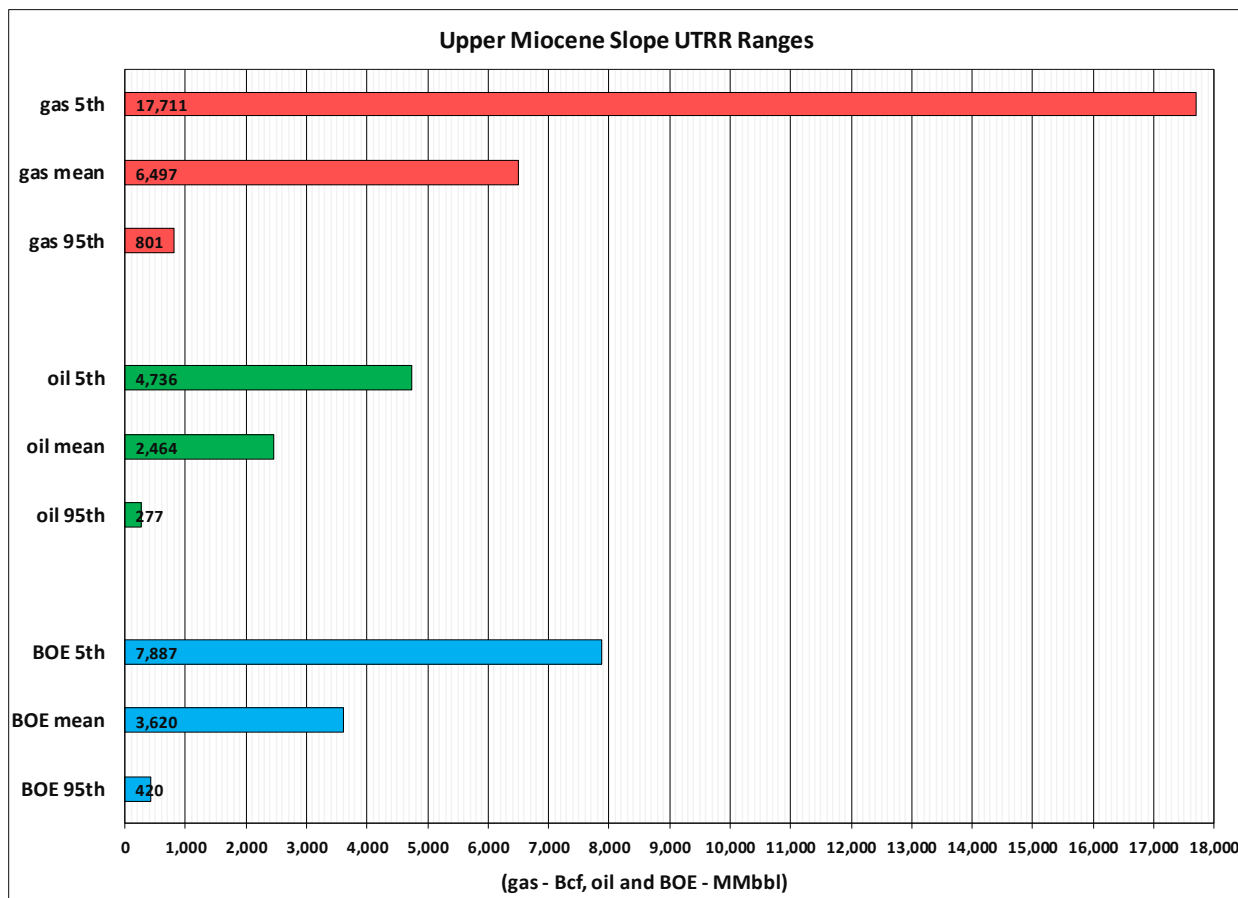


Figure 101. Upper Miocene Slope gas, oil, and BOE UTRR ranges.

Pliocene Shelf

Geology

The Pliocene Shelf AU is defined by sediments deposited in the Zanclean and Piacenzian Stages (Table 4) within the modern GOA shelf. The stratigraphic framework within the GOA Basin for Pliocene rocks is illustrated in Figure 25. The Shelf AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east, and in the dip direction, it extends from state waters to the modern shelf-slope break at a water depth of 656 ft (200 m) (Figure 102).

The Pliocene shelf margin advanced to the limit of the protraction area southern additions with large fluvial-dominated delta systems sourced from the paleo-Red, -Mississippi, and -Tennessee Rivers underlying most of the modern Louisiana shelf (Figure 26). Deepwater turbidite sediments and mass-transport deposits were delivered over the shelf margin into intraslope basins formed from salt withdrawal accompanying loading and extrusion of the Sigsbee Salt Canopy. Reservoirs of the Pliocene Shelf AU include the full range of depositional environments from fluvial-deltaic through deepwater submarine fans. Shallow-water facies include (1) stacked, blocky, sand-dominated sediments deposited in fluvial channel-levee complexes, crevasse splays, and point bars, (2) deltaic distributary channel-levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches and barrier islands, and (3) shallow marine shelf delta fringes and slumps. Deepwater fan systems include channel-levee systems and sheet sand lobes.

The Shelf AU includes traps against and above salt diapirs and remnant allochthonous salt bodies along Rooho welds (Figure 24), the remnants of earlier salt canopies. Other traps are upthrown three-way fault closures or downthrown rollover anticlines along growth faults associated with salt-withdrawal minibasins.

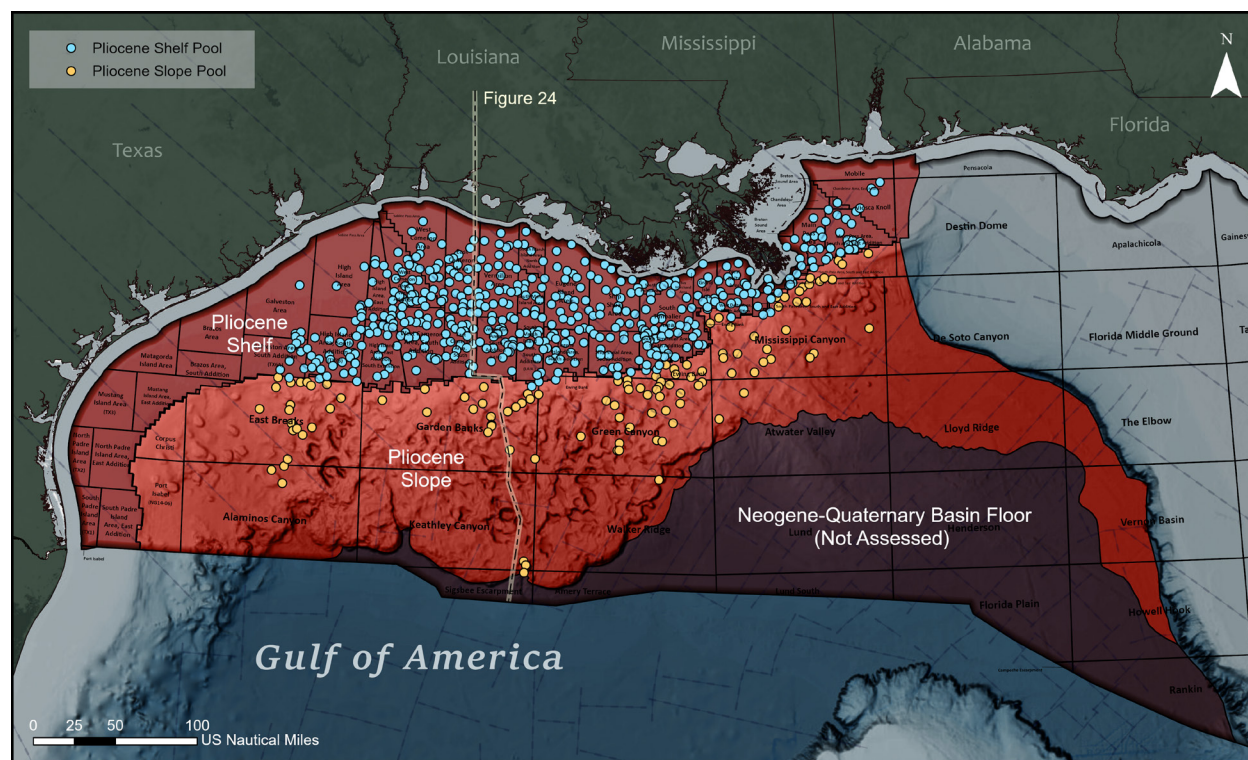


Figure 102. Pliocene Shelf and Slope locations and associated discovered pools.

Discoveries

Pools have been discovered in the Galveston and High Island Areas of offshore Texas and occur from the West Cameron to Viosca Knoll Areas of offshore Louisiana and Mississippi (Figure 102). There are 477 BOEM-designated hydrocarbon discoveries. Discovery dates range from 1948 to 2009 and peaked in the 1980s (Figure 103). The Shelf AU contains 5,440 MMbbl of oil and 50,114 Bcf of gas (total BOE of 14,357 MMbbl) (Table 8). Discovered in 1960, Ship Shoal 208 is the largest pool, containing an estimated 559 MMBOE (Figure 104). Other sizable pools include South Pass 89, Eugene Island 238, Eugene Island 330, and Ship Shoal 169, all of which contain more than 300 MMBOE (Figure 104). Pools have been discovered in water depths ranging from 12 to 650 ft, and subsea depths of these pools range from 1,115 to 16,118 ft.

Figure 105 illustrates cumulative resources for Shelf AU pool discoveries through time and the size of the discoveries. The flattening of the curve and decreasing discovery sizes through time clearly reflect a well-established, mature AU with the largest pools found early in its exploration history. The most recent OCS pool was found in 2009 (Figure 103).

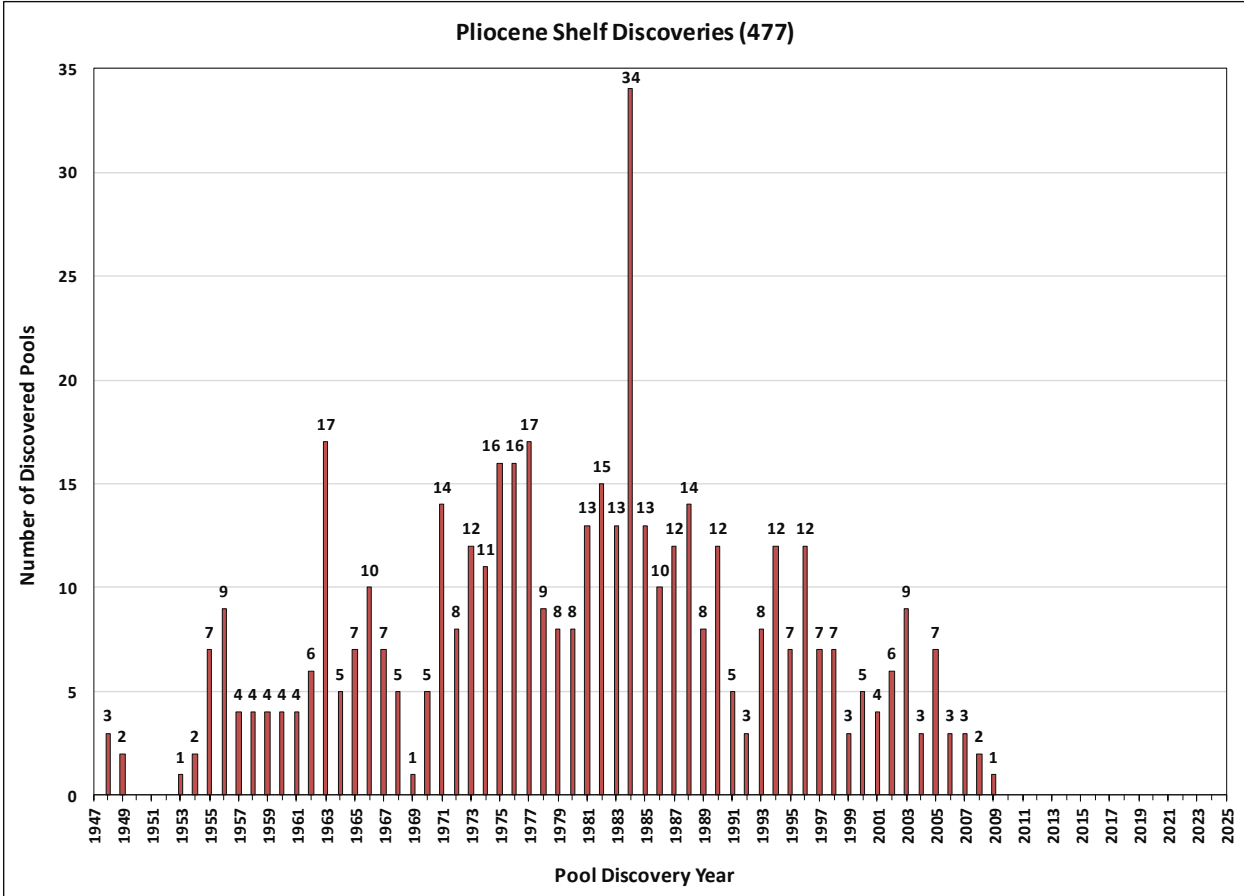


Figure 103. Pliocene Shelf pool discovery history.

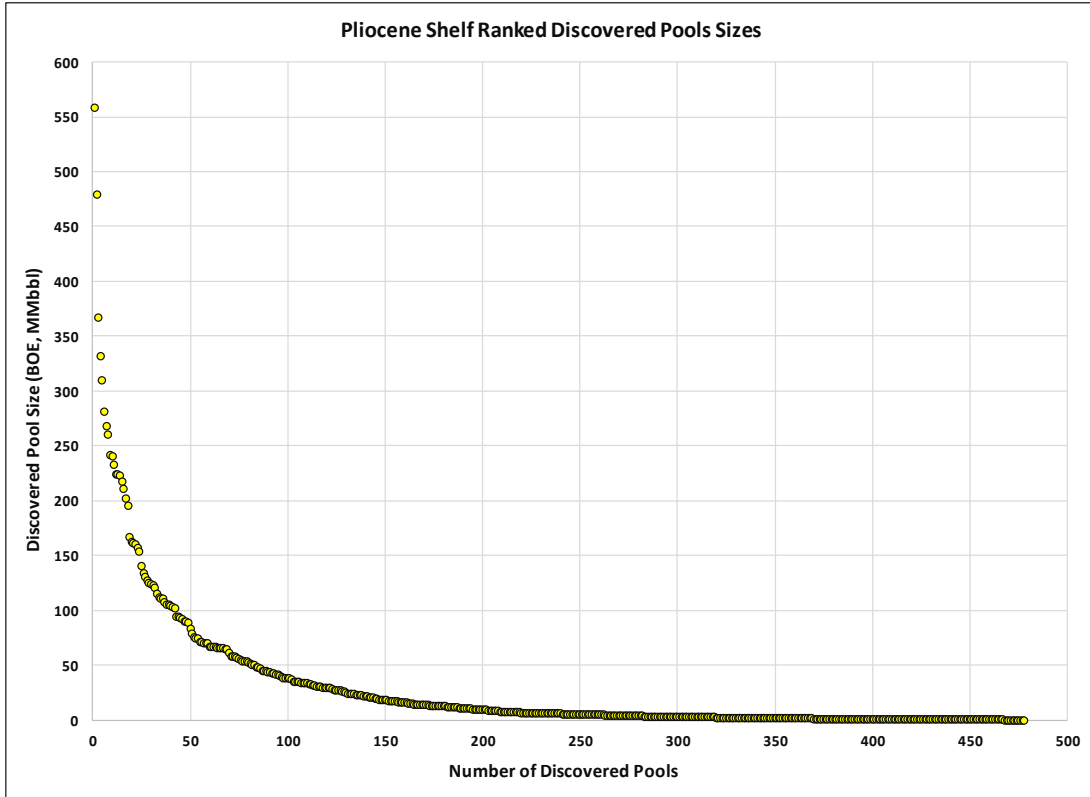


Figure 104. Pliocene Shelf discovered pool-rank plot.

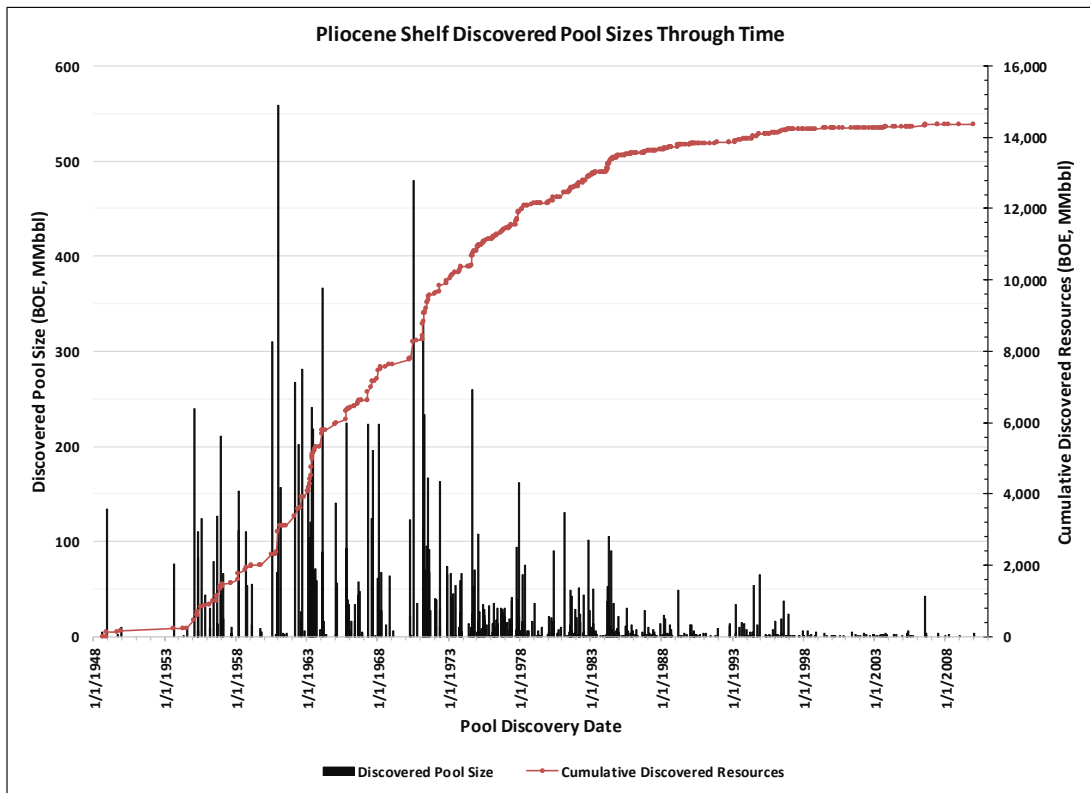


Figure 105. Pliocene Shelf pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 29% ([Figure 4](#))
- exploration-level: 29% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The Shelf AU was modeled with very little opportunity for significant undiscovered resources based on (1) a long discovery and production history dating back to 1948, (2) no discoveries greater than 50 MMBOE since 1994, (3) no discoveries at all since 2009, and (4) a present-day cumulative resources curve that is flat, indicative of very mature and highly explored plays ([Figure 105](#)).

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 68 to 238. Applying risk results in 20 to 70 undiscovered pools, with a mean of 45.

The pool-size distribution was modeled with the 477 discoveries in the AU. These pools range in size from 0.005 to 559 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 5 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 7 to 97 MMbbl, and undiscovered gas resources range from 46 to 1,432 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 106](#)). Because of the large number of discoveries controlling the lognormal distribution of the assessment model, there is very little uncertainty in the number and size of undiscovered pools remaining. The slight increase in mean forecast UTRR values from the [2021](#) to 2026 resource assessments of 99 to 138 MMBOE ([Figure 106](#)) is from difficulties with the GRASP program being able to model such a mature AU. Of all 30 assessment units in this study, the Pliocene Shelf ranks 24th based on mean-level undiscovered BOE resources ([Figure 10](#)).

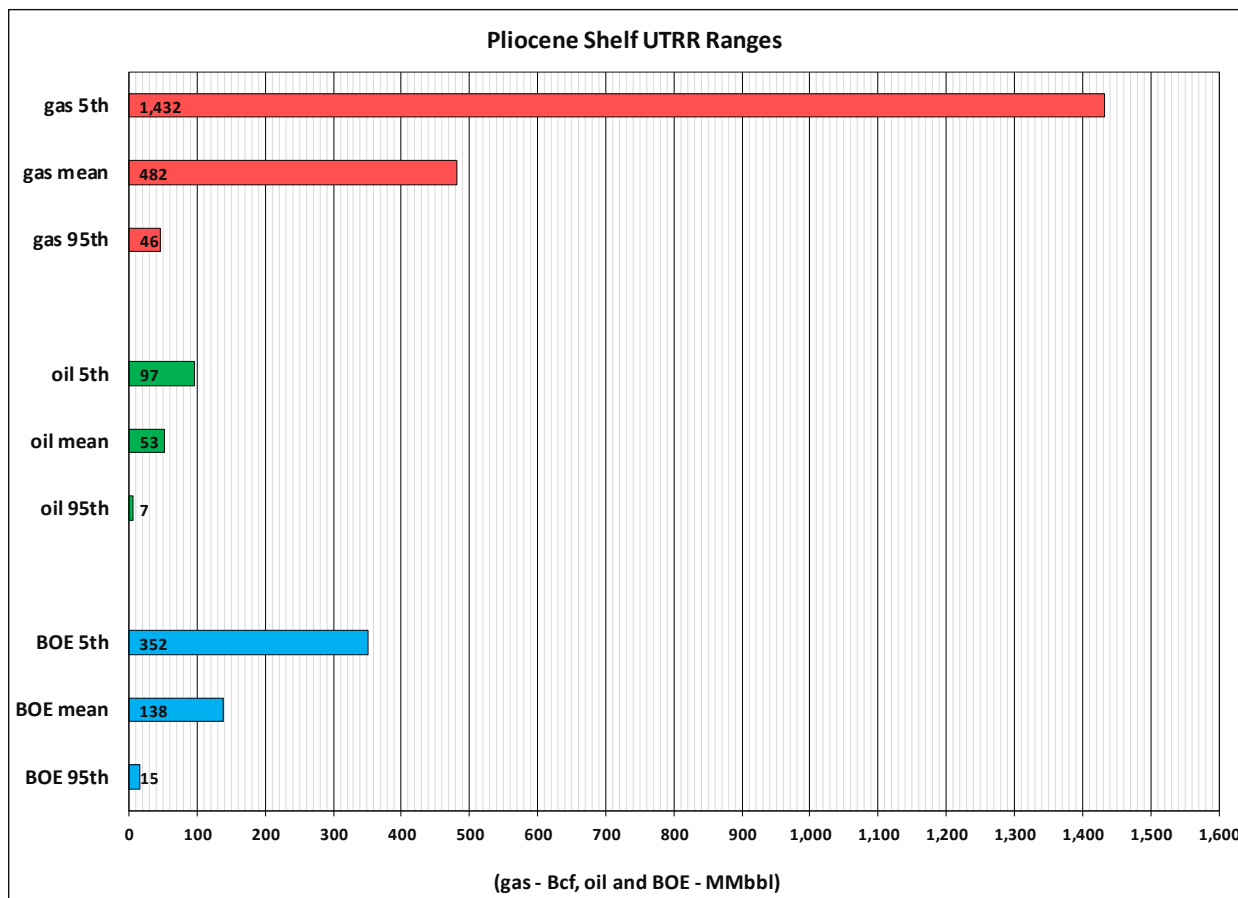


Figure 106. Pliocene Shelf gas, oil, and BOE UTRR ranges.

Pliocene Slope

Geology

The Pliocene Slope AU is defined by (1) deep-sea fan sediments deposited in the Zanclean and Piacenzian Stages (Table 4) and (2) a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern GOA slope (Figure 24). The stratigraphic framework within the GOA Basin for Pliocene rocks is illustrated in Figure 25. The AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east (Figure 102). In the dip direction, it extends from the modern shelf-slope break to the basinward limit of the Sigsbee Salt Canopy. Beyond the eastward limit of the Sigsbee Salt Canopy, the distal limit of the Slope AU follows the basinward limit of the Mesozoic salt nappes (Figure 23).

The Slope AU is underlain by large Pliocene submarine fan systems which advanced across the Sigsbee Salt Canopy in the central GOA (Figure 26) to emerge onto the abyssal plain. Deepwater turbidite systems followed tortuous paths through a complex depositional topography dominated by salt-withdrawal minibasins in a fill and spill fashion, leaving a record of ponded and bypass facies (Prather et al.,1998). Reservoir facies include channel-levee complexes and sheet-sand lobes.

The Slope AU includes structural and stratigraphic traps above the flanks of tabular salt bodies and sheets around the periphery of salt-withdrawal minibasins (Figure 24). Subsalt traps are present beneath the leading edge of the Sigsbee Salt Canopy.

Discoveries

In addition to wells whose primary objective is the Pliocene interval on the slope, it is also seen in those wells targeting deeper objectives; therefore, it is a relatively mature AU for the modern slope. There are 112 BOEM-designated hydrocarbon discoveries. Discovery dates range from 1975 to 2014 ([Figure 107](#)). The Slope AU contains 4,950 MMbbl of oil and 12,679 Bcf of gas (total BOE of 7,206 MMbbl) ([Table 8](#)). The subsalt Lucius discovery (Keathley Canyon 875) is the largest pool, containing an estimated 656 MMBOE ([Figure 108](#)). Other sizable, discovered pools include Mississippi Canyon 194 (Cognac), Mississippi Canyon 807 (Mars-Ursa complex), and Garden Banks 426 (Auger), all estimated to contain more than 350 MMBOE ([Figure 108](#)). Pools have been discovered in water depths ranging from 659 to 8,566 ft, and subsea depths of these pools range from 2,758 to 24,030 ft.

[Figure 109](#) illustrates cumulative resources for Slope AU pool discoveries through time and the size of the discoveries. Numerous large pool discoveries have resulted in sharp upticks in volumes added to the AU through time, with the most recent example being the Lucius discovery in 2004. The most recent OCS pool was found in 2014 ([Figure 107](#)).

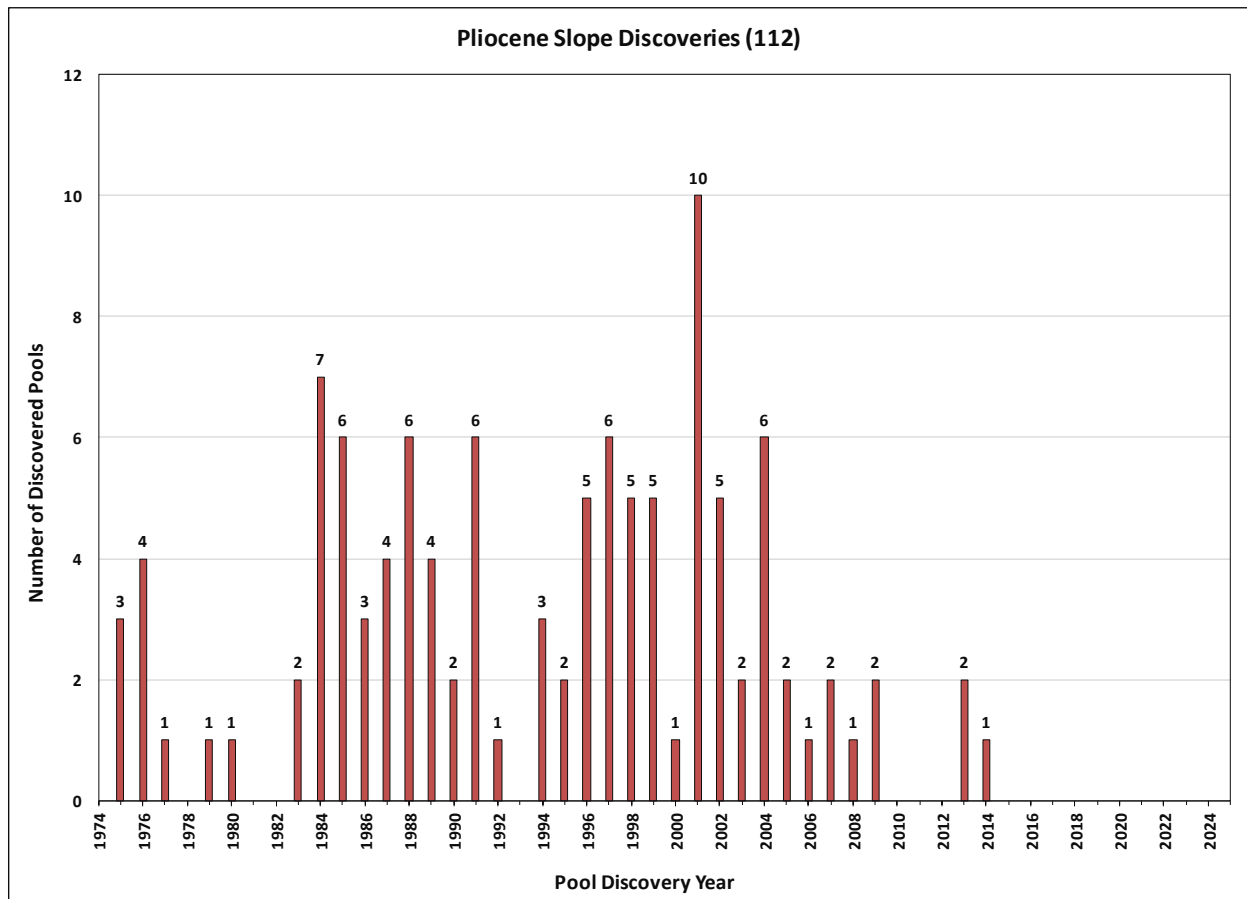


Figure 107. Pliocene Slope pool discovery history.

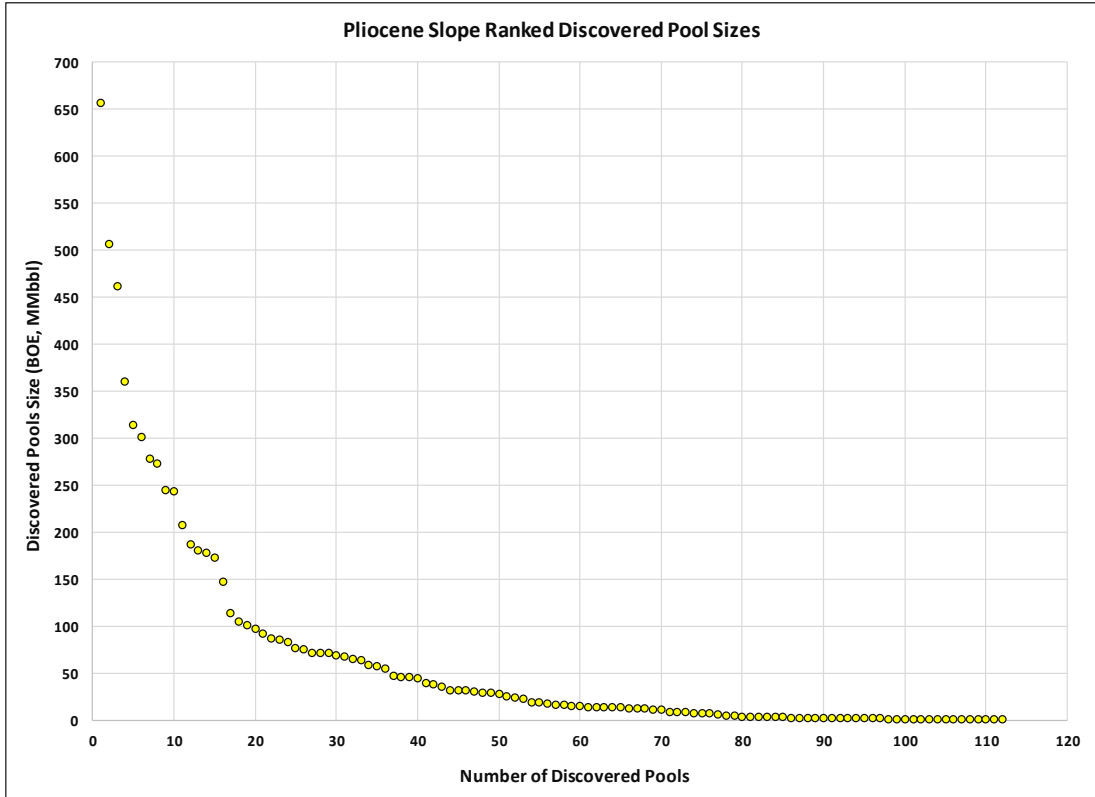


Figure 108. Pliocene Slope discovered pool-rank plot.

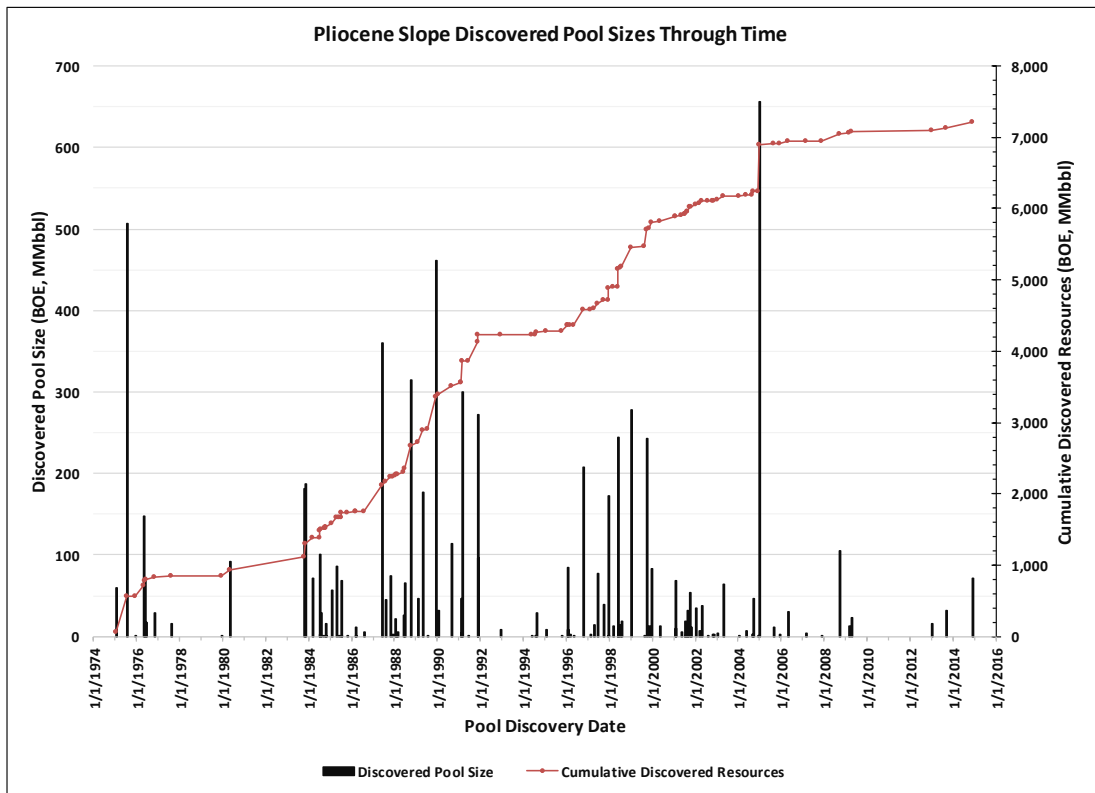


Figure 109. Pliocene Slope pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 25% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms and reservoir quality. See [Appendix B](#) for details.

Undiscovered Resources

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 119 to 595. Applying risk results in 30 to 150 undiscovered pools, with a mean of 90.

The pool-size distribution was modeled with the 112 discoveries in the AU. These pools range in size from 0.099 to 656 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 31 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 152 to 1,875 MMbbl, and undiscovered gas resources range from 320 to 4,250 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 110](#)). Of all 30 assessment units in this study, the Pliocene Slope ranks 7th based on mean-level undiscovered BOE resources ([Figure 10](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values for the Pliocene Slope have increased from 572 to 1,134 MMBOE ([Figure 110](#)). The increase in estimated volumes is primarily attributed to the evaluation of Pliocene Slope potential in the western GOA and the central to northern Green Canyon and Garden Banks Areas. Some of these areas are covered by poor-quality seismic data, leaving significant portions of prospective acreage uninterpretable.

Notable anomalous discoveries, such as Hadrian (Keathley Canyon 919) and Lucius (Keathley Canyon 875), have collectively contributed an estimated 656 MMBOE in grown discovered reserves to the AU. While another discovery of this scale is unlikely, it remains within the realm of possibility. The 2021 assessment estimate for UTRR of 572 MMBOE, which excluded several unexplored areas, left little room for significant new discoveries.

Similarly, analysis of suprasalt minibasins throughout underexplored regions of the GOA suggests that additional Pliocene Slope pools may exist beyond previous assessments. However, most of these prospects remain uneconomic and are in areas with limited or no existing infrastructure, presenting significant development challenges.

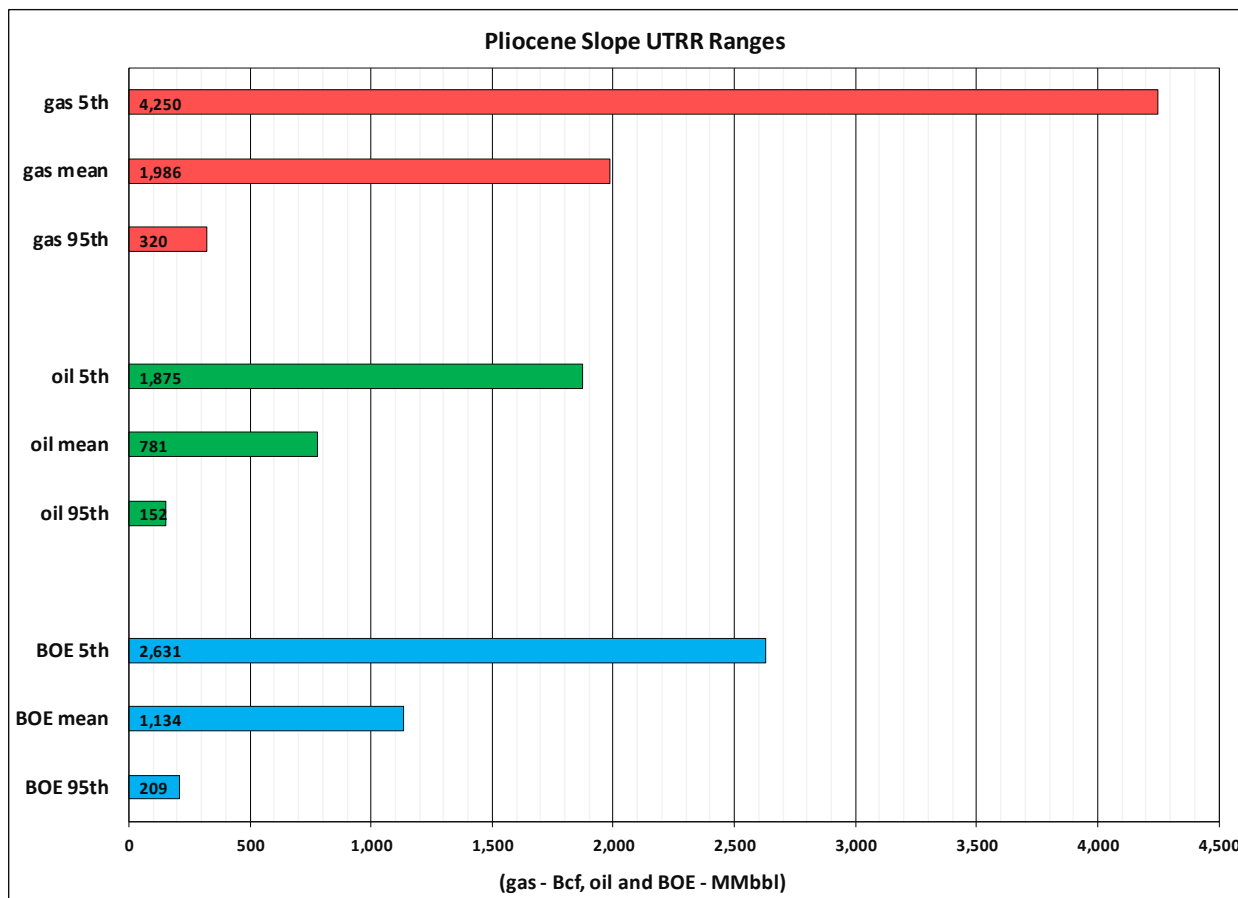


Figure 110. Pliocene Slope gas, oil, and BOE UTRR ranges.

Pleistocene Shelf

Geology

The Pleistocene Shelf AU is defined by sediments deposited in the Gelasian, Calabrian, Ionian, and Tarantian Stages ([Table 4](#)) within the modern GOA shelf. These sediments represent the youngest prospective stratigraphy in the GOA Basin ([Figure 25](#)). The Shelf AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east, and in the dip direction, it extends from state waters to the modern shelf-slope break at a water depth of 656 ft (200 m) ([Figure 111](#)).

The Shelf AU, including eastern-most offshore Texas and the western and central Louisiana shelf, is underlain by large fluvial-dominated delta systems that were sourced from the paleo-Red, -Mississippi, and -Tennessee rivers and prograded basinward to the modern shelf-slope break ([Figure 26](#)). Sediments of the Shelf AU were deposited in fluvial-deltaic, coastal, and shallow marine environments. Shallow-water facies include (1) stacked, blocky, sand-dominated sediments deposited in fluvial channels, levees, crevasse splays, and point bars, (2) deltaic distributary channels, crevasse splays, distributary mouth bars, bay fill, beaches and barrier islands, and (3) shallow marine shelf sand bodies.

The Shelf AU includes traps against and above salt diapirs and remnant allochthonous salt bodies along Roho welds ([Figure 24](#)), the remnants of earlier salt canopies. Other traps are upthrown three-way fault closures or downthrown rollover anticlines along growth faults associated with salt-withdrawal minibasins.

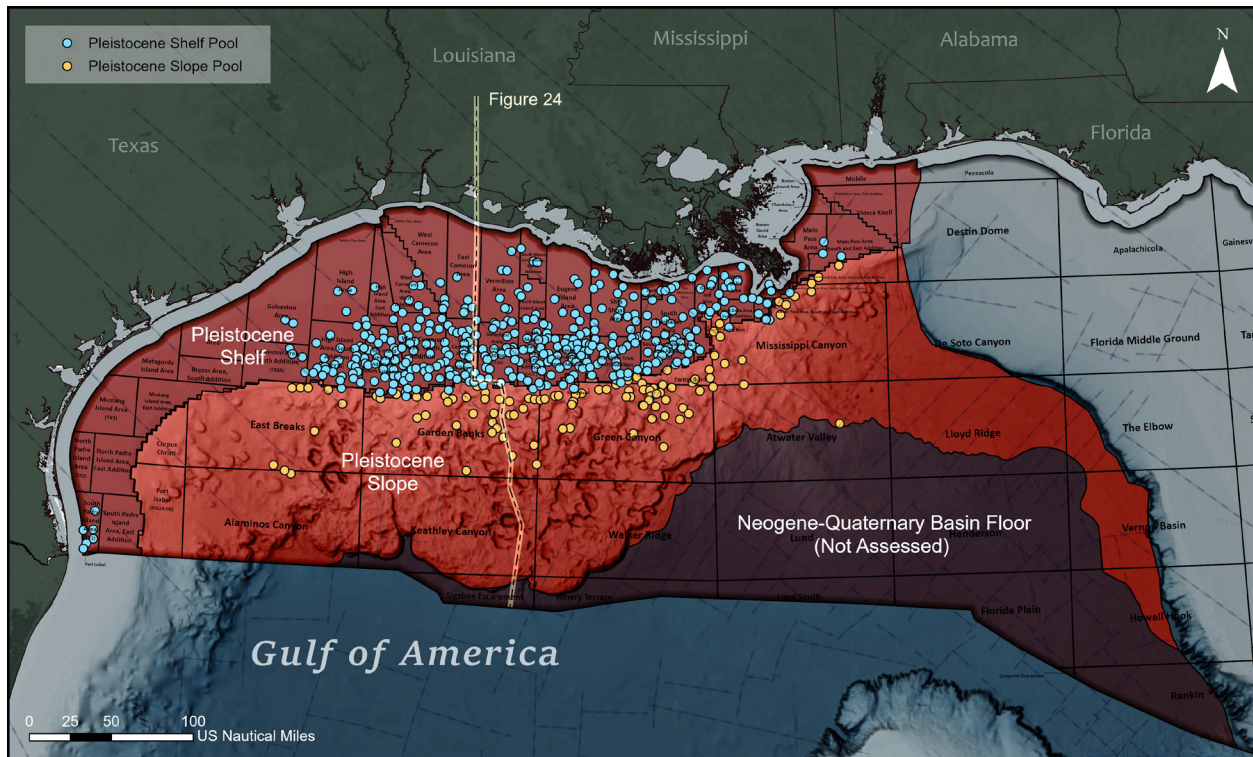


Figure 111. Pleistocene Shelf and Slope locations and associated discovered pools.

Discoveries

The Pleistocene Shelf AU is very mature, as these sediments overlie older targets. Pools have been discovered in the South Padre Island, Galveston, and High Island Areas of offshore Texas, and occur from the West Cameron to Main Pass Areas of offshore Louisiana and Mississippi (Figure 111). There are 392 BOEM-designated hydrocarbon discoveries. Discovery dates range from 1947 to 2007, with the peak of discoveries occurring in the mid-1970s (Figure 112). The Shelf AU contains 2,112 MMbbl of oil and 35,940 Bcf of gas (total BOE of 8,507 MMbbl) (Table 8). Discovered in 1971, Eugene Island 330 is the largest pool, containing an estimated 596 MMBOE (Figure 113). Other sizable, discovered pools include Eugene Island 292, South Marsh Island 130, Eugene Island 296, and West Cameron 587, all estimated contain more than 200 MMBOE (Figure 113). Pools have been discovered in water depths ranging from 12 to 639 ft, and subsea depths of these pools range from 881 to 13,043 ft.

Figure 114 illustrates cumulative resources for Shelf AU pool discoveries through time and the size of the discoveries. A present-day flat cumulative resources curve and decreasing discovery sizes through time clearly reflect a well-established, mature AU that has been extensively explored, with the most recent OCS pool found in 2007 (Figure 112).

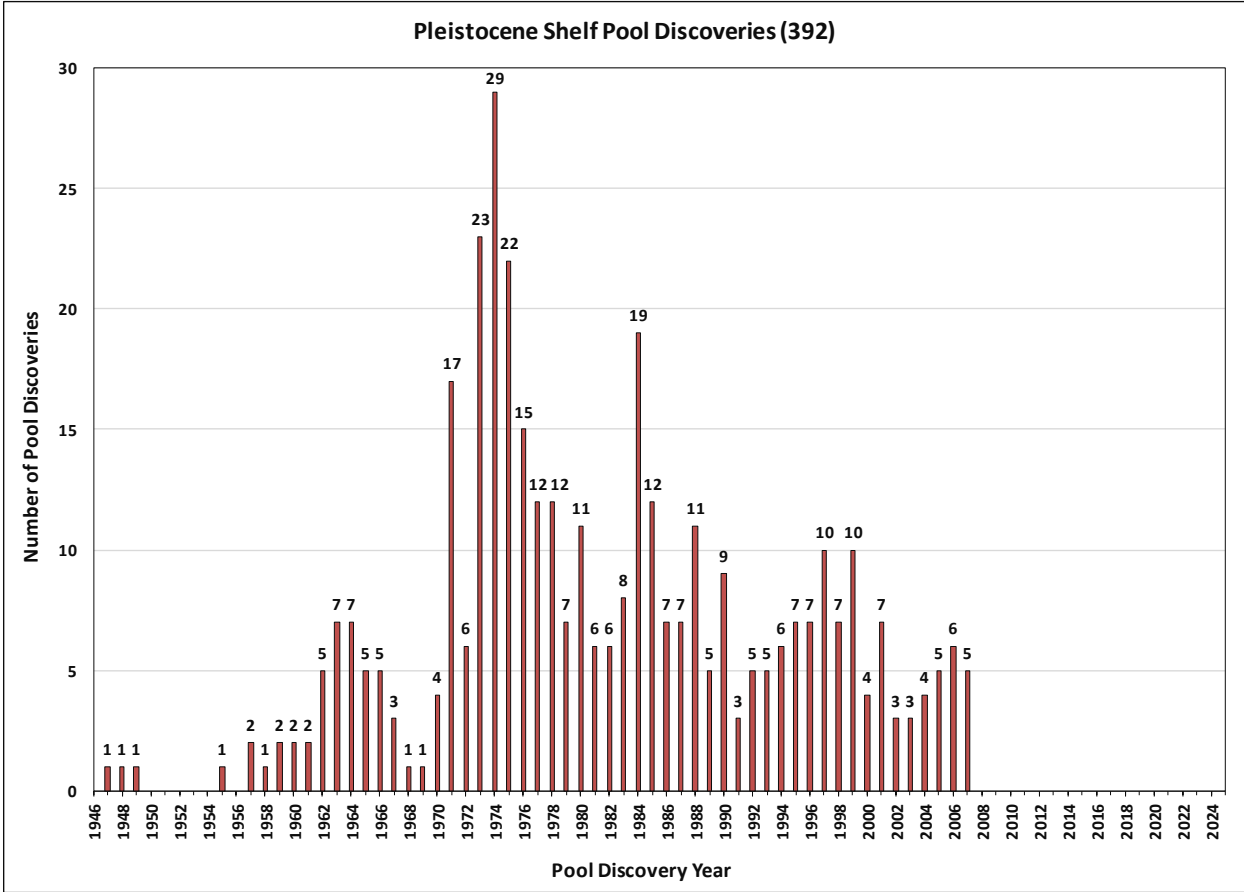


Figure 112. Pleistocene Shelf pool discovery history.

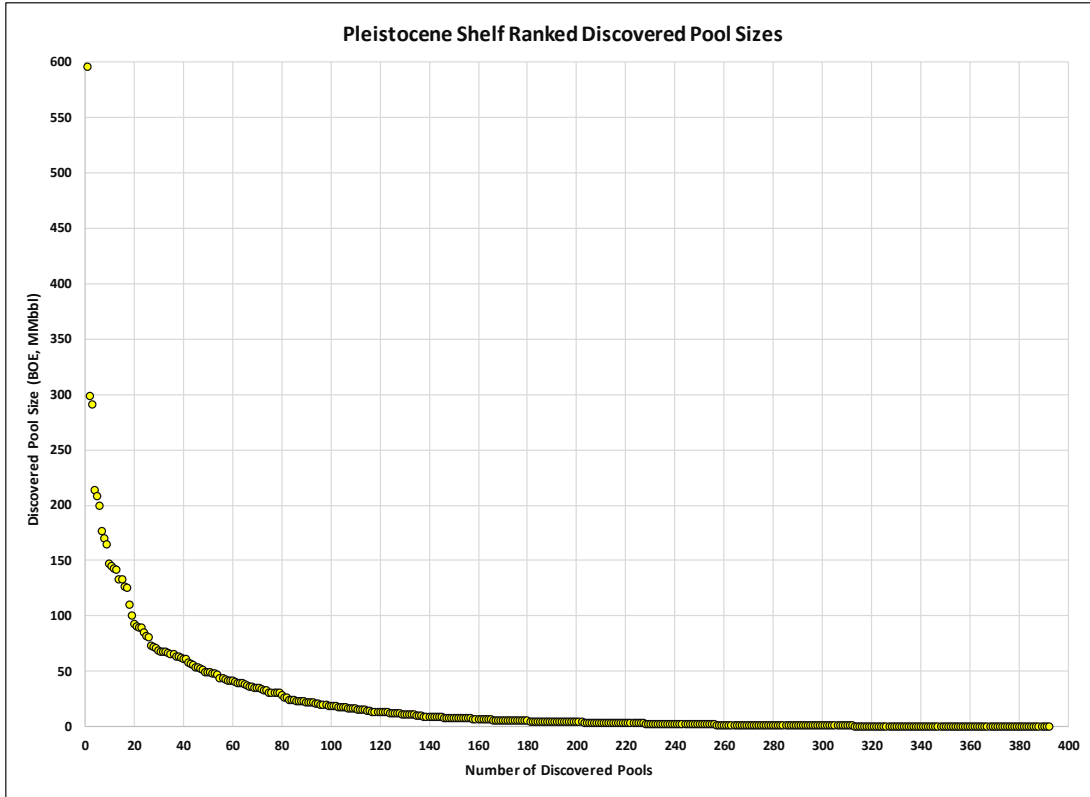


Figure 113. Pleistocene Shelf discovered pool-rank plot.

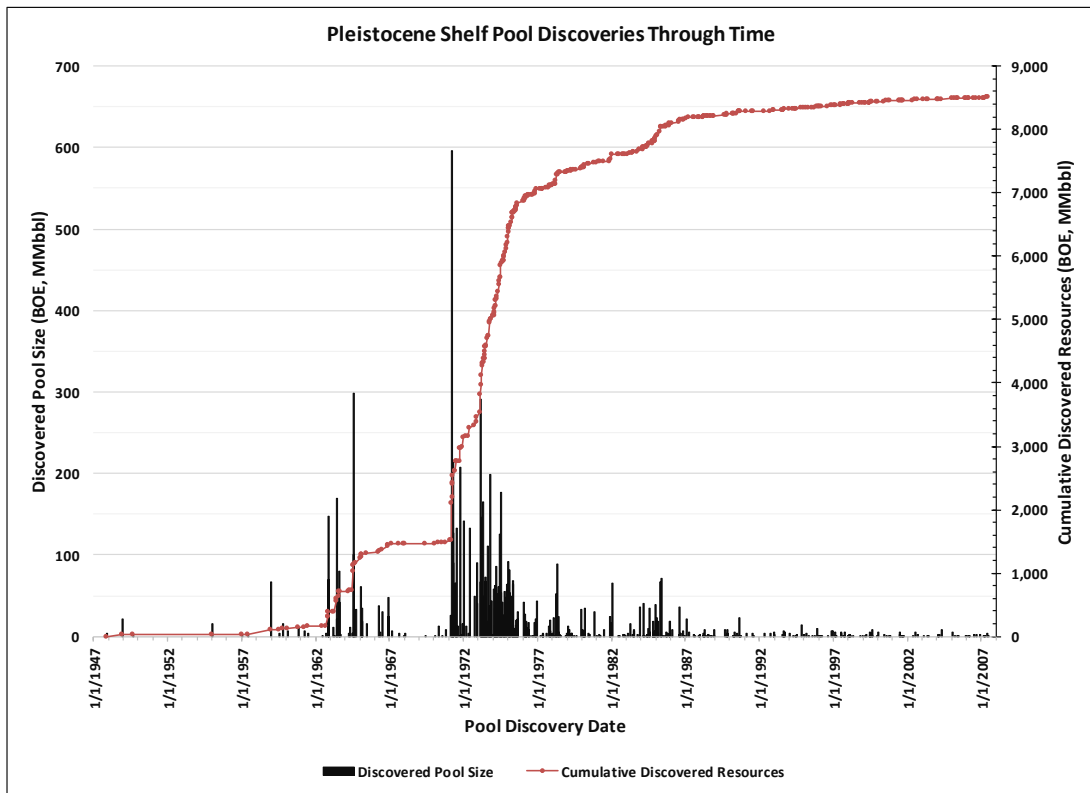


Figure 114. Pleistocene Shelf pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 43% ([Figure 4](#))
- exploration-level: 43% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms. See [Appendix B](#) for details.

Undiscovered Resources

The Shelf AU was modeled with very little opportunity for undiscovered resources based on (1) a long discovery and production history dating back to 1947, (2) no discoveries greater than 50 MMBOE since 1985, (3) no discoveries at all since 2007, and (4) a present-day flat cumulative resources curve indicative of mature, highly explored plays ([Figure 114](#)).

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 23 to 116. Applying risk results in 10 to 50 undiscovered pools, with a mean of 30.

The pool-size distribution was modeled with the 392 discoveries in the AU. These pools range in size from 0.001 to 596 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 1 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 1 to 23 MMbbl, and undiscovered gas resources range from 22 to 733 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 115](#)). Because of the large number of discoveries controlling the lognormal distribution of the assessment model, there is very little uncertainty in the number and size of undiscovered pools remaining. The slight increase in mean forecast UTRR values from the [2021](#) to 2026 resource assessments of 52 to 59 MMBOE ([Figure 115](#)) is from difficulties with the GRASP program being able to model such a mature AU. Of all 30 assessment units in this study, the Pleistocene Shelf ranks 27th based on mean-level undiscovered BOE resources ([Figure 10](#)).

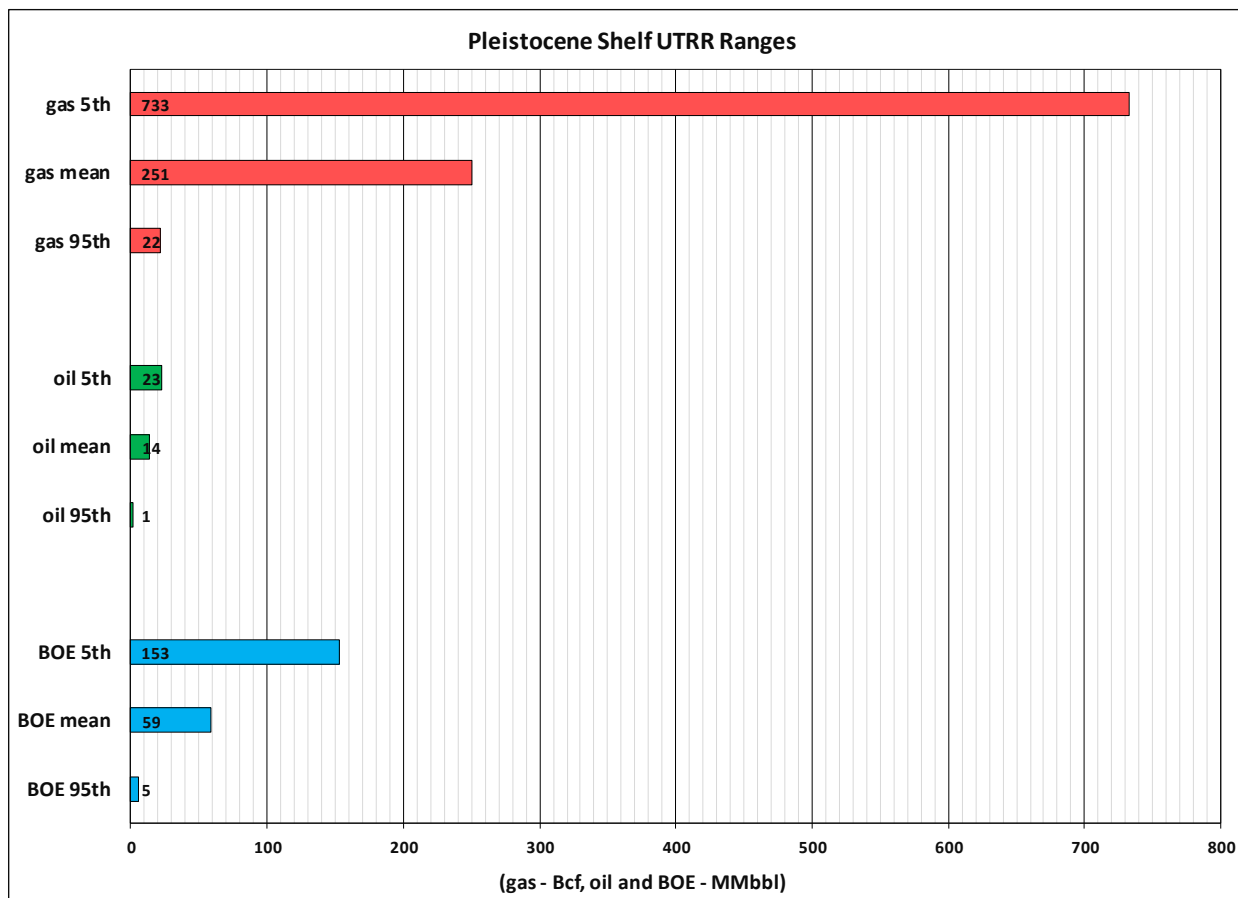


Figure 115. Pleistocene Shelf gas, oil, and BOE UTRR ranges.

Pleistocene Slope

Geology

The Pleistocene Slope AU is defined by (1) sediments deposited in the Gelasian, Calabrian, Ionian, and Tarantian Stages (Table 4) and (2) a structural regime of allochthonous salt sheets and canopies with intervening salt-withdrawal basins located on the modern GOA slope (Figure 24). These sediments represent the youngest prospective stratigraphy in the GOA Basin (Figure 25). The Slope AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east (Figure 111). In the dip direction, it extends from the modern shelf-slope break to the basinward limit of the Sigsbee Salt Canopy. Beyond the eastward limit of the Sigsbee Salt Canopy, the distal limit of the Slope AU follows the basinward limit of the Mesozoic salt nappes (Figure 23).

Large volumes of sediments were delivered to the slope in Pleistocene time, filling remaining accommodation space in salt-withdrawal minibasins in fill and spill fashion to deposit the Mississippi, Bryant, and Alaminos Fans on the basin floor (Figure 26). Reservoir facies of the Pleistocene Slope AU are deepwater turbidite sediments, including channel-levee complexes and sheet-sand lobes.

The Slope AU includes structural and stratigraphic traps above the flanks of tabular salt bodies and sheets around the periphery of salt-withdrawal minibasins (Figure 24). Subsalt traps are possible beneath the leading edge of the Sigsbee Salt Canopy.

Discoveries

The Slope AU is very mature, as these sediments overlie older targets. Pools have been discovered from the East Breaks and Alaminos Canyon Areas in the west along strike to the Viosca Knoll Area in the

east (Figure 111). There are 104 BOEM-designated hydrocarbon discoveries. Discovery dates range from 1975 to 2009, with peaks occurring in the 1980s and late 1990s–early 2000s (Figure 116). The Slope AU contains 1,360 MMbbl of oil and 7,605 Bcf of gas (total BOE of 2,713 MMbbl) (Table 8). Discovered in 1994, Green Canyon 244 (Troika) is the largest pool, containing an estimated 333 MMBOE (Figure 117). Other sizable, discovered pools include Garden Banks 426 (Auger) and Alaminos Canyon 25 (Hoover), both estimated to contain more than 150 MMBOE (Figure 117). Pools have been discovered in water depths ranging from 659 to 6,623 ft, and subsea depths of these pools range from 2,338 to 21,027 ft.

Figure 118 illustrates cumulative resources for Slope AU pool discoveries through time and the size of the discoveries. The cumulative resources curve throughout the history of GOA exploration has stair-stepped with periodic large discoveries. Decreasing discovery sizes through time, however, reflect a well-established, mature AU that has been extensively explored, with the most recent OCS pool found in 2009 (Figure 116).

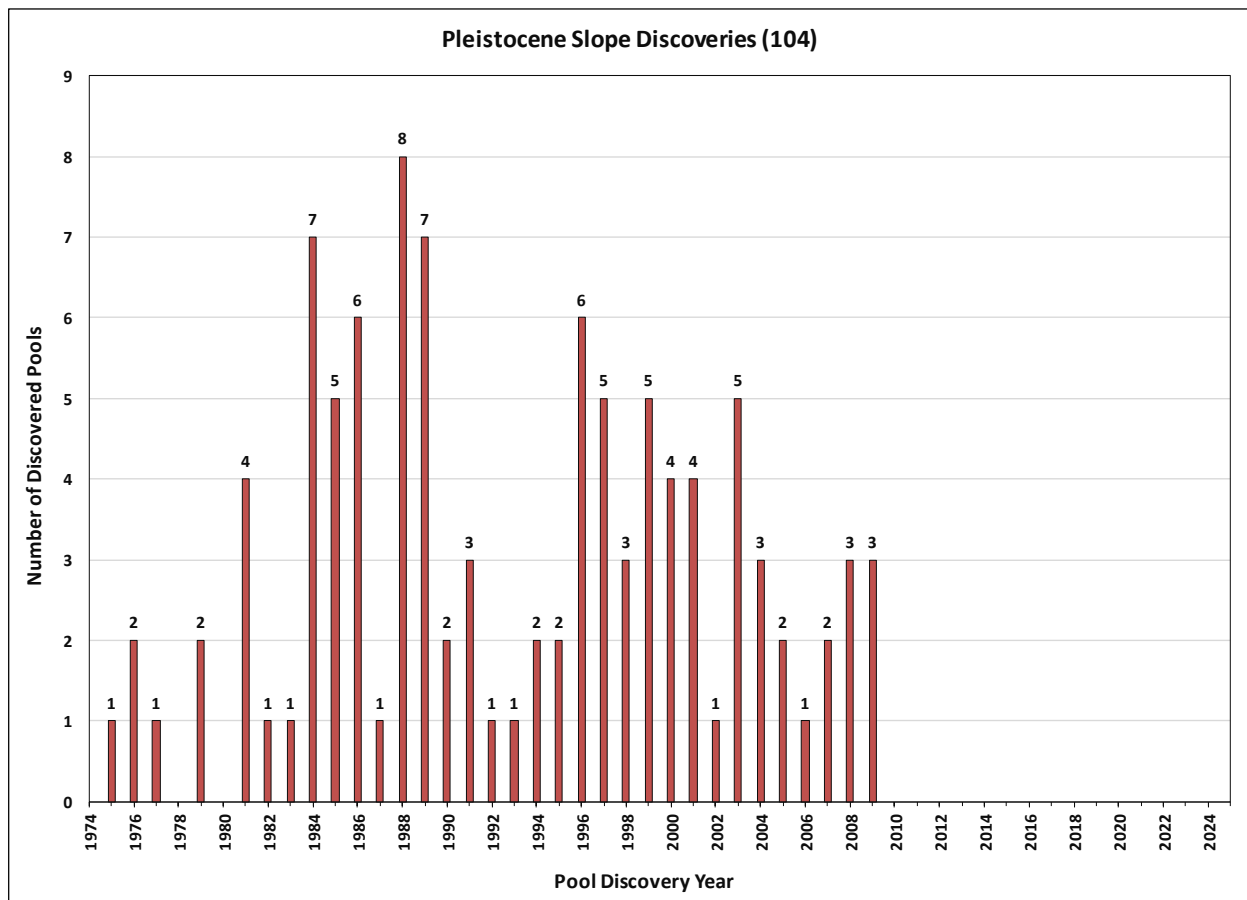


Figure 116. Pleistocene Slope pool discovery history.

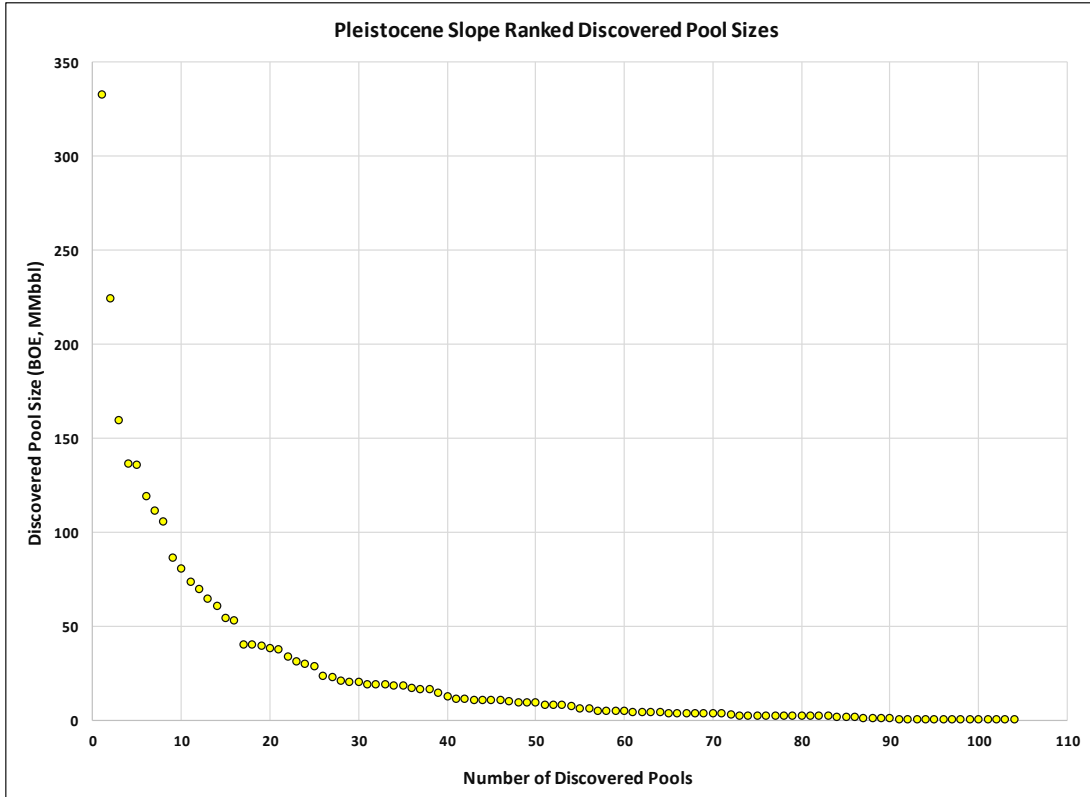


Figure 117. Pleistocene Slope discovered pool-rank plot.

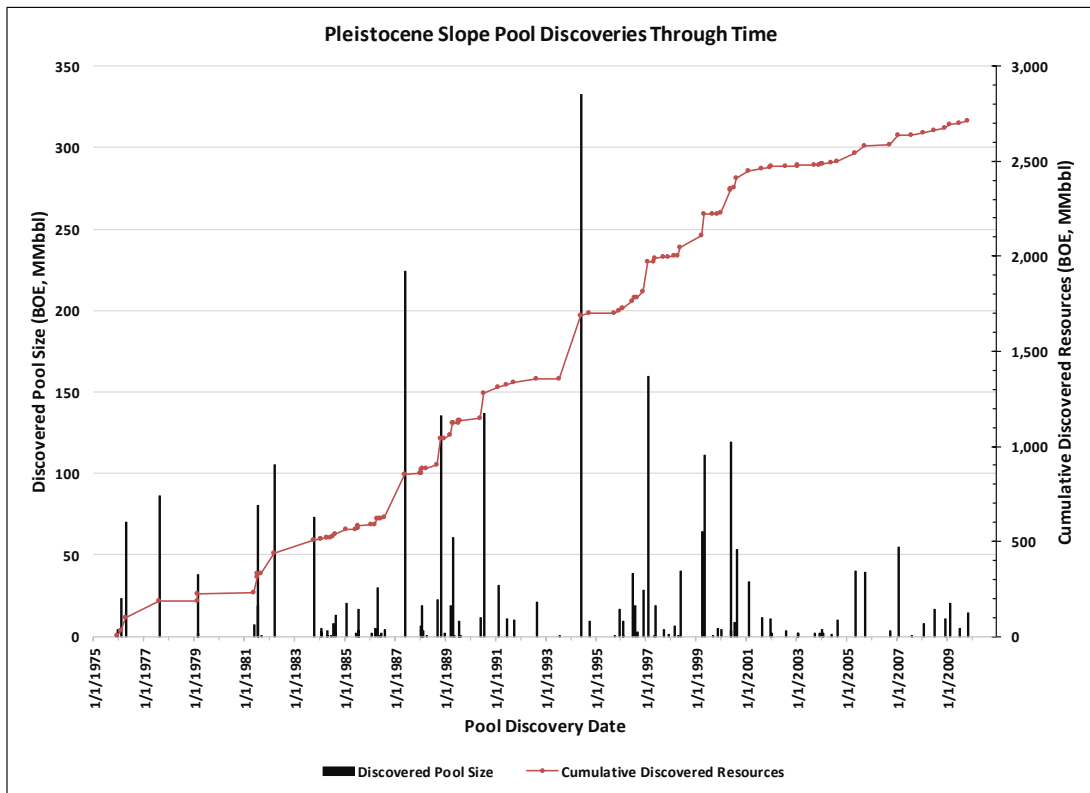


Figure 118. Pleistocene Slope pool discoveries through time.

Risk

Risk analysis by the assessors resulted in the following chances of success:

- play-level: 100% ([Figure 3](#))
- prospect-level: 25% ([Figure 4](#))
- exploration-level: 25% ([Figure 5](#))

With numerous discoveries, there is no play-level risk. The highest prospect-level risk was deemed to be effective seal mechanisms and reservoir quality. See [Appendix B](#) for details.

Undiscovered Resources

The Slope AU was modeled with relatively little opportunity for undiscovered resources based on a long discovery and production history dating back to 1975 and no discoveries since 2009.

The number of remaining prospects for this established AU was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 139 to 496. Applying risk results in 35 to 125 undiscovered pools, with a mean of 80.

The pool-size distribution was modeled with the 104 discoveries in the AU. These pools range in size from 0.051 to 333 MMBOE. From the pool-size and number of pools distributions, the lognormal GRASP model indicates the largest undiscovered pool is 8 MMBOE.

From the discovered data information, GRASP returned UTRR volumes for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Assessment results indicate that undiscovered oil resources range from 26 to 242 MMbbl, and undiscovered gas resources range from 102 to 1,608 Bcf at the 95th and 5th percentiles, respectively ([Table 8](#) and [Figure 119](#)). Of all 30 assessment units in this study, the Pleistocene Slope ranks 20th based on mean-level undiscovered BOE resources ([Figure 10](#)).

From the [2021](#) to 2026 resource assessments, the mean forecast UTRR values have increased slightly from 111 to 227 MMBOE ([Figure 119](#)). Analysis of the suprasalt minibasins across underexplored areas of the Gulf of America suggests that there may be more Pleistocene Slope pools than previously estimated. However, the majority of these remain uneconomic and are potentially located in regions with minimal or no existing infrastructure.

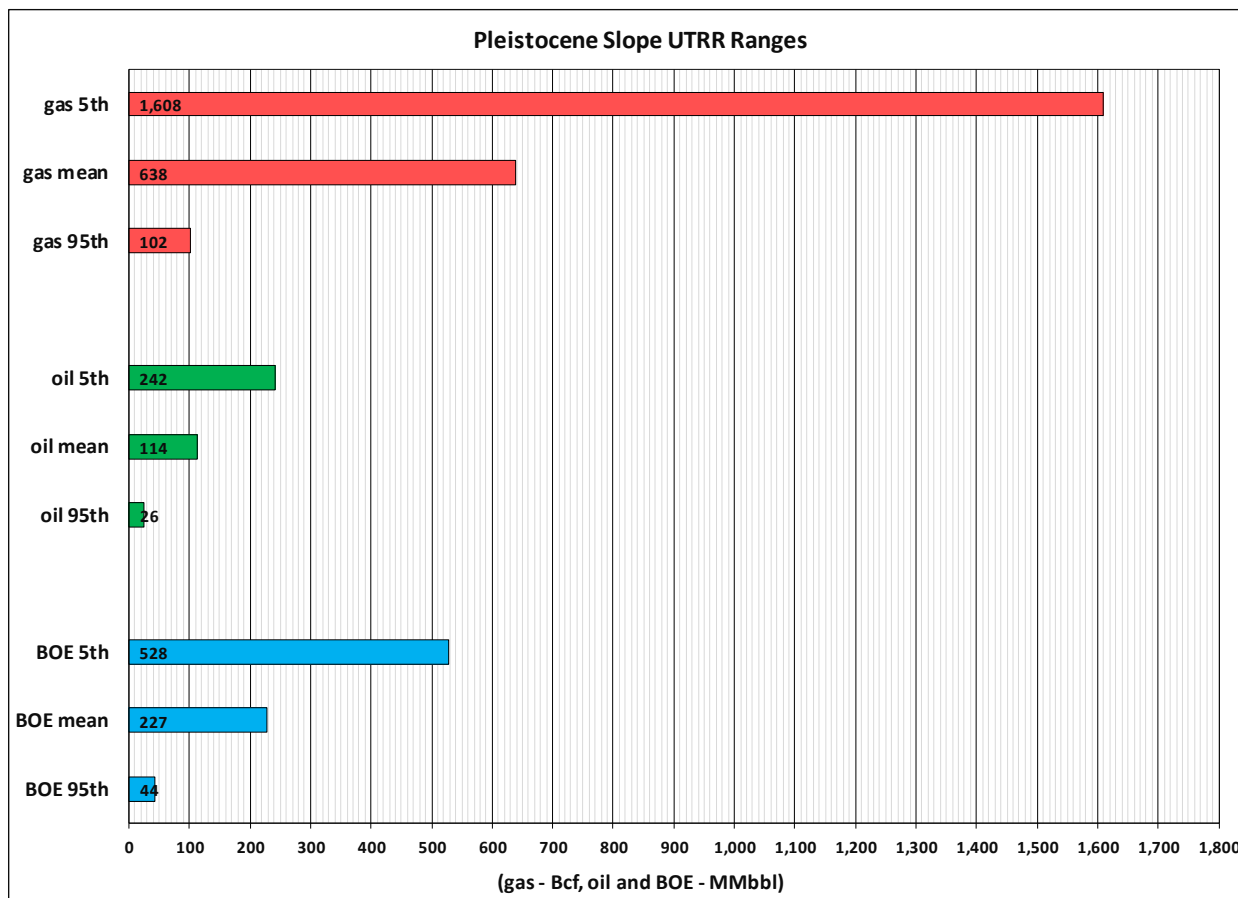


Figure 119. Pleistocene Slope gas, oil, and BOE UTRR ranges.

Neogene–Quaternary Basin Floor (unassessed)

Geology

The undifferentiated Neogene–Quaternary Basin Floor AU contains no discoveries and conceptually includes all Miocene, Pliocene, and Pleistocene strata. The Neogene–Quaternary Basin Floor is situated outboard of the Perdido, Keathley, Walker Ridge, and Atwater Fold Belts and extends from the distal edge of the Sigsbee Salt Canopy or the Mesozoic salt nappes (Figure 23), downdip to the limits of U.S. waters (Figure 2). It is generally coincident with the modern abyssal plain, beyond the structural influence of salt tectonism.

There are no exploration wells in the AU, though the younger section was cored by the Deep Sea Drilling Project (Bouma et al., 1986). The most likely objectives are Miocene submarine fan systems that are known from seismic facies mapping to have prograded onto the abyssal plain (DeVay et al., 2000; Stephens, 2001) and climb structurally to the south toward the Campeche Escarpment. Potential traps are limited to stratigraphic pinchouts or drape closures, which are less abundant than in the **Lower Tertiary Basin Floor Play**. As discussed in the **Mesozoic Basin Floor Play**, the region is largely underlain by oceanic crust. Tithonian source rocks are absent over the crest of the spreading ridge, and Cretaceous source rocks may be immature. Seismically detectable vertical migration pathways are generally lacking. A network of strata-bound compaction faults in the Paleogene section spans the region but terminates vertically at the base of the Miocene section. Most of the AU is blanketed by up to 4,000 m (13,123 ft) of Pliocene and Pleistocene submarine fan lobes, channel-levee deposits, and mass transport deposits of the Mississippi Fan (Weimer, 1990).

The Neogene–Quaternary Basin Floor AU was excluded from assessment due to the high level of geologic risk perceived and the limited number of prospects available.

GLOSSARY

Assessment Unit: All hydrocarbon reservoirs of a specific geologic age in a specified geographic area. Used interchangeably with “play” herein.

Shelf: An assessment unit in water depths less than 656 ft (less than 200 m). Synonymous with “shallow water” as used herein.

Slope: An assessment unit in water depths greater than or equal to 656 ft (greater than or equal to 200 m). Synonymous with “deep water” (noun) and “deepwater” (adjective) as used herein.

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

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

Sand: The aggregation of all fault-block portions (reservoirs) of an originally continuous sandstone body.

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).

Play: A group of pools that share common geologic, geographic, and temporal properties, such as history of hydrocarbon generation, migration, reservoir development, and entrapment. Used interchangeably with “assessment unit” herein.

Conceptual or Undiscovered Play: A play hypothesized based on subsurface geophysical data and regional geologic knowledge of the area. It is still a hypothesis, and the play concept has not been verified. These plays have considerable play-level risk.

Established or Discovered Play: A play in which (1) hydrocarbons have been discovered in at least one well, establishing a working petroleum system or (2) one or more pools have been discovered for which reserves have been estimated. These plays have no play-level risk.

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

Prospect: A geologic feature having the potential for trapping and accumulating hydrocarbons.

Reserves Growth (also known as, Reserves Appreciation): The observed incremental increase through time in the volumetric estimates of hydrocarbons in an oil and/or gas field. It is that part of the discovered resources over and above estimated volumes that will likely be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs.

Resources: Concentrations in the earth’s crust of naturally occurring liquid or gaseous hydrocarbons that conceivably can be discovered and recovered. Normal usage encompasses both Discovered Resources and Undiscovered Resources.

Discovered Resources: Hydrocarbons in which the location and quantity are known or estimated from specific geologic evidence. Included are Reserves and Contingent Resources ([Table 1](#)). The designation depends upon economic, technical, contractual, or regulatory criteria.

Reserves: 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:

Developed Producing: Reserves that are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Developed Non-Producing: Reserves that are precluded from producing due to being shut-in or behind-pipe.

Undeveloped: 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 that have previously shown favorable response to improved recovery projects.

Reserves Justified for Development: Reserves for which implementation of a development project is justified based on reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals and contracts will be obtained.

Contingent Resources: Those quantities of hydrocarbons 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.

Undiscovered Resources: Hydrocarbons postulated, based on geologic knowledge and theory, to exist outside of known fields or accumulations ([Table 1](#)).

Undiscovered Technically Recoverable Resources (UTRR): Oil and gas that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability.

Undiscovered Economically Recoverable Resources (UERR): The portion of the Undiscovered Technically Recoverable Resources that is economically recoverable under imposed economic and technologic conditions.

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APPENDICES

APPENDIX A. MESOZOIC RISK ANALYSIS FORMS

BOEM Play and Prospect Risk Analysis Form					
Assessment Province:	Gulf of America	Assessment Unit Name:	Pre-Salt or Equivalent		
Assessor(s):	Mesozoic Team	Play-Level Risk:	Yes (undiscovered play)		
Date:	2025	Assessment:	2026 Gulf of America		
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component			0.7000		0.5000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.7000		0.5000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.7000		0.5000	
2. Reservoir Component			0.8000		0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.8000		0.6000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.	2b	0.8000		0.6000	
3. Trap Component			0.8000		0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.	3a	0.9000		0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.8000		0.6000	
Overall Play Chance			0.4480		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.1800
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance		Overall Exploration Chance			
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		0.0806			
Probabilities are as follows:					
Component Probably Exists		1.0 - 0.8			
Component will Possibly Exist		0.8 - 0.6			
Equally Likely Component is Present or Absent		0.6 - 0.4			
Component is Possibly Lacking		0.4 - 0.2			
Component is Probably Lacking		0.2 - 0.0			
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					
Rifts work around the world, so the Pre-Salt or Equivalent Play should be less risky than the Expanded Jurassic Play.					
The usual GOA source rocks are above the Pre-Salt or Equivalent Play. Sources could be localized (e.g., lacustrine).					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Expanded Jurassic			
Assessor(s): Mesozoic Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	0.6000	0.5000	0.5000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	0.6000	0.5000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	0.6000	0.5000	
2. Reservoir Component		2	0.7000	0.6000	0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	0.7000	0.6000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.7000	0.6000	
3. Trap Component		3	0.8000	0.7000	0.7000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	0.9000	0.9000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	0.8000	0.7000	
Overall Play Chance			0.3360		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.2100
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance				Overall Exploration Chance	
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				0.0706	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Norphlet Shelf			
Assessor(s): Mesozoic Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000	0.6000	0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.8000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000	0.7000	0.7000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.9000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.7000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2940
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>					0.2940
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Norphlet Slope			
Assessor(s): Mesozoic Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.6000	0.6000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.6000	
2. Reservoir Component		2	1.0000	0.4000	0.4000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.4000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.5000	
3. Trap Component		3	1.0000	0.7000	0.7000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.9000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.7000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.1680
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				Overall Exploration Chance <i>0.1680</i>	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Smackover			
Assessor(s): Mesozoic Team		Play-Level Risk: No (hydrocarbon system has been proven)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000	0.5000	0.5000
a. Presence of Reservoir Facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.6000	
b. Reservoir Quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.5000	
3. Trap Component		3	1.0000	0.7000	0.7000
a. Presence of Trap Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.8000	
b. Effective Seal Mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.7000	
Overall Play Chance			1.0000		
(1 * 2 * 3) Product of All Subjective Play Chance Factors					
Average Conditional Prospect Chance¹					0.2450
(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors					
¹ Assumes that the play exists (where all play chance factors = 1.0)					
Exploration Chance		Overall Exploration Chance			
(Product of Overall Play Chance and Average Conditional Prospect Chance)		0.2450			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					
The G06396_001 well in Pensacola Block 996 flowed a calculated 43 barrels of oil per day proving the existence of an active petroleum system. Therefore, there is no play risk.					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Florida Basement Clastic			
Assessor(s): Mesozoic Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	0.7000	0.6000	0.6000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	0.7000	0.6000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	0.8000	0.7000	
2. Reservoir Component		2	0.7000	0.6000	0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	0.7000	0.7000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.7000	0.6000	
3. Trap Component		3	0.7000	0.6000	0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	0.9000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	0.7000	0.6000	
Overall Play Chance			0.3430		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.2160
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance				Overall Exploration Chance	
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				0.0741	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Cotton Valley Clastic Shelf			
Assessor(s): Mesozoic Team		Play-Level Risk: No (hydrocarbon system has been proven)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000	0.5000	0.5000
a. Presence of Reservoir Facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.6000	
b. Reservoir Quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.5000	
3. Trap Component		3	1.0000	0.6000	0.6000
a. Presence of Trap Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.9000	
b. Effective Seal Mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance			1.0000		
(1 * 2 * 3) Product of All Subjective Play Chance Factors					
Average Conditional Prospect Chance¹					0.2100
(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors					
¹ Assumes that the play exists (where all play chance factors = 1.0)					
Exploration Chance		Overall Exploration Chance			
(Product of Overall Play Chance and Average Conditional Prospect Chance)		0.2100			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					
Cotton Valley sands exhibit hydrocarbon shows by mud log in wells in Viosca Knoll and Mobile Areas proving the existence of an active petroleum system. Therefore, there is no play risk.					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Cotton Valley Clastic Slope			
Assessor(s): Mesozoic Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	0.9000	0.7000	
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	0.9000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	0.9000	0.7000	
2. Reservoir Component		2	0.6000	0.5000	
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	0.6000	0.6000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.6000	0.5000	
3. Trap Component		3	0.8000	0.6000	
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	0.9000	0.9000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	0.8000	0.6000	
Overall Play Chance			0.4320		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.2100
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance		Overall Exploration Chance			
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		0.0907			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Sunniland			
Assessor(s): Mesozoic Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	0.9000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	0.9000	0.7000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	0.9000	0.7000	
2. Reservoir Component		2	0.8000	0.6000	0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	0.8000	0.6000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.8000	0.7000	
3. Trap Component		3	0.7000	0.6000	0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	0.8000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	0.7000	0.6000	
Overall Play Chance			0.5040		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.2520
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance				Overall Exploration Chance	
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				0.1270	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Lower Cretaceous Carbonate			
Assessor(s): Mesozoic Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.7000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.8000	
2. Reservoir Component		2	1.0000	0.6000	0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.7000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000	0.5000	0.5000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.5000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance			1.0000		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.2100
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance				Overall Exploration Chance	
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				0.2100	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Lower Cretaceous Clastic Shelf			
Assessor(s): Mesozoic Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	0.8000	0.7000	
a. Presence of Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	0.8000	0.7000	
2. Reservoir Component		2	0.9000	0.6000	
a. Presence of Reservoir Facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.7000	
b. Reservoir Quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.9000	0.6000	
3. Trap Component		3	0.8000	0.6000	
a. Presence of Trap Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	0.8000	0.6000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			0.5760		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2520
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				Overall Exploration Chance 0.1452	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Lower Cretaceous Clastic Slope			
Assessor(s): Mesozoic Team		Play-Level Risk: No (hydrocarbon system has been proven)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000	0.5000	0.5000
a. Presence of Reservoir Facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.7000	
b. Reservoir Quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.5000	
3. Trap Component		3	1.0000	0.5000	0.5000
a. Presence of Trap Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.1750
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				Overall Exploration Chance <i>0.1750</i>	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					
The discovery well at the Norphlet discovery "Appomattox" logged hydrocarbons in the Paluxy Formation proving the existence of an active petroleum system. Therefore, there is no play risk.					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Lower Tuscaloosa Shelf			
Assessor(s): Mesozoic Team		Play-Level Risk: No (hydrocarbon system has been proven)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000	0.6000	0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.7000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000	0.6000	0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.8000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors			1.0000		
Average Conditional Prospect Chance¹ (1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors ¹ Assumes that the play exists (where all play chance factors = 1.0)					0.2520
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)				Overall Exploration Chance 0.2520	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					
OCS G05055 A001 ST00 in Main Pass Block 254 flowed hydrocarbons from the Lower Tuscaloosa sand proving the existence of an active petroleum					
Therefore, there is no play risk.					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Lower Tuscaloosa Slope			
Assessor(s): Mesozoic Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	0.6000	0.5000	0.5000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	0.6000	0.6000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.6000	0.5000	
3. Trap Component		3	0.9000	0.7000	0.7000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	0.9000	0.9000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	0.9000	0.7000	
Overall Play Chance			0.5400		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.2450
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance				Overall Exploration Chance	
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				0.1323	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Mesozoic Shelf			
Assessor(s): Mesozoic Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.9000	0.9000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.9000	
2. Reservoir Component		2	0.5000	0.4000	0.4000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.7000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.5000	0.4000	
3. Trap Component		3	1.0000	0.5000	0.5000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.8000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance			0.5000		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.1800
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance				Overall Exploration Chance	
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				0.0900	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province:	Gulf of America	Assessment Unit Name:	Mesozoic Slope
Assessor(s):	Mesozoic Team	Play-Level Risk:	Yes (undiscovered play)
Date:	2025	Assessment:	2026 Gulf of America

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	0.6000		0.5000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.7000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.6000	0.5000	
3. Trap Component		3	1.0000		0.5000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.8000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			0.6000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.1750
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				Overall Exploration Chance 0.1050	
Probabilities are as follows:					
Component Probably Exists		1.0 - 0.8			
Component will Possibly Exist		0.8 - 0.6			
Equally Likely Component is Present or Absent		0.6 - 0.4			
Component is Possibly Lacking		0.4 - 0.2			
Component is Probably Lacking		0.2 - 0.0			
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

APPENDIX B. CENOZOIC RISK ANALYSIS FORMS

BOEM Play and Prospect Risk Analysis Form						
Assessment Province: Gulf of America		Assessment Unit Name: Lower Tertiary Shelf				
Assessor(s): Lower Tertiary Team		Play-Level Risk: No (discovered play)				
Date: 2025		Assessment: 2026 Gulf of America				
Risk Components and Associated Elements			Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.			Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component				1.0000		0.9000
a. Presence of Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.			1a	1.0000	0.9000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.			1b	1.0000	0.9000	
2. Reservoir Component				1.0000		0.4000
a. Presence of Reservoir Facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.			2a	1.0000	0.7000	
b. Reservoir Quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.			2b	1.0000	0.4000	
3. Trap Component				1.0000		0.5000
a. Presence of Trap Probability of presence of the trap with a minimum rock volume.			3a	1.0000	0.8000	
b. Effective Seal Mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.			3b	1.0000	0.5000	
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors				1.0000		
Average Conditional Prospect Chance¹ (1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors ¹ Assumes that the play exists (where all play chance factors = 1.0)						0.1800
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)						Overall Exploration Chance 0.1800
Probabilities are as follows:						
Component Probably Exists		1.0 - 0.8				
Component will Possibly Exist		0.8 - 0.6				
Equally Likely Component is Present or Absent		0.6 - 0.4				
Component is Possibly Lacking		0.4 - 0.2				
Component is Probably Lacking		0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.						
Comments:						

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Frio Slope			
Assessor(s): Lower Tertiary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.6000	0.6000
a. Presence of Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.6000	
2. Reservoir Component		2	1.0000	0.5000	0.5000
a. Presence of Reservoir Facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.5000	
3. Trap Component		3	1.0000	0.5000	0.5000
a. Presence of Trap Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.6000	
b. Effective Seal Mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance			1.0000		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.1500
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance		Overall Exploration Chance			
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		0.1500			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Wilcox Slope			
Assessor(s): Lower Tertiary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.7000	0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000	0.6000	0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000	0.6000	0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.8000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2520
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				Overall Exploration Chance <i>0.2520</i>	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of America		Assessment Unit Name: Lower Tertiary Basin Floor			
Assessor(s): Lower Tertiary Team		Play-Level Risk: Yes (undiscovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.6000	0.6000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.6000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.6000	
2. Reservoir Component		2	0.7000	0.5000	0.5000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	0.8000	0.5000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	0.7000	0.5000	
3. Trap Component		3	0.8000	0.6000	0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	0.8000	0.6000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	0.9000	0.7000	
Overall Play Chance			0.5600		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.1800
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance				Overall Exploration Chance	
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>				0.1008	
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Lower Miocene Shelf			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000		0.5000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2100
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2100			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Lower Miocene Slope			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.7000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000		0.5000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.6000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2100
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2100			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Middle Miocene Shelf			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.7000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.7000	
3. Trap Component		3	1.0000		0.5000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2450
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2450			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Middle Miocene Slope			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.7000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.8000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.7000	
3. Trap Component		3	1.0000		0.5000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.5000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2450
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2450			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Upper Miocene Shelf			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.7000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.7000	
3. Trap Component		3	1.0000		0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2940
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2940			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
NOTE: If any probability is 0, the petroleum system does not exist.					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Upper Miocene Slope			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.7000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.8000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.7000	
3. Trap Component		3	1.0000		0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2940
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2940			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Pliocene Shelf			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.7000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.7000	
3. Trap Component		3	1.0000		0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2940
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2940			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Pliocene Slope			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.8000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000		0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.7000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2520
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2520			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Pleistocene Shelf			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000	0.9000	0.9000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	1.0000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.9000	
2. Reservoir Component		2	1.0000	0.8000	0.8000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.8000	
3. Trap Component		3	1.0000	0.6000	0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.9000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance			1.0000		
<i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>					
Average Conditional Prospect Chance¹					0.4320
<i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i>					
¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					
Exploration Chance		Overall Exploration Chance			
<i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		0.4320			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					

BOEM Play and Prospect Risk Analysis Form

Assessment Province: Gulf of Mexico		Assessment Unit Name: Pleistocene Slope			
Assessor(s): Neogene-Quaternary Team		Play-Level Risk: No (discovered play)			
Date: 2025		Assessment: 2026 Gulf of America			
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill Component		1	1.0000		0.7000
a. Presence of Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.		1a	1.0000	0.9000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.		1b	1.0000	0.7000	
2. Reservoir Component		2	1.0000		0.6000
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.		2a	1.0000	0.9000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.		2b	1.0000	0.6000	
3. Trap Component		3	1.0000		0.6000
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.		3a	1.0000	0.9000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.		3b	1.0000	0.6000	
Overall Play Chance <i>(1 * 2 * 3) Product of All Subjective Play Chance Factors</i>			1.0000		
Average Conditional Prospect Chance¹ <i>(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors</i> ¹ <i>Assumes that the play exists (where all play chance factors = 1.0)</i>					0.2520
Exploration Chance <i>(Product of Overall Play Chance and Average Conditional Prospect Chance)</i>		Overall Exploration Chance 0.2520			
Probabilities are as follows:					
Component Probably Exists	1.0 - 0.8				
Component will Possibly Exist	0.8 - 0.6				
Equally Likely Component is Present or Absent	0.6 - 0.4				
Component is Possibly Lacking	0.4 - 0.2				
Component is Probably Lacking	0.2 - 0.0				
<i>NOTE: If any probability is 0, the petroleum system does not exist.</i>					
Comments:					
Team decided not to use 20% of Wilcox pools but to apply risk					



U.S. Department of the Interior (DOI)

The Department of the Interior (DOI) conserves and manages the Nation's natural resources and cultural heritage for the benefit and enjoyment of the American people, provides scientific and other information about natural resources and natural hazards to address societal challenges and create opportunities for the American people, and honors the Nation's trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities to help them prosper.



Bureau of Ocean Energy Management (BOEM)

The Department of the Interior's Bureau of Ocean Energy Management (BOEM) manages development of U.S. Outer Continental Shelf (OCS) energy, mineral, and geological resources in an environmentally and economically responsible way.