OCS Report
BOEM 2021-082

2021 Assessment of Technically and Economically Recoverable Oil and Natural Gas Resources of the Gulf of Mexico Outer Continental Shelf

U.S. Department of the Interior
Bureau of Ocean Energy Management
New Orleans Office
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ABBREVIATIONS AND ACRONYMS

2D	two-dimensional
3D	three-dimensional
A	organic matter acme
Bbbl	billion barrels
BBOE	billion barrels of oil equivalent
BOE	barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management
DOI	Department of the Interior
F	Fahrenheit
ft	feet
Ga	billions of years
GOM	Gulf of Mexico
GOR	gas-oil-ratio
m	meters
Ma	millions of years
Mcf	thousand cubic feet
MMBOE	million barrels of oil equivalent
mya	million years ago
Myr	million years
OAE	oceanic anoxic event
OCS	Outer Continental Shelf
PETM	Paleocene–Eocene Thermal Maximum
SDR	seaward dipping reflector
Tcf	trillion cubic feet
TFZ	transfer or transform fault zone
UERR	undiscovered economically recoverable resources
U.S.	United States
UTRR	undiscovered technically recoverable resources

INTRODUCTION

The Bureau of Ocean Energy Management (BOEM) is an agency within the Department of the Interior (DOI) whose responsibilities include assessing the amounts of technically and economically recoverable undiscovered oil and natural gas resources located outside of known oil and gas fields for the United States (U.S.) portion of the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) (**Figure 1**). The OCS comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction.

The assessment summarized herein represents a comprehensive appraisal that (1) considered the most recent geophysical, geological, technological, and economic data and information available (2) incorporated advances in petroleum exploration and development technologies, (3) employed new methods of resource assessment, and (4) utilized internal geological and reservoir engineering data from BOEM-designated oil and gas fields as of the end of 2018.

A play-based approach to estimate the undiscovered resources of oil and gas was used. This methodology is suitable for both conceptual plays where there is little or no specific information available and for established plays where there are discovered oil and gas fields and considerable information is available. This method has a strong relationship between information derived from oil and gas exploration activities and the geologic model developed by the assessment teams. An extensive effort was involved in developing play models, delineating the geographic limits of each play, and compiling data on critical geologic and reservoir engineering parameters. These parameters were crucial input in the determination of the total quantities of recoverable undiscovered resources in each play.

The observed incremental increase through time in the estimates of reserves of an oil and/or gas field is known as reserves growth or appreciation. It is that part of the known resources over reserves that will be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. The reserves growth phenomenon contributes a significant portion of the current domestic petroleum supply and must be an integral part of any resource assessment. For this assessment, a growth factor was applied to the original estimates of reserves to account for this growth phenomenon, and all discovered volumes presented herein are grown values.

Due to the inherent uncertainties associated with an assessment of undiscovered resources, probabilistic techniques were employed. Results are reported as a range of values corresponding to different probabilities of occurrence. The probability model for the relative frequency distribution of hydrocarbon accumulations within each play was assumed to be lognormal. For plays in areas with sparse data, analogs were developed using subjective probabilities to cover the range of uncertainties. For mature areas with significant amounts of data, plays were analyzed using a method based on statistical parameters of discovered pools and historical trends.

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 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.

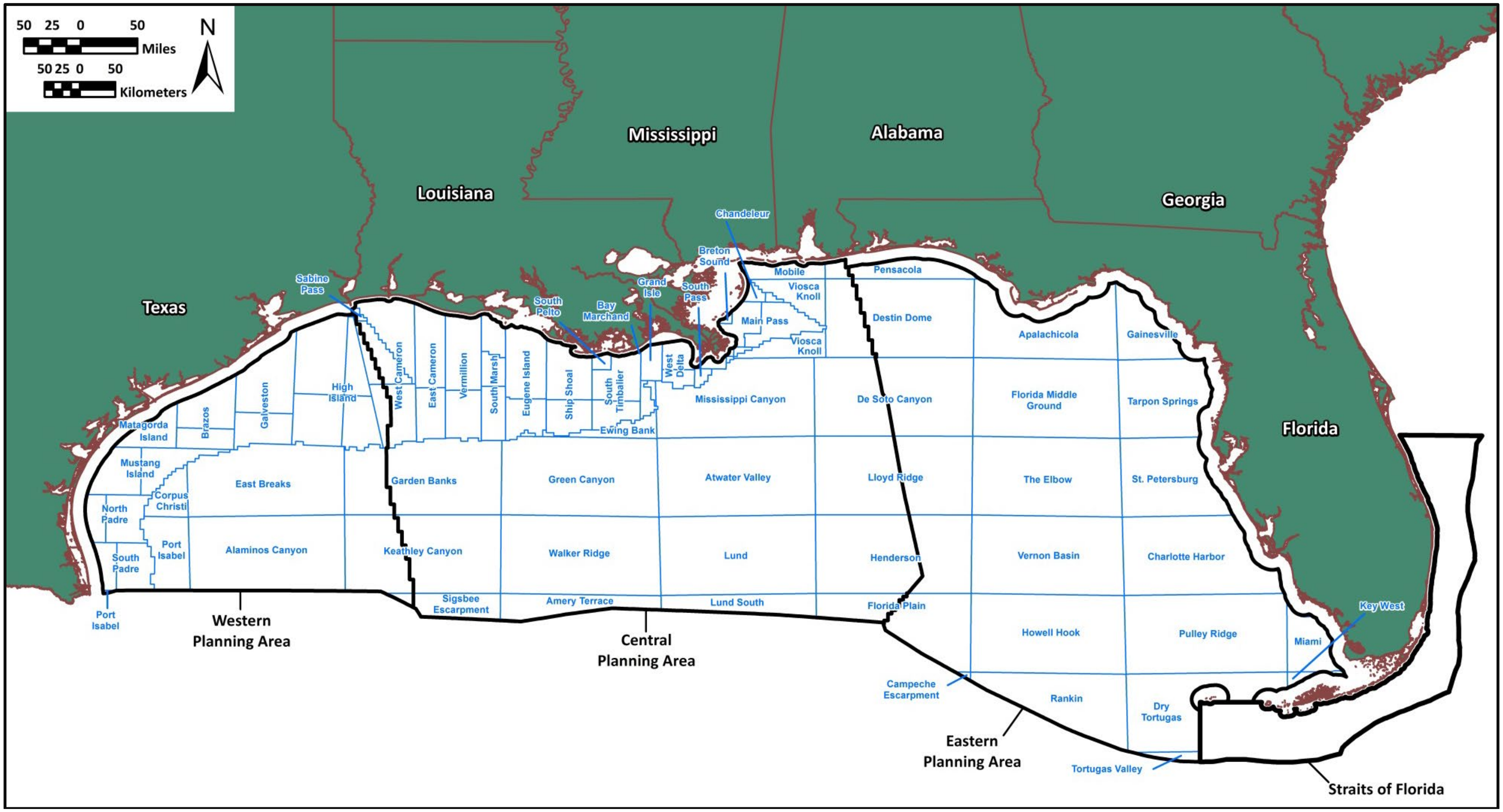

Figure 1. Federal OCS waters of the Gulf of Mexico delineated by planning and protraction areas.

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 of UTRR and UERR are presented at the 95th and 5th percentile levels, as well as the mean estimate. This range of estimates corresponds to a 95-percent probability (a 19 in 20 chance) and a 5-percent probability (a 1 in 20 chance) of there being more than those amounts present, respectively. The 95- and 5-percent probabilities are considered reasonable minimum and maximum values, and the mean is the average value for the analysis.

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 Mexico Biostratigraphic Chart 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. This chart is the basis upon which BOEM subdivides the sedimentary section in the GOM Basin into geologic ages and plays for assessment purposes. The foraminiferal, coccolith, dinoflagellate, ostracod, radiolarian, and pollen biostratigraphic markers are placed in a chronologic, chronostratigraphic, and chronozonal context as determined by the BOEM Resource Evaluation biostratigrapher.

Relative age changes on the biostratigraphic charts of industry consultants Waterman (Paleo-Data) (2017) and Applied Biostratigraphix (2009), along with new chronostratigraphy from Gradstein and Ogg's Geologic Time Scale (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. Over 160 new markers were added to BOEM's paleo database.

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 Eocene (Ypresian) to Early Paleocene (Danian) markers were added, better defining the Wilcox Formation and older Paleogene sections. The Jurassic and Cretaceous biostratigraphy was updated, adding new microfossil markers and changes to earlier stratigraphic positions. These changes and additions offer a stratigraphy more in line with current GOM industry biostratigraphic usage.

Abbreviated Cenozoic and Mesozoic versions of BOEM's 2018 biostratigraphic chart are presented in **Table 2** and **Table 3**, respectively.

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		
		Pleistocene Middle	Ionian	Middle Pleistocene	Globorotalia flexuosa acme Trimosina "A"	Emiliania huxleyi (base of acme) Pseudoemiliania lacunosa "B"
		Pleistocene Lower	Calabrian Gelasian	Lower Pleistocene	Stilostomella antillea Sphaeroidinella dehiscens acme A Sphaeroidinella dehiscens acme B Globorotalia crassula acme, Globorotalia praehirsuta Menardella miocenica	Pseudoemiliania ovata Gephyrocapsa aperta acme Calcidiscus macintyrei Discoaster brouweri Discoaster surculus
	Neogene	Pliocene Upper	Piacenzian	Upper Pliocene	Dentoglobigerina altispira=Valvulineria "H" Textularia 1	Discoaster tamalis Sphenolithus abies
		Pliocene Lower	Zanclean	Lower Pliocene	Globorotalia margaritae Globigerina nepenthes Globorotalia plesiotumida acme	Reticulofenestra pseudoumbilica Ceratolithus acutus
		Miocene Upper	Messinian Tortonian	Upper Upper Miocene	Menardella menardii (coil change, right-to-left) Bigenerina floridana / "A" Globorotalia acostaensis (coiling change, right-to-left) Globigerina nepenthes acme A Globigerina nepenthes acme B	Discoaster quinqueramus Discoaster berggrenii Discoaster berggrenii "A" Discoaster neohamatus Reticulofenestra gelida acme
			Tortonian	Lower Upper Miocene	Bolivina thalmanni, Globorotalia lenguaensis Uvigerina 3	Discoaster prepentaradiatus increase Coccolithus miopelagicus
		Miocene Middle	Serravallian	Upper Middle Miocene	Fohsella robusta Textularia "W"	Discoaster kugleri increase Cyclicargolithus floridanus
			Serravallian	Middle Middle Miocene	Fohsella lobata Fohsella fohsi Fohsella peripheroronda	Discoaster sanmiguelensis Discoaster sanmiguelensis increase Sphenolithus heteromorphus
			Langhian	Lower Middle Miocene	Cibicides opima Praeorbulina glomerosa Globigerinoides bisphericus	Discoaster petaliformis Helicosphaera ampliaperta Discoaster deflandrei acme
		Miocene Lower	Burdigalian	Upper Lower Miocene	Robulus "L" / 43 Catapsydrax stainforthi	Discoaster calculosus Sphenolithus disbelemnos
			Burdigalian	Middle Lower Miocene	Catapsydrax dissimilis Robulus chambersi, Discorbis bolivarensis / "B" Globigerinoides primordius	Sphenolithus belemnos Triquetrorhabdulus carinatus Cyclicargolithus abisectus
			Aquitanian	Lower Lower Miocene	Siphonina davisi Paragloborotalia kugleri Lenticulina jeffersonensis = Cristellaria "R"	Sphenolithus dissimilis Cyclicargolithus abisectus increase Triquetrorhabdulus challengeri
	Paleogene (Lower Tertiary)	Oligocene Upper	Chattian	Upper Oligocene	Globigerina ciperoensis ciperoensis Globigerina angulosuteralis Paragloborotalia opima opima	Dictyococcites bisectus Triquetrorhabdulus carinatus acme Sphenolithus predistentus
		Oligocene Lower	Rupelian	Lower Oligocene	Chiloguembelina cubensis Turborotalia increbescens	Helicosphaera compacta Ericsonia formosa increase
		Eocene Upper	Priabonian	Upper Eocene	Turborotalia cerroazulensis cocoaensis Turborotalia pomeroli Globigerinatheka mexicana	Discoaster saipanensis, Chiasmolithus consuetus Cribrocentrum reticulatum Sphenolithus obtusus
		Eocene Middle	Bartonian Lutetian	Middle Eocene	Acarinina spinuloinflata Acarinina bulbrooki Igorina broedermanni Morozovella aragonensis Morozovella caucasica	Chiasmolithus grandis Sphenolithus furcatolithoides increase Discoaster wemmelensis Chiasmolithus gigas Discoaster lodoensis
		Eocene Lower	Ypresian	Lower Eocene	Acarinina soldadoensis Apectodinium homomorphum acme (dinoflagellate) / PETM[2]	Discoaster kuepperi Fasciculithus tympaniformis
		Paleocene Upper	Thanetian Selandian	Upper Paleocene	Bathysiphon spp increase Subbotina triloculinoides Igorina pusilla pusilla Morozovella conicotruncana Planorotalites compressa	Ericsonia robusta Prinsius martinii increase Chiasmolithus danicus Cruciplacolithus edwardsii Fasciculithus chowii
		Paleocene Lower	Danian	Lower Paleocene	Parasubbotina pseudobulloides Globocontusa daubjergensis Parvularugoglobigerina eugubina	Neochiastozygus eosaepes Hornibrookina edwardsii Neobiscutum romeinii

[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	Contusotruncana contusa	Micula decussata
					Rosita fornicata	Tranolithus orionatus
			Campanian		Globotruncana ventricosa	Aspidolithus parcus constrictus
					Globotruncanita calcarata	Reinhardtites anthophorus
					Marginotruncana coronata	Lithastrinus grilli
					Whiteinella baltica	Eprolithus floralis
			Santonian		Dicarinella asymetrica	
					Marginotruncana sinuosa	Zeugrhabdotus noeliae
					Marginotruncana sigali	Chiastozygus platyrhethus
			Coniacian		Whiteinella archaeocretacea	Lithastrinus septenarius
					Hedbergella planispira	Stoverius achylosus
					Dicarinella hagni	
			Turonian	Lower Upper Cretaceous	Planulina eaglefordensis	
					Helvetoglobotruncana helvetica	Lithraphidites pseudoquatratus
					Dicarinella algeriana	Calculites axosuturalis
			Cenomanian		Praeglobotruncana stephani, Helvetoglobotruncana praehelvetica	
					Rotalipora cushmani	Helenea chiastia
					Globigerinelloides bentonensis increase	Braarudosphaera stenorhetha
		Lower	Albian	Upper Lower Cretaceous	Planomalina buxtorfi	Hayesites albiensis
					Biticinella breggiensis	Crucicribrum anglicum
					Rotalipora subticinensis	
				Middle Lower Cretaceous	Hedbergella gorbachikae	Sollasites falklandensis
					Hedbergella infracretacea	Diadorhombus rectus
					Paraticinella transitoria	
			Aptian	Lower Lower Cretaceous	Paraticinella eubejaouaensis	Assipetra infracretacea
					Favusella hoteriva	Conusphaera rothii
			Barremian		Epistomina hechti	
					Lenticulina saxonica	Conusphaera mexicana
					Lenticulina ouachensis increase	Eprolithus antiquus
			Hauterivian		Muderongia simplex (dinoflagellate)	Lithraphidites bollii
					Everticyclammina virginulina	Cruciellipsis cuvillieri
						Eiffellithus windii
			Valanginian			Rucinolithus wisei
					Conoglobigerina helvetojurassica	Micrantholithus speetonensis
					Globuligerina oxfordiana	
			Berriasian		Lenticulina busnardoi	
					Epistomina stellacostata	Polycostella senaria
					Anchispirocyclina lusitanica	
	Jurassic	Upper	Tithonian	Upper Jurassic	Hutsonia vulgaris / callahani, Galliaecytheridea postrotunda (ostracods)	Lotharingius sigillatus
					Alveosepta jaccardi	Hexalithus noelae
			Kimmeridgian		Reinholdella A (increase)	Anfractus harrisonii
					Gonyaulacysta jurassica (dinoflagellate)	
					Haplophragmoides canui	Crepidolithus perforatus
			Oxfordian		Praekumubia crusei	
					Alveosepta jaccardi acme	Lotharingius crucicentralis
					Globuligerina oxfordiana increase	Stephanolithion hexum
		Middle	Callovian	Middle Jurassic	Globuligerina calloviensis	Lotharingius velatus
					Reinholdella crebra increase, Garantella ornata	Stephanolithion speciosum

*All species represent extinction points unless noted.

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

ASSESSMENT UNITS

2021 Cenozoic Assessment Units

For this inventory of undiscovered resources in the Cenozoic sediments of the U.S. Gulf of Mexico OCS, the geologic analyses inherent in resource assessments occur at the play level. As with past GOM assessments, each discovered reservoir in a BOEM-designated field is evaluated and assigned to a distinctive play that shares common geologic factors which influence the accumulation of hydrocarbons. (See the OCS Operations Field Directory for details of how fields are defined within BOEM.) Because resource assessments strive to predict ultimate hydrocarbon volumes, reserves appreciation (a.k.a., 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” (AUs) 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 (“deepwater”), 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., shallow-water drilling vs. deepwater drilling) 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, the data from 1,753 pools on the shelf and 448 pools on the slope were utilized.

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

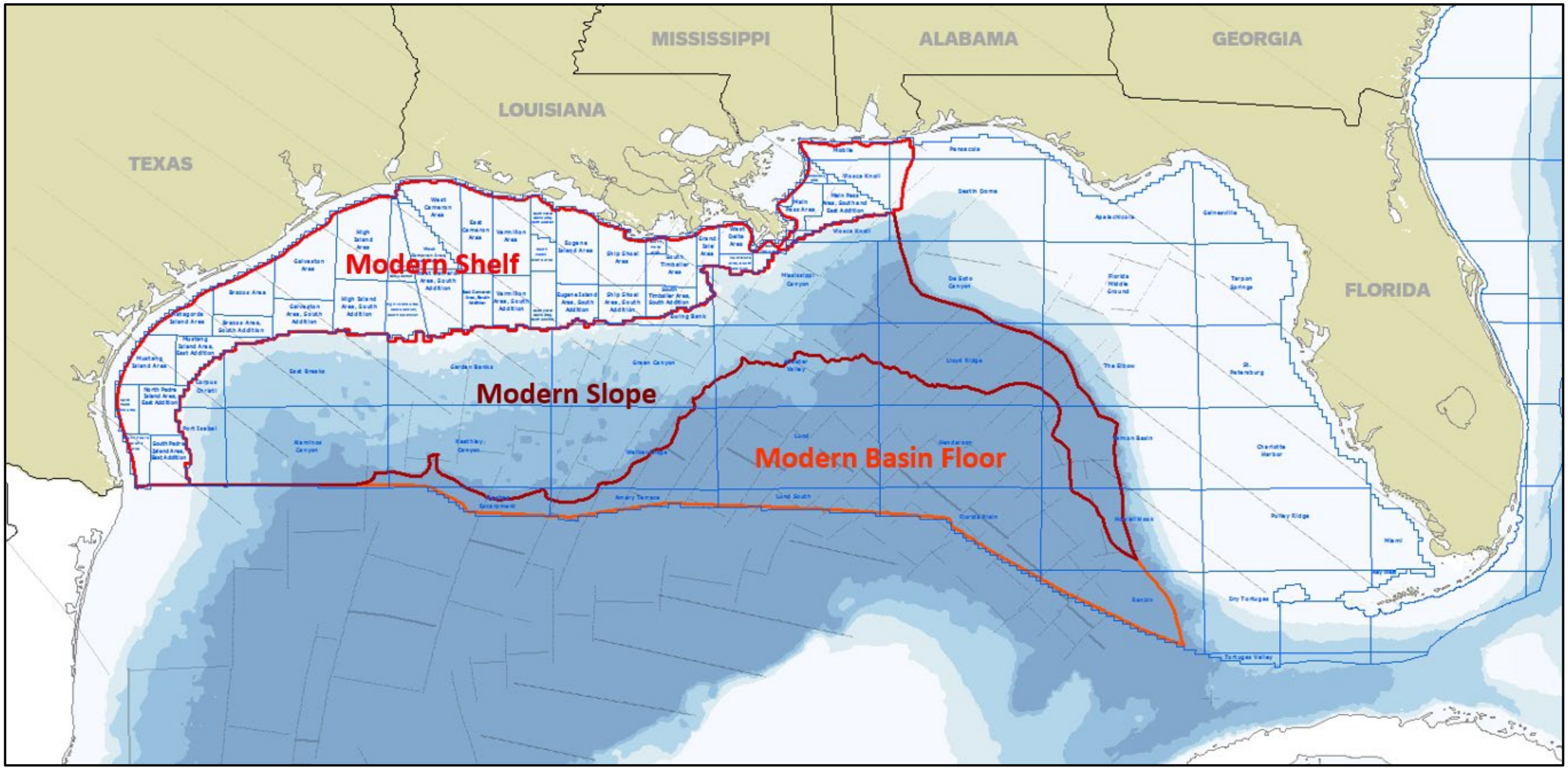

Figure 2. Locations of the modern shelf, slope, and basin floor in the northern Gulf of Mexico OCS.

Table 4. BOEM Cenozoic chronostratigraphy and associated assessment units.

Chronostratigraphic Unit						Stratigraphic Unit	Gulf of Mexico 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				Middle Miocene Shelf	Middle Miocene Slope	
					MMM						
				Langhian	MLM						
			Lower	Burdigalian	MUL				Lower Miocene Shelf	Lower Miocene Slope	
					MML						
				Aquitanian	MLL						
	Lower Tertiary (Paleogene)	Oligocene	Upper	Chattian	OU	Anahuac Formation			Lower Tertiary Shelf	Frio Slope	Lower Tertiary Basin Floor
			Lower	Rupelian	OL	Frio Formation Vicksburg Formation					
		Eocene	Upper	Priabonian	EU	Jackson Group					
			Middle	Bartonian Lutetian	EM	Clairborn 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)

2021 Mesozoic Assessment Units

Unlike the aggregated AUs of the Cenozoic sediments, for this inventory of undiscovered resources in the Mesozoic sediments of the U.S. Gulf of Mexico OCS, most Mesozoic sediments are differentiated by specific rock formations (e.g., Norphlet, Smackover, Sunniland). Several of these offshore Mesozoic plays continue onshore and are, therefore, defined as AUs because of 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 GOM and the South Florida Basin area of Florida, respectively. Rock units assessed in this report are highlighted in light blue. Parts of the stratigraphic columns are modeled after onshore sections; rock units listed, therefore, may or may not be present throughout the entire northeastern GOM or Florida offshore.

Specifically, Mesozoic sediments are divided into 20 AUs, 16 of which are assessed in this study (**Table 5** and **Table 6**). The four unassessed AUs are deemed to contribute insignificant volumes of resources to the GOM Basin or lack a significant prospect inventory. As of this study's cutoff date of January 1, 2019, there are three Mesozoic AUs (Norphlet Shelf, Norphlet Slope, and Lower Cretaceous Carbonate) with discoveries, comprising a combined total of 37 pools in the offshore. For most of the remaining 13 assessed Mesozoic AUs with no discoveries in offshore waters, onshore Gulf Coast discoveries are used as pool-size analogs for modeling undiscovered resources.

Comparison of BOEM Assessment Units from 2016 to 2021

This 2021 resource assessment is a departure from previous BOEM assessments in that more emphasis has been 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 are 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.

Table 7 compares AUs from BOEM's 2016 resource assessment (USDOI, 2017) and this 2021 resource assessment. Details are provided in each individual 2021 AU narrative in this report. Notable changes from 2016 to 2021 follow.

- The differentiation of the Frio and Wilcox Formations into two AUs on the slope.
- The expansion of the 2016 Lower Tuscaloosa, Lower Cretaceous Clastic, and Cotton Valley Clastic AUs into a downdip slope environment resulting in three newly assessed plays.
- Mesozoic Shelf and Slope AUs are now modeled with Cenomanian Tuscaloosa Sand reservoirs as opposed to the Cretaceous carbonate Poza Rica Trend reservoir model of 2016.
- The combination of three Lower Cretaceous carbonate formations (Sligo, James, and Andrew) into a single AU.
- The differentiation of the Norphlet Formation into updip shelf (gas) and downdip slope (oil) Plays.
- The assessment of the Pre-Salt or Equivalent and Expanded Jurassic Plays.
- The replacement of the Buried Hills Structural Play (fractured basement highs with continental affinities) and associated deposits of the Buried Hills Stratigraphic Play with non-prospective oceanic crust straddling a Jurassic spreading center.
- The reallocation of the Buried Hills Drape Play into the Lower Tertiary Basin Floor Play.

Table 5. BOEM Mesozoic chronostratigraphy and associated assessment units.

Erathem	System	Series	Stage	Chronozone	Stratigraphic Unit (Generalized Louisiana Coast/NE Gulf of Mexico)	Shelf (Eastern)	Slope (Eastern)	Shelf (Central/Western)	Slope (Central/Western)	Abyssal Plain
Mesozoic	Cretaceous	Upper	Maastrichtian	KUU	Selma Group					
			Campanian							
			Santonian		Eutaw Formation					
			Coniacian							
			Turonian	KLU	Upper Tuscaloosa					
					Tuscaloosa Marine Shale	Tuscaloosa Marine Shale				
			Cenomanian		Lower Tuscaloosa	Lower Tuscaloosa Shelf	Lower Tuscaloosa Slope	Mesozoic Shelf	Mesozoic Slope	Mesozoic Basin Floor
		Lower	Albian	KUL	Washita Group-Dantzler Formation	Lower Cretaceous Clastic Shelf	Lower Cretaceous Clastic Slope			
					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					
			Barremian		Hosston Formation		Lower Cretaceous Clastic Slope			
			Hauterivian			Lower Cretaceous Clastic Shelf				
			Valanginian							
			Berriasian		Cotton Valley Carbonates	Knowles Carbonate				
	Jurassic	Upper	Tithonian	JU	Cotton Valley Clastics	Cotton Valley Clastic Shelf	Cotton Valley Clastic Slope			
			Kimmeridgian		Haynesville-Buckner					
			Oxfordian		Smackover Formation	Smackover				
					Norphlet Formation	Norphlet Shelf	Norphlet Slope			
		Middle		JM	Louann Salt		Expanded Jurassic			
					Werner Formation		Pre-Salt or Equivalent			
		Lower		JL	Eagle Mills Formation					Buried Hills
	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			Major Unconformity			
Mesozoic	Cretaceous	Upper	Maastrichtian	KUU	Pine Key Formation			
Mesozoic	Cretaceous	Upper	Campanian	KUU	Pine Key Formation			
Mesozoic	Cretaceous	Upper	Santonian	KUU	Pine Key Formation			
Mesozoic	Cretaceous	Upper	Coniacian	KUU	Pine Key Formation			
Mesozoic	Cretaceous	Upper	Turonian	KLU	Atkinson Formation			
Mesozoic	Cretaceous	Upper	Cenomanian	KLU	Atkinson Formation; Major Unconformity			
Mesozoic	Cretaceous	Lower	Albian	KUL	Corkscrew Swamp Formation		Naples Bay Group	
Mesozoic	Cretaceous	Lower	Albian	KUL	Rookery Bay Formation		Naples Bay Group	
Mesozoic	Cretaceous	Lower	Albian	KUL	Panther Camp Formation		Naples Bay Group	
Mesozoic	Cretaceous	Lower	Albian	KUL	Dollar Bay Formation		Big Cypress Group	
Mesozoic	Cretaceous	Lower	Albian	KUL	Gordon Pass Formation		Big Cypress Group	
Mesozoic	Cretaceous	Lower	Albian	KUL	Marco Junction Formation		Big Cypress Group	
Mesozoic	Cretaceous	Lower	Albian	KML	Rattlesnake Hammock Formation		Ocean Reef Group	
Mesozoic	Cretaceous	Lower	Albian	KML	Lake Trafford Formation		Ocean Reef Group	
Mesozoic	Cretaceous	Lower	Albian	KML	Sunniland Formation		Ocean Reef Group	Sunniland
Mesozoic	Cretaceous	Lower	Albian	KML	Punta Gorda Anhydrite		Glades Group	
Mesozoic	Cretaceous	Lower	Aptian	KLL	Able Member	Lehigh Acres Formation	Glades Group	
Mesozoic	Cretaceous	Lower	Aptian	KLL	Twelve Mile Member (Brown Dolomite Zone)	Lehigh Acres Formation	Glades Group	
Mesozoic	Cretaceous	Lower	Aptian	KLL	West Felda Shale Member	Lehigh Acres Formation	Glades Group	
Mesozoic	Cretaceous	Lower	Barremian	KLL	Pumpkin Bay Formation			
Mesozoic	Cretaceous	Lower	Hauterivian	KLL	Bone Island Formation			
Mesozoic	Cretaceous	Lower	Valanginian	KLL	Bone Island Formation			
Mesozoic	Cretaceous	Lower	Berriasian	KLL	Wood River Formation			
Mesozoic	Jurassic	Upper	Tithonian	JU	Wood River Formation; Basement Clastics			Florida Basement Clastic
Mesozoic	Jurassic	Upper	Kimmeridgian	JU	Basement Clastics			Florida Basement Clastic
Mesozoic	Jurassic	Upper	Oxfordian	JU	Basement Clastics			Florida Basement Clastic
Mesozoic	Jurassic	Middle		JM	Basement			
Mesozoic	Jurassic	Lower		JL	Basement			
Mesozoic	Triassic				Basement			

Symbology:
Predominantly Clastics
Predominantly Carbonates and Evaporites
BOEM Assessment Unit (assessed)
Major Unconformity
Basement

Table 7. Comparison of BOEM assessment units from 2016 to 2021.

Erathem	2016 Assessment Unit	2021 Assessment Unit	Changes from 2016 to 2021/Comments
Cenozoic	Pleistocene Shelf	Pleistocene Shelf	**2021 Assessment Units** **30 Assessed:** ▸ **14 Cenozoic** ▸ **16 Mesozoic**
	Pleistocene Slope	Pleistocene Slope	
	Pliocene Shelf	Pliocene Shelf	
	Pliocene Slope	Pliocene Slope	
	Upper Miocene Shelf	Upper Miocene Shelf	
	Upper Miocene Slope	Upper Miocene Slope	
	Middle Miocene Shelf	Middle Miocene Shelf	
	Middle Miocene Slope	Middle Miocene Slope	
	Lower Miocene Shelf	Lower Miocene Shelf	
	Lower Miocene Slope	Lower Miocene Slope	
	Lower Tertiary Shelf (Frio & Wilcox)	Lower Tertiary Shelf (Frio & Wilcox)	Sizable prospective area condemned because of high subsurface temperatures.
	Lower Tertiary Slope (Frio & Wilcox)	Frio Slope	2016 AU split into Oligocene Frio and Lower Eocene-Upper Paleocene Wilcox. Numerous wells have tested Frio on the way down to Wilcox eliminating areas of prospectivity.
		Wilcox Slope	
	Buried Hill Drape	Neogene & Quaternary Basin Floor (not assessed)	No prospects of this age identified.
		Lower Tertiary Basin Floor	Large closures on the basin floor.
Mesozoic	Buried Hill Stratigraphic	Mesozoic Basin Floor (not assessed)	No evidence of Mesozoic deep-sea fan systems on the basin floor.
	Mesozoic Deep Shelf	Mesozoic Shelf (central/western GOM)	Lower Tuscaloosa clastics replace the old carbonate (e.g., Golden Lane Field) model.
	Mesozoic Slope	Mesozoic Slope (central/western GOM)	Modeled as Lower Tuscaloosa clastics.
	Tuscaloosa Marine Shale (not assessed)	Tuscaloosa Marine Shale (not assessed)	No conventional reservoir (must be fracked).
	Lower Tuscaloosa	Lower Tuscaloosa Shelf (eastern GOM)	Extended the 2016 AU to include mapped prospects in paleo-deepwater.
	not assessed	Lower Tuscaloosa Slope (eastern GOM)	
	Lower Cretaceous Clastic	Lower Cretaceous Clastic Shelf	Extended the 2016 AU to include mapped prospects in paleo-deepwater.
	not assessed	Lower Cretaceous Clastic Slope	
	Andrew	Lower Cretaceous Carbonate	Combined the three 2016 AUs for more robust data to aid in modeling.
	James		
	Sligo		
	Sunniland	Sunniland	Increased the play area to the north beyond the South Florida Basin.
	Knowles Carbonate (not assessed)	Knowles Carbonate (not assessed)	Has been explored without significant volumes of oil and gas found.
	Cotton Valley Clastic	Cotton Valley Clastic Shelf	Extended the 2016 AU to include mapped prospects in paleo-deepwater.
	not assessed	Cotton Valley Clastic Slope	
	Florida Basement Clastic	Florida Basement Clastic	Included more area based on new depth-to-magnetic basement survey.
	Smackover	Smackover	Included larger onshore grainstone fields in the pool-size modeling analog.
	Norphlet	Norphlet Shelf	2016 AU split into updip gas shelf and downdip oil slope.
		Norphlet Slope	
	not assessed	Expanded Jurassic	New plays that have never been assessed before.
	not assessed	Pre-Salt or Equivalent	
	Buried Hill Structural	Buried Hills (not assessed)	Non-prospective basaltic oceanic crust replaces the weathered "granitic hills" concept.

Note: Chicxulub breccias and Cretaceous shelf-edge debris flows were not considered for assessment.

RESERVES APPRECIATION

Estimates of the quantity of reserves in a field typically increase as the field is developed and produced; this is known as reserves appreciation (a.k.a, reserves growth) and was first reported by Arrington (1960). Root and Attanasi (1993) estimated that the growth of known fields from 1978 to 1990 in the United States accounted for 90 percent of the annual additions to domestic reserves. The National Petroleum Council (NPC) (1992) estimated that field growth accounts for 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 appreciation 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 appreciation effort in this resource assessment were to (1) estimate the quantity of reserves from known fields that, owing to the reserves appreciation phenomenon, will contribute to the Nation's future oil and gas supply and (2) explicitly incorporate field growth in the measure of past performance, which forms the basis for projecting future discoveries within defined plays. All discovered resources reported herein are grown values.

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 appreciation have been almost universally applied to large areas, such as countries, states, provinces, and basins, using highly aggregated data.

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

Root and Attanasi (1993) reviewed the history and basic approaches traditionally employed to model the reserves appreciation phenomenon. The approach employed in this study was to calculate annual growth factors (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 appreciation have operated, and
- the factors causing future appreciation will result in patterns and magnitudes of growth similar to those observed in the past.

Since growth factors are calculated from revisions to estimates of reserves, the individual growth factors are specific to the particular data set used. Assessors that are more aggressive in their revisions of the initial estimate will calculate different 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 GOM 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 proved 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 because of the increased capital requirements and more rigorous design criteria for offshore versus onshore infrastructure.

Pool-Size Distributions

The second objective of the reserves appreciation effort was to consider field growth in the measure of past performance. Incorporating reserves growth in developing pool-size distributions addresses a systemic bias inherent in previous assessments, which assumed 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 appreciation 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 appreciation were complicated by the play approach utilized in this resource assessment. Ideally, reserves growth factors would be calculated from play data sets and then applied directly to play-level size distributions to derive ultimate recoveries, which included reserves appreciation to a given point in the future. The complication arises because the play consists of grouped reservoirs (termed pools in this effort) within individual fields that produce from the same chronozone 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. As of January 1, 2019, almost 60 percent of Gulf of Mexico 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 appreciation into the assessment process are rather subtle. In mature plays with reasonably complete pool-size distributions, the commonly older, large accumulations are not projected to experience significant growth as expressed as a percentage of the current estimate of field size. Consistent with the concept of resource exhaustion, smaller accumulations, which are generally younger, experience proportionately more appreciation and grow to fill "gaps" in the pool-size distribution, leaving behind gaps in their old, smaller size position in the distribution. This occurs with all pools throughout the distribution. Conversely, in immature plays, the overall empirical distribution is not well developed. The largest accumulations will be projected to experience significant appreciation, creating gaps in the projected pool-size distribution, which will then accommodate significant-sized pools. The effect of explicitly considering reserves appreciation for an active, mature play that acknowledges reserves growth will tend to result in a smaller estimate of the quantity of resources remaining to be discovered than one that does not incorporate the reserves appreciation phenomenon. Alternatively, a resource assessment for moderately mature to immature plays will project larger quantities of undiscovered resources when appreciation is considered.

ASSESSMENT METHODOLOGY

The general workflow the assessment teams perform includes

- 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 distribution (minimum, most likely, and maximum) 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 GOM, seismic data coverage was insufficient to delineate individual prospects across some or all of a play. In cases where seismic data could be used to generate a prospect inventory over only a portion of a play, a prospect density was calculated and extrapolated across the remaining play area. If no offshore 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 for the play. One of the important questions for the assessment teams is if the largest pool has already 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 Federal OCS are downdip extensions of onshore plays, these analogs come mostly from onshore Gulf Coast discoveries. Some of the most important questions for the assessment teams are the size of the largest undiscovered pool and the number of undiscovered pools based on offshore mapped prospects and regional studies.

GEOLOGIC RISK ANALYSIS

For the 2021 resource assessment, BOEM implemented several changes to standardize risking methodologies at the play and prospect level (USDOI, 2021a). This improved methodology provides a more consistent approach across all OCS regions and ensures that (1) component parts are developed using a singular BOEM methodology and (2) the aggregation of regional assessments into a national assessment includes components and results that were developed using an aligned corporate approach.

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 geological 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 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 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 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 component. There is a dependency between the elements of play chance. The risk assessment is documented on a worksheet (**Table 8**) used by the assessment teams for this analysis. The probability of the presence of each factor is subjectively estimated by the assessment team. The presence or absence of direct evidence supporting the play model is a major consideration in the analysis for each component. 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 within the play 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, seismic image quality, 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 or frontier play has been defined, it is necessary to address the question of its probable presence. However, in conceptual plays and at the earliest stages of exploration in frontier plays, we cannot state with absolute confidence that these critical factors occur throughout the extent of the delineated play. 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. All AUs with a play-level chance of success equaling 100 percent either have discovered pools or have at least one hydrocarbon-bearing well proving a petroleum system. See the individual assessment unit descriptions for details. Completed risking worksheets are presented in Appendix A (Mesozoic) and Appendix B (Cenozoic).

Table 8. BOEM play and prospect risk analysis worksheet.

BOEM Play and Prospect Risk Analysis Form

Assessment Province:		Assessment Unit Name:	
Assessor(s):		Assessment Unit UAI:	
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	0.0000		0.0000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.0000		0.0000	
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	0.0000		0.0000	
b. Reservoir Quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity and permeability.	2b	0.0000		0.0000	
3. Trap Component	3		*0.0000*		*0.0000*
a. Presence of Trap					
Probability of presence of the trap with a minimum rock volume.	3a	0.0000		0.0000	
b. Effective Seal Mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.0000		0.0000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.0000		
Average Conditional Prospect Chance[1] (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:

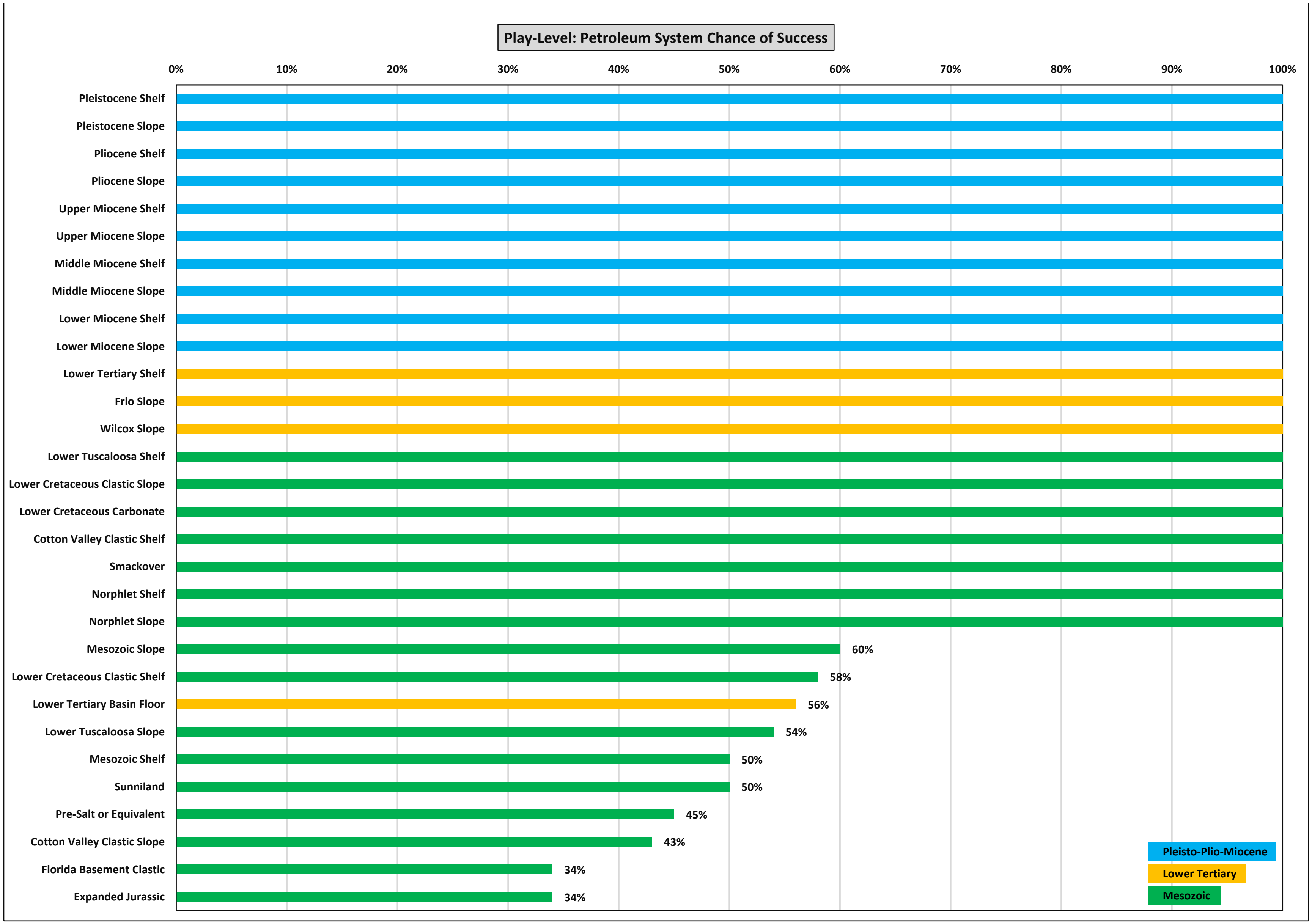

Figure 3. Petroleum system chance of success for the evaluated assessment units.

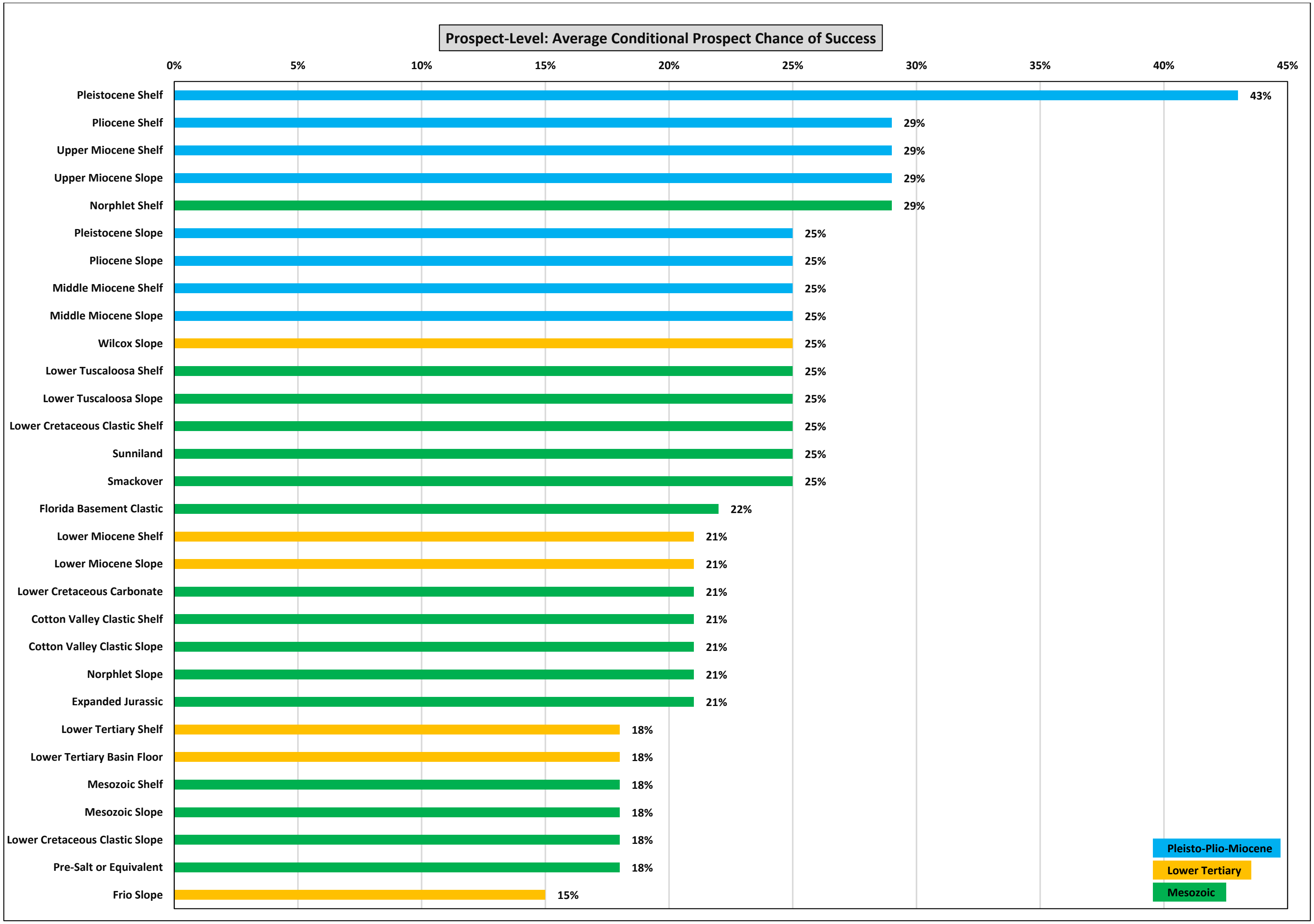

Figure 4. Average conditional prospect chance of success for the evaluated assessment units.

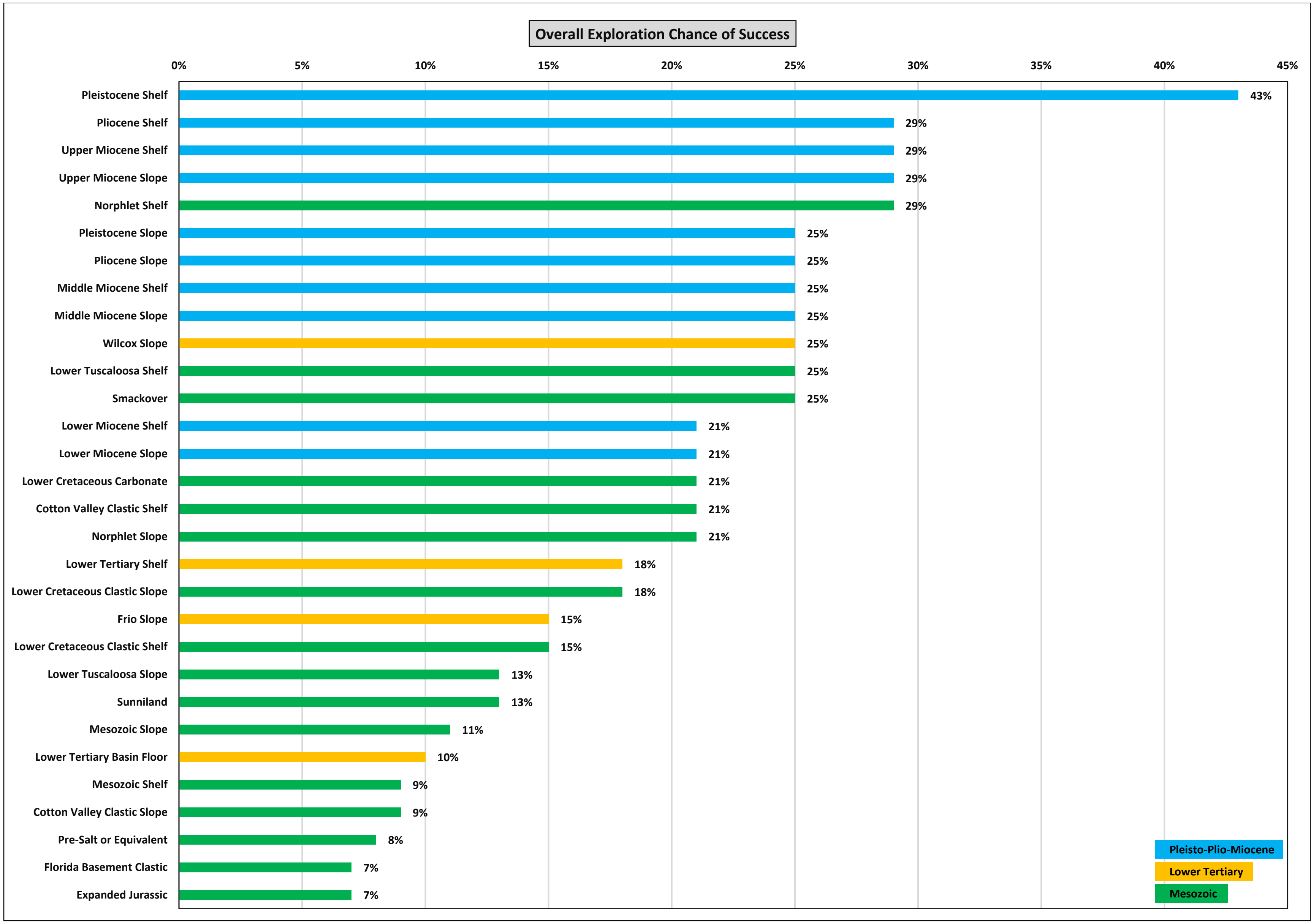

Figure 5. Overall exploration chance of success for the evaluated assessment units.

ASSESSMENT MODELING PROGRAM

MODEL OVERVIEW

The Bureau of Ocean Energy Management 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 OCS regions within BOEM (GOM, Atlantic, Pacific, and Alaska) 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 Mexico 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 the 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 GOM are described as either conceptual or established. Conceptual plays are hypothesized to exist but not yet verified by hydrocarbon discoveries. Established plays have a discovery in one or more pools and a reserve estimate. When GRASP was first adopted by the agency 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." The plays with discoveries were assessed with discovered inputs and the discovered modules of GRASP. These plays became associated with the "discovered methodology" process.

In the last two Gulf of Mexico OCS assessments, the methodology was revised so all plays would be assessed using the subjective methodology. For the plays with discoveries, the MATCH module and a new module, TRIMPOOLS, were introduced to facilitate this change in methodology. This improvement makes the process consistent with the methodology used in all OCS regions within BOEM. **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. Because no pools have yet been discovered in conceptual plays, pool volumes are derived from volumes of analog plays that are assumed to be similar to the play being assessed. The resulting distribution is further refined by truncation. Because the lognormal curve continues to infinity 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 discovered pools 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 have more discoveries, MATCH can produce distributions that more accurately describe the full 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 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 expectation of the play. Further adjustments to the inputs are made, and iterations continue until the analyst can chose 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.

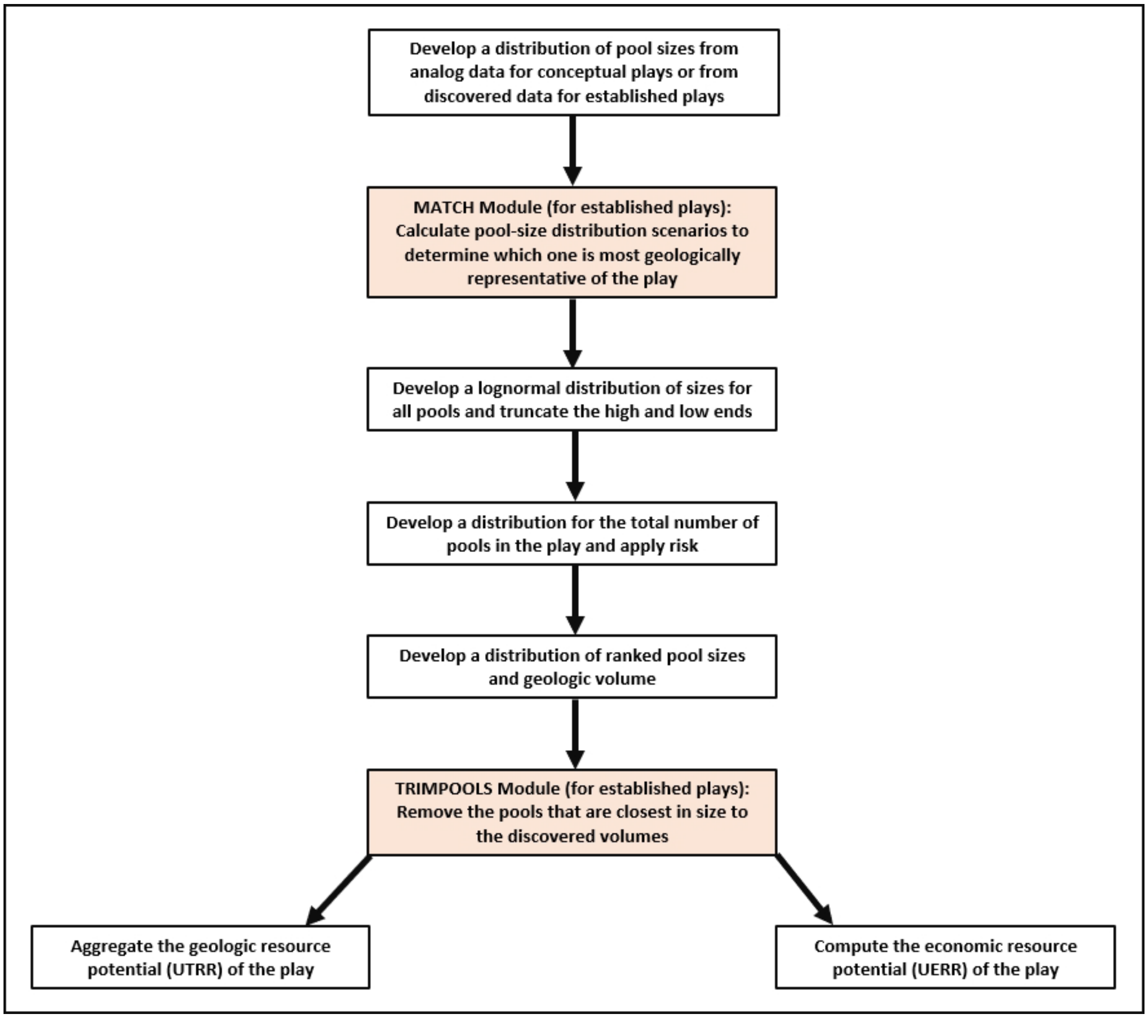

Figure 6. GRASP geologic model methodology.

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 exploratory well may be drilled in each prospect to determine if it is hydrocarbon bearing. If the exploratory well encounters hydrocarbons that are initially assessed to be of a size and characteristic sufficient to warrant additional drilling, further exploration and delineation wells would be drilled to justify the installation and determine the appropriate size of a platform or satellite complex. A development drilling program leading to production will also be determined. If the interrelationships of these factors result in a forecast of real-term profits, the accumulation is developed. The production profile will subsequently size production equipment and pipelines for timely installation and transportation of production to the market. Ultimately, the field would be abandoned when the revenue from production was insufficient to cover the costs of production (operating costs, taxes, and royalties). 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 a standard in the petroleum and other industries for making decisions under conditions of uncertainty. The technique enables the evaluator to incorporate uncertainty as a range of 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 Mexico 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 percent discount rate.

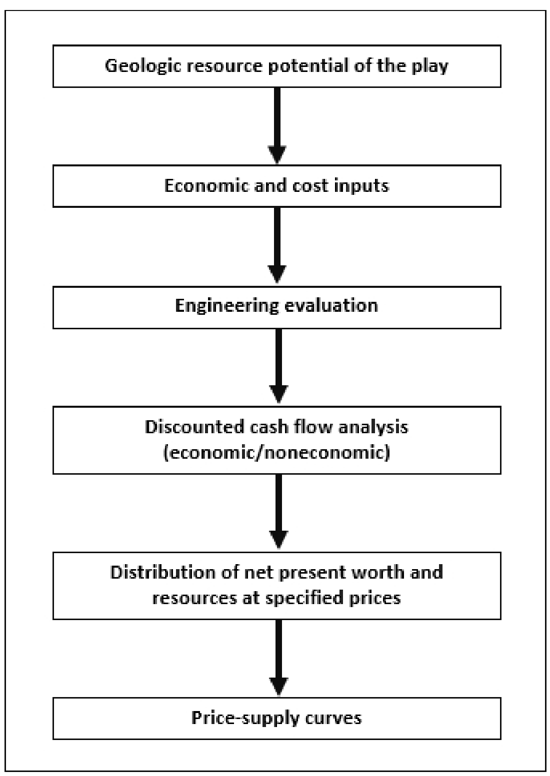

Figure 7. Economic evaluation methodology.

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 does consider all leasehold, geophysical, geologic, and exploration costs incurred subsequent to a decision to explore in determining the economic viability of a prospect. The decision point is whether or not to explore. However, in the exploration process, fields are often discovered that cannot support both exploration and development costs. 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 northern Gulf of Mexico 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.

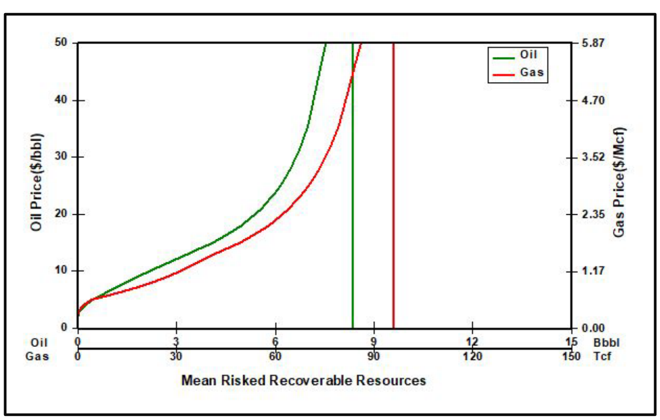

Figure 8. Example price-supply curve.

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 38.409 Bbbl of oil and 235.791 Tcf of gas (total BOE of 80.365 Bbbl), BOEM estimates 29.590 Bbbl of oil and 54.845 Tcf of gas (total BOE of 39.345 Bbbl) mean-level UTRR remain to be found in the Gulf of Mexico 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 of all the AUs, with the Miocene-aged AUs on the present-day slope holding significant undiscovered resource potential as well. Of the Mesozoic-aged AUs, Norphlet Slope aeolian dunes and Smackover grainstones hold the greatest potential for discoveries.

Detailed values of UTRR are presented by individual AU (**Table 9**) and by water depth categories within each planning area (**Table 10**). **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 AUs do not return successful case values for the 95th percentile.

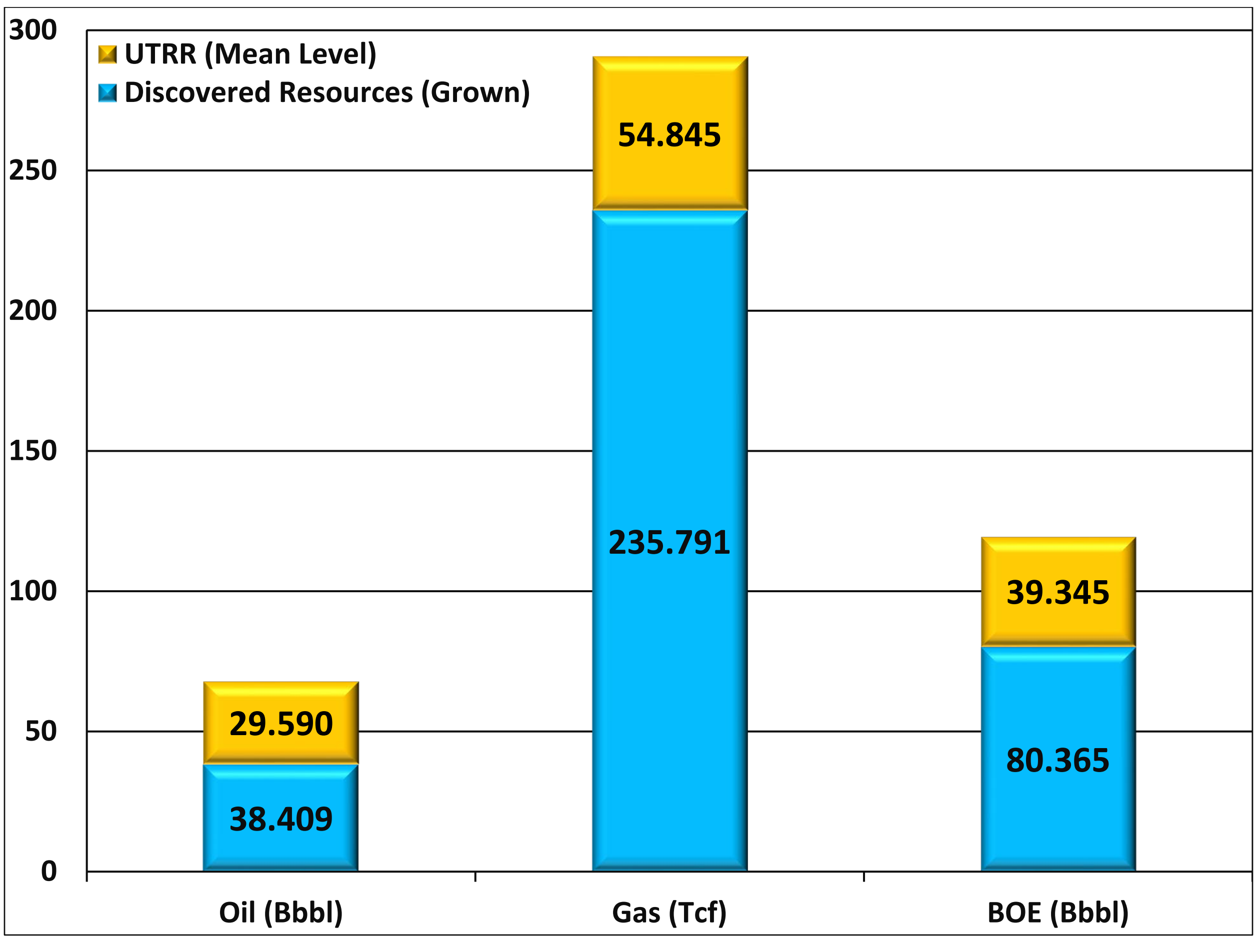

Figure 9. Estimated grown discovered resources and UTRR in the Gulf of Mexico OCS.

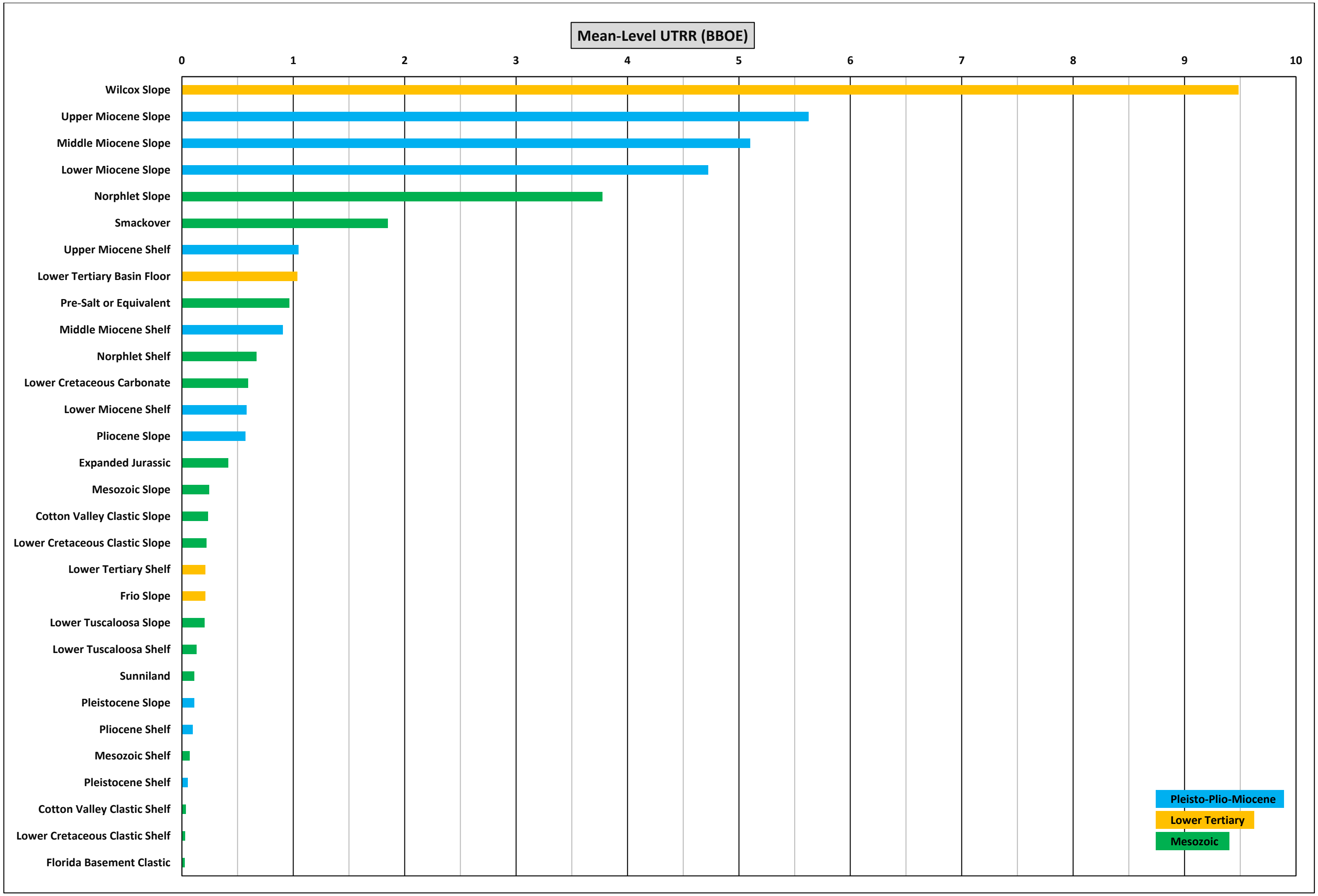

Figure 10. Assessment units ranked by mean-level UTRR.

Table 9. Grown discovered resources and UTRR by assessment unit.

Gulf of Mexico OCS		Grown Discovered Resources				Undiscovered Technically Recoverable Resources (UTRR)									
Era	Assessment Unit	# of pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	# of pools (mean)	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
							95th	mean	5th	95th	mean	5th	95th	mean	5th
Cenozoic	Pleistocene Shelf	392	1.816	36.279	8.272	28	0.001	0.011	0.037	0.014	0.227	0.787	0.003	0.052	0.177
	Pleistocene Slope	107	1.075	7.238	2.363	79	0.016	0.051	0.130	0.112	0.341	0.905	0.036	0.111	0.291
	Pliocene Shelf	481	4.768	48.824	13.456	89	0.009	0.035	0.084	0.095	0.362	0.835	0.026	0.099	0.233
	Pliocene Slope	111	4.669	12.044	6.812	99	0.141	0.391	1.103	0.369	1.021	2.997	0.207	0.572	1.637
	Upper Miocene Shelf	473	6.444	48.307	15.039	177	0.264	0.450	0.746	1.974	3.352	5.552	0.616	1.046	1.734
	Upper Miocene Slope	103	5.067	14.433	7.635	149	2.300	3.724	5.336	6.321	10.682	15.563	3.424	5.625	8.105
	Middle Miocene Shelf	246	0.617	30.792	6.096	105	0.046	0.093	0.189	2.260	4.568	8.376	0.449	0.906	1.680
	Middle Miocene Slope	84	5.636	9.611	7.346	196	2.049	3.923	6.306	3.325	6.622	10.363	2.641	5.101	8.150
	Lower Miocene Shelf	159	0.223	19.935	3.770	61	0.007	0.034	0.087	0.622	3.075	7.972	0.118	0.581	1.505
	Lower Miocene Slope	10	3.494	1.526	3.765	80	2.097	4.385	7.441	0.916	1.915	3.249	2.260	4.725	8.019
	Lower Tertiary Shelf	2	0.001	0.050	0.010	18	0.006	0.013	0.023	0.491	1.113	1.887	0.093	0.212	0.359
	Frio Slope	5	0.187	0.108	0.206	11	0.030	0.191	0.473	0.017	0.110	0.272	0.033	0.211	0.521
	Wilcox Slope	28	3.457	1.854	3.787	90	4.760	8.658	12.806	2.551	4.641	6.864	5.214	9.483	14.027
	Lower Tertiary Basin Floor	0	0.000	0.000	0.000	8	0.000	0.991	2.999	0.000	0.257	0.777	0.000	1.036	3.137
Mesozoic	Mesozoic Shelf	0	0.000	0.000	0.000	5	0.000	0.005	0.019	0.000	0.372	1.419	0.000	0.071	0.271
	Mesozoic Slope	0	0.000	0.000	0.000	8	0.000	0.206	0.750	0.000	0.219	0.797	0.000	0.245	0.892
	Lower Tuscaloosa Shelf	0	0.000	0.000	0.000	10	0.005	0.058	0.132	0.040	0.416	0.968	0.012	0.132	0.304
	Lower Tuscaloosa Slope	0	0.000	0.000	0.000	7	0.000	0.182	0.707	0.000	0.131	0.508	0.000	0.205	0.798
	Lower Cretaceous Clastic Shelf	0	0.000	0.000	0.000	6	0.000	0.013	0.053	0.000	0.096	0.417	0.000	0.030	0.127
	Lower Cretaceous Clastic Slope	0	0.000	0.000	0.000	7	0.011	0.197	0.589	0.008	0.142	0.423	0.012	0.223	0.664
	Lower Cretaceous Carbonate	12	<0.001	0.639	0.114	42	0.058	0.262	0.523	0.470	1.859	3.641	0.141	0.593	1.171
	Sunniland	0	0.000	0.000	0.000	18	0.000	0.113	0.343	0.000	0.000	0.000	0.000	0.113	0.343
	Cotton Valley Clastic Shelf	0	0.000	0.000	0.000	11	0.002	0.017	0.038	0.015	0.116	0.323	0.005	0.037	0.096
	Cotton Valley Clastic Slope	0	0.000	0.000	0.000	8	0.000	0.209	0.843	0.000	0.150	0.606	0.000	0.236	0.951
	Florida Basement Clastic	0	0.000	0.000	0.000	9	0.000	0.021	0.095	0.000	0.025	0.118	0.000	0.025	0.116
	Smackover	0	0.000	0.000	0.000	119	0.244	0.824	1.621	1.542	5.757	11.510	0.519	1.848	3.669
	Norphlet Shelf	18	<0.001	3.464	0.617	25	<0.001	0.001	0.001	1.646	3.770	6.322	0.293	0.671	1.126
	Norphlet Slope	7	0.955	0.687	1.077	80	1.745	3.347	5.152	1.255	2.406	3.705	1.969	3.775	5.812
	Expanded Jurassic	0	0.000	0.000	0.000	8	0.000	0.369	1.559	0.000	0.265	1.121	0.000	0.416	1.758
	Pre-Salt or Equivalent	0	0.000	0.000	0.000	14	0.000	0.816	2.603	0.000	0.835	2.661	0.000	0.965	3.076
Total Gulf of Mexico OCS		**2,238**	**38.409**	**235.791**	**80.365**	**1,567**	**23.311**	**29.590**	**36.271**	**46.883**	**54.845**	**62.558**	**31.653**	**39.345**	**47.402**

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

Table 10. UTRR by planning areas and water depth.

Gulf of Mexico 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 Mexico	**23.311**	**29.590**	**36.271**	**46.883**	**54.845**	**62.558**	**31.653**	**39.345**	**47.402**
0 - 200 m	1.039	1.799	2.605	16.278	21.613	28.452	3.936	5.645	7.668
200 - 800 m	3.468	4.358	5.276	5.889	7.396	9.270	4.516	5.674	6.925
800 - 1,600 m	6.851	8.904	11.125	8.829	11.069	13.292	8.422	10.874	13.490
1,600 - 2,400 m	5.497	7.317	9.232	6.255	7.694	9.277	6.610	8.686	10.883
> 2,400 m	5.075	7.210	9.743	5.799	7.073	8.389	6.107	8.468	11.236
Western Gulf of Mexico	**4.453**	**6.049**	**7.803**	**9.333**	**11.394**	**13.356**	**6.113**	**8.077**	**10.179**
0 - 200 m	0.178	0.242	0.326	3.759	6.214	9.851	0.846	1.348	2.079
200 - 800 m	0.662	0.908	1.176	0.743	0.923	1.124	0.794	1.072	1.376
800 - 1,600 m	2.255	3.182	4.168	2.260	2.874	3.513	2.657	3.694	4.793
1,600 - 2,400 m	0.708	1.002	1.324	0.645	0.832	0.993	0.822	1.150	1.501
> 2,400 m	0.489	0.716	0.958	0.431	0.551	0.670	0.565	0.814	1.077
Central Gulf of Mexico	**14.594**	**18.652**	**22.989**	**26.366**	**31.186**	**36.173**	**19.285**	**24.201**	**29.425**
0 - 200 m	0.384	0.517	0.708	6.937	9.478	12.622	1.618	2.203	2.954
200 - 800 m	1.804	2.286	2.822	2.695	3.505	4.384	2.284	2.910	3.602
800 - 1,600 m	4.143	5.323	6.576	5.851	7.346	9.089	5.184	6.630	8.194
1,600 - 2,400 m	4.678	6.196	7.810	5.287	6.630	7.951	5.619	7.375	9.224
> 2,400 m	2.860	4.331	6.212	3.349	4.227	4.993	3.456	5.083	7.101
Eastern Gulf of Mexico	**3.273**	**4.867**	**6.776**	**7.864**	**12.251**	**17.058**	**4.672**	**7.047**	**9.811**
0 - 200 m	0.341	1.032	1.992	3.589	5.916	8.287	0.979	2.085	3.466
200 - 800 m	0.734	1.159	1.633	1.722	2.964	4.533	1.041	1.686	2.439
800 - 1,600 m	0.238	0.392	0.558	0.527	0.844	1.258	0.332	0.542	0.781
1,600 - 2,400 m	0.072	0.120	0.172	0.144	0.232	0.349	0.098	0.162	0.234
> 2,400 m	1.501	2.163	2.892	1.812	2.295	2.841	1.823	2.572	3.397
Straits of Florida	**0.000**	**0.020**	**0.049**	**0.000**	**0.014**	**0.038**	**0.000**	**0.022**	**0.055**
0 - 200 m	0.000	0.007	0.018	0.000	0.005	0.013	0.000	0.008	0.020
200 - 800 m	0.000	0.006	0.014	0.000	0.004	0.011	0.000	0.006	0.016
800 - 1,600 m	0.000	0.007	0.017	0.000	0.005	0.013	0.000	0.008	0.019

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

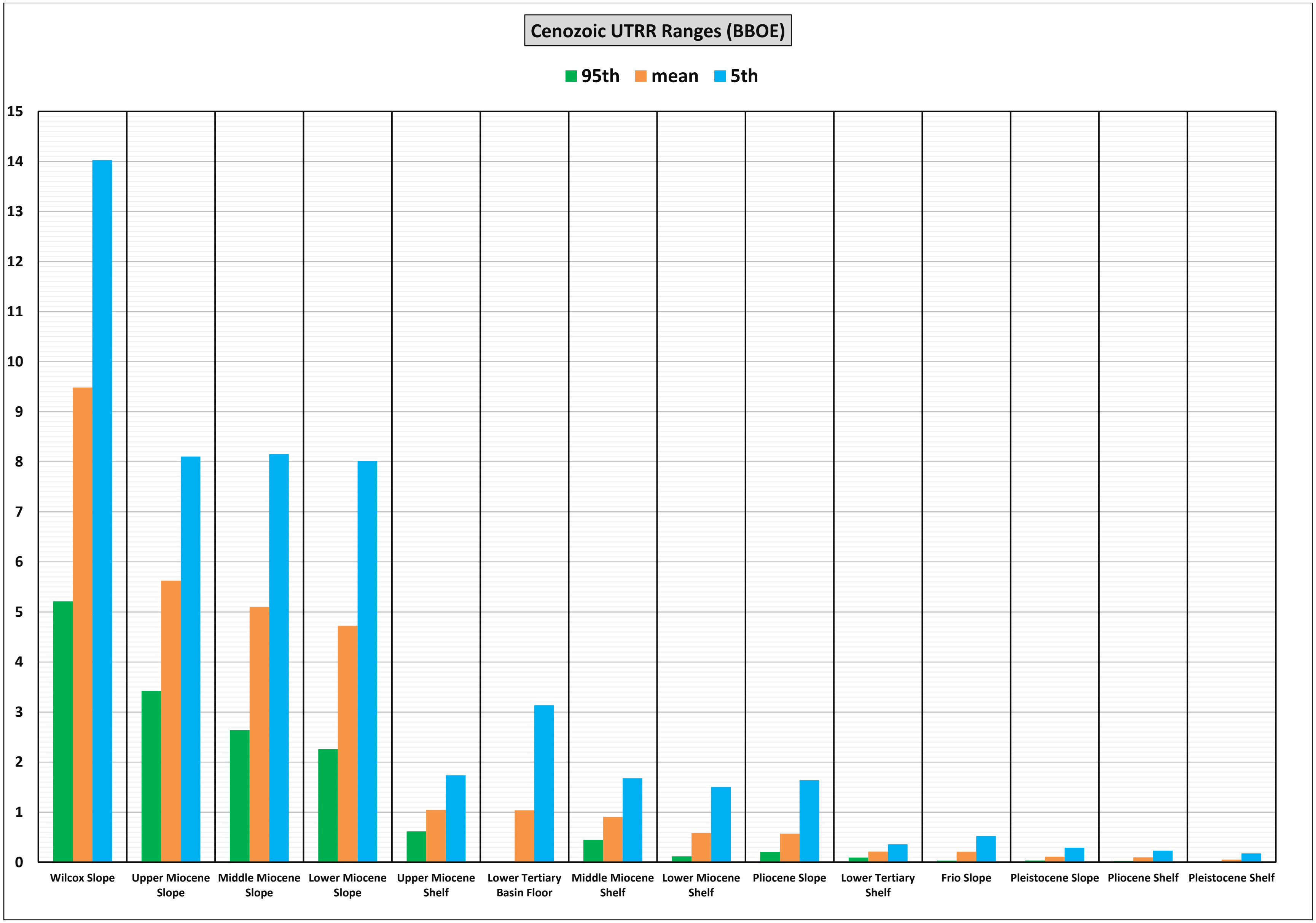

Figure 11. Undiscovered resource ranges for the Cenozoic assessment units sorted by the mean value.

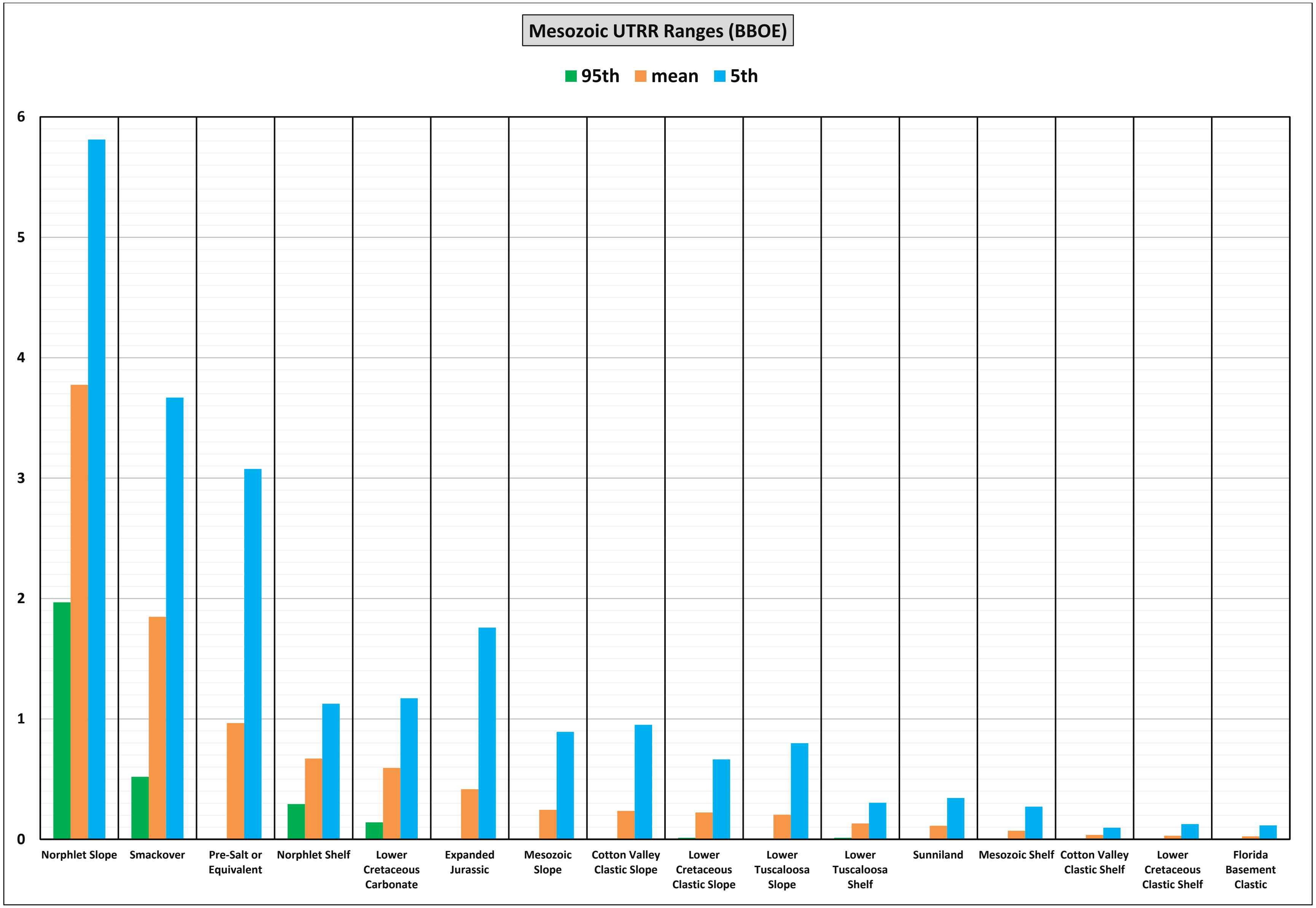

Figure 12. Undiscovered resource ranges for the Mesozoic assessment units sorted by the mean value.

Comparison of UTRR from 2016 to 2021

For this 2021 study, all pertinent prospect and discovery databases, as well as salt, structural, and depositional maps, were utilized to determine a reasonable number and size of undiscovered pools for the assessment units in the Gulf of Mexico OCS. Based on mean-level BOE, this 2021 analysis results in a 34.343 BBOE decrease in UTRR from that of BOEM's 2016 resource assessment (USDOI, 2017), with 93 percent of that decrease attributed to the Cenozoic assessment units (**Figure 13** and **Table 11**).

The assessment units of Pleistocene, Pliocene, and Miocene age decreased by 20.469 BBOE (**Table 11**). Several factors contributed to this result.

For the shelf AUs:

- All have hundreds of discoveries with exploration histories dating back to the late-1940s.
- All have present-day flat pseudo-creaming curves indicative of mature, highly explored plays with minimal discovered volumes being added.

For the slope AUs:

- Of just over 400 discoveries, only 14 percent have been found in the last 10 years.
- Only four discoveries in the last 10 years were of a substantial size (>100 MMBOE) for deep water.

The Lower Tertiary assessment units decreased by 11.630 BBOE (**Table 11**). Similar to the Pleistocene-Pliocene-Miocene AUs, numerous considerations contributed to this decrease.

For the Lower Tertiary Shelf (Wilcox and Frio):

- High-temperature drilling environments eliminated areas of prospectivity.
- BOEM estimated reserves for the Wilcox "Davy Jones" Prospect (South Marsh Island Block 230) was decreased from 760 MMBOE in 2016 to 0.2 MMBOE in 2021, eliminating justification for such large pools in the pool-size model.

For the Frio Slope:

- Numerous wells have tested the Oligocene Frio Formation on the way down to the Lower Eocene-Upper Paleocene Wilcox Formation, eliminating areas of prospectivity.

For the Wilcox Slope:

- BOEM estimated reserves for the "Kaskida" (Keathley Canyon Block 292) discovery was decreased from 2.367 BBOE in 2016 to 0.086 BBOE in 2021, eliminating justification for such large pools in the pool-size model.

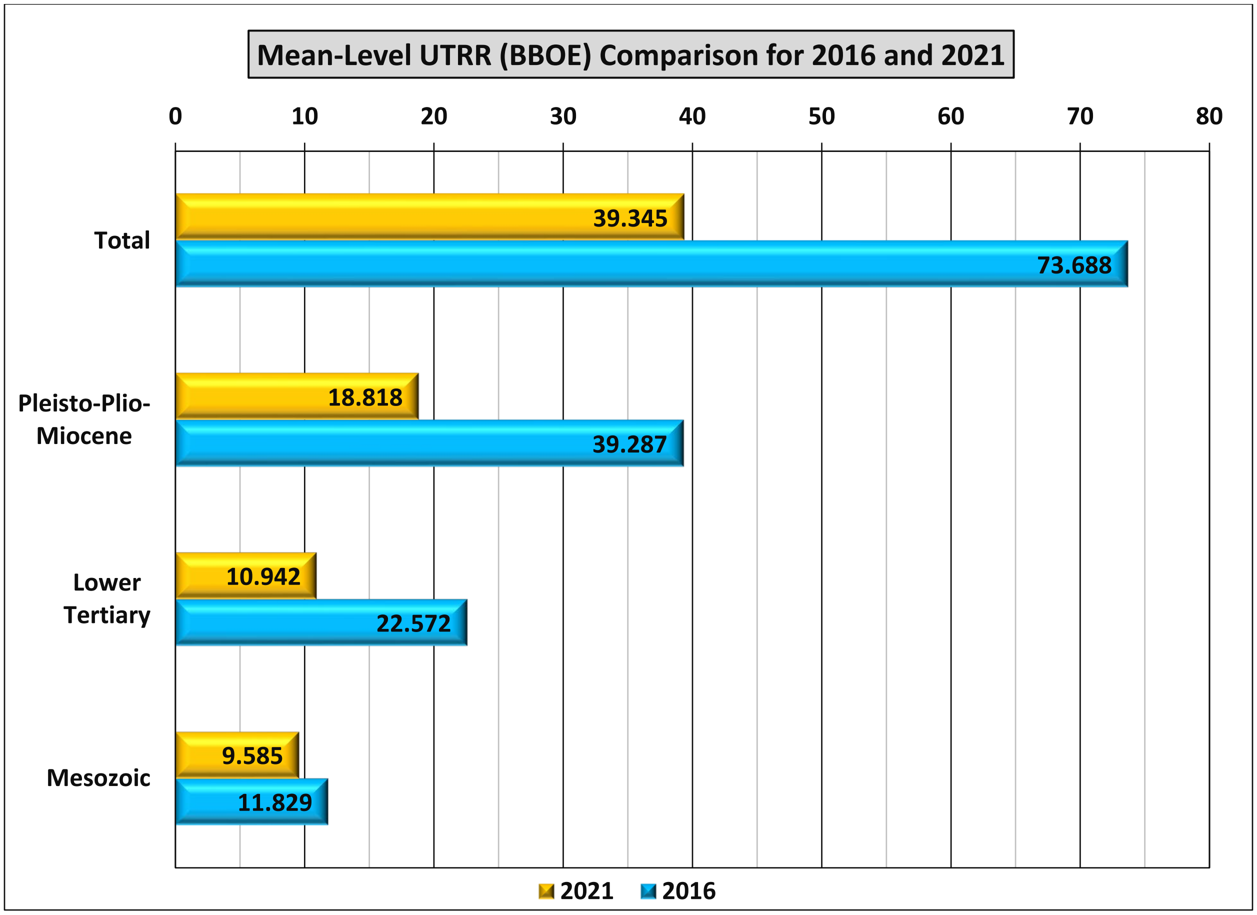

Figure 13. Comparison of mean-level UTRR for 2016 and 2021.

Table 11. Change in mean-level UTRR from 2016 to 2021.

Age	2016 UTRR (mean, BBOE)	2021 UTRR (mean, BBOE)	Change (BBOE)
Pleisto-Plio-Miocene	39.287	18.818	-20.469
Lower Tertiary	22.572	10.942	-11.630
Mesozoic	11.829	9.585	-2.244
Total	73.688	39.345	-34.343

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES (UERR)

Undiscovered economically recoverable resources presented herein are full-cycle results associated with a 30 percent economic value of gas relative to oil. **Figure 14** compares mean-level values of UERR at five specific price pairs with UTRR for the entire Gulf of Mexico OCS. **Table 12** 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 Mexico OCS (**Figure 15**) and for each planning area within the Gulf of Mexico 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 UTRR oil and gas resources and are independent of commodity price.

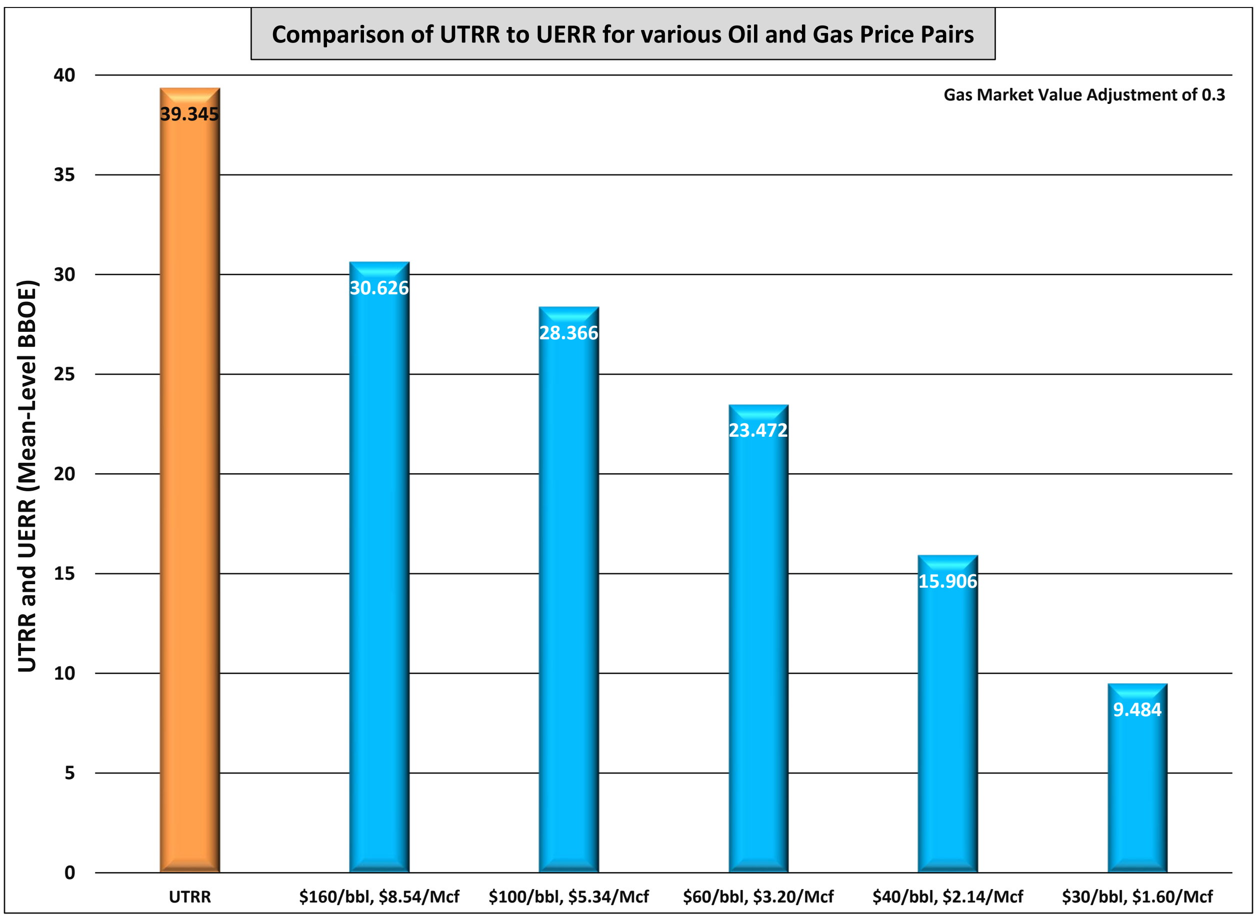

Figure 14. Mean-value comparison of UTRR to UERR for various oil and gas price pairs.

Table 12. Mean-level UERR values at specific oil and gas price pairs.

Gulf of Mexico OCS	Undiscovered Economically Recoverable Resources (UERR)														
	Mean Values with a Gas Market Value Adjustment of 0.3														
Planning Area	$30/bbl, $1.60/Mcf			$40/bbl, $2.14/Mcf			$60/bbl, $3.20/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)	oil (Bbbl)	gas (Tcf)	BOE (Bbbl)	oil (Bbbl)	gas (Tcf)	BOE (Bbbl)
Total Gulf of Mexico	**8.272**	**6.813**	**9.484**	**13.734**	**12.202**	**15.906**	**19.843**	**20.394**	**23.472**	**23.531**	**27.171**	**28.366**	**25.137**	**30.848**	**30.626**
0 - 200 m	0.227	0.409	0.300	0.468	1.452	0.727	0.767	4.132	1.502	0.981	6.951	2.217	1.097	8.638	2.634
200 - 800 m	1.217	1.079	1.409	1.999	1.819	2.323	2.871	2.780	3.366	3.393	3.493	4.014	3.622	3.865	4.310
800 - 1,600 m	2.759	2.231	3.156	4.378	3.641	5.026	6.171	5.463	7.143	7.269	6.825	8.484	7.738	7.521	9.076
1,600 - 2,400 m	2.247	1.705	2.550	3.623	2.802	4.121	5.154	4.191	5.900	6.085	5.193	7.009	6.474	5.688	7.486
> 2,400 m	1.822	1.388	2.069	3.266	2.488	3.709	4.880	3.827	5.561	5.804	4.709	6.641	6.205	5.136	7.119
Western Gulf of Mexico	**1.796**	**1.277**	**2.023**	**2.890**	**2.318**	**3.303**	**4.138**	**4.033**	**4.856**	**4.938**	**5.611**	**5.936**	**5.282**	**6.506**	**6.439**
0 - 200 m	0.031	0.076	0.045	0.052	0.362	0.117	0.087	1.128	0.288	0.119	2.016	0.477	0.137	2.574	0.595
200 - 800 m	0.279	0.202	0.315	0.440	0.326	0.498	0.622	0.485	0.708	0.738	0.605	0.846	0.789	0.666	0.907
800 - 1,600 m	0.980	0.670	1.099	1.571	1.090	1.765	2.237	1.618	2.524	2.655	2.001	3.011	2.831	2.187	3.220
1,600 - 2,400 m	0.298	0.196	0.333	0.484	0.321	0.541	0.696	0.476	0.780	0.830	0.588	0.935	0.888	0.642	1.002
> 2,400 m	0.208	0.133	0.232	0.343	0.220	0.382	0.498	0.326	0.556	0.596	0.402	0.667	0.637	0.437	0.715
Central Gulf of Mexico	**5.585**	**4.753**	**6.431**	**8.981**	**8.144**	**10.430**	**12.756**	**13.199**	**15.105**	**15.050**	**17.423**	**18.150**	**16.047**	**19.738**	**19.559**
0 - 200 m	0.071	0.161	0.100	0.121	0.593	0.226	0.193	1.839	0.521	0.255	3.249	0.833	0.290	4.125	1.024
200 - 800 m	0.744	0.709	0.870	1.138	1.140	1.340	1.569	1.713	1.874	1.832	2.162	2.217	1.948	2.401	2.375
800 - 1,600 m	1.718	1.509	1.986	2.659	2.430	3.092	3.691	3.644	4.339	4.321	4.577	5.136	4.594	5.065	5.495
1,600 - 2,400 m	1.931	1.494	2.196	3.094	2.446	3.529	4.383	3.655	5.034	5.164	4.532	5.970	5.490	4.968	6.374
> 2,400 m	1.122	0.880	1.279	1.969	1.535	2.243	2.921	2.347	3.338	3.478	2.903	3.994	3.725	3.178	4.290
Eastern Gulf of Mexico	**0.889**	**0.781**	**1.028**	**1.857**	**1.735**	**2.166**	**2.938**	**3.153**	**3.499**	**3.531**	**4.126**	**4.265**	**3.796**	**4.593**	**4.613**
0 - 200 m	0.124	0.172	0.155	0.293	0.496	0.381	0.483	1.162	0.690	0.603	1.682	0.902	0.665	1.934	1.009
200 - 800 m	0.194	0.168	0.224	0.420	0.352	0.482	0.677	0.579	0.781	0.819	0.723	0.948	0.882	0.795	1.024
800 - 1,600 m	0.061	0.051	0.070	0.145	0.119	0.167	0.240	0.198	0.275	0.289	0.244	0.332	0.309	0.265	0.356
1,600 - 2,400 m	0.018	0.015	0.021	0.045	0.036	0.052	0.075	0.060	0.086	0.090	0.073	0.103	0.097	0.079	0.111
> 2,400 m	0.492	0.375	0.558	0.954	0.733	1.084	1.462	1.154	1.667	1.730	1.404	1.980	1.843	1.521	2.113
Straits of Florida	**0.003**	**0.002**	**0.003**	**0.006**	**0.005**	**0.007**	**0.010**	**0.009**	**0.012**	**0.012**	**0.010**	**0.014**	**0.013**	**0.011**	**0.015**
0 - 200 m	0.001	0.001	0.001	0.002	0.002	0.003	0.004	0.003	0.004	0.004	0.004	0.005	0.005	0.004	0.005
200 - 800 m	0.001	0.001	0.001	0.002	0.002	0.002	0.003	0.003	0.003	0.004	0.003	0.004	0.004	0.003	0.004
800 - 1,600 m	0.001	0.001	0.001	0.002	0.002	0.003	0.004	0.003	0.004	0.004	0.004	0.005	0.005	0.004	0.005

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

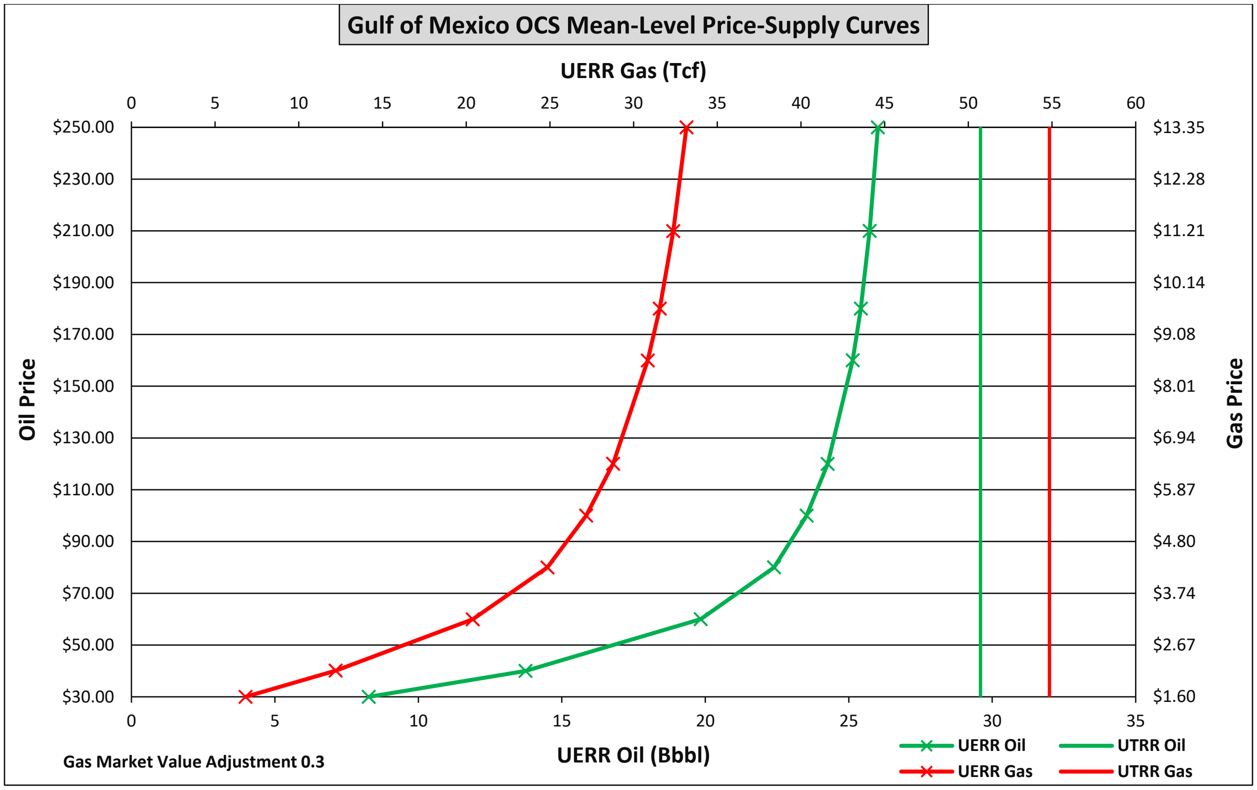

Figure 15. Mean-level price-supply curves for the Gulf of Mexico OCS.

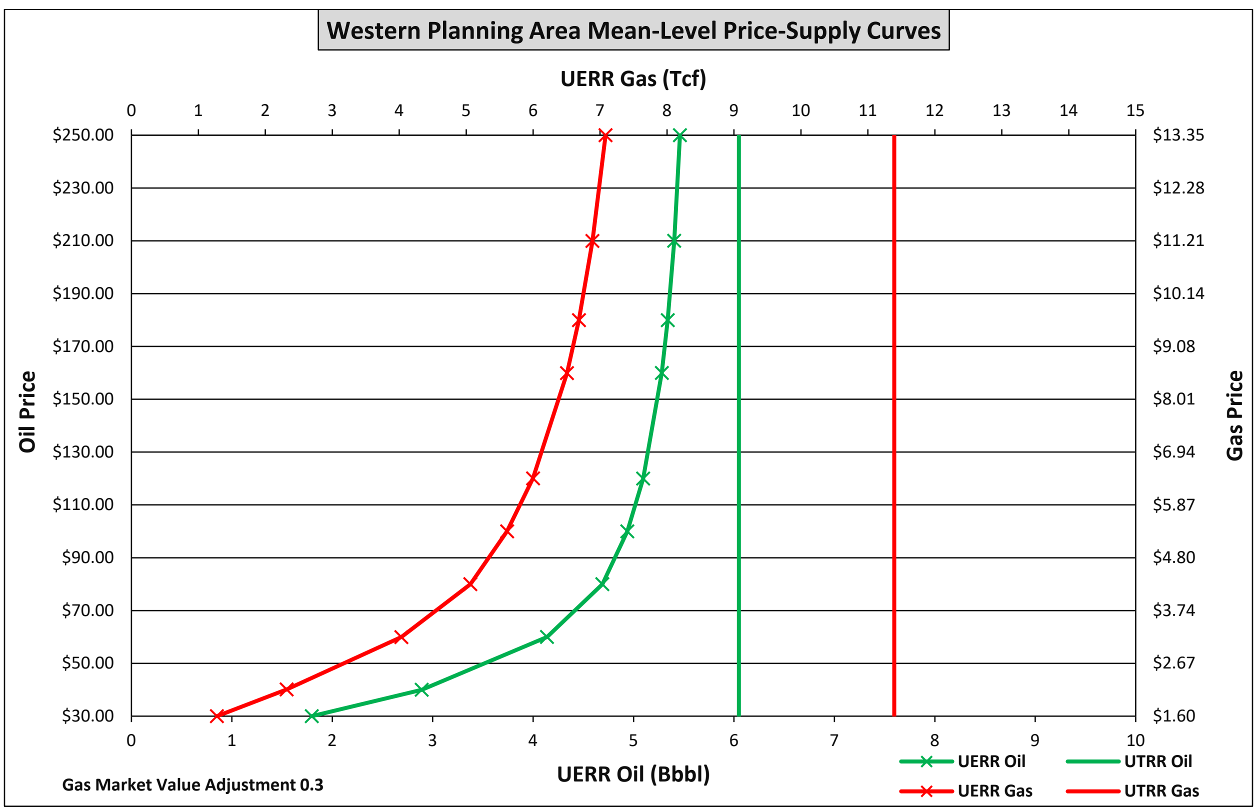

Figure 16. Mean-level price-supply curves for the Western Planning Area.

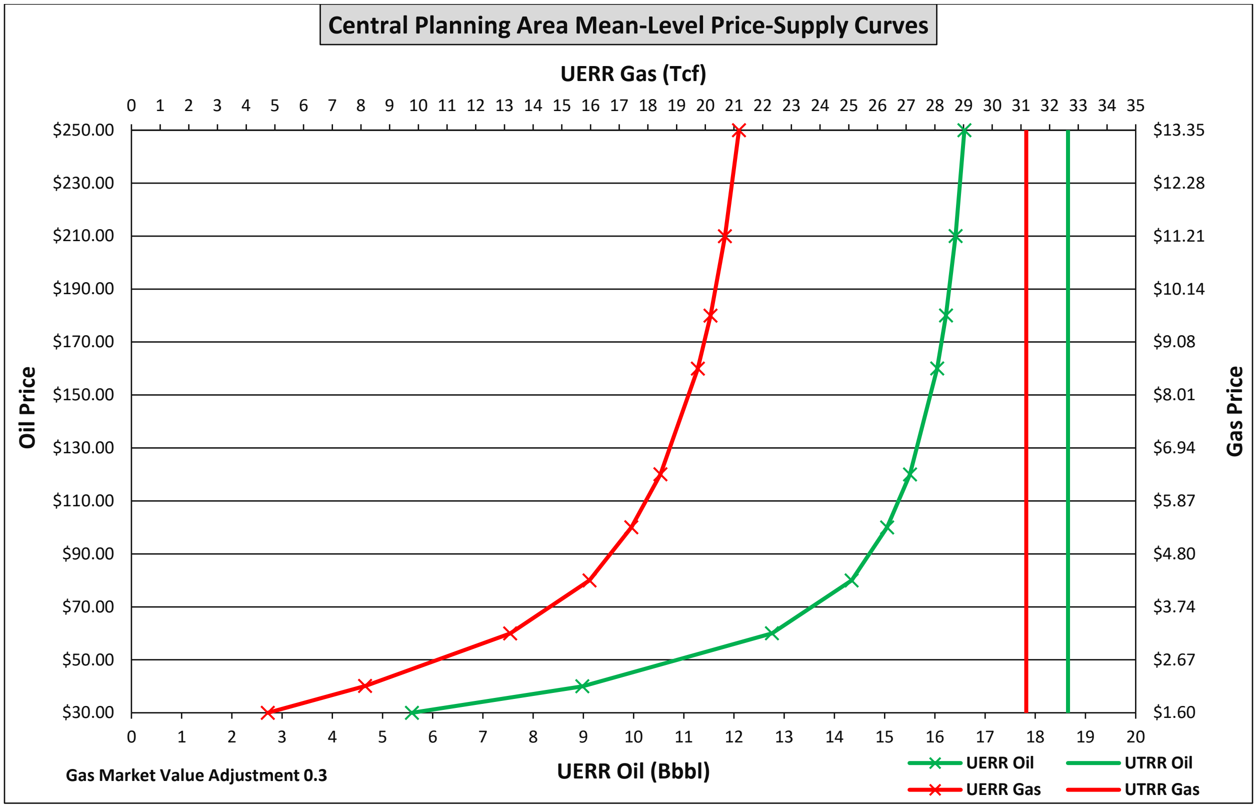

Figure 17. Mean-level price-supply curves for the Central Planning Area.

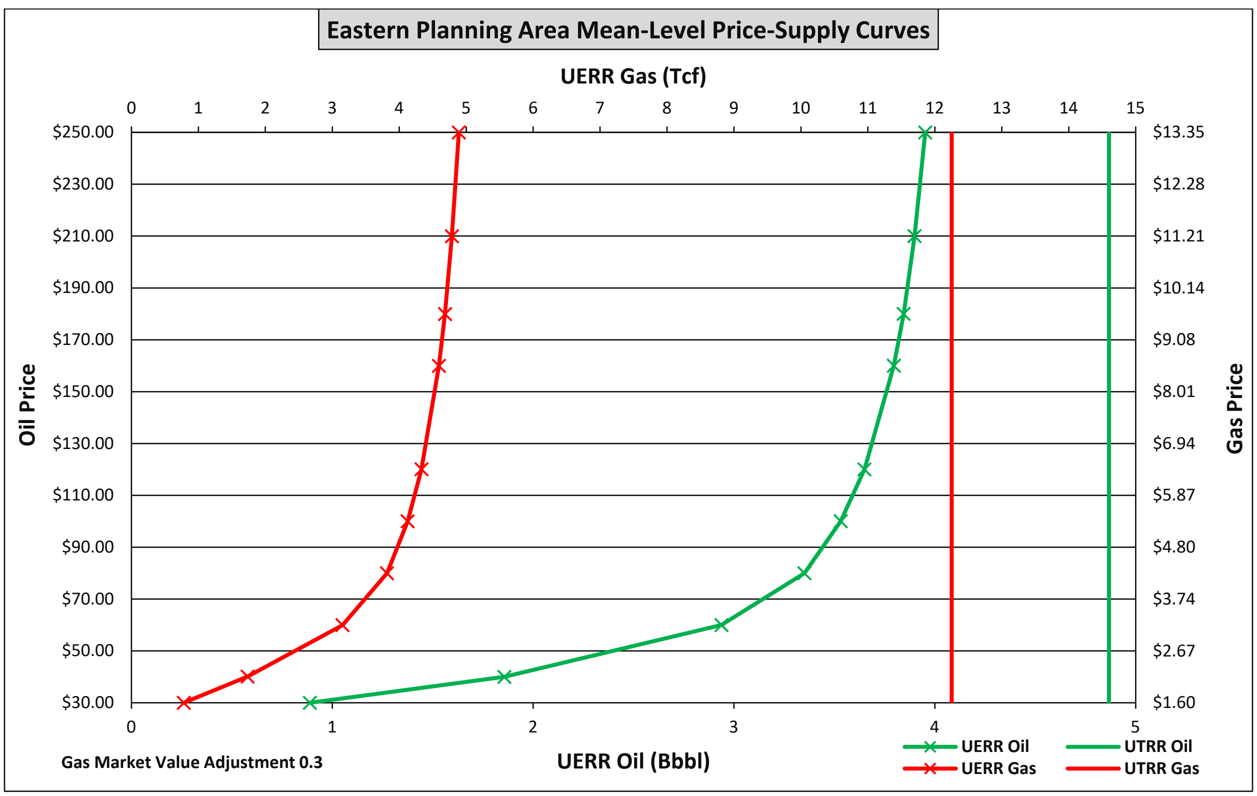

Figure 18. Mean-level price-supply curves for the Eastern Planning Area.

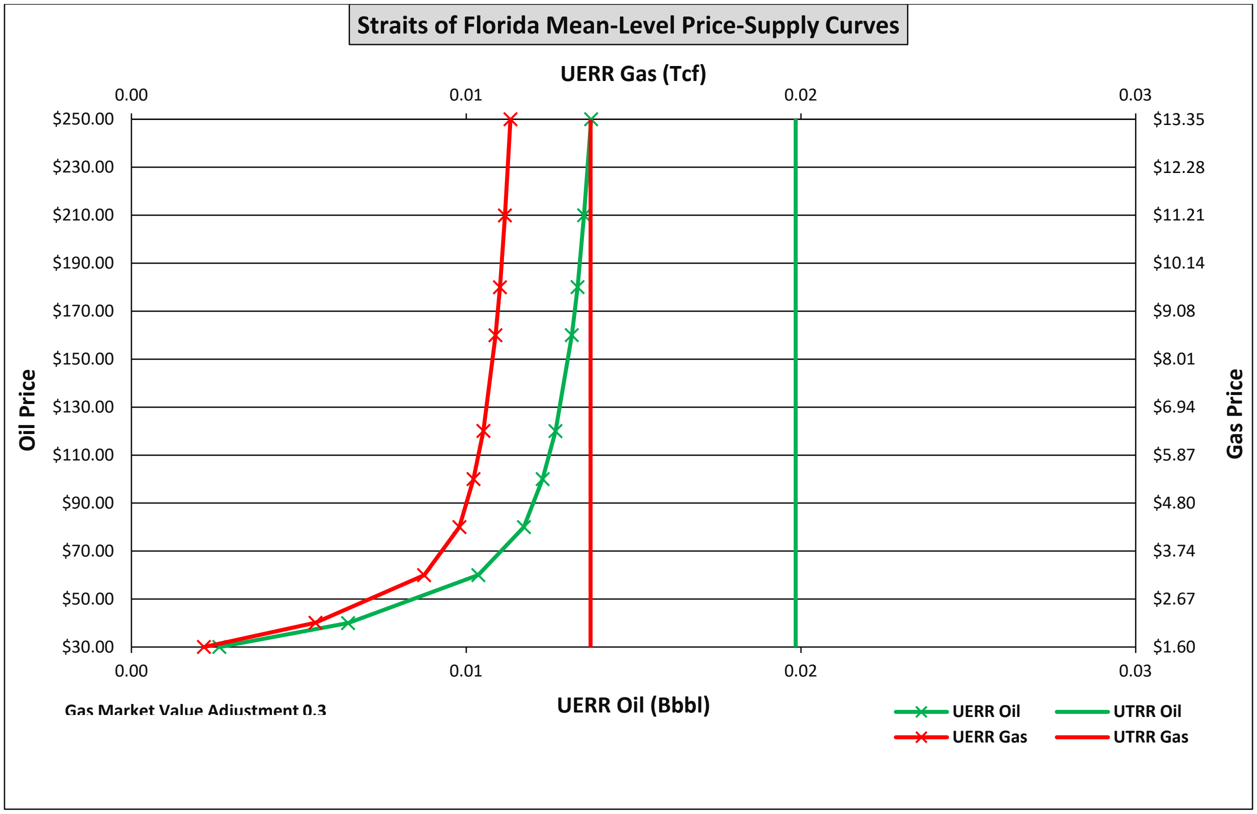

Figure 19. Mean-level price-supply curves for the Straits of Florida.

GEOLOGIC OVERVIEW

The geology of the GOM 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 geological evolution and hydrocarbon potential of the offshore areas of the northern GOM in U.S. waters. For historical and current overviews, the reader is referred to Galloway (2008), Salvador (1991), 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 GOM. Satellite, aerial, and marine potential field datasets have revealed the extent of oceanic crust underlying the GOM Basin and helped to refine plate reconstructions (Norton et al., 2016; Pindell et al., 2016; Sandwell et al., 2014). Long offset 2D seismic reflection and refraction surveys have imaged the deep crustal structure to unprecedented depths (e.g., Pascoe et al., 2016; Pindell et al., 2014; Van Avendonk et al., 2016) and provided new insights into crustal evolution. Improved seismic imaging of the 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). Source to sink studies employing detrital zircon geochronology are providing new insights into the tectonic evolution of the hinterlands and sediment routing to GOM depositional systems (e.g., Blum & Pecha, 2016; Sharman et al., 2017).

The Lower Tertiary Trend of the deepwater GOM continues to mature. The deepwater Norphlet Trend sees ongoing development (Godo, 2019), and industry has shown some interest in older and younger Mesozoic plays (Harding et al., 2016). Industry interest and exploration efforts in Mexican waters has 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 GOM and provided analogs for some Mesozoic plays (e.g., Steier & Mann, 2019; Williams-Rojas et al., 2012). 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).

This report is a departure from previous assessments in that more emphasis has been placed on the structural controls of play extents. Cenozoic AUs are grouped as a function of modern bathymetric setting and geologic age. In contrast, Mesozoic plays are more closely aligned with their respective depositional shelf-slope breaks. Play 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.

TECTONIC HISTORY OF THE GULF OF MEXICO BASIN

Discussions of the GOM 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 GOM is to some degree inherited from Precambrian and Paleozoic events (Keller et al., 2016; Salvador, 1991; Thomas, 2006), as discussed in the following sections.

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 offshore

GOM. 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/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 Pangaea—resulted in the inherited basement fabric evident today in the GOM. 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 GOM 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-tending 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 GOM (Thomas, 2006). Some of these basement faults may have been reactivated during the Cretaceous Laramide Orogeny (Adams, 2009; Jackson and Laubach, 1988; Zahm et al., 2016). These basement lineaments, or shear zones, have been referred to as transfer or transform fault zones (TFZ) (Adams, 1993, 1997; Bradshaw & Watkins, 1995; Kinsland, 1984) 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 GOM 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 GOM. Red-beds and interbedded volcanics of the Eagle Mills Formation were deposited in the rift basins (Salvador 1991; Millekin, 1988; Frederick et al., 2016) or possibly into post-rift sag basins (Norton et al., 2018). “Rift” structures in the deep subsurface of the Gulf Coast and U.S. waters of the offshore GOM (**Figure 20**) have herein been compiled from seismic data and a proprietary interpretation of the depth to magnetic basement. They 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 GOM 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 GOM 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 section of this report. Seaward dipping reflectors (**Figure 21**) observed in 2D and 3D seismic surveys in the eastern GOM 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 just prior to the emplacement of oceanic crust (Imbert, 2005). A similar feature, 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 GOM 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 GOM 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 GOM (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 (Curry et al., 2018; Pindell et al., 2016). Much of the deepwater GOM 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 GOM that may have equivalents in the southern GOM (**Figure 20**) beneath the Campeche Salt Basin (Miranda-Peralta et al., 2014; Williams-Rojas et al., 2012). These sediments, along with the Triassic Eagle Mills Formation, are the objectives of the Pre-Salt or Equivalent Play of this report.

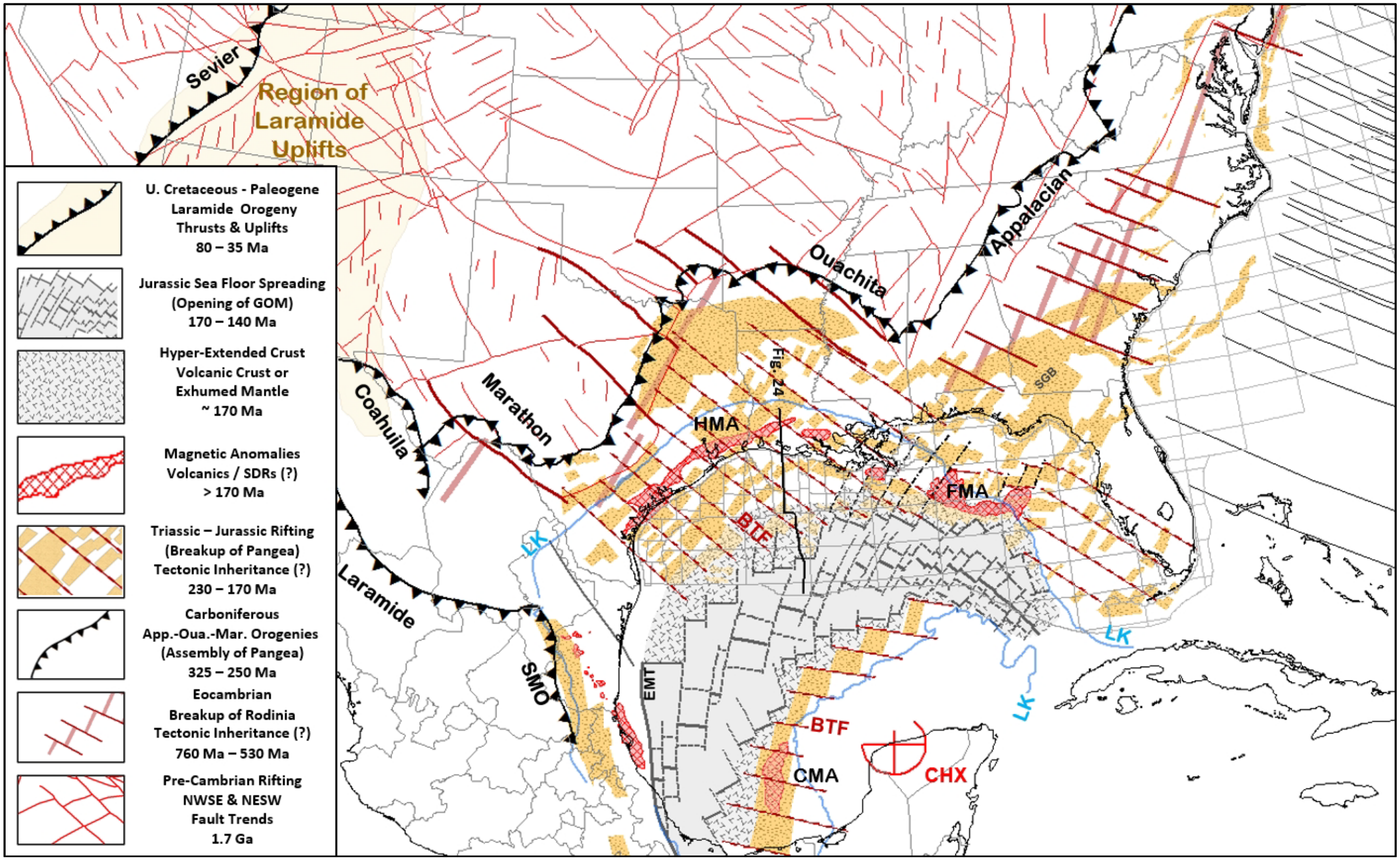

Figure 20. Basement fabric and selected Proterozoic through Cenozoic tectonic events of North America and the Gulf of Mexico.

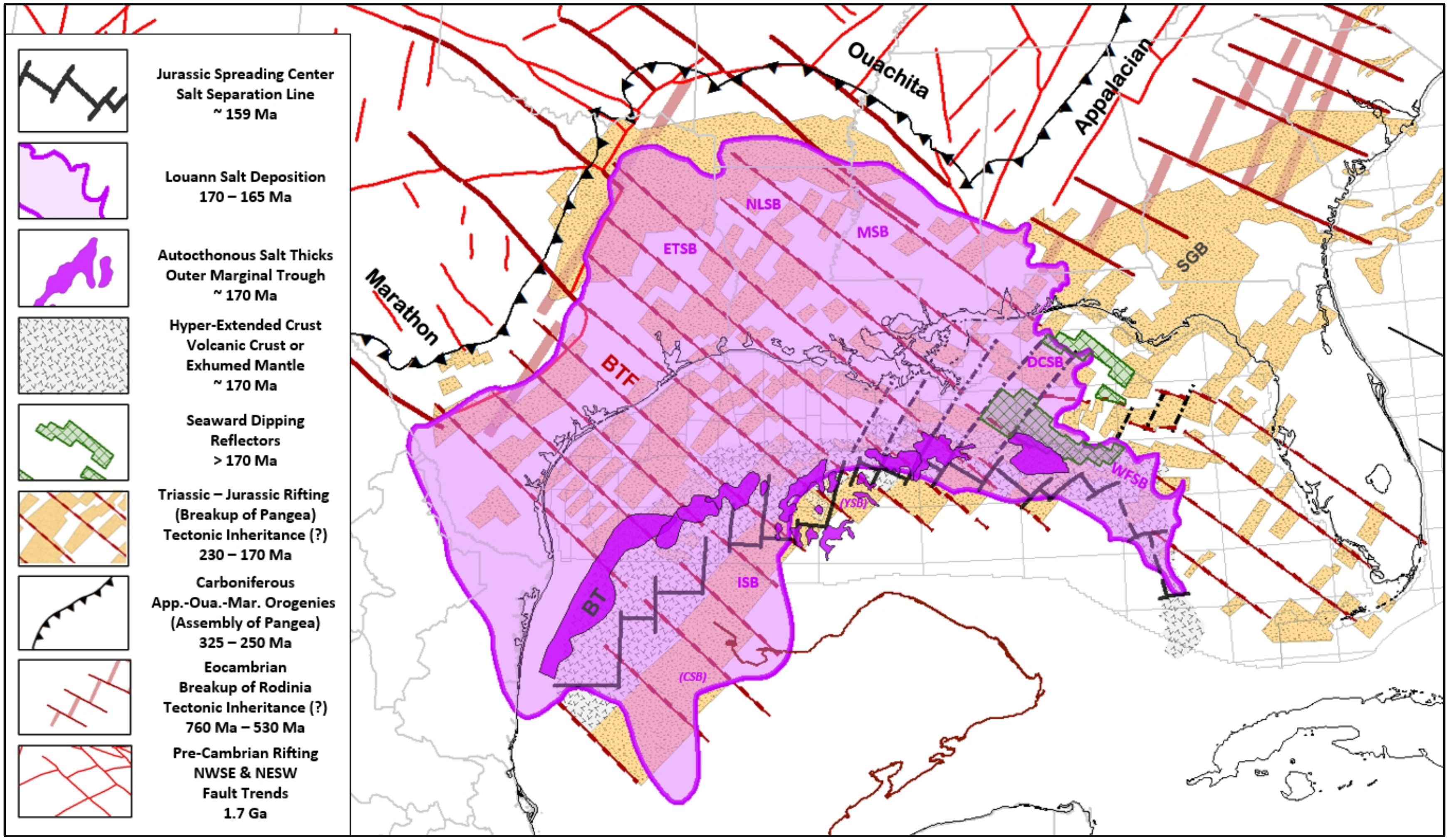

Figure 21. Depositional extent of Louann Salt restored to 170 Ma after Snedden and Galloway (2019) superimposed on selected basement trends and inferred rift architecture.

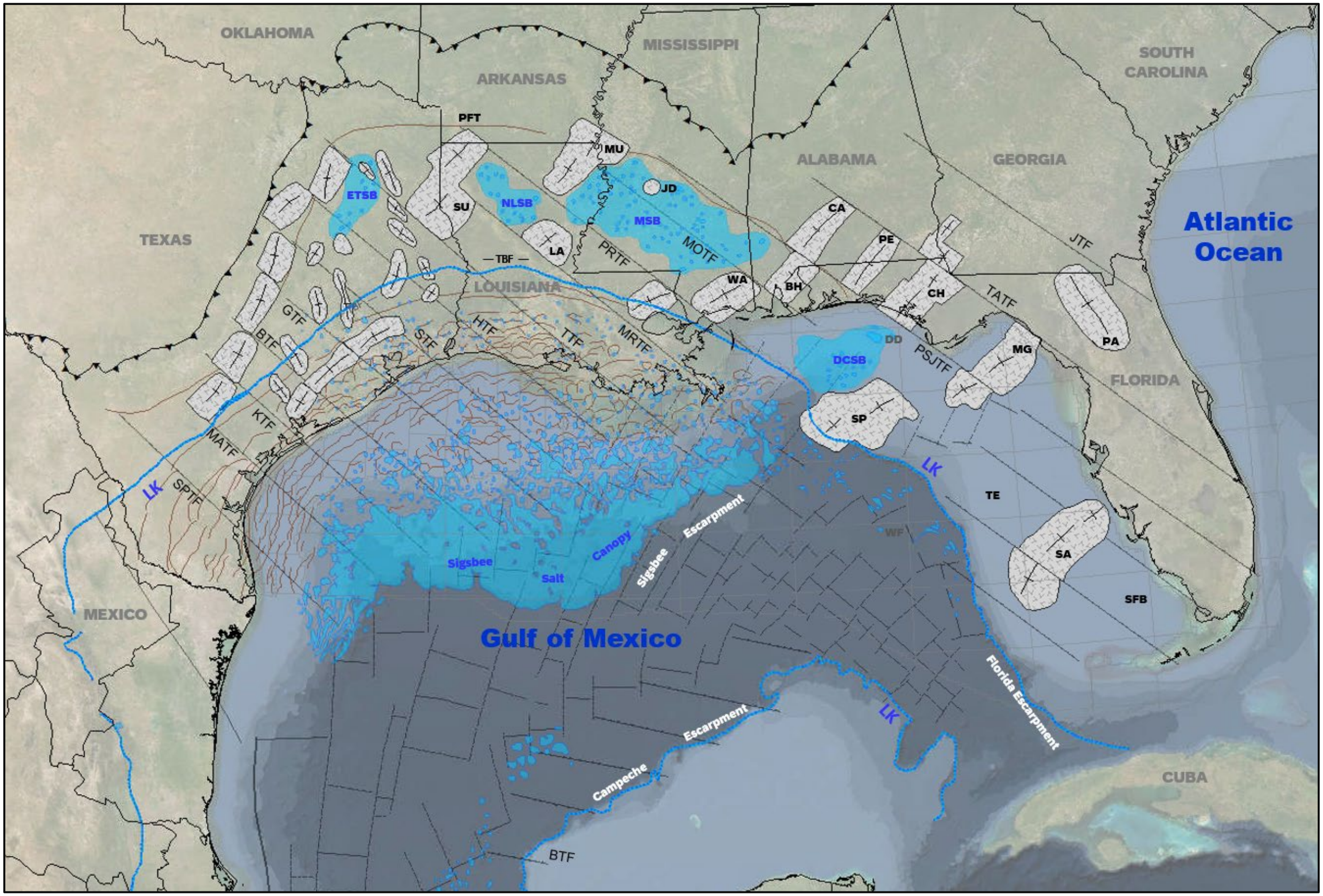

Figure 22. Selected physiographic and structural features of the northern Gulf of Mexico Basin.

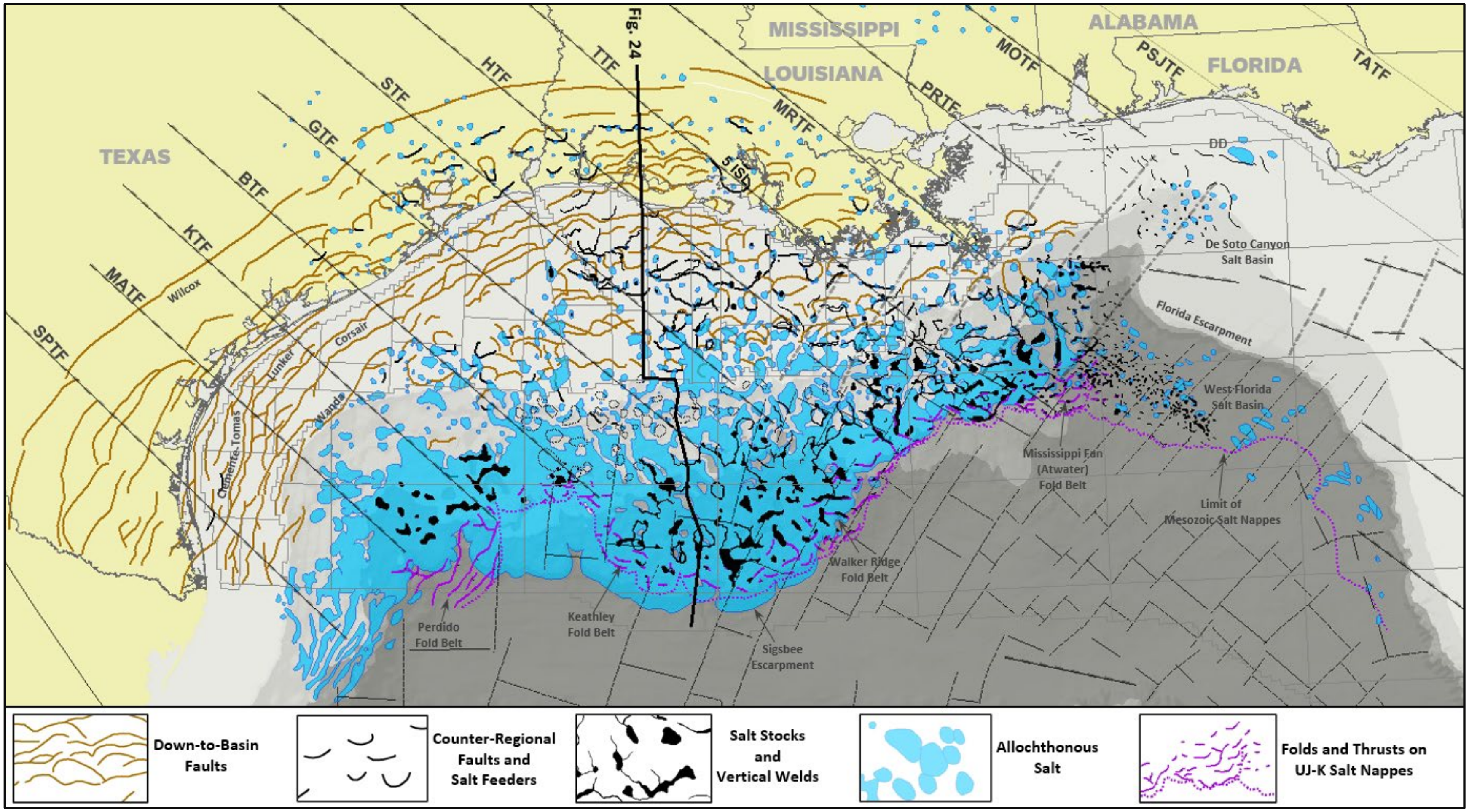

Figure 23. Allochthonous salt and salt-related structural features of the northern Gulf of Mexico. Salt after Muehlberger (1992), Simmons (1992), and Lopez (1995). Faults after Diegel et al. (1995). Folds after Weimer et al. (2017). Stocks and welds from BOEM. Oceanic transform faults after Pindell et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

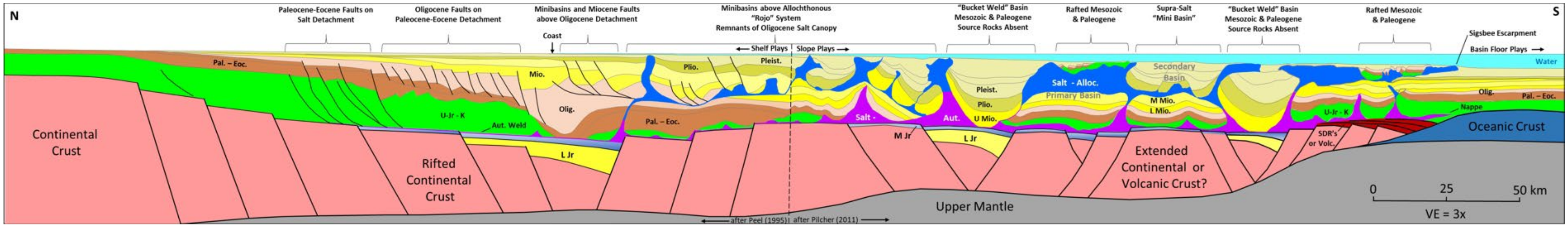

Figure 24. Regional transect from onshore Louisiana through the Sigsbee Salt Canopy illustrating crustal architecture, salt structures, and primary and secondary sedimentary basins. Pre-salt geology is conjectural and not to scale. Modified from Peel et al. (1995) and Pilcher et al. (2011). Vertical exaggeration = 3X. See Figure 20 and Figure 23 for location.

Deposition of the Louann Salt: 170 Ma–165 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 GOM, 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 GOM Salt Basin (Hudec et al., 2013a). 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). The age of the Louann Salt has been estimated to be 162–163 Ma (Callovian) (Salvador, 1987), but recent evidence from isotopic studies (Pullham et al., 2019) and plate reconstructions suggests that the salt is somewhat older and was deposited in a 5 million year time span from 170 to 165 Ma (Bajocian to Early Callovian, **Figure 25**). Mesozoic rift architecture and basement topography (**Figure 21**) have been inferred to have controlled the depositional thickness of the salt (Bradshaw and Watkins, 1985; Hudec et al., 2013a; Stephens, 2009). 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 GOM and the distribution of hydrocarbon accumulations cannot be overstated.

The thickest autochthonous salt was 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 GOM 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). 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 Terrebone Transfer Fault (TTF, **Figure 23**) of Stephens (2001, 2009).

The emplacement of oceanic crust split the GOM 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 GOM Salt Basin. Transfer fault zones of the northern GOM have been projected onto the conjugate margin of the southern GOM 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**).

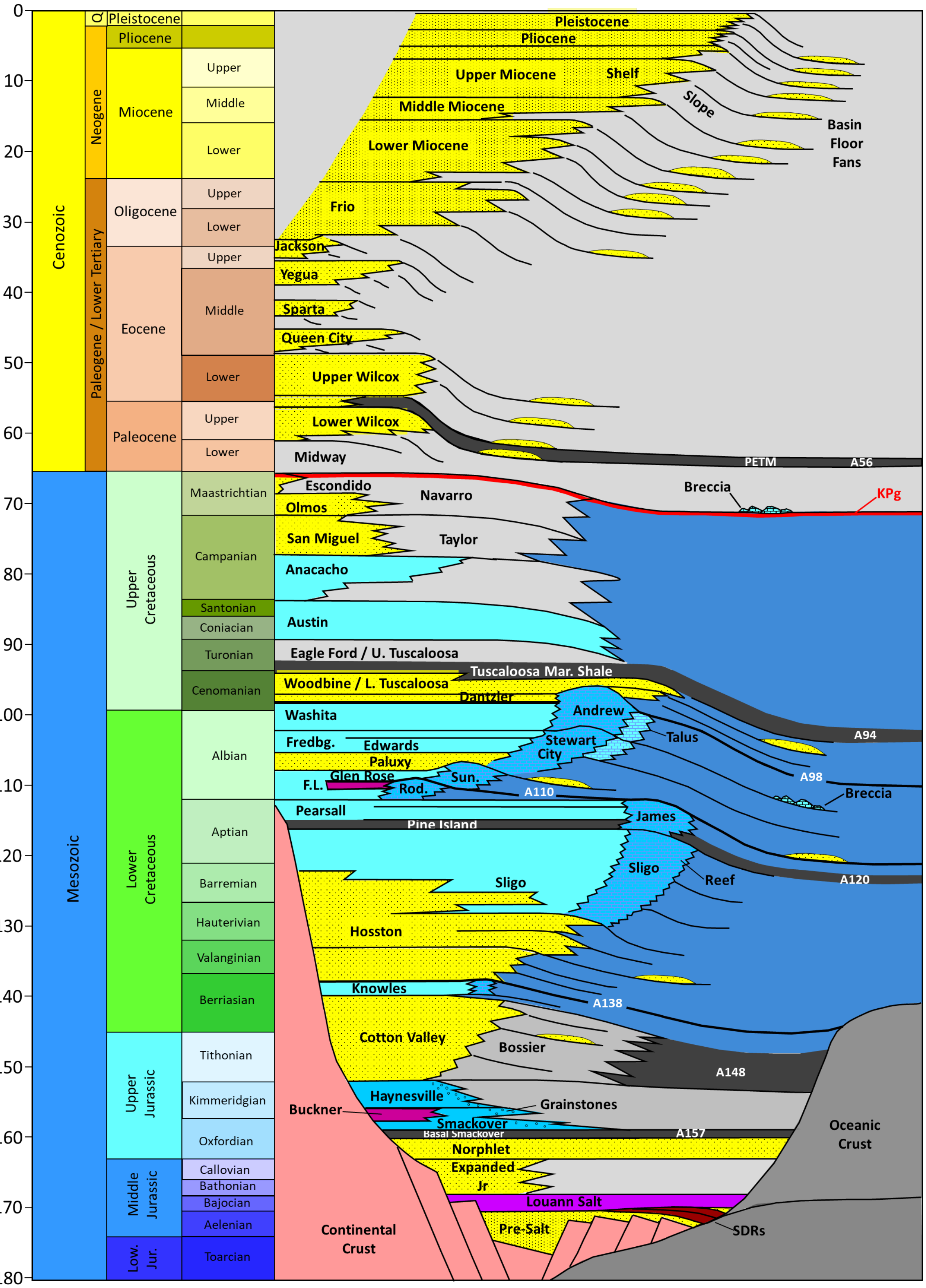

Figure 25. Stratigraphy and depositional architecture of the northern Gulf of Mexico (after Galloway 2008).

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 GOM 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, 2013b; Pilcher et al., 2014). Mesozoic extensional fault systems related to rafting in the eastern GOM 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 with the Norphlet and Smackover Plays of this report. 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 (Dooley and Hudec, 2017; Pilcher et al., 2011). 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, comprised of aeolian sand dunes. These deposits constitute the productive Oxfordian Norphlet Formation of the northeastern GOM (**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 Mexico OCS indicate the presence of a previously unknown post-salt, pre-Norphlet sedimentary section, which is the basis for the newly-assessed 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 GOM 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 AUs.

Mesozoic and Cenozoic Source Rock Families

The majority of the hydrocarbon source rocks in the GOM are Mesozoic and are centered around basin-wide depositional acmes designated by “A” prefix and age in Ma (**Figure 25**), some of which coincide with global oceanic anoxic events (OAE) 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 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 reservoired oils and gasses in most areas of the GOM 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 with the Mesozoic Basin Floor AU.

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 GOM were influenced by the basement fabric described in previous sections (**Figure 20**). Recent source-to-sink studies utilizing detrital zircon geochronology suggest GOM 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 GOM 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 offshore, 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 to the stratigraphic and structural evolution of the northern GOM 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 GOM.

Cenozoic Sedimentation and Salt Sediment Interaction 65 Ma–Present

The Cenozoic sedimentary record in the northern GOM consists of approximately 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) affecting accommodation, 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 high stands 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 high-stands of sea level tend to sequester sediments on the shelf, whereas periods of relative low-stands 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 coals are 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 GOM 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 GOM (Fulthorpe et al., 2014).

Ongoing uplift in the western U.S. continued to source sediments to the GOM 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 GOM 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 Plio-Pleistocene time correlates to the establishment of permanent ice sheets in North America, which delivered large volumes of sediment to the GOM through the Mississippi River drainage (Lawless et al., 1997). Plio-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 GOM 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 GOM, 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 balance updip extension in shelf margin growth faults and detachments.

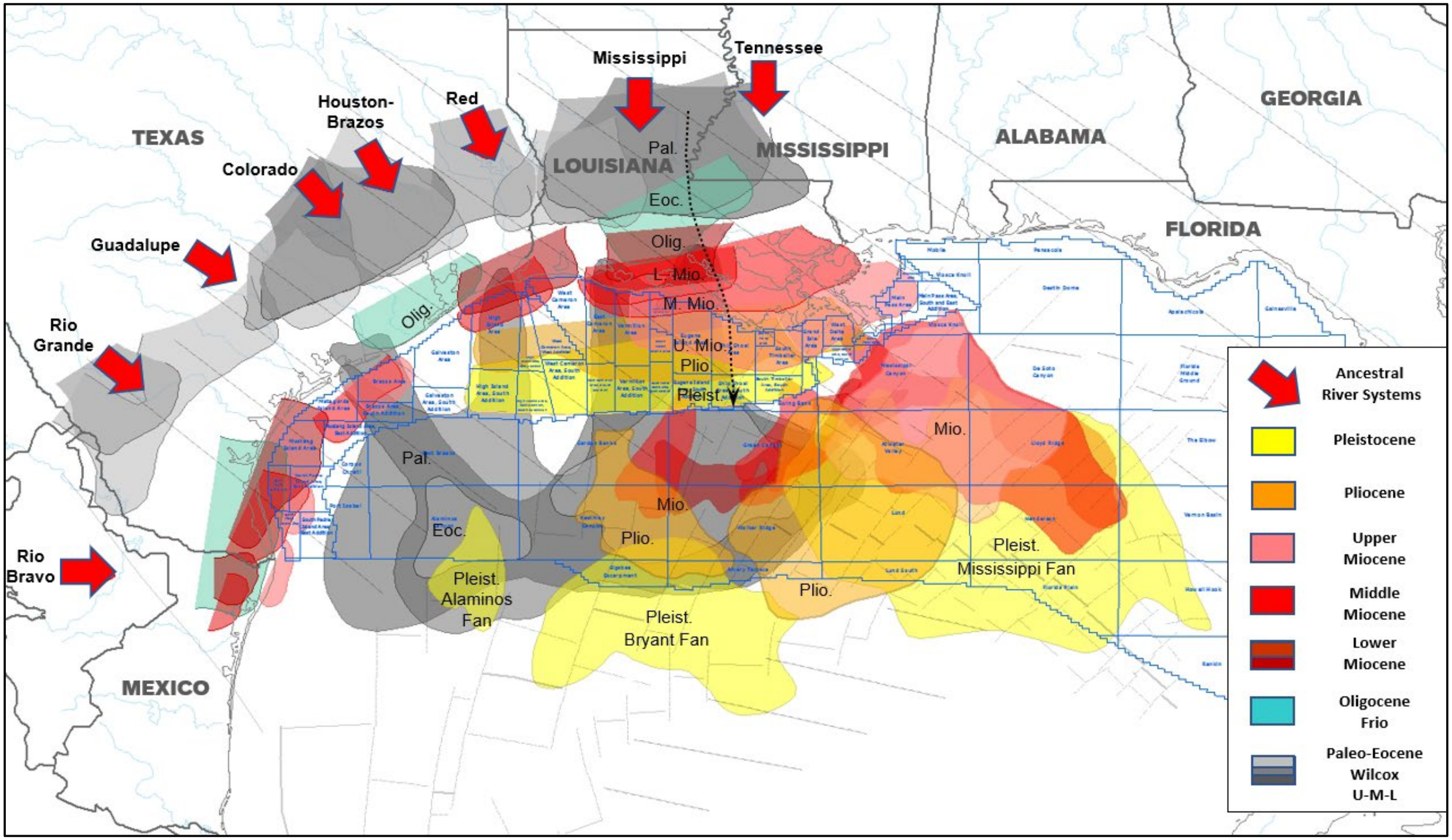

Figure 26. Major Cenozoic deltaic depocenters and equivalent basin-floor fans (after Snedden and Galloway, 2019).

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 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 GOM 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.

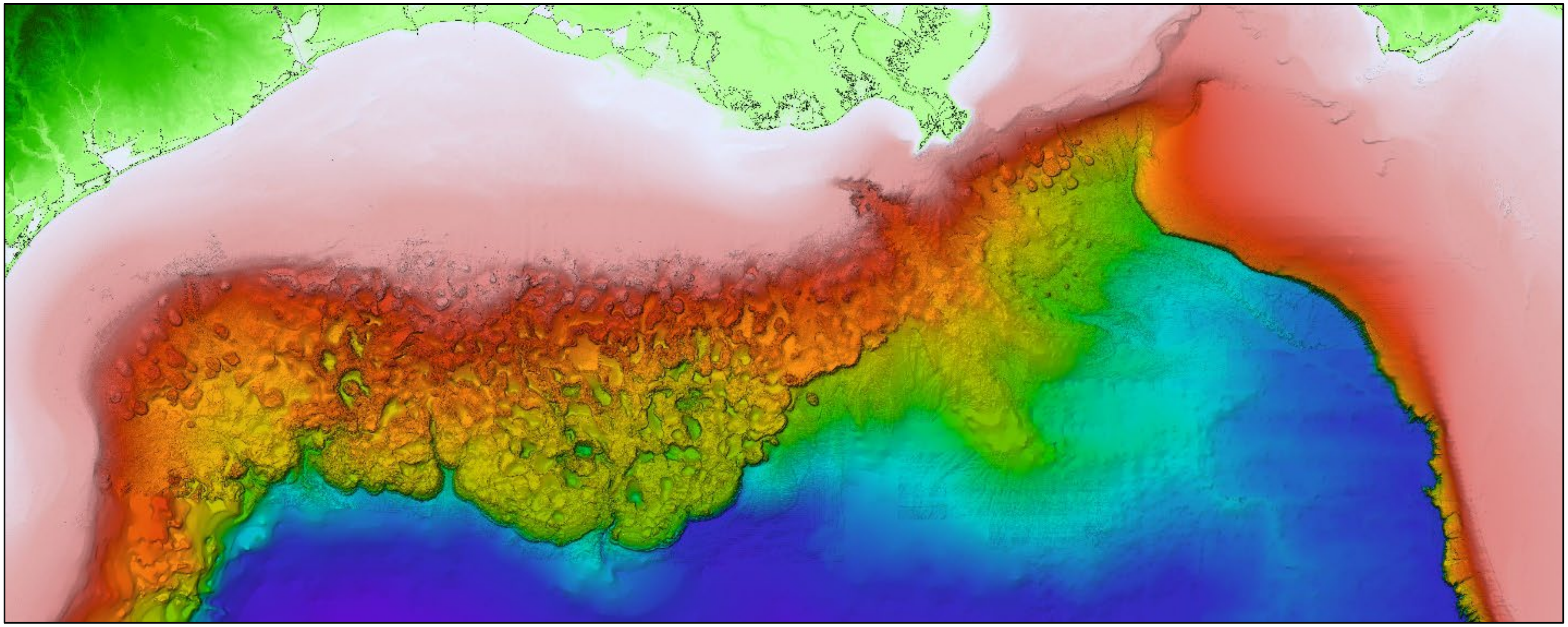

Figure 27. Modern seafloor bathymetry of the northern Gulf of Mexico. BOEM deepwater high-resolution bathymetry after Kramer and Shedd (2017).

MESOZOIC ASSESSMENT UNITS

Pre-Salt or Equivalent

Geology

A speculative Mesozoic (Triassic to Middle Jurassic) Pre-Salt or Equivalent Play has been identified in the northeast GOM extending from the Mississippi Canyon/De Soto Canyon/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 GOM 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–Callovian), or approximately 170 to 165 Ma in age, providing a minimum stratigraphic age for the play. The base of autochthonous salt in the De Soto Canyon/Lloyd Ridge areas ranges in depth from 22,000 to 30,000 ft and deepens westward into Mississippi Canyon to over 40,000 ft.

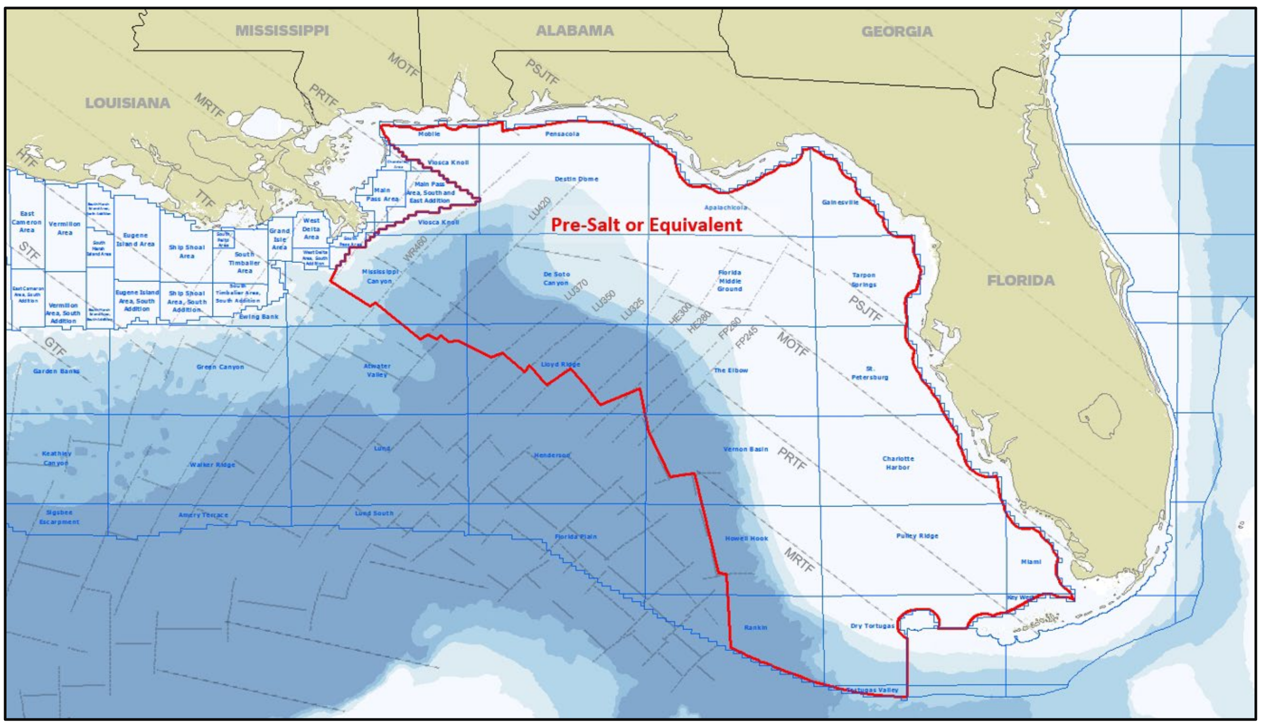

Figure 28. Pre-Salt or Equivalent location.

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 of the play 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 GOM beneath the Isthmian Salt Basin (ISB, **Figure 21**) (Miranda-Peralta et al., 2014; Williams-Rojas et al., 2012).

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 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). Reservoir objectives in the phase 2 rifts are thought to be Lower to Middle Jurassic age, distinctly younger than the Eagle Mills Formation. Recent lease sale bidding in the De Soto Canyon (SW ¼) and Lloyd Ridge (NW ¼) Protraction Areas conform to areas of phase 2 rifting.

With no phase 2 rift well penetrations in Federal OCS waters, the identification of this play in the Gulf of Mexico OCS 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/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 paleo reports show that some of these wells are in grabens faulted into Paleozoic basement.

The eastern GOM Pre-Salt or Equivalent Play is analogous to the U.S. Geological Survey-assessed Atlantic Margin grabens and formed at similar Triassic-age latitudes (10 degrees to 23 degrees north) (Blakey, 2013; Whiteside et al., 2011). These eastern-GOM grabens today are structurally along strike from these 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 these 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.

Water depths within the play outline on the Florida Platform range from 1,000 to 7,000 ft. Wells drilled for the Pre-Salt or Equivalent Play in the Florida Platform area will require drilling depths in the range of 17,500 to 37,000 ft depending on location.

Water depths within the play outline in the De Soto Canyon/Lloyd Ridge areas range from 7,000 to 10,000 ft. Wells drilled in the Pre-Salt or Equivalent Play in the De Soto Canyon/Lloyd Ridge areas will require drilling depths in the range of 25,000 to 37,000 ft depending on location.

Risk

The primary risk for the Pre-Salt or Equivalent Play 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 AU; 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 area of the play and could provide an excellent vertical seal for prospects.

For the play as a whole, the petroleum system chance of success of 45 percent (**Figure 3**). At the prospect level, the average conditional chance of success is 18 percent (**Figure 4**). This equates to an overall exploration chance of success of just 8 percent (**Figure 5**), making this play one of the riskiest evaluated. See Appendix A for details.

Undiscovered Resources

This conceptual play holds 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 GOM could be 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 for this conceptual play 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 0.493 to 738 MMBOE, with a mean size of 88 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 455 MMBOE.

The play was modeled as 100 percent oil. With no discoveries or definitive knowledge of the source rocks in the play, gas-oil-ratios (GOR) were calculated from the analog volumes, with GRASP returning UTRR volumes for black oil and solution gas. Because of the play-level petroleum system risk for the play, only 45 percent of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 2.603 Bbbl at the 5th percentile, with a mean of 0.816 Bbbl, and 2.661 Tcf at the 5th percentile, with a mean of 0.835 Tcf, respectively (**Table 9** and **Figure 29**). Total undiscovered BOE resources are 3.076 Bbbl at the 5th percentile, with a mean of 0.965 Bbbl (**Figure 30**). Based on mean-level undiscovered BOE resources, the play ranks 9th of all 30 GOM assessment units (**Figure 10**).

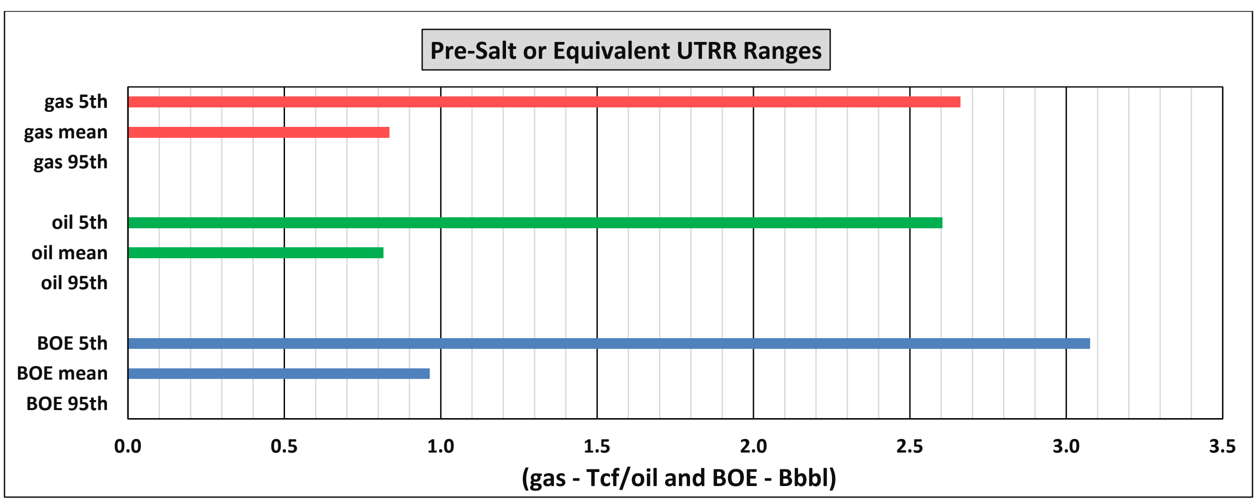

Figure 29. Pre-Salt or Equivalent gas, oil, and BOE UTRR ranges.

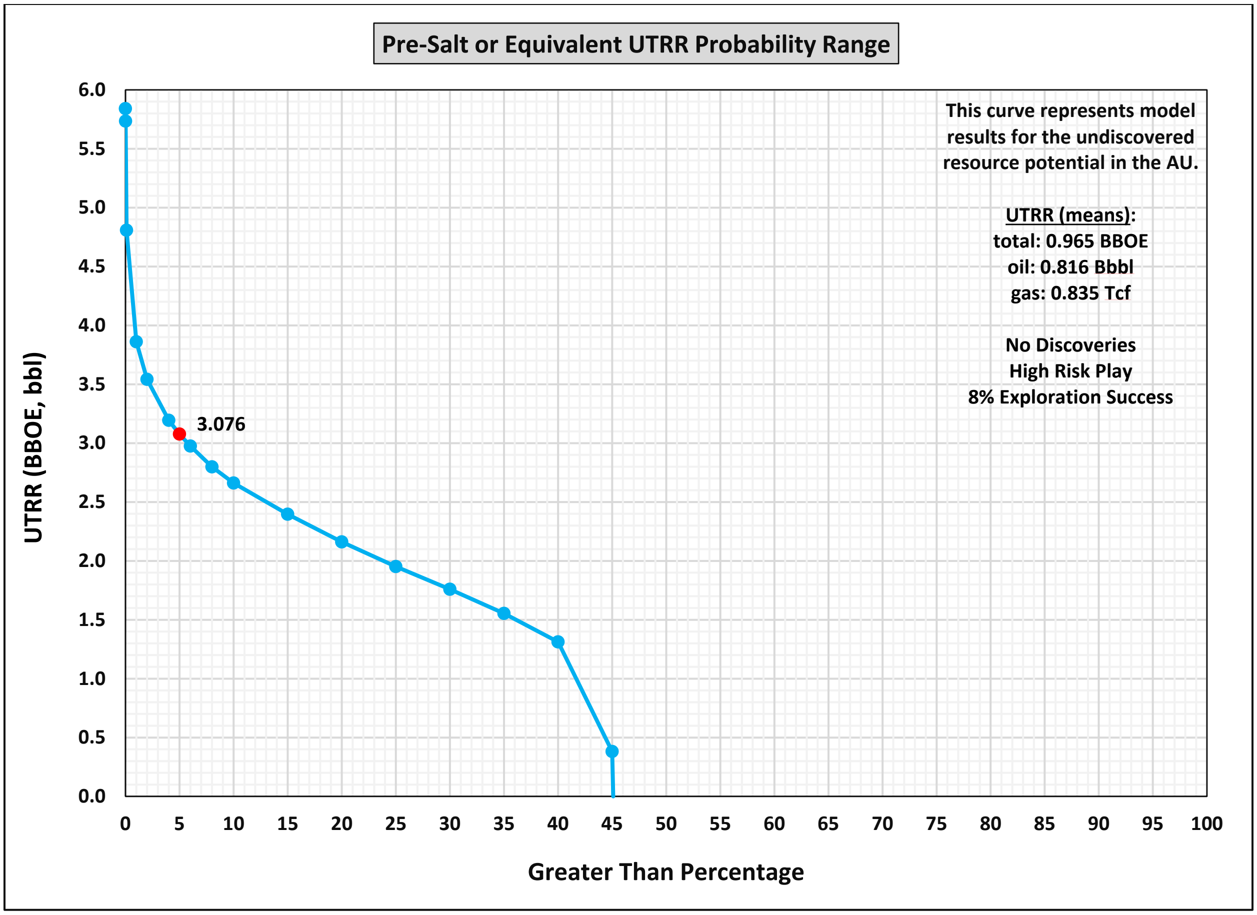

Figure 30. Pre-Salt or Equivalent UTRR probability range based on total BOE.

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 31**). The expanded geologic section is positioned stratigraphically immediately above the Louann Salt of Middle Jurassic age (Bajocian–Callovian) and below the basal Smackover Formation (Oxfordian) and is therefore postulated to be of late Callovian and/or 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 31**). To the southwest, the play limit is the edge of the underlying Mesozoic salt nappes (**Figure 23**), which 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 downdip into the Mesozoic salt nappes provided the accommodation for the exceptional thickness of post-Louann, pre-Smackover expanded Jurassic section.

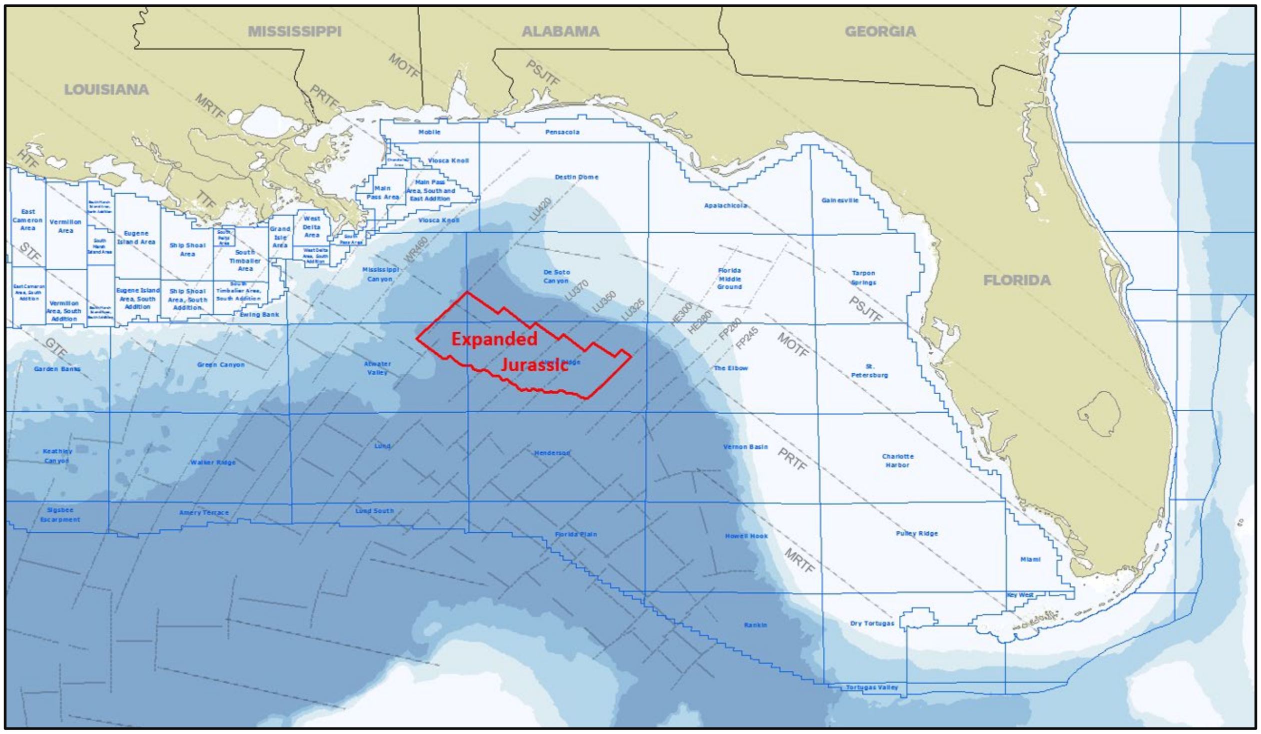

Figure 31. Expanded Jurassic location.

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 in the play 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 ±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 to 75 percent 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. A second well adjacent to the trend, Cheyenne, in Lloyd Ridge Block 399 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 require drilling depths in the range of 20,000 to 28,000 ft depending on location.

Risk

The highest risks for the Expanded Jurassic Play are the presence of mature source rocks and hydrocarbon migration from said source rocks to reservoir. However, the source bed potential of the Smackover Formation, the formation directly above this section, 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 Domaine (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. Due to sparse well information within the play, the presence and quality of reservoir rock of this age are relatively unknown.

For the play as a whole, the petroleum system chance of success of 34 percent (**Figure 3**). At the prospect level, the average conditional chance of success is 21 percent (**Figure 4**). This equates to an overall exploration chance of success of just 7 percent (**Figure 5**), making this play one of the riskiest evaluated. See Appendix A for details.

Undiscovered Resources

Available 3D seismic data in the GOM could be used to generate an inventory of 42 prospects over only 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 eight.

The pool-size distribution for this conceptual play was modeled with the seven Norphlet Slope discoveries in the deepwater GOM. These discoveries range in size from 0.246 to 322 MMBOE, with a mean size of 154 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 303 MMBOE.

The play was modeled as 100 percent oil. Based on GORs from the Norphlet Slope pools, GRASP returned UTRR volumes for black oil and solution gas. Because of the play-level petroleum system risk for the play, only 34 percent of the probabilistic trials in the assessment model returned successful case values. Assessment results indicate that undiscovered oil and gas resources are 1.559 Bbbl at the 5th percentile, with a mean of 0.369 Bbbl, and 1.121 Tcf at the 5th percentile, with a mean of 0.265 Tcf, respectively (**Table 9** and **Figure 32**). Total undiscovered BOE resources are 1.758 Bbbl at the 5th percentile, with a mean of 0.416 Bbbl (**Figure 33**). Based on mean-level undiscovered BOE resources, the play ranks 15th of all 30 GOM assessment units (**Figure 10**).

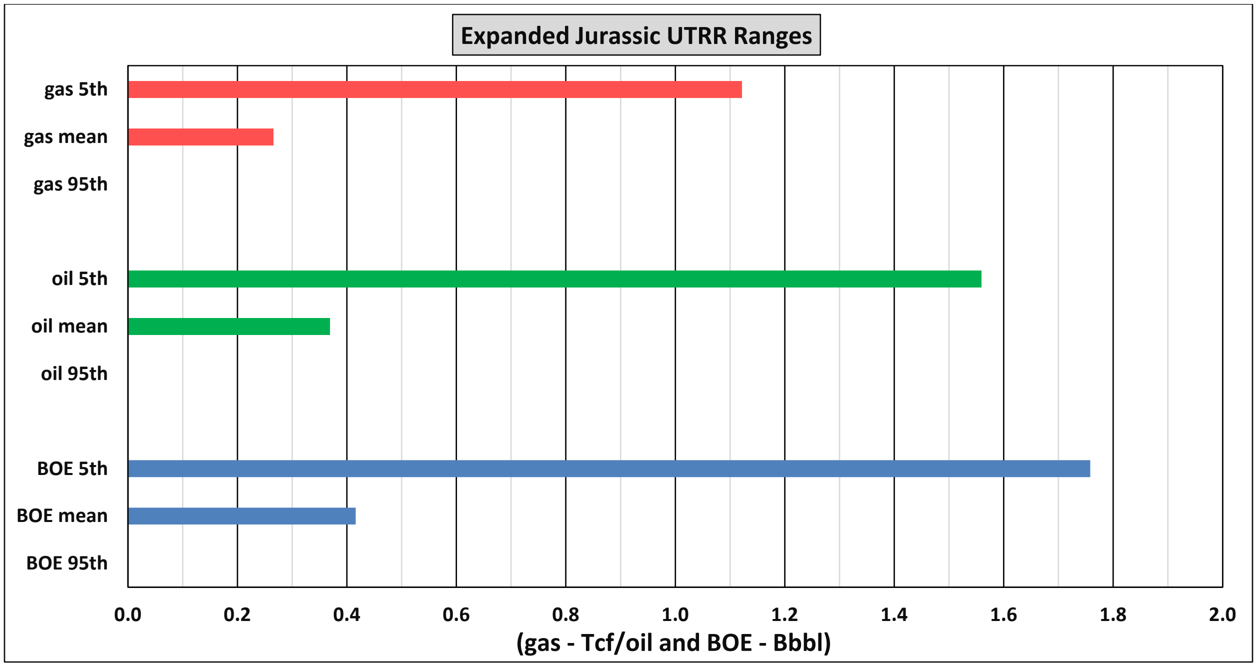

Figure 32. Expanded Jurassic gas, oil, and BOE UTRR ranges.

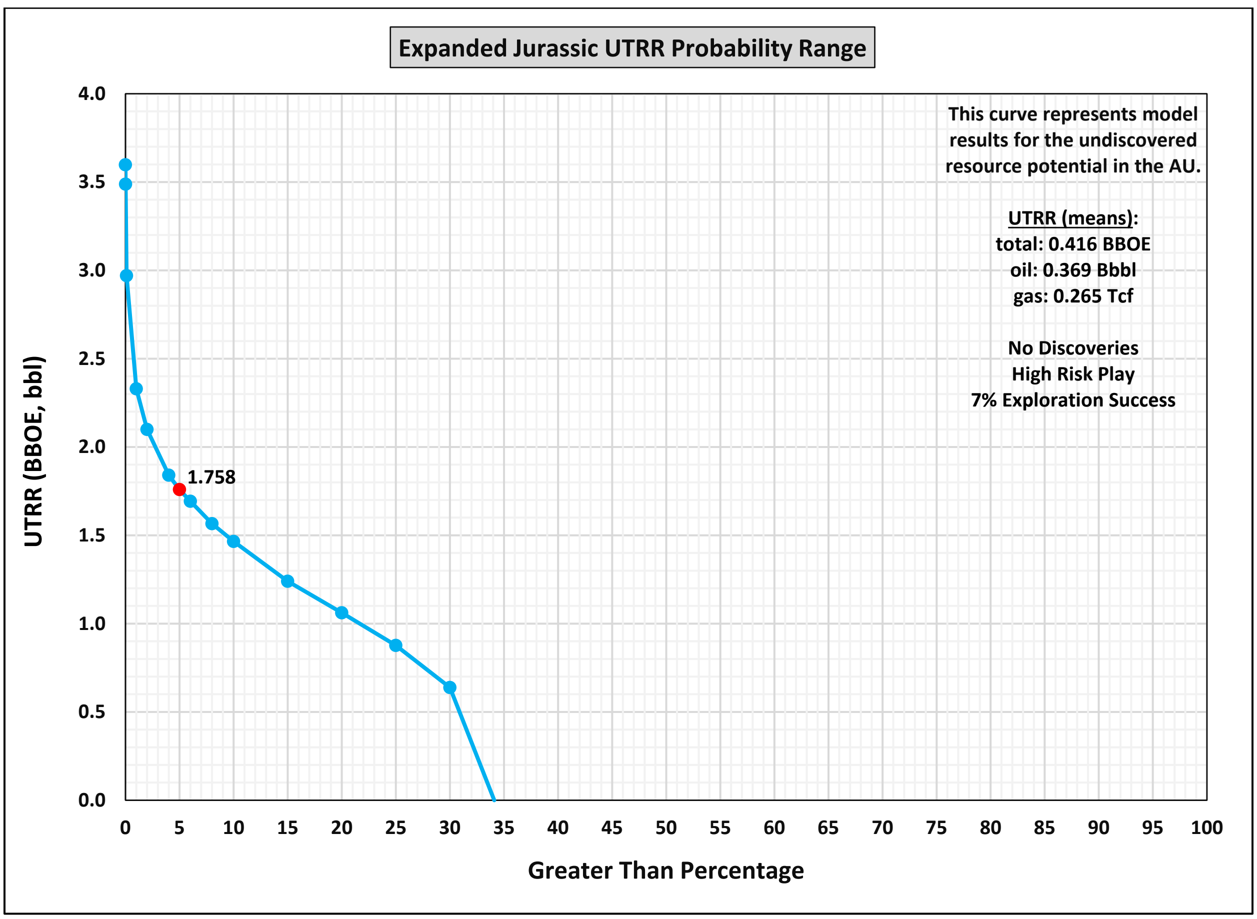

Figure 33. Expanded Jurassic UTRR probability range based on total BOE.

NORPHLET

The Upper Jurassic Norphlet Formation in the eastern GOM is defined by aeolian dune sediments deposited during the Oxfordian Stage (**Table 5** and **Figure 25**). Productive Norphlet reservoirs consist of aeolian dunes 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 34**).

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.

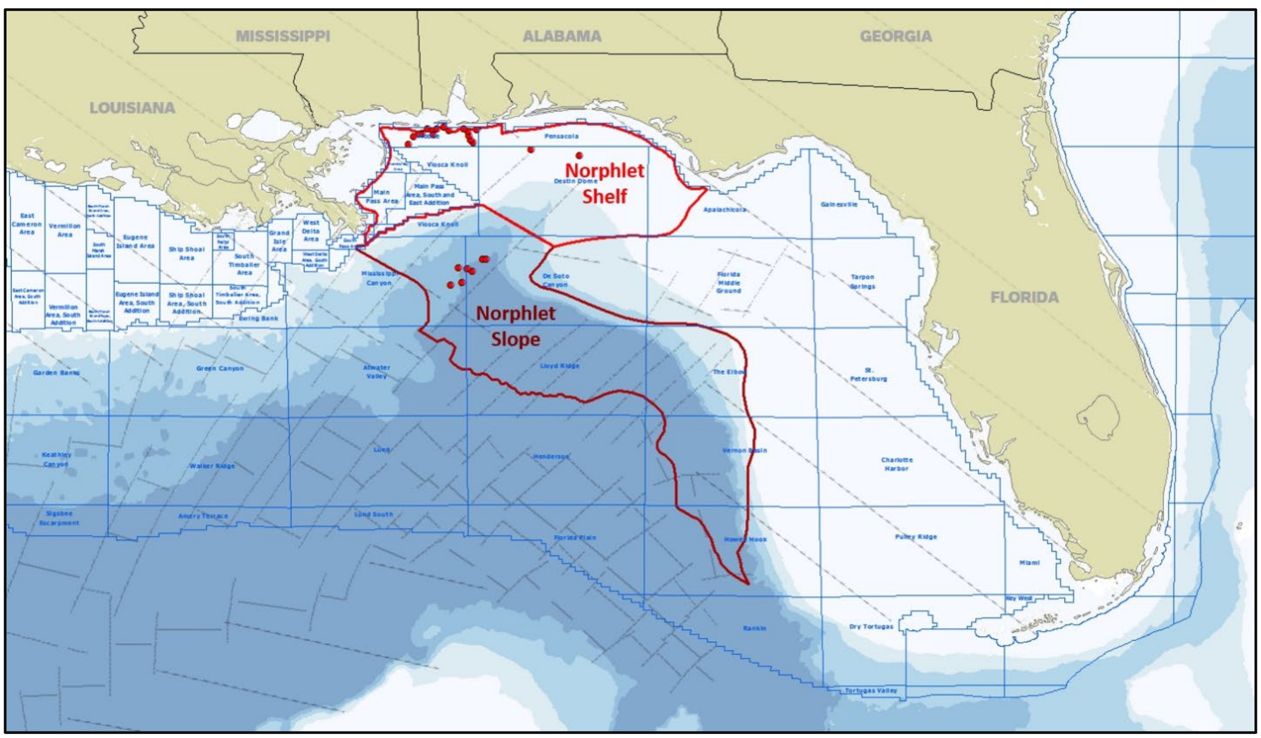

Figure 34. Norphlet Shelf and Slope locations and associated discovered pools.

Norphlet Shelf

Geology

The Norphlet Shelf AU references the modern shelf-slope break and is an offshore extension of an early onshore trend that was established around the northern Gulf rim in Texas, Louisiana, Mississippi, Alabama, and Florida between 1967 and 1980. The trend was extended into Alabama State Waters off Mobile Bay with the establishment of sour gas production in the 1980s and 1990s, and eventually into Federal waters of the Destin Dome and Pensacola Areas, where small discoveries were never commercialized because of a Federally mandated moratorium on drilling.

The Norphlet Shelf AU extends eastward across the Pensacola, Destin Dome, and western-most Apalachicola Areas, encompassing the De Soto Canyon Salt Basin (**Figure 34**). 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 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**).

For the Norphlet Shelf AU, 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 because of 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 GOM, 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

Discovered pools within the Norphlet Shelf have been discovered in the Mobile and Destin Dome Areas (**Figure 34**). As of the end of 2018, 18 hydrocarbon-bearing pools have been discovered, with discovery dates mainly in the 1980s (**Figure 35**). The Shelf AU is a gas play containing 3.464 Tcf (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 1983, Mobile 823 is the largest pool in the Shelf AU, containing an estimated 0.199 BBOE (**Figure 36**). 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 18,350 to 22,950 ft.

Figure 37 illustrates the pseudo-creaming curve for Norphlet Shelf pool discoveries superimposed on the number and size of the discoveries through time. With the last pool discovery sized at over 100 MMBOE occurring in 1988, the present-day curve is flat, indicative of a mature play with little resources being added.

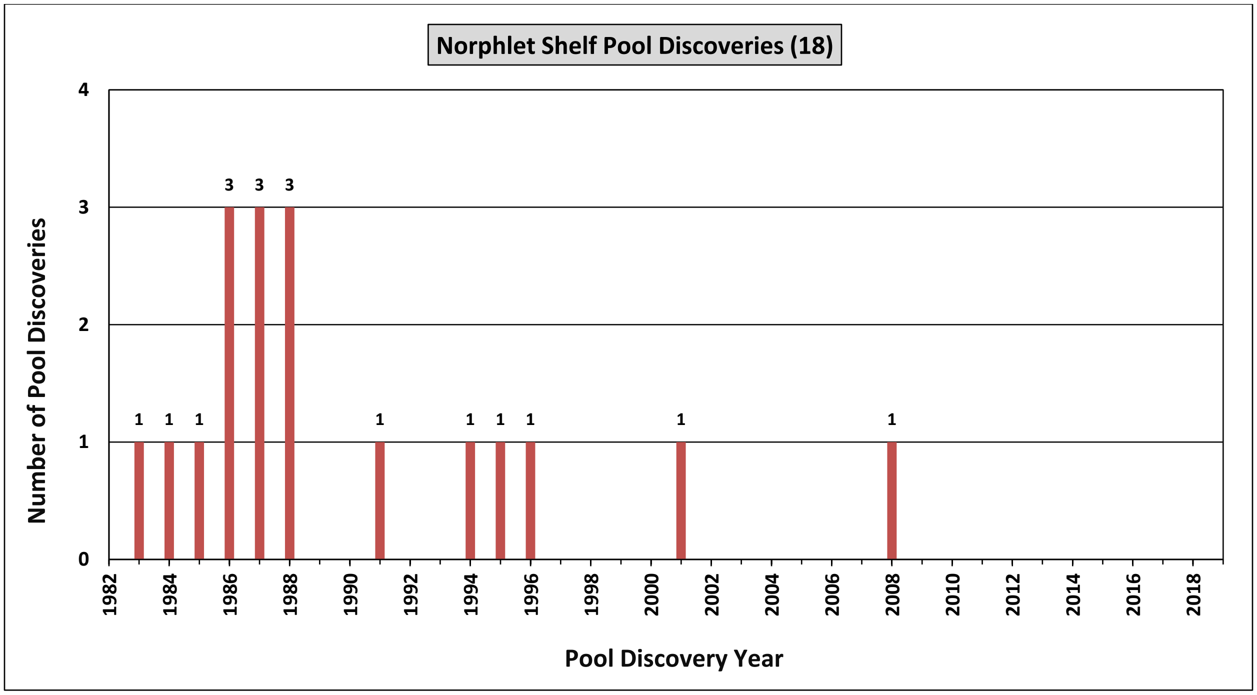

Figure 35. Norphlet Shelf pool discovery history.

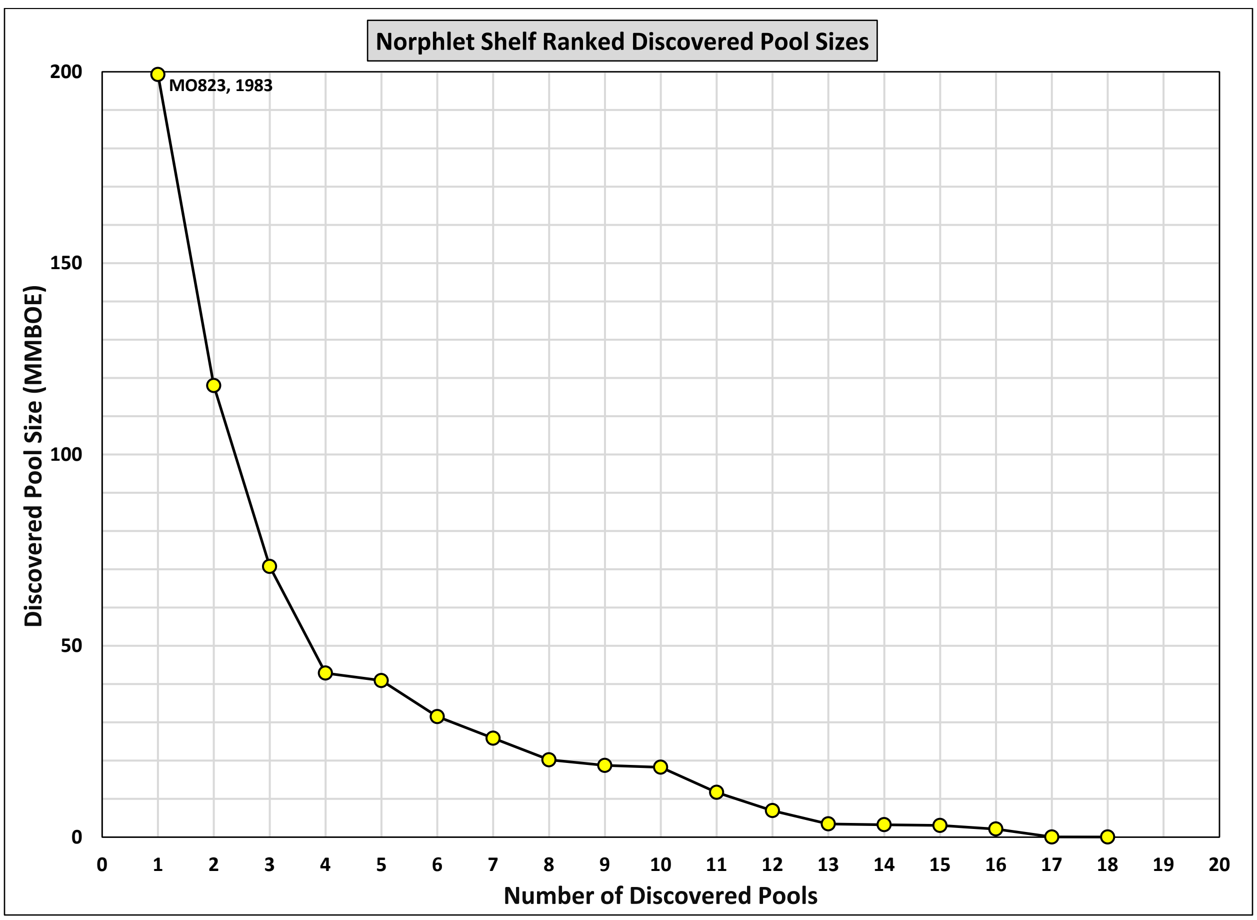

Figure 36. Norphlet Shelf discovered pool-rank plot.

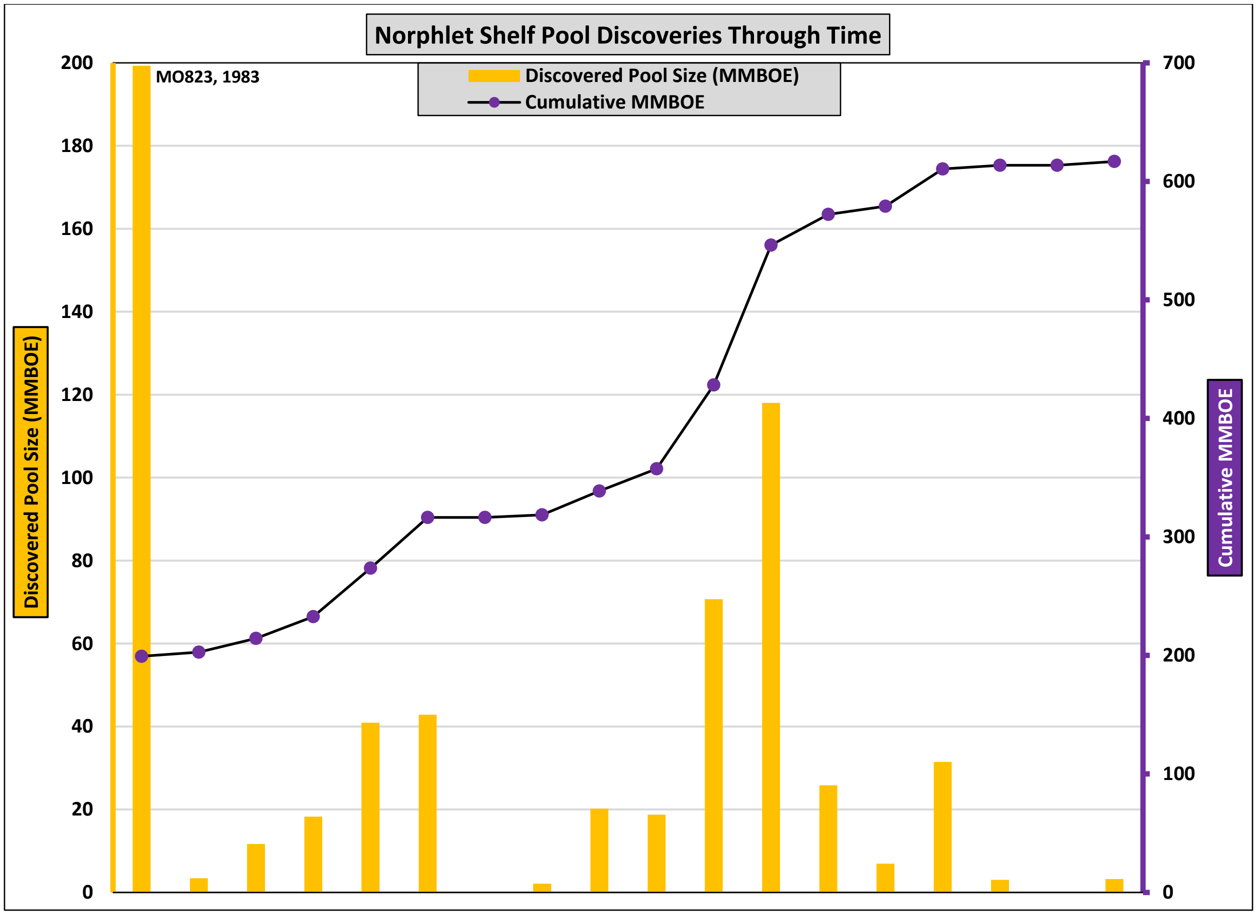

Figure 37. Norphlet Shelf pseudo-creaming curve.

Risk

Because an active petroleum system has clearly been established, there is no play-level risk (**Figure 3**). At the prospect level, the highest risk is reservoir quality, resulting in an average conditional prospect chance of success of 29 percent (**Figure 4**). This equates to an overall exploration chance of success of 29 percent (**Figure 5**). 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 AU. From this, the assessors determined that the number of prospects ranges from 50 to 110. Applying risk results in 15 to 35 undiscovered pools, with a mean of 25.

The pool-size distribution was modeled with the 18 discoveries in the AU. These pools range in size from 0.026 to 199 MMBOE, with a mean size of 34 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 119 MMBOE.

From the discovered data information, the play was modeled as 100 percent gas, with GRASP returning UTRR volumes for dry gas and small amounts of condensate. Assessment results indicate that undiscovered gas resources range from 1.646 to 6.322 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 38**). Total BOE undiscovered resources range from 0.293 to 1.126 Bbbl at the 95th and 5th percentiles, respectively (**Figure 39**). Of all 30 assessment units in this study, the Norphlet Shelf ranks 11th based on mean-level undiscovered BOE resources (**Figure 10**).

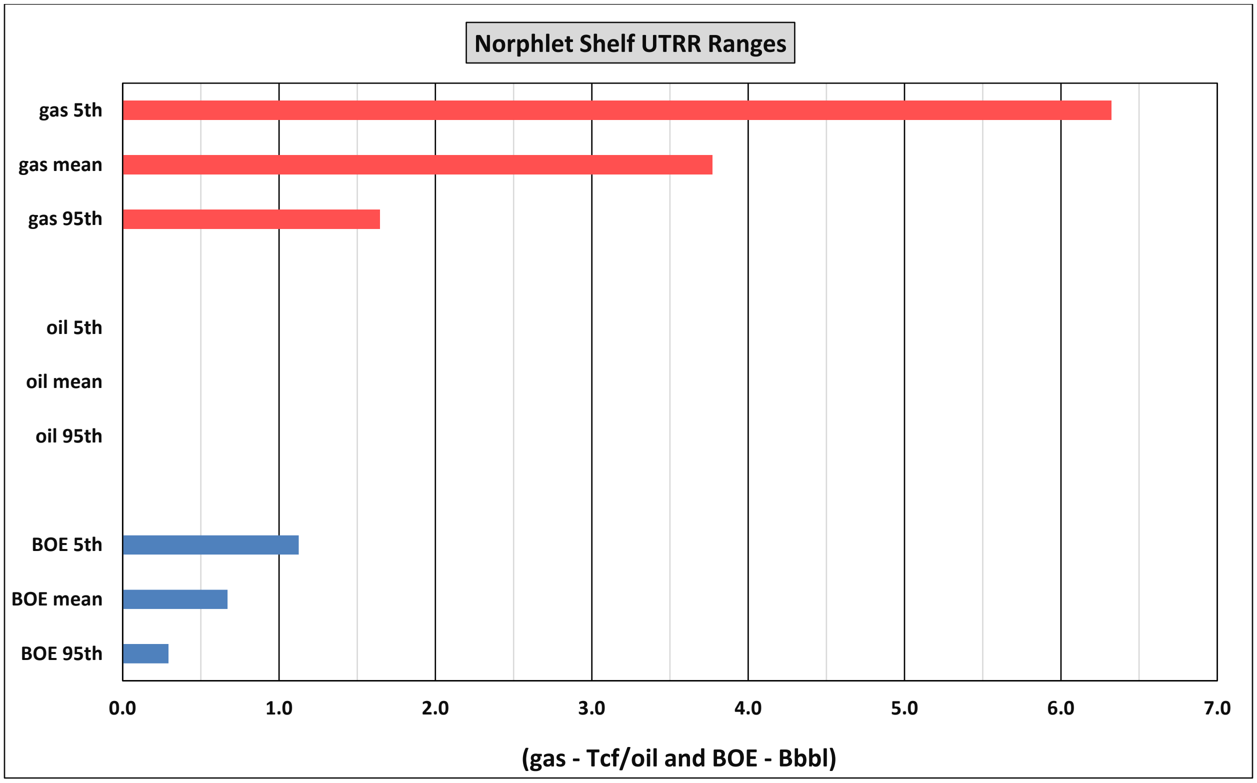

Figure 38. Norphlet Shelf gas, oil, and BOE UTRR ranges.

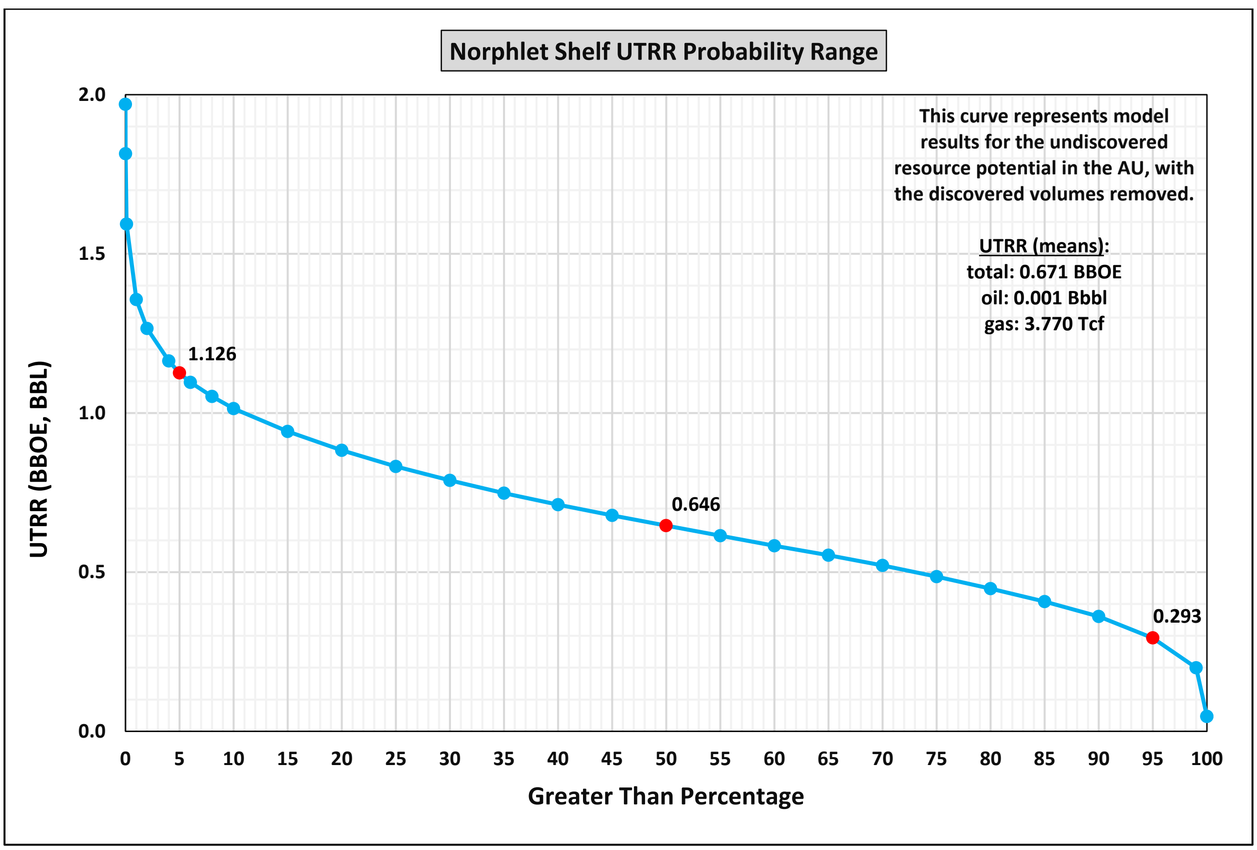

Figure 39. Norphlet Shelf UTRR probability range based on total BOE.

Norphlet Slope

Geology

The Norphlet Slope AU is located basinward of the modern shelf-slope break in the Eastern and Central GOM Planning Areas (**Figure 34**). 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 play boundary generally follows the modern Florida Escarpment. To the southwest, the play boundary is coincident 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. It should be noted that there have been discoveries in Mexican waters of the southern-most GOM 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 paleo-geographic 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 Norphlet Slope 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. 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, p 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

Hydrocarbon-bearing pools within the Norphlet Slope have been discovered in the Mississippi Canyon and De Soto Canyon Areas (**Figure 34**). As of the end of 2018, BOEM has estimated sizes of seven pools (**Figure 40**). The slope AU is an oil play containing 0.955 Bbbl of oil and 0.687 Tcf of solution gas (total BOE of 1.077 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. The largest discoveries in the play, Mississippi Canyon 392 (Appomattox) and Mississippi Canyon 522 (Fort Sumter), are both estimated to contain more than 300 MMBOE (**Figure 41**). Pools have been discovered in water depths ranging from 6,830 ft in the

Mississippi Canyon Area to 7,579 ft in the De Soto Canyon Area. Subsea depths of the discovered pools range from 23,207 to 27,773 ft.

Figure 42 illustrates the pseudo-creaming curve for Norphlet Slope pool discoveries superimposed on the number and size of the discoveries through time. Only seven BOEM-designated discoveries so far and a climbing cumulative volume are indicative of an immature play in exploration phase.

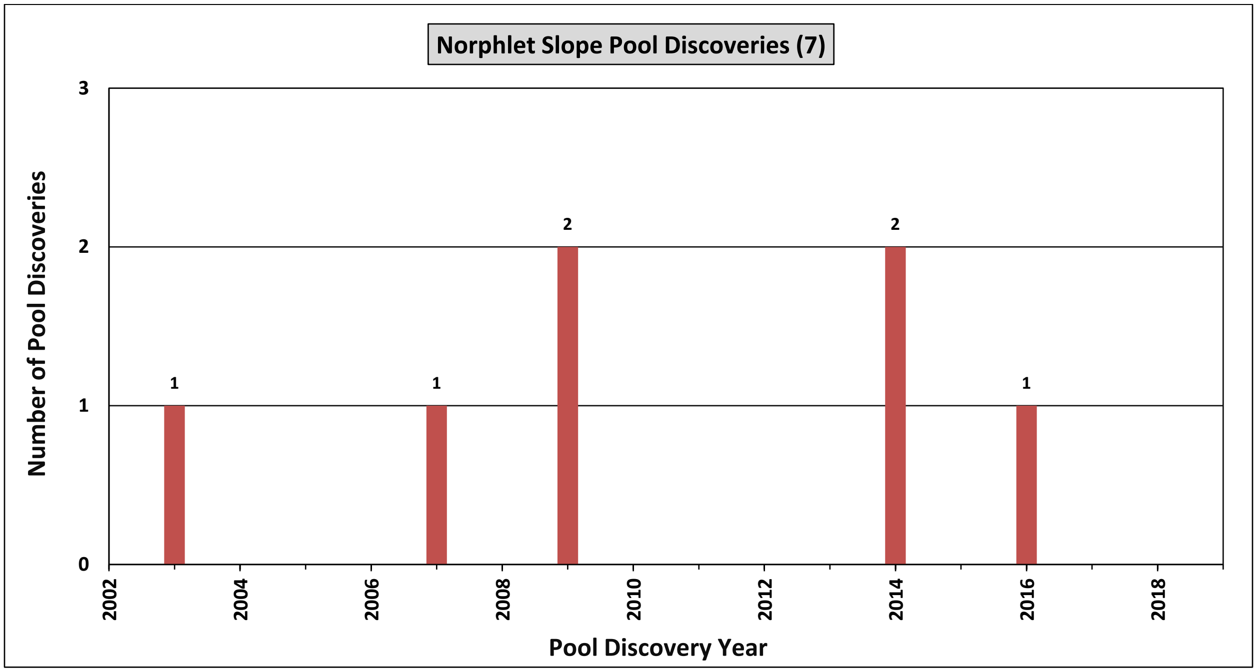

Figure 40. Norphlet Slope pool discovery history.

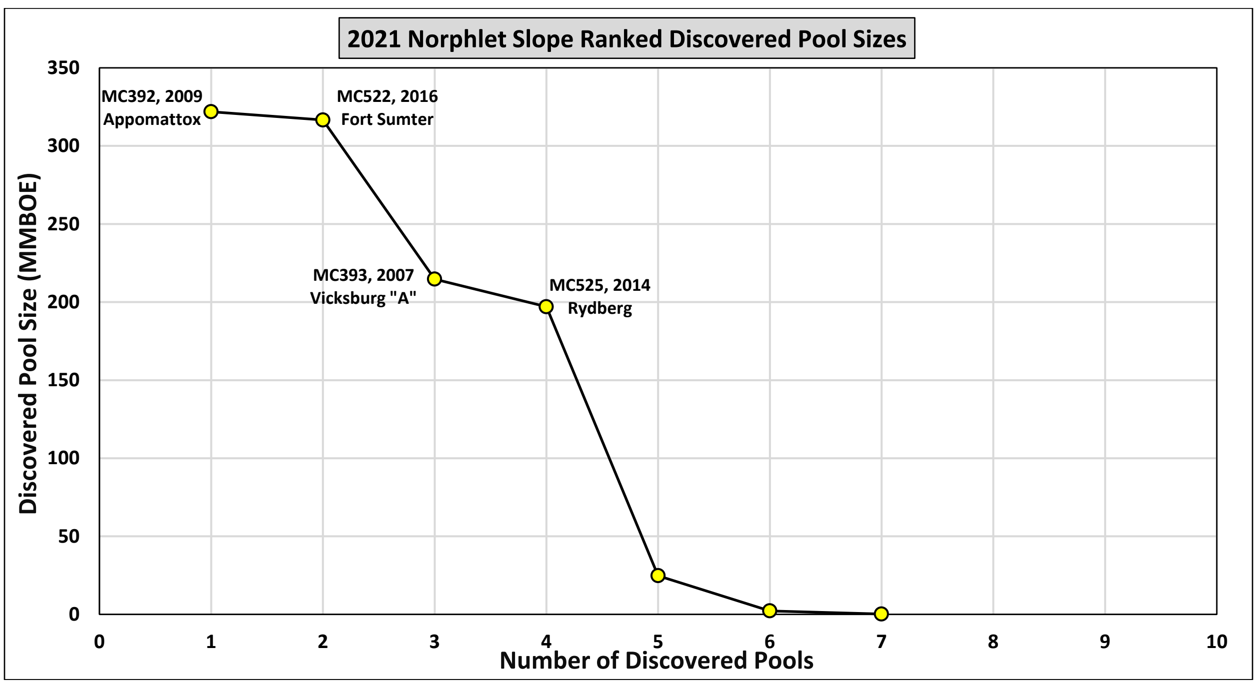

Figure 41. Norphlet Slope discovered pool-rank plot.

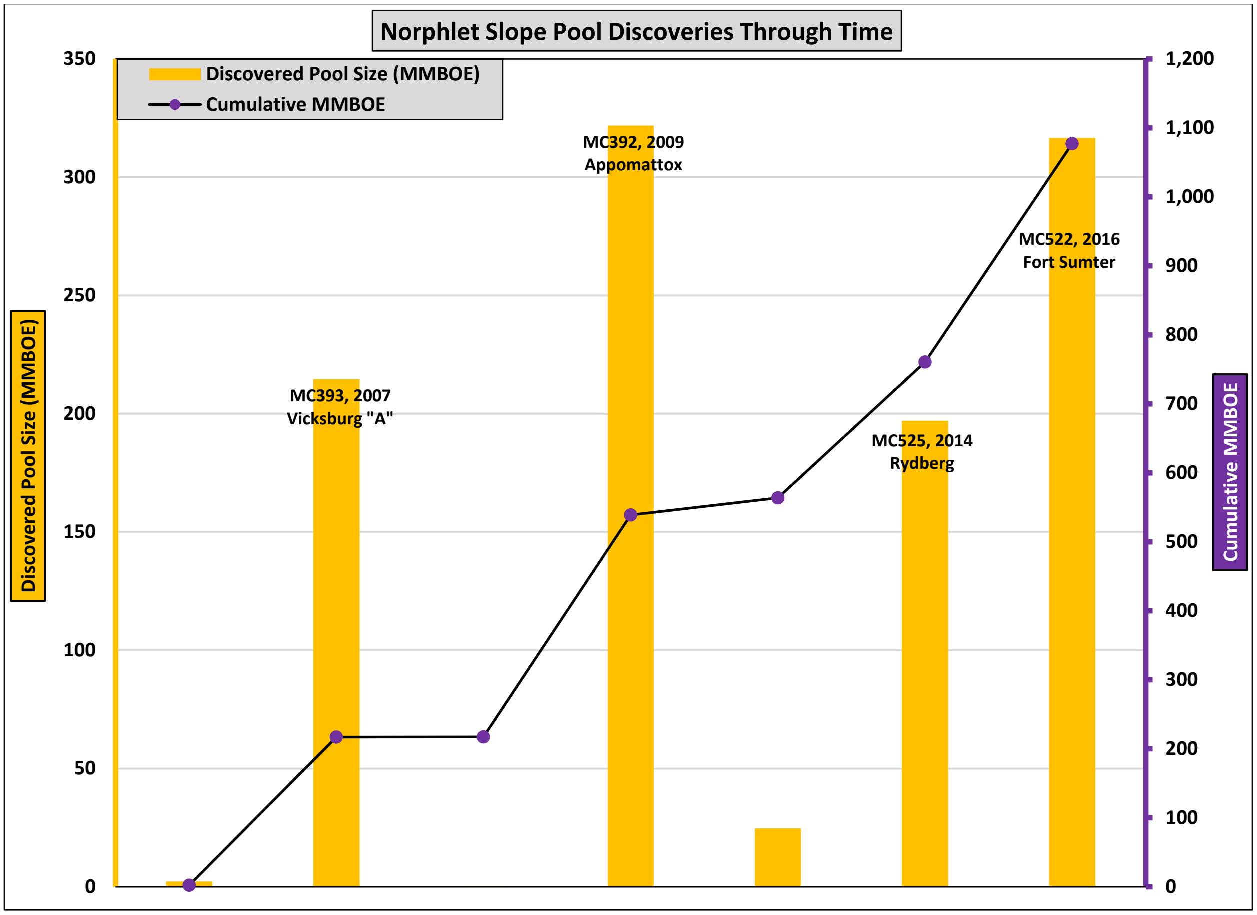

Figure 42. Norphlet Slope pseudo-creaming curve.

Risk

Because an active petroleum system has clearly been established in the deepwater Norphlet, there is no play-level risk (**Figure 3**). At the prospect level, the highest risks are reservoir quality and hydrocarbon expulsion and migration, resulting in an average conditional prospect chance of success of 21 percent (**Figure 4**). This equates to an overall exploration chance of success of 21 percent (**Figure 5**). 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 that the number of prospects ranges from 240 to 540. Applying risk results in 50 to 110 undiscovered pools, with a mean of 80.

The pool-size distribution was modeled with the seven discoveries in the AU. These pools range in size from 0.246 to 322 MMBOE, with a mean size of 154 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 382 MMBOE. In fact, based on the large areal extent of the play, prospect mapping, and rafted blocks of self-contained Norphlet reservoir and Smackover source bed providing structural constraints, BOEM has modeled several undiscovered pools to be analogous in size to the largest discoveries.

From the discovered data information, the play was modeled as 100 percent oil, with GRASP returning UTRR volumes for black oil and solution gas. Assessment results indicate that undiscovered oil resources range from 1.745 to 5.152 Bbbl, and undiscovered gas resources range from 1.255 to 3.705 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 43**). Total BOE undiscovered resources range from 1.969 to 5.812 Bbbl at the 95th and 5th percentiles, respectively (**Figure 44**). Of all 30 assessment units in this study, the Norphlet Slope ranks 5th based on mean-level undiscovered BOE resources (**Figure 10**), and is the highest ranking Mesozoic play in the GOM.

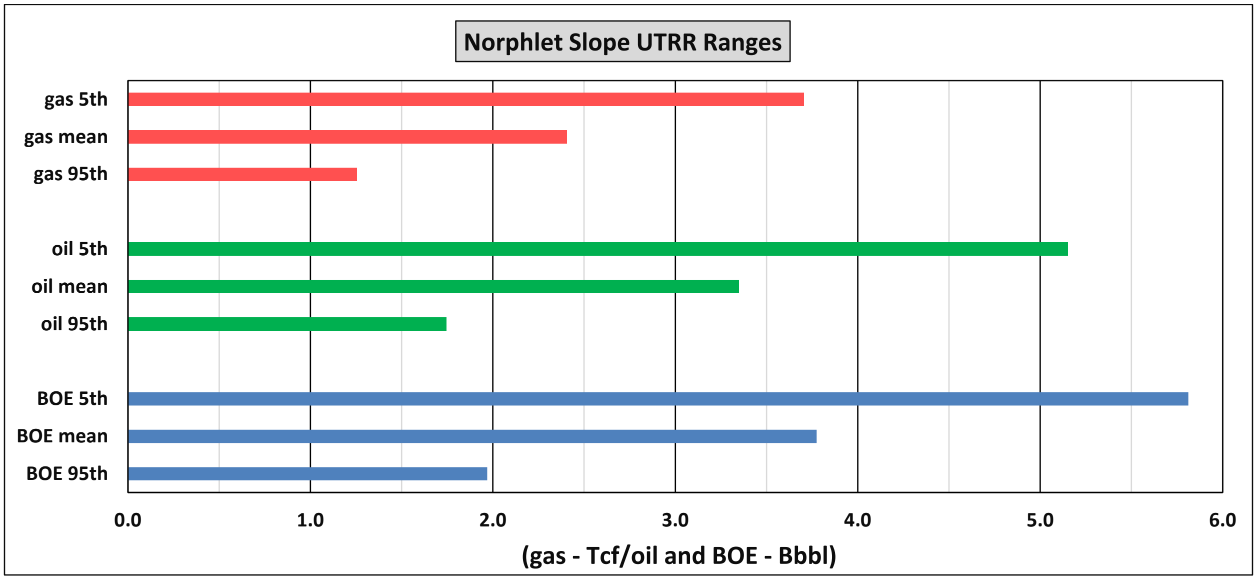

Figure 43. Norphlet Slope gas, oil, and BOE UTRR ranges.

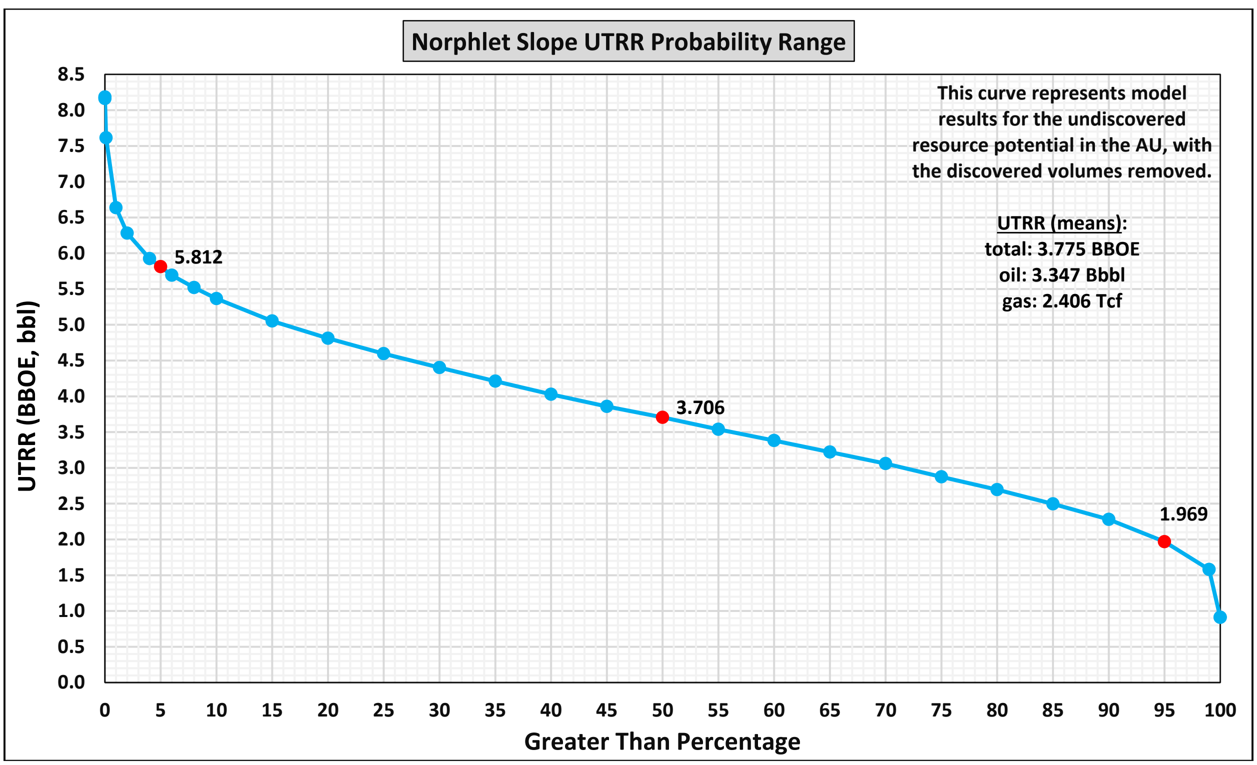

Figure 44. Norphlet Slope UTRR probability range based on total BOE.

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 seal level high-stand across the northern rim of the GOM. 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 45**). The play consists of algal buildups or "thrombolite" reservoirs over positive basement highs on the nearshore shelf and across the Southern Platform (Petty, 2010) and 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 calculated oil pay proving the existence of an active petroleum system. 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.

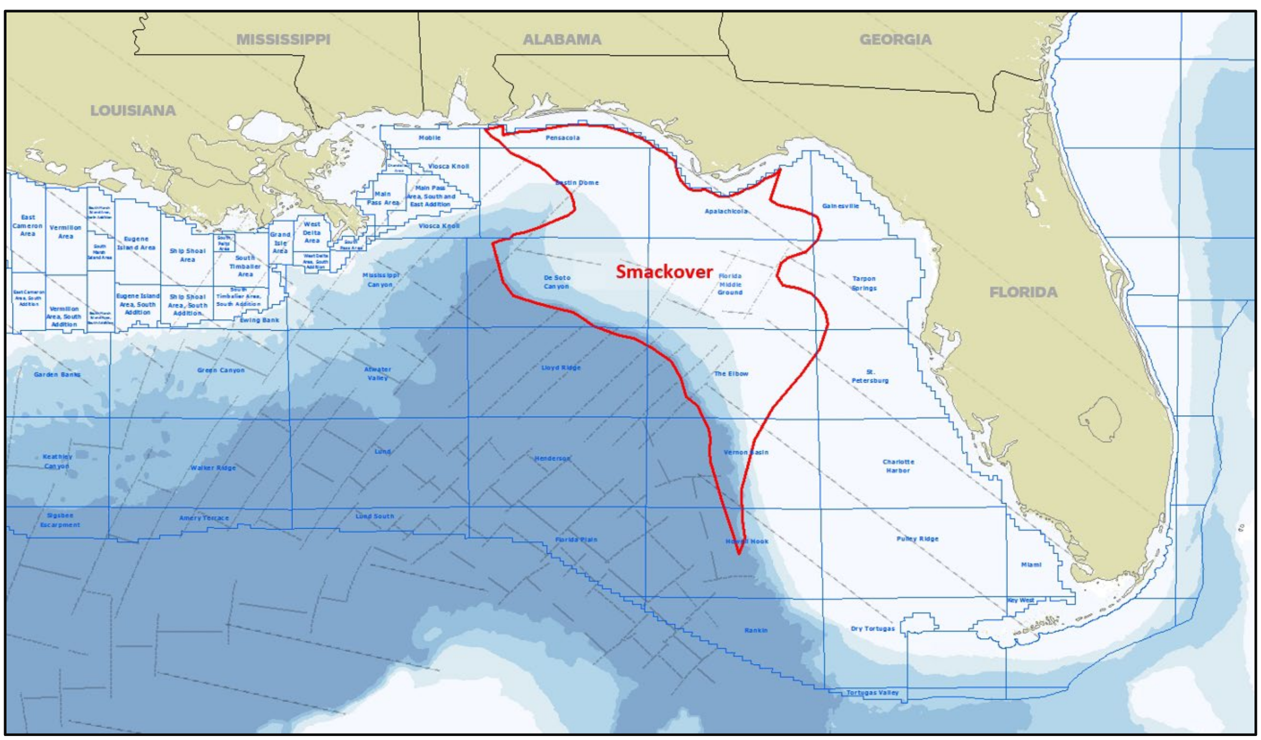

Figure 45. Smackover location.

Onshore, reservoirs in the upper Smackover section consists 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 in the offshore (Pashin et al., 2016; Petty, 2010).

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).

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 (Pashin et al., 2016; Pilcher, 2014). 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

Because (1) of a long history of onshore production from Smackover reservoir facies and examples of these facies in offshore 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 risks are reservoir quality and effective seal mechanisms, resulting in an average conditional prospect chance of success of 25 percent (**Figure 4**). This equates to an overall exploration chance of success of 25 percent (**Figure 5**). See Appendix A for details.

Undiscovered Resources

Two sub-populations of prospects, grainstone shoals and thrombolite buildups, were modeled for this conceptual 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 offshore 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 AU. 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. From this maximum of 764 prospects, the assessors determined that the number of prospects ranges from 200 to 750. Applying risk results in 28 to 233 undiscovered pools, with a mean of 119.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 106 onshore Gulf Coast Smackover discoveries (**Figure 46**). These discoveries range in size from 0.007 to 518 MMBOE, with a mean size of 10 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 512 MMBOE.

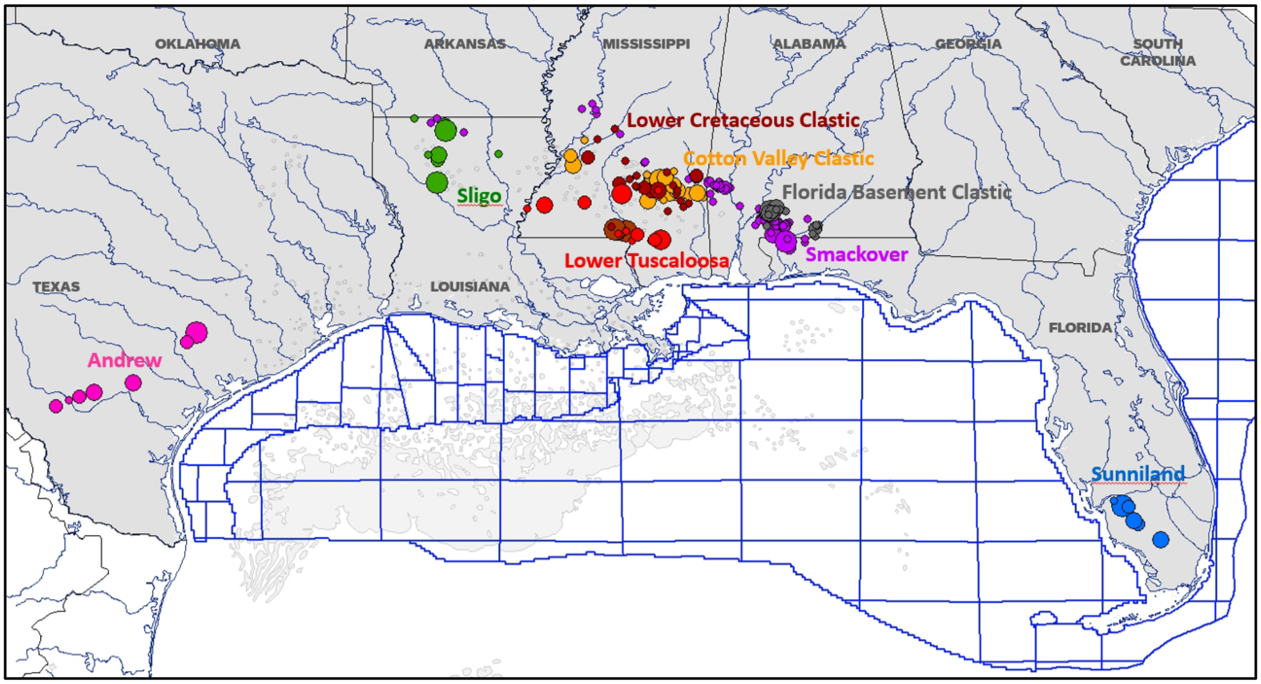

Figure 46. Onshore Gulf Coast discoveries used for analog pool sizes in the Federal OCS.

The play was modeled as 50 percent oil and 50 percent gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOM 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 0.244 to 1.621 Bbbl, and undiscovered gas resources range from 1.542 to 11.510 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 47**). Total BOE undiscovered resources range from 0.519 to 3.669 Bbbl at the 95th and 5th percentiles, respectively (**Figure 48**). Of all 30 assessment units in this study, the Smackover Play ranks 6th based on mean-level undiscovered BOE resources (**Figure 10**).

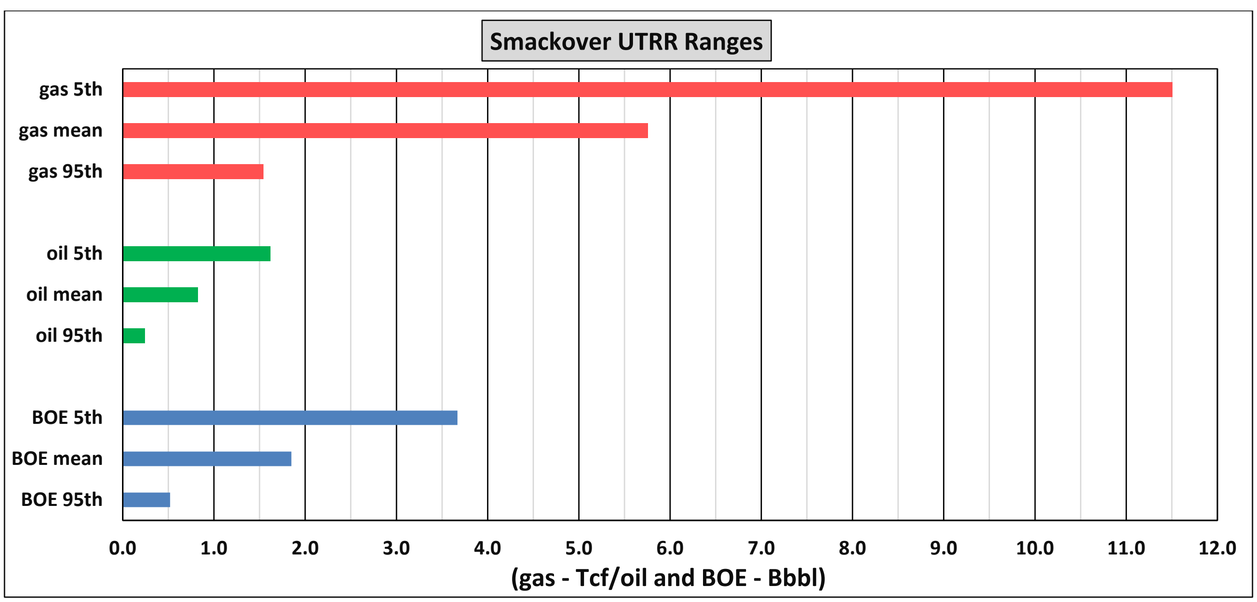

Figure 47. Smackover gas, oil, and BOE UTRR ranges.

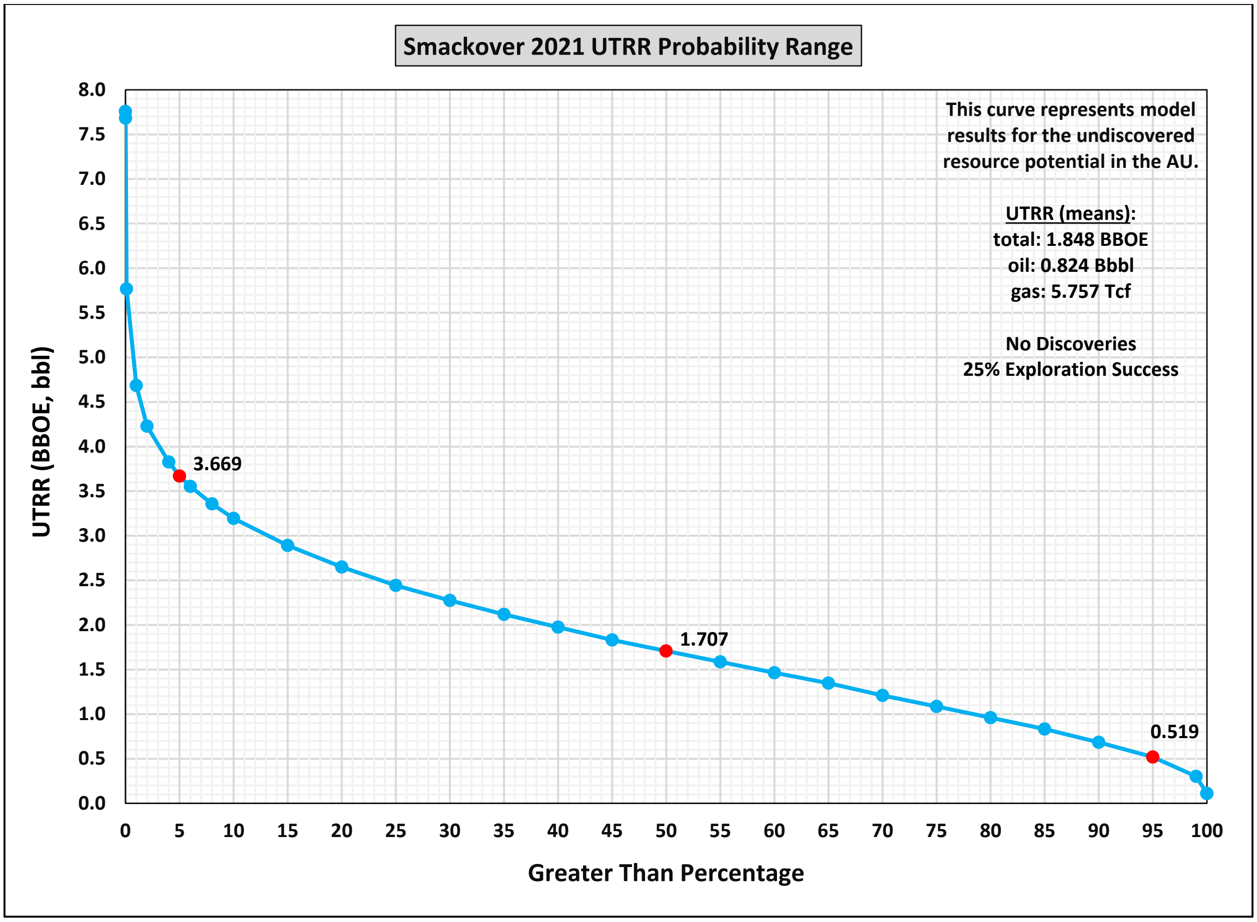

Figure 48. Smackover UTRR probability range based on total BOE.

FLORIDA BASEMENT CLASTIC

Geology

The Florida Basement Clastic Play (**Figure 49**) 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. 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, conglomeritic, 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).

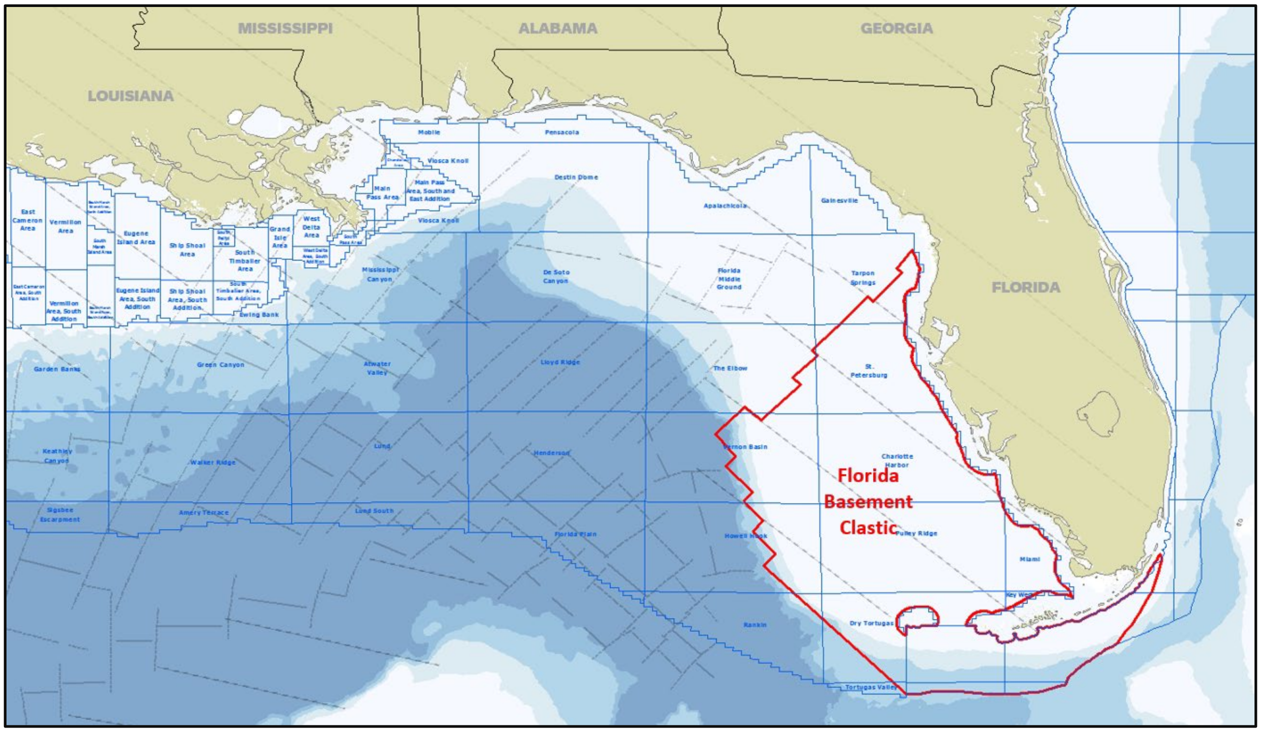

Figure 49. Florida Basement Clastic location.

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. Source rock maturity in the area of the play is demonstrated by produced oil in the South Florida Basin, though maturity is likely to diminish onto the Sarasota Arch, given the relatively shallow burial depths.

Risk

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 in the play carries the least risk. The weakest element of the trap is the presence of a top seal. These factors result in a petroleum system chance of success of 34 percent (**Figure 3**), and an average conditional prospect chance of success of 22 percent (**Figure 4**). This equates to an overall exploration chance of success of just 7 percent (**Figure 5**), making the Florida Basement Clastic one of the riskiest plays in this study. 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 62 undiscovered pools, with a mean of nine.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 21 onshore Frisco City Trend discoveries in southern Alabama (**Figure 46**). These discoveries range in size from 0.004 to 20 MMBOE, with a mean size of 2 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 24 MMBOE.

The play was modeled as 100 percent 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 of the play-level petroleum system risk for the play, only 34 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil and gas resources are 0.095 Bbbl at the 5th percentile, with a mean of 0.021 Bbbl, and 0.118 Tcf at the 5th percentile, with a mean of 0.025 Tcf, respectively (**Table 9** and **Figure 50**). Total undiscovered BOE resources are 0.116 Bbbl at the 5th percentile, with a mean of 0.025 Bbbl (**Figure 51**). Based on mean-level undiscovered BOE resources, the play ranks last of all 30 GOM assessment units (**Figure 10**).

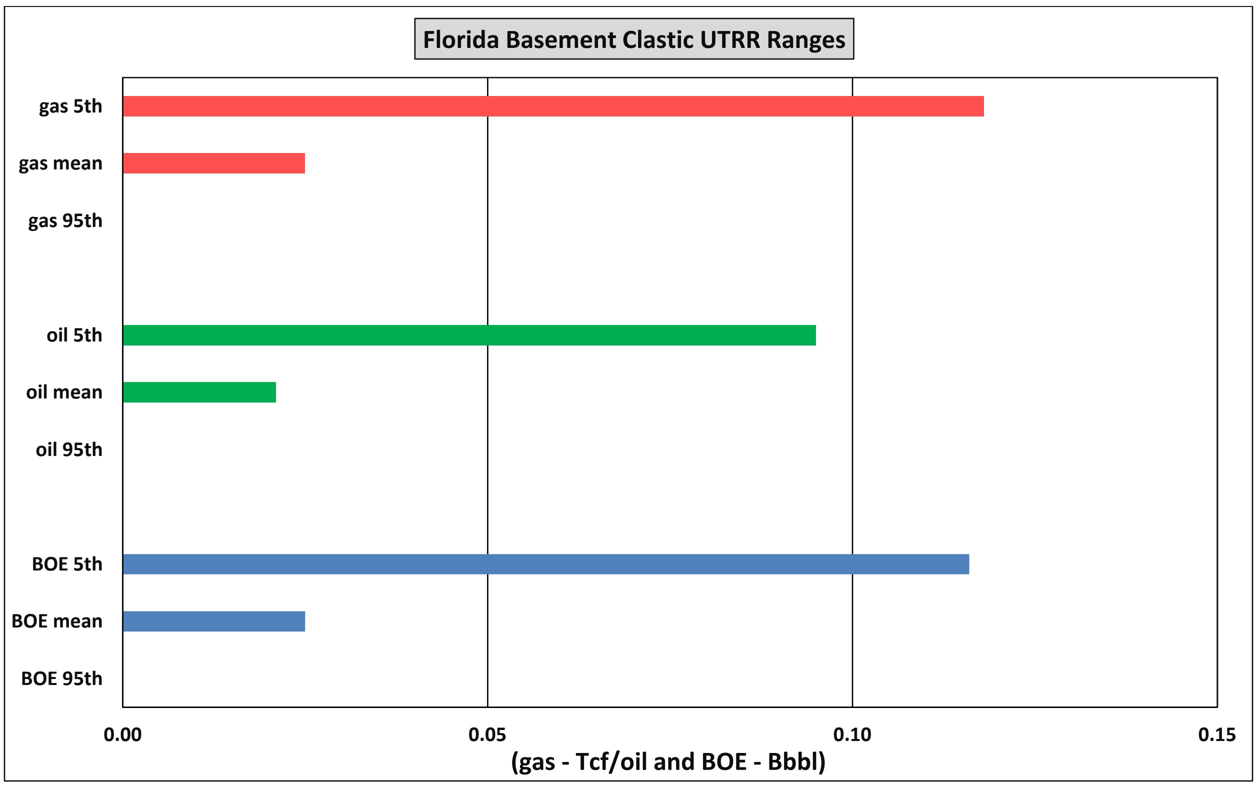

Figure 50. Florida Basement Clastic gas, oil, and BOE UTRR ranges.

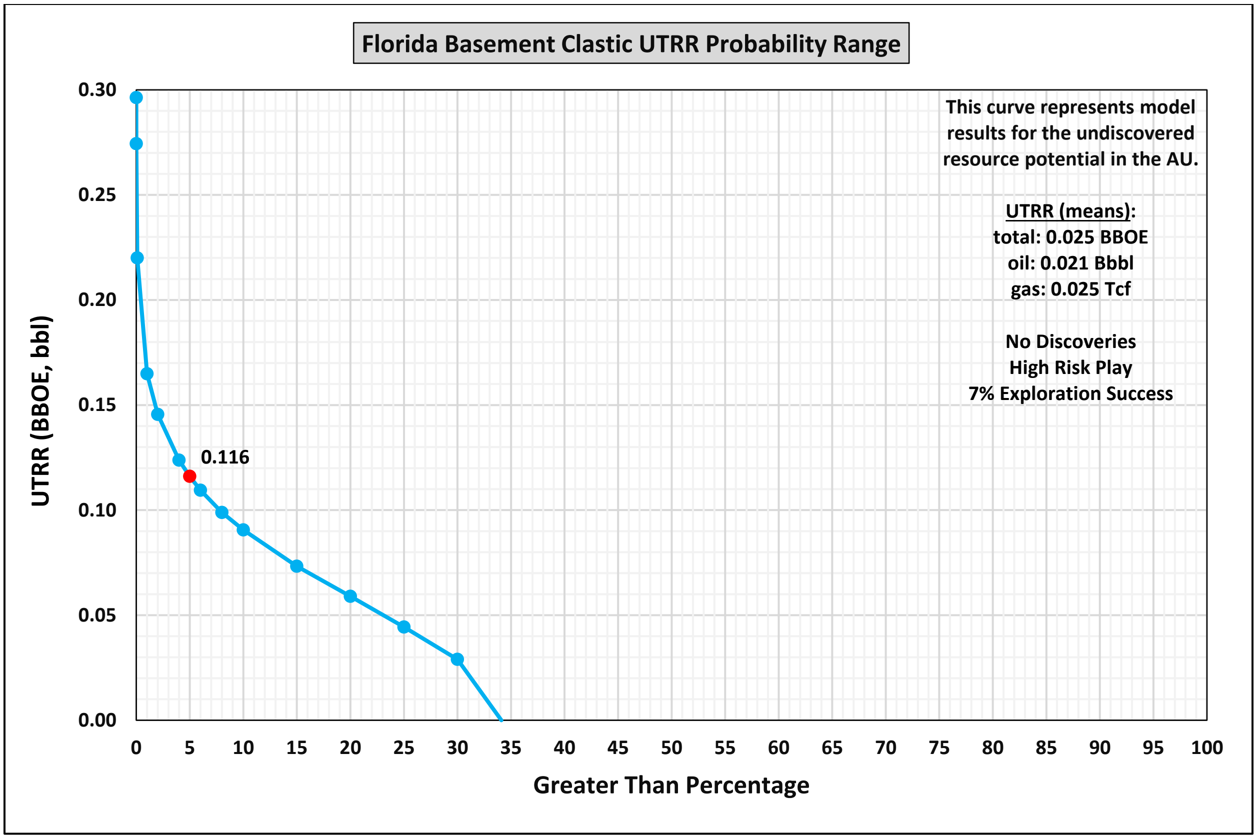

Figure 51. Florida Basement Clastic UTRR probability range based on total BOE.

Cotton Valley Clastic

The Cotton Valley Clastic Shelf and Slope AUs target the Upper Jurassic (Tithonian) to Lower Cretaceous (Berriasian) Cotton Valley Group (**Table 5** and **Figure 25**), which include 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 GOM from east Texas to Alabama. The Shelf and Slope AUs are delineated by the modern shelf-slope break (**Figure 52**).

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 Federal OCS, two wells in Federal waters demonstrate that there is a working hydrocarbon system in place, and that additional hydrocarbon exploration in the Federal OCS within the Cotton Valley Clastic AUs 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 percent (Cunningham et al., 2016), there is a high probability of the presence of source rocks for the offshore Cotton Valley Clastic AUs.

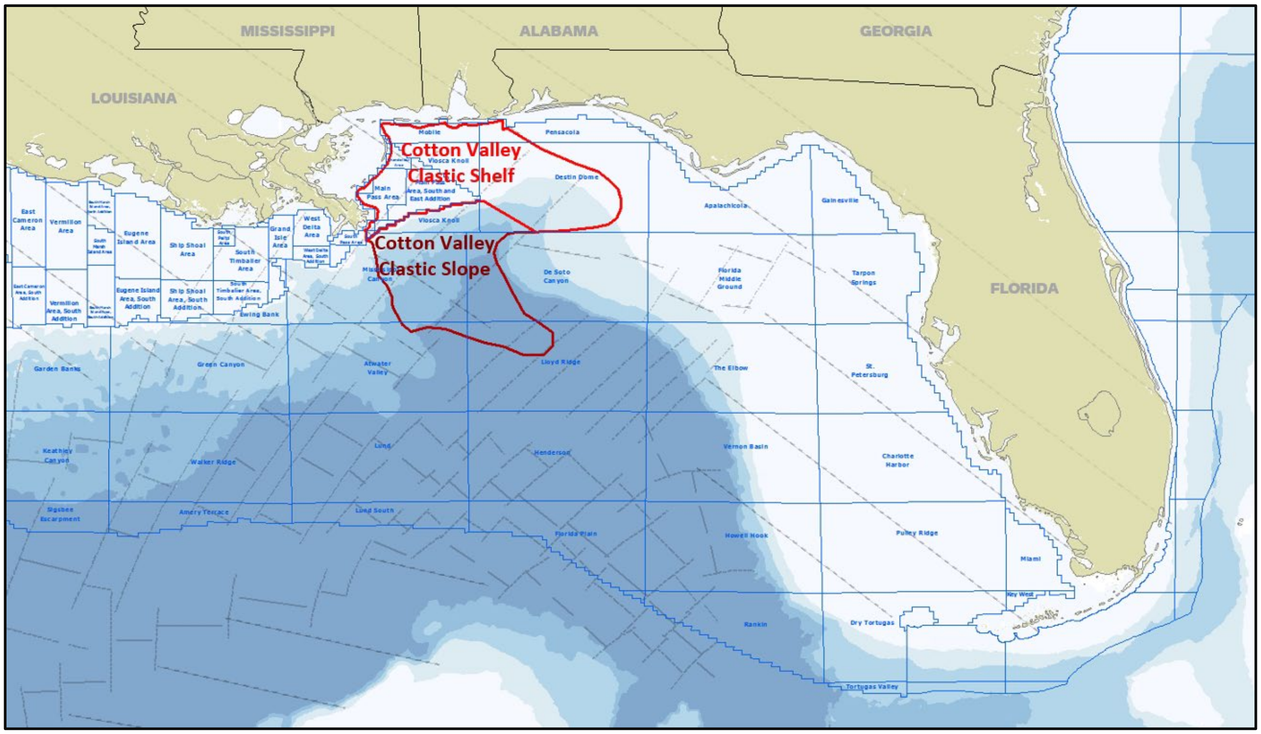

Figure 52. Cotton Valley Clastic Shelf and Slope locations.

Cotton Valley Clastic Shelf

Geology

The Cotton Valley Clastic Shelf AU 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 52**).

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 and Jones, 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 Cotton Valley Clastic Shelf AU to be reworked in a shallow shelf-edge environment.

Clastics of the Shelf AU 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 in the Shelf AU 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

(Pashin et al., 2016; Pilcher et al., 2014), 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 to 6.7 percent (Thomas and Jones, 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 in the Shelf AU are described as silty, fine-to-coarse grained quartz sandstones with porosity values of 13 to 18 percent and permeability values of 2 to 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

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 the reservoir component, resulting in an average conditional prospect chance of success of 21 percent (**Figure 4**). This equates to an overall exploration chance of success of 21 percent (**Figure 5**). 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 offshore, the pool-size distribution for this play was modeled with 43 Cotton Valley discoveries in onshore Mississippi (**Figure 46**). These discoveries range in size from 0.011 to 36 MMBOE, with a mean size of 2 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 19 MMBOE.

The play was modeled as 50 percent oil and 50 percent gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOM 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 0.002 to 0.038 Bbbl, and undiscovered gas resources range from 0.015 to 0.323 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 53**). Total BOE undiscovered resources range from 0.005 to 0.096 Bbbl at the 95th and 5th percentiles, respectively (**Figure 54**). Of all 30 assessment units in this study, the Cotton Valley Clastic Shelf ranks 28th based on mean-level undiscovered BOE resources (**Figure 10**).

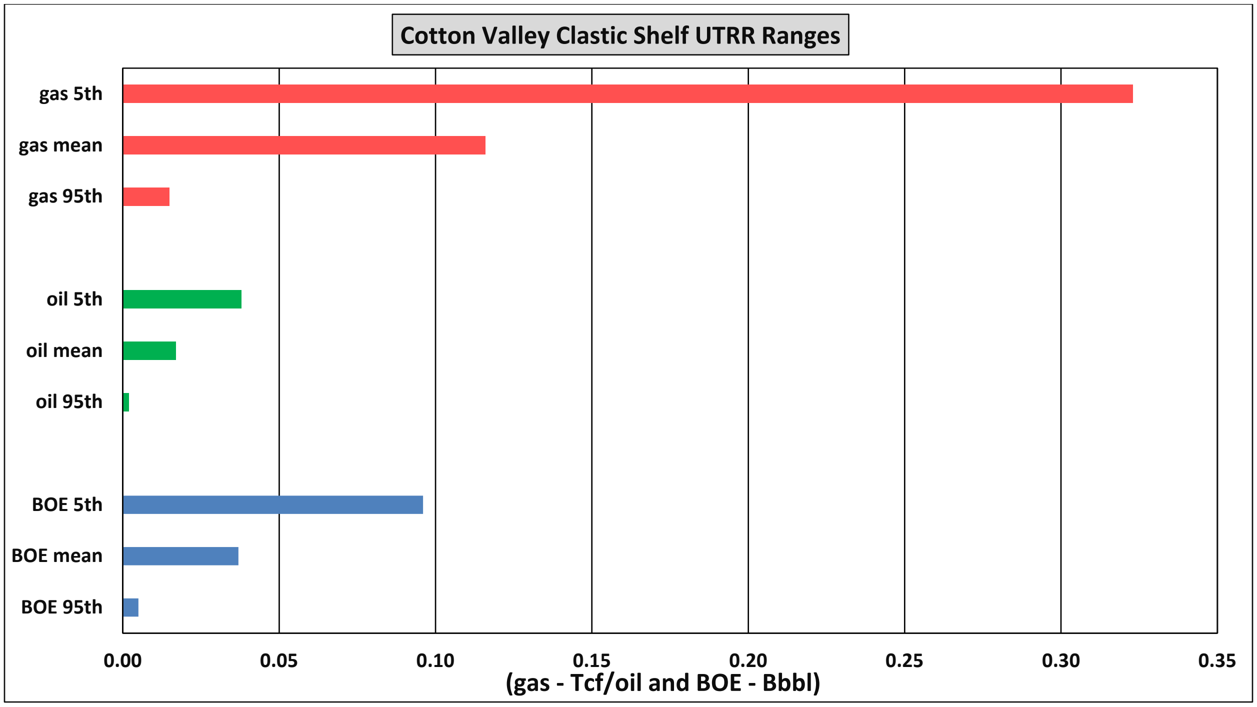

Figure 53. Cotton Valley Clastic Shelf gas, oil, and BOE UTRR ranges.

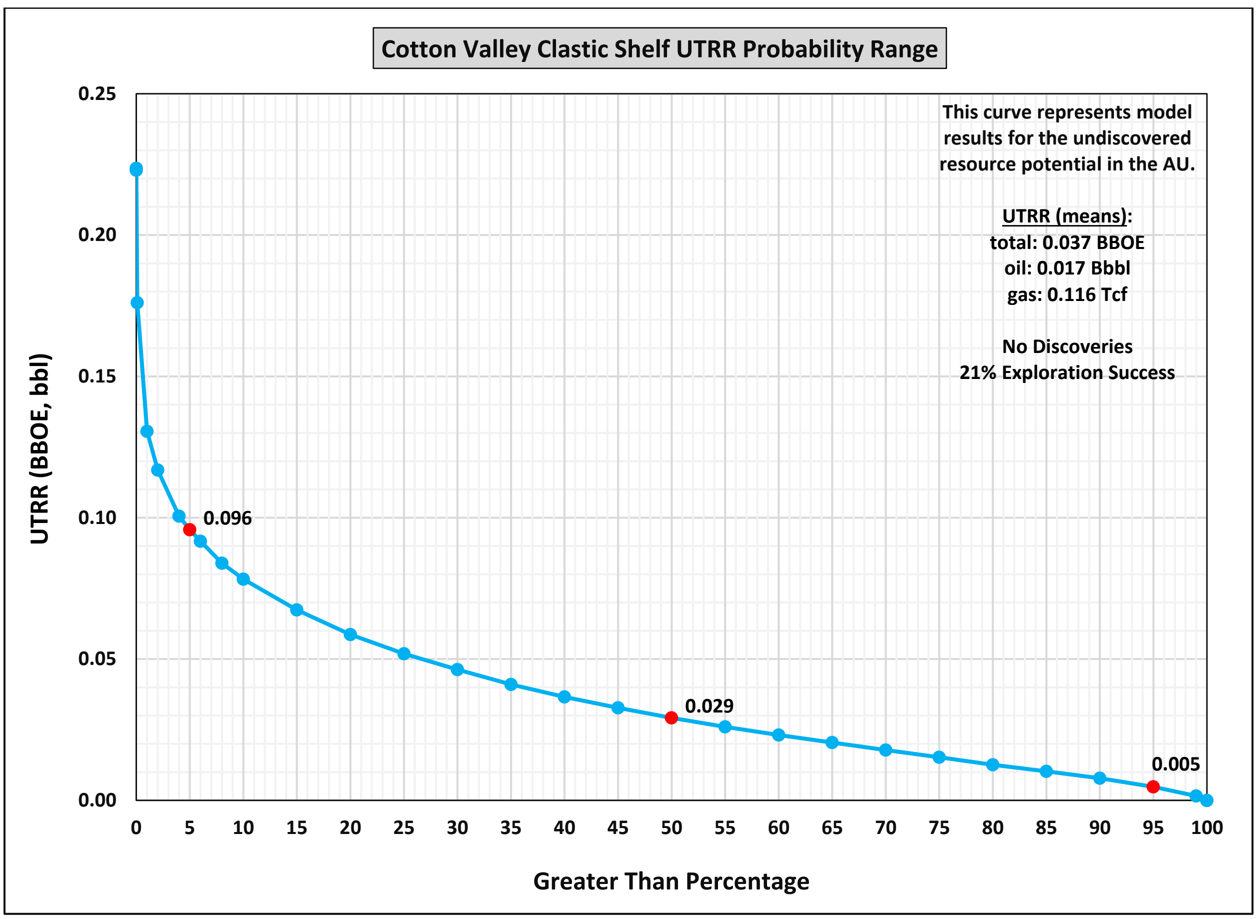

Figure 54. Cotton Valley Clastic Shelf UTRR probability range based on total BOE.

Cotton Valley Clastic Slope

Geology

The Cotton Valley Clastic Slope AU extends southwestward from the shelf across portions of the Viosca Knoll, Mississippi Canyon, De Soto Canyon, Atwater Valley, and Lloyd Ridge Areas (**Figure 52**). The downdip extent of the Slope AU 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 Slope AU 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).

Within the Slope AU, 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 Slope AU would be the earliest Cretaceous regressive unit trapped in expulsion rollover systems, displacing thick autochthonous Louann Salt (Harding et al., 2016).

Risk

The riskiest components for the Slope AU at the play level are the presence and quality of the reservoir facies, resulting in a petroleum system chance of success of 43 percent (**Figure 3**). At the prospect level, again the highest risks are the presence and quality of the reservoir facies, resulting in an average conditional prospect chance of success of 21 percent (**Figure 4**). This equates to an overall exploration chance of success of just 9 percent (**Figure 5**), making the Cotton Valley Clastic Slope one of the riskiest AUs evaluated. 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 eight.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 24 Lower Tuscaloosa Formation discoveries in onshore Mississippi (**Figure 46**). 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 offshore slope play area. These Lower Tuscaloosa discoveries range in size from 0.030 to 242 MMBOE, with a mean size of 36 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 226 MMBOE.

The play was modeled as 100 percent oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOM discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Because of the play-level petroleum system risk for the play, only 43 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil and gas resources are 0.843 Bbbl at the 5th percentile, with a mean of 0.209 Bbbl, and 0.606 Tcf at the 5th percentile, with a mean of 0.150 Tcf, respectively (**Table 9** and **Figure 55**). Total undiscovered BOE resources are 0.951 Bbbl at the 5th percentile, with a mean of 0.236 Bbbl (**Figure 56**). Based on mean-level undiscovered BOE resources, the Cotton Valley Clastic Slope ranks 17th of all 30 GOM assessment units (**Figure 10**).

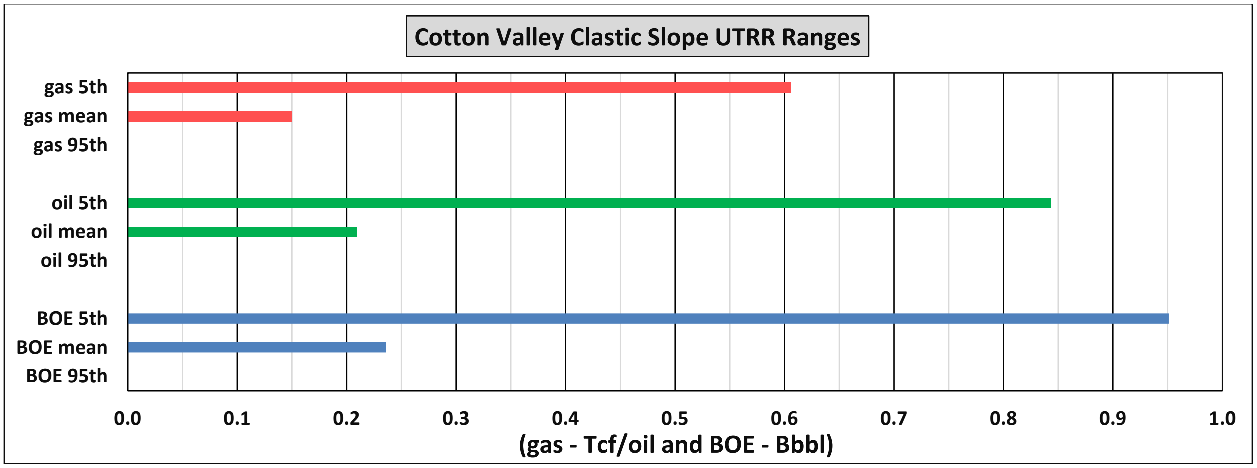

Figure 55. Cotton Valley Clastic Slope gas, oil, and BOE UTRR ranges.

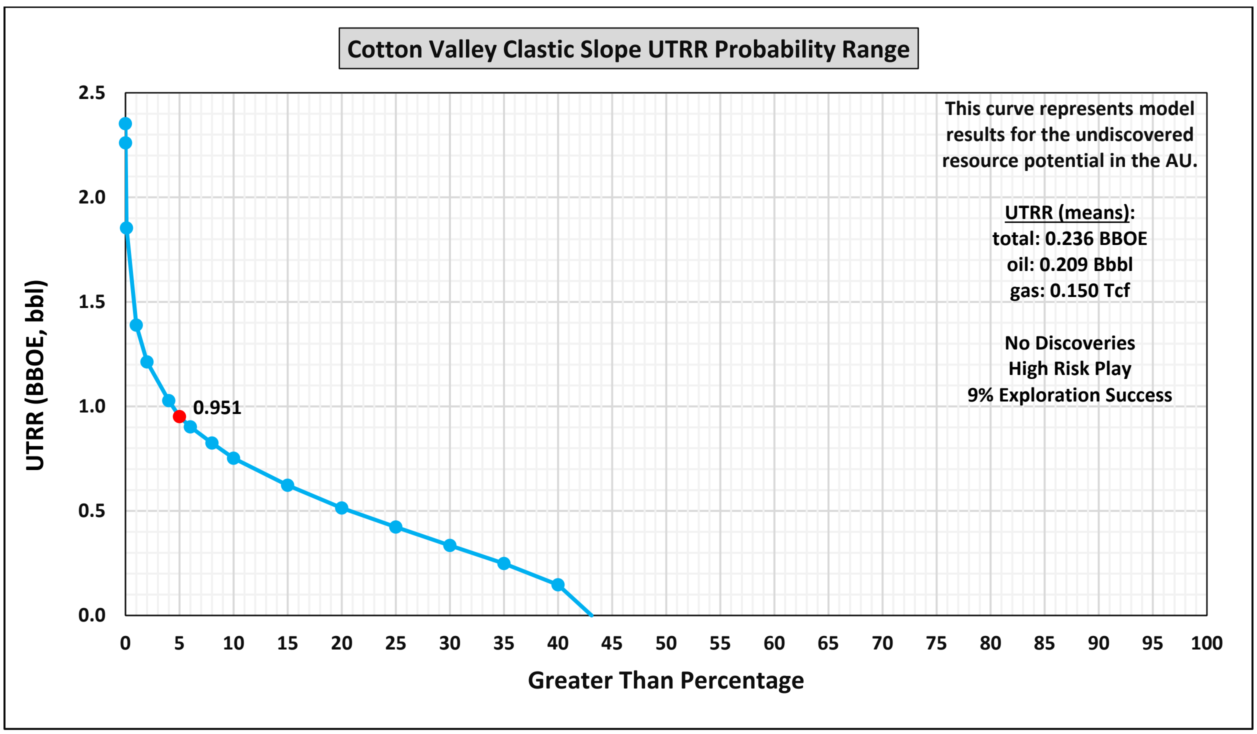

Figure 56. Cotton Valley Clastic Slope UTRR probability range based on total BOE.

KNOWLES CARBONATE (UNASSESSED)

Geology

The unassessed Knowles Carbonate Play is composed of Berriasian–Valanginian platforms that cap the underlying Cotton Valley Clastic AU (**Table 5** and **Figure 25**). In the eastern GOM, the Knowles 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 57**). 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 clinoforms, 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 percent. 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.

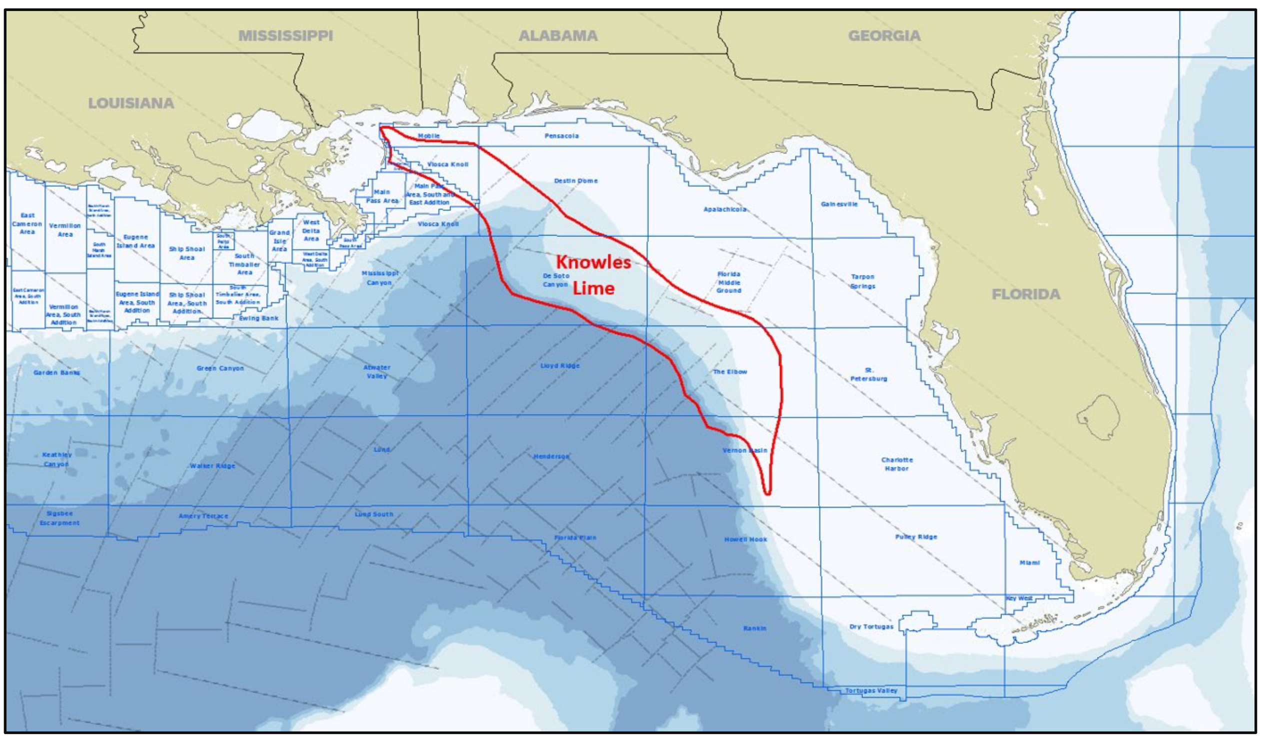

Figure 57. Knowles Carbonate location.

Combined thickness of the carbonates ranges from 2,200 ft (670 m) at the shelf edge to zero 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 Play in the Federal offshore. 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 are no commercial discoveries thus far in the Federal OCS, gas shows have been encountered (e.g., Main Pass Block 154 well number 1 and Viosca Knoll Block 202 well number 1).

Because it has been explored offshore without significant volumes of oil and gas found and because of a limited prospect inventory, undiscovered resources were not assessed for the Knowles Carbonate Play.

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 58**). 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.

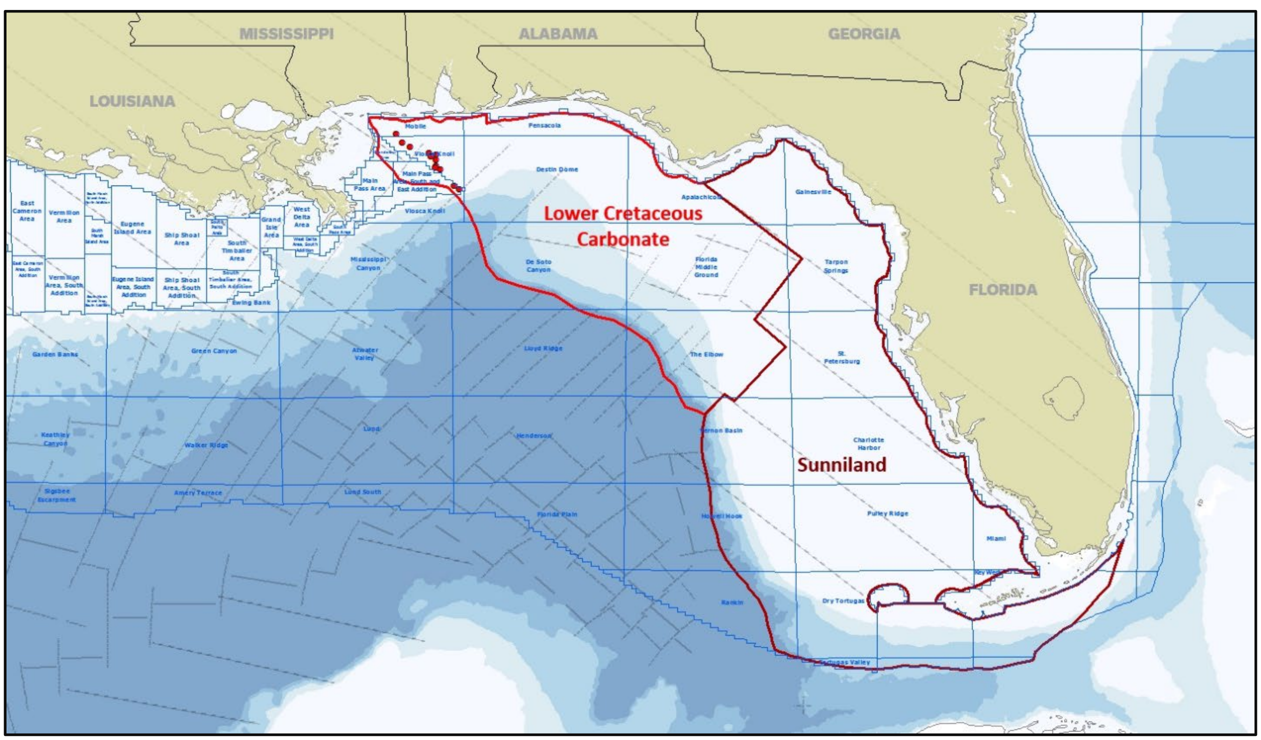

Figure 58. Sunniland and Lower Cretaceous Carbonate locations and associated discovered pools.

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 offshore 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 percent (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 offshore 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 oceanic anoxic event OAE 1b and organic matter acme A110 (**Figure 25**) of Pepper (2016). Based on the similar geological history of the onshore and offshore Sunniland areas, hydrocarbon expulsion and migration chances are high in the offshore.

Top and bottom seal are based on existing stratigraphic relationships. The Sunniland Formation occurs between two extensive anhydrite formations, the Ferry Lake below and the 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

The riskiest component for the Sunniland at the play level is associated with the trap component, resulting in a petroleum system chance of success of 50 percent (**Figure 3**). At the prospect level, the highest risks are the reservoir and trap components, resulting in an average conditional prospect chance of success of 25 percent (**Figure 4**). This equates to an overall exploration chance of success of 13 percent (**Figure 5**). 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, nine 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 69 undiscovered pools, with a mean of 18.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 14 Sunniland discoveries in onshore Florida (**Figure 46**). These discoveries range in size from 0.002 to 49 MMBOE, with a mean size of 9 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 50 MMBOE.

With onshore discoveries producing very little gas, the play was modeled as 100 percent black oil for the offshore portion. Because of the play-level petroleum system risk for the play, only 50 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil resources are 0.343 Bbbl at the 5th percentile, with a mean of 0.113 Bbbl (**Table 9**, **Figure 59**, and **Figure 60**). Based on mean-level undiscovered BOE resources, Sunniland ranks 23rd of all 30 GOM assessment units (**Figure 10**).

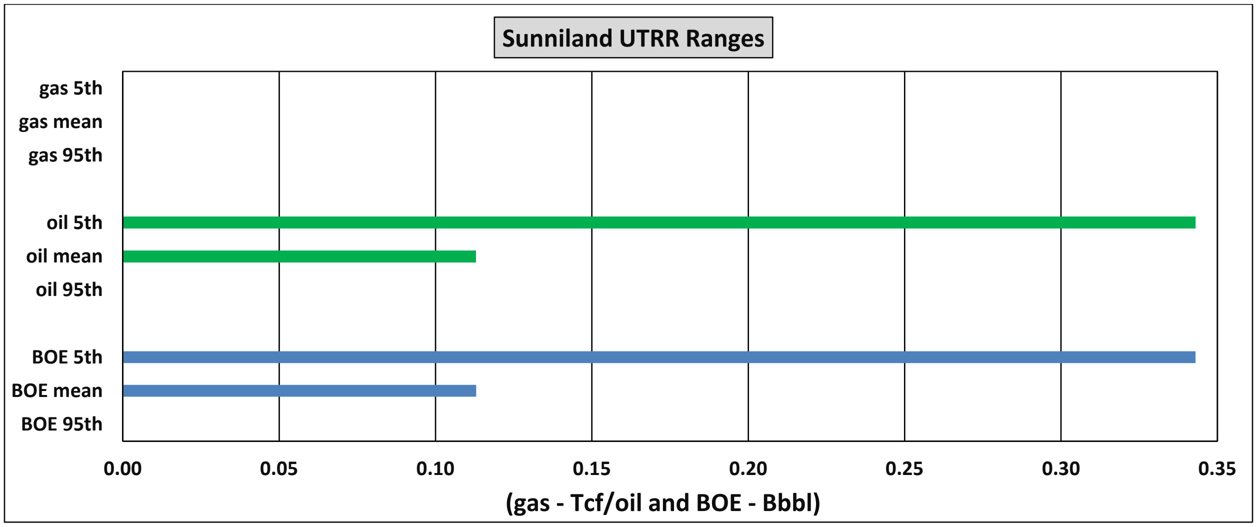

Figure 59. Sunniland oil UTRR ranges.

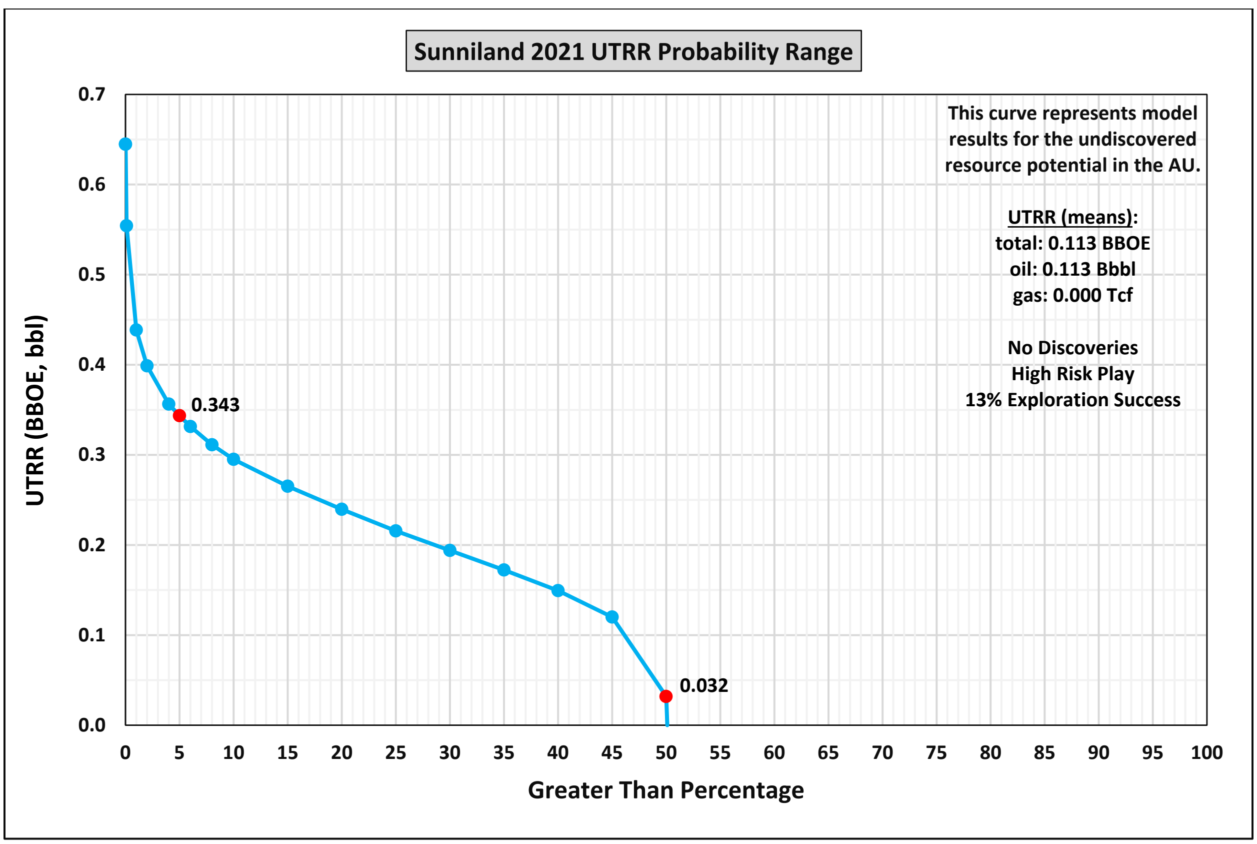

Figure 60. Sunniland UTRR probability range based on total BOE.

Lower Cretaceous Carbonate

Geology

The Aptian Sligo Formation and James Limestone and the Albian Andrew Formation of previous assessments have been aggregated into a single AU—the Lower Cretaceous Carbonate. Each of these three stratigraphic intervals are 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 GOM Basin and outlying basement highs. In the eastern GOM, 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 58**). The play 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, the AU is limited to the west 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 GOM. 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.

Source rocks include anoxic-environment shales (A120, **Figure 25**) equivalent to oceanic anoxic event OAE 1b (Olson et al., 2015) identified regionally just above the Sligo and immediately below the James. Other potential source rocks are laminated shales and micrites of the Upper Jurassic Smackover Formation that underwent hydrocarbon generation during the Lower Cretaceous. Existing offshore 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 offshore Federal waters.

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 Federal OCS. The Pine Island Shale member found onshore in the Pearsall Formation is a carbonate in the Federal OCS that is lithologically indistinguishable from the James Limestone. In the offshore, the James Limestone and Pine Island Shale members are commonly identified by operators as the Upper and Lower James Limestone (**Table 5**).

There are 10 discovered James pools in the Federal OCS as of this study's January 1, 2019, cutoff date. 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 to 5 mile (4.8 to 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 about 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 Federal 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 (Petty, 1999; Yurewicz et al., 1993). 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.

As of this study's January 1, 2019, cutoff date, two Andrew pools have been discovered in the play. 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, digenetic leaching, and dolomitization. Hydrocarbons are trapped in small anticlines located within the porous and permeable facies. Marine shales, micrites, and anhydrites provide seals for the play. For a detailed discussion, see Petty (1999) and Bascle et al., (2001).

Discoveries

As of the end of 2018, 10 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 (**Figure 58** and **Figure 61**). No Sligo discoveries lie within the Federal offshore to date. The two small oil pools in the

Andrew Formation were discovered in the early-1970s, while the 10 gas pools in the James Formation were discovered from 1993 to 2001 (**Figure 61**). Combined, all 12 pools in the play contain less than 0.001 Bbbl of oil and 0.639 Tcf of gas (total BOE of 0.114 Bbbl) (**Table 9**). The Andrew carbonate platform discoveries lie in an average water depth of approximately 270 ft, and the James patch reef discoveries are in an average water depth of approximately 120 ft. Subsea depths for the two Andrew pools have an average of 8,846 ft subsea, and the older James pools range from 14,312 to 15,243 ft subsea.

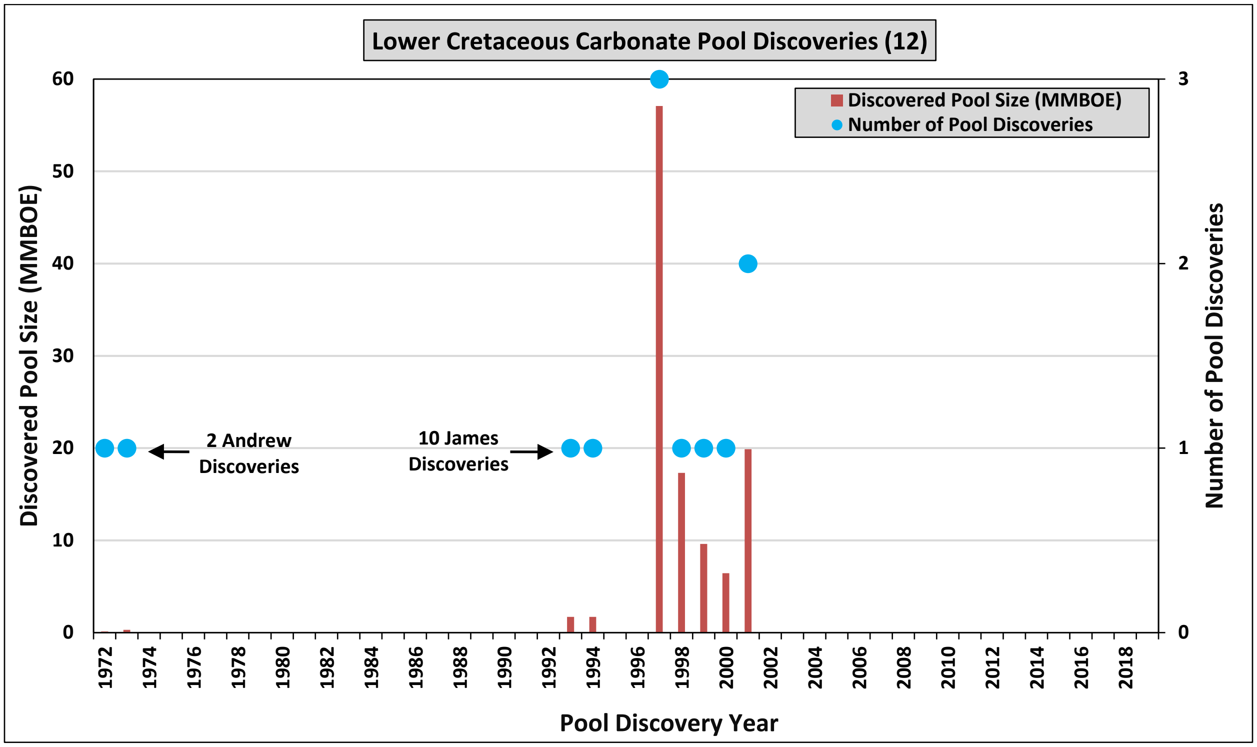

Figure 61. Lower Cretaceous Carbonate pool discovery history.

Risk

Because an active petroleum system has clearly been established by the 12 offshore OCS discoveries, there is no play-level risk (**Figure 3**). At the prospect level, the highest risks are presence of traps and effective seal mechanisms, resulting in an average conditional prospect chance of success of 21 percent (**Figure 4**). This equates to an overall exploration chance of success of 21 percent (**Figure 5**). See Appendix A for details.

Undiscovered Resources

A mapped prospect inventory was not available for the play, 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 for this play 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 0.121 to 160 MMBOE, with a mean size of 21 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 159 MMBOE.

The play was modeled as 50 percent oil and 50 percent gas. Using the discovered offshore 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 0.058 to 0.523 Bbbl, and undiscovered gas resources range from 0.470 to 3.641 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 62**). Total BOE undiscovered resources range from 0.141 to 1.171 Bbbl at the 95th and 5th percentiles, respectively (**Figure 63**). Of all 30 assessment units in this study, the Lower Cretaceous Carbonate ranks 12th based on mean-level undiscovered BOE resources (**Figure 10**).

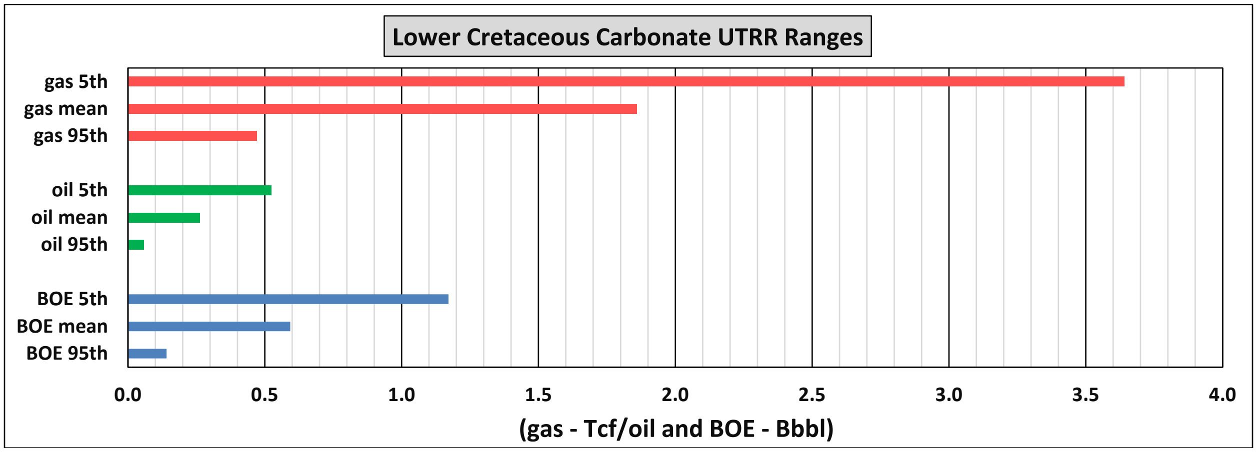

Figure 62. Lower Cretaceous Carbonate gas, oil, and BOE UTRR ranges.

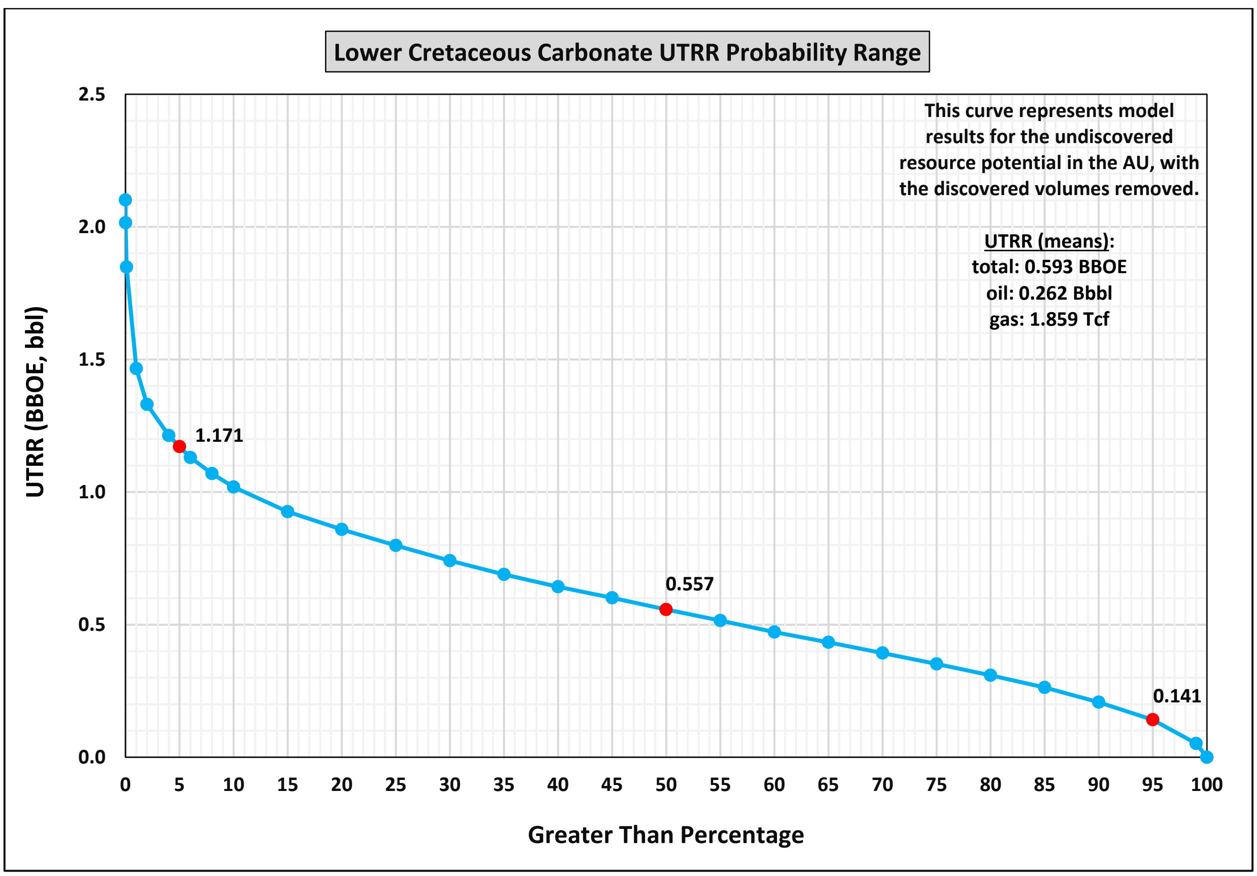

Figure 63. Lower Cretaceous Carbonate UTRR probability range based on total BOE.

Lower Cretaceous Clastic

Objectives of the Lower Cretaceous Clastic Play are siliciclastic sediments of the Hosston (Valanginian–Barremian), Paluxy (Albian), and Dantzler (Albian–Cenomanian) Formations (**Table 5** and **Figure 25**). The play is delineated into a shelf and slope component by the modern shelf-slope break (**Figure 64**). 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 Federal OCS wells that penetrated this play, all were dry; however, this play was probably not the primary exploration target for these wells.

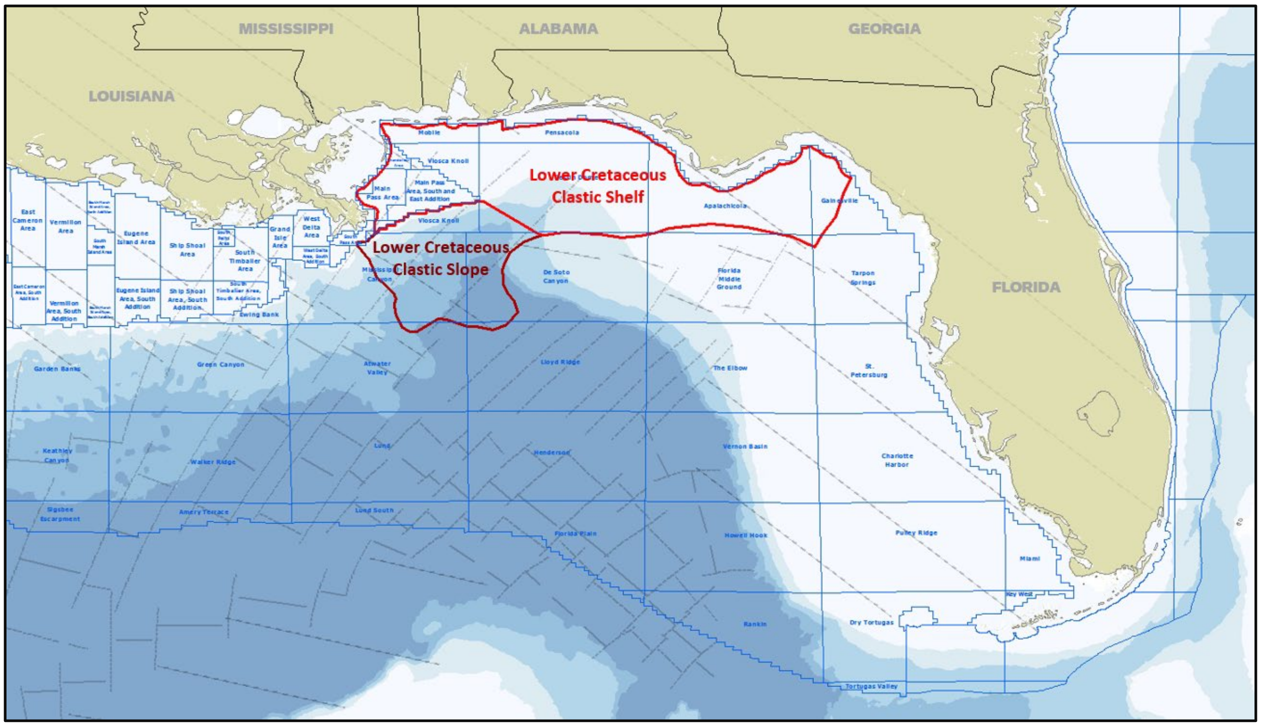

Figure 64. Lower Cretaceous Clastic Shelf and Slope locations.

Reservoir characteristics in the Shelf and Slope AUs are largely unknown, but because of 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 and Jones, 2005), it can be assumed that quartz framework grains similar to those described in the Lower Tuscaloosa AUs 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 because of the close association with carbonate shelf and slope limestones.

Each formation in this play 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 because of 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 64**). In these protraction areas, each 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 (Pashin et al., 2016; Pilcher et al., 2014), 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 offshore 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-Arbuckle 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 present-day Pensacola, Destin Dome, and Apalachicola Areas. This 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

The riskiest components for the Shelf AU at the play level are associated with the hydrocarbon fill and trap components, resulting in a petroleum system chance of success of 58 percent (**Figure 3**). At the prospect level, the highest risks are associated with the reservoir and trap components, resulting in an average conditional prospect chance of success of 25 percent (**Figure 4**). This equates to an overall exploration chance of success of 15 percent (**Figure 5**). 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 six.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 35 Lower Cretaceous clastic discoveries in onshore Mississippi (**Figure 46**). These discoveries range in size from 0.014 to 28 MMBOE, with a mean size of 3 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 32 MMBOE.

The play was modeled as 50 percent oil and 50 percent gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOM discovered data, with GRASP returning UTRR values for all four hydrocarbon streams (black oil, solution gas, dry gas, and condensate). Because of the play-level petroleum system risk for the play, only 58 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil and gas resources are 0.053 Bbbl at the 5th percentile, with a mean of 0.013 Bbbl, and 0.417 Tcf at the 5th percentile, with a mean of 0.096 Tcf, respectively (**Table 9** and **Figure 65**). Total undiscovered BOE resources are 0.127 Bbbl at the 5th percentile, with a mean of 0.030 Bbbl (**Figure 66**). Based on mean-level undiscovered BOE resources, the Lower Cretaceous Clastic Shelf ranks 29th of all 30 GOM assessment units (**Figure 10**).

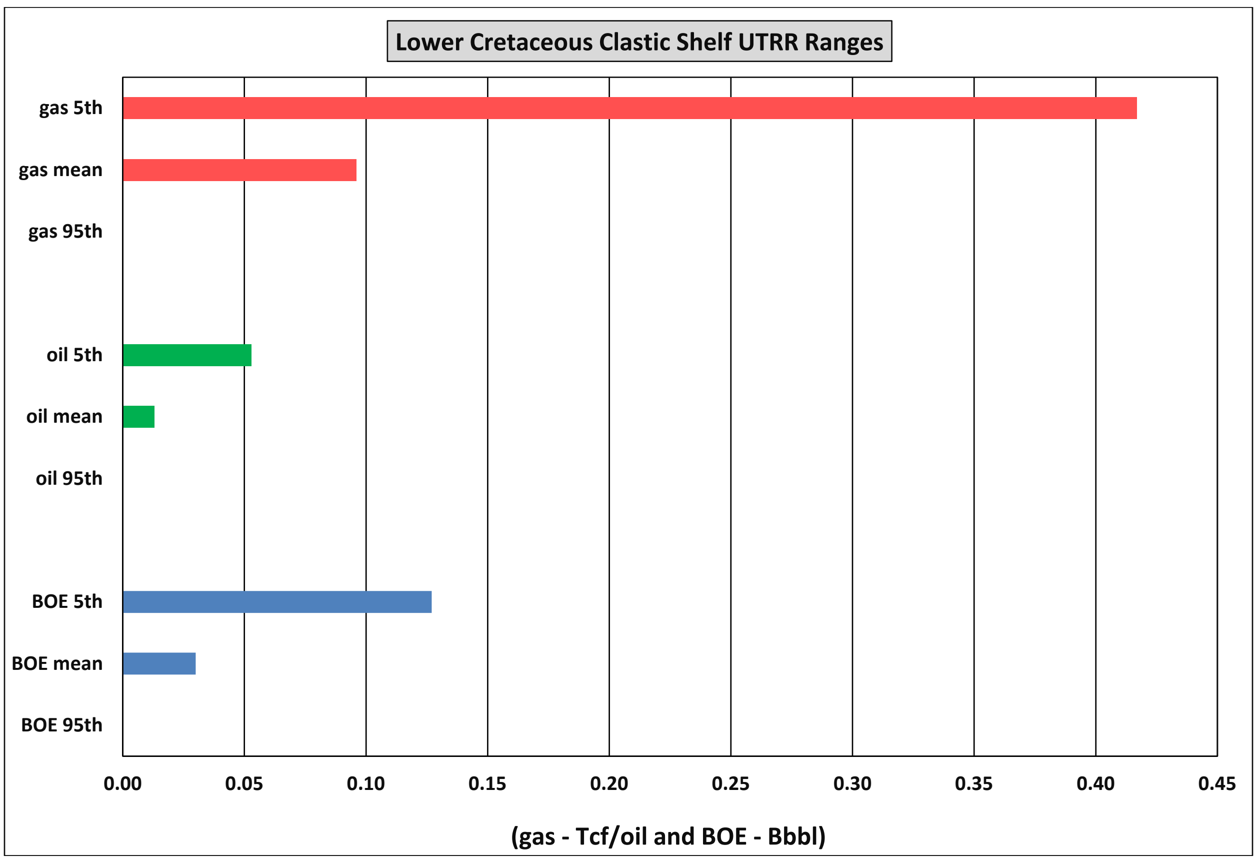

Figure 65. Lower Cretaceous Clastic Shelf gas, oil, and BOE UTRR ranges.

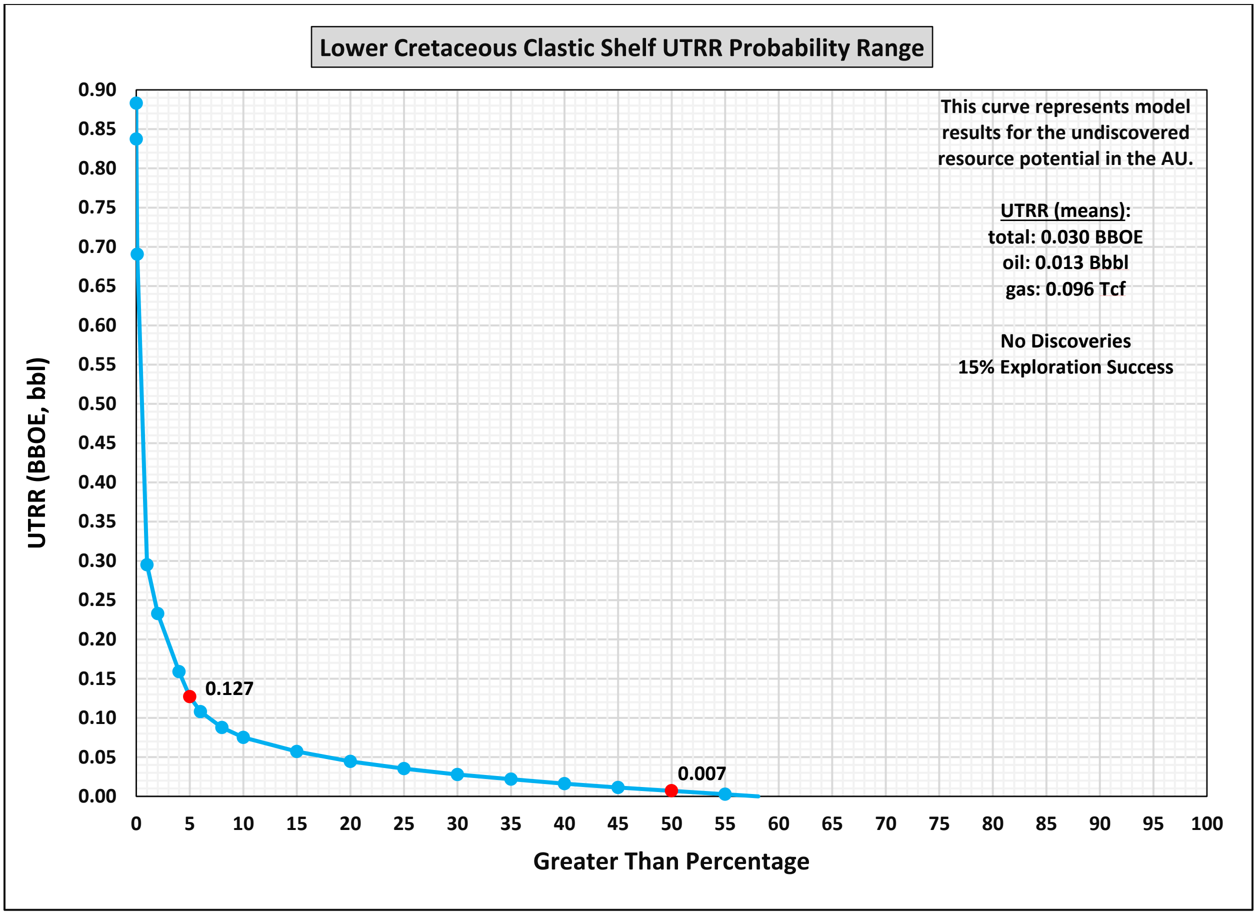

Figure 66. Lower Cretaceous Clastic Shelf UTRR probability range based on total BOE.

Lower Cretaceous Clastic Slope

Geology

The Slope AU extends downdip from the Cretaceous shelf margin into deepwater in the Viosca Knoll, western De Soto Canyon, and eastern Mississippi Canyon Areas (**Figure 64**). To the north, the Slope AU abuts the Lower Cretaceous Clastic Shelf AU along the modern shelf-slope break. To the southeast, the Slope AU onlaps the Southern Platform (SP, **Figure 22**). To the southwest, the play onlaps inflated salt of the Mesozoic salt nappes. To the west, the play abuts the Mesozoic Shelf AU 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 because of 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

Geochemical modeling predicts a favorable oil generation window for the Tithonian shale beneath the Lower Cretaceous Clastic 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, and therefore a working petroleum system has been established, resulting in a marginal probability of hydrocarbons of 1.0 (**Figure 3**). At the prospect level, the highest risks are associated with the reservoir and trap components, resulting in an average conditional prospect chance of success of 18 percent (**Figure 4**). This equates to an overall exploration chance of success of 18 percent (**Figure 5**). 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 seven.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 24 Lower Tuscaloosa Formation discoveries in onshore Mississippi (**Figure 46**). 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 offshore slope play area. These Lower Tuscaloosa discoveries range in size from 0.030 to 242 MMBOE, with a mean size of 36 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 133 MMBOE.

The play was modeled as 100 percent oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOM discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Assessment results indicate that undiscovered oil resources range from 0.011 to 0.589 Bbbl, and undiscovered gas resources range from 0.008 to 0.423 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 67**). Total BOE undiscovered resources range from 0.012 to 0.664 Bbbl at the 95th and 5th percentiles, respectively (**Figure 68**). Of all 30 assessment units in this study, the Lower Cretaceous Clastic Slope ranks 18th based on mean-level undiscovered BOE resources (**Figure 10**).

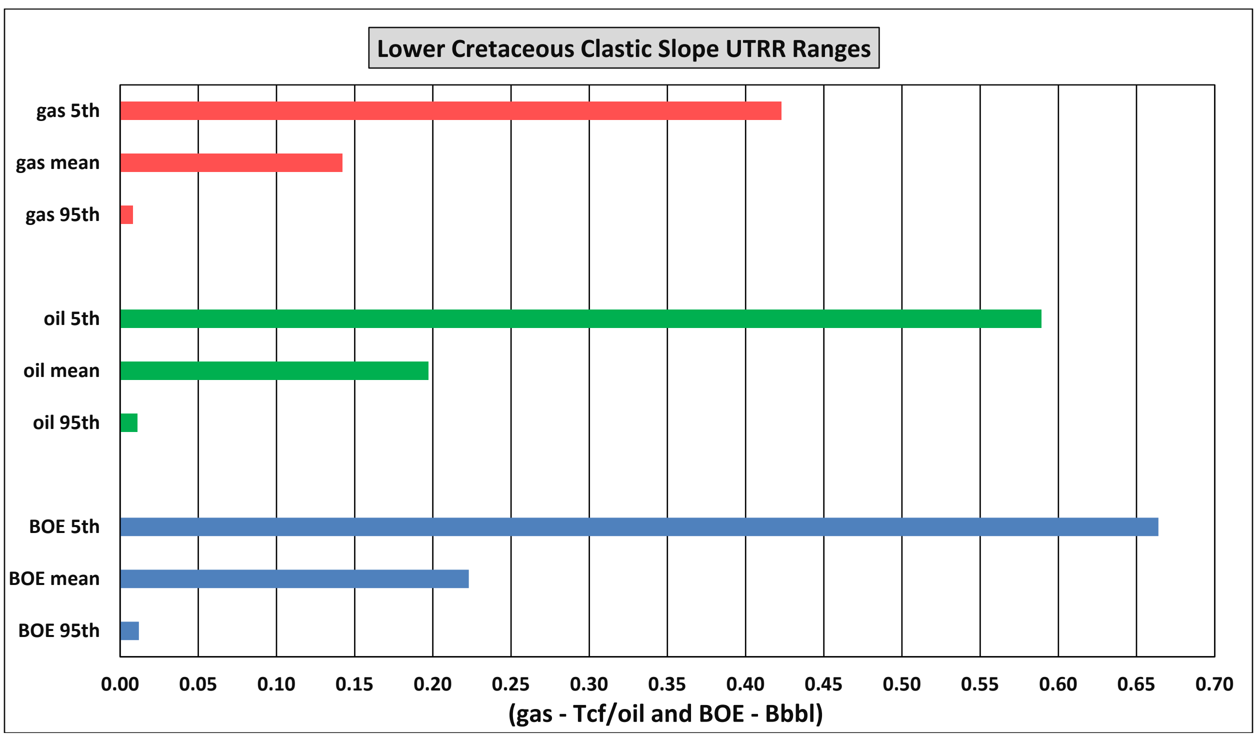

Figure 67. Lower Cretaceous Clastic Slope gas, oil, and BOE UTRR ranges.

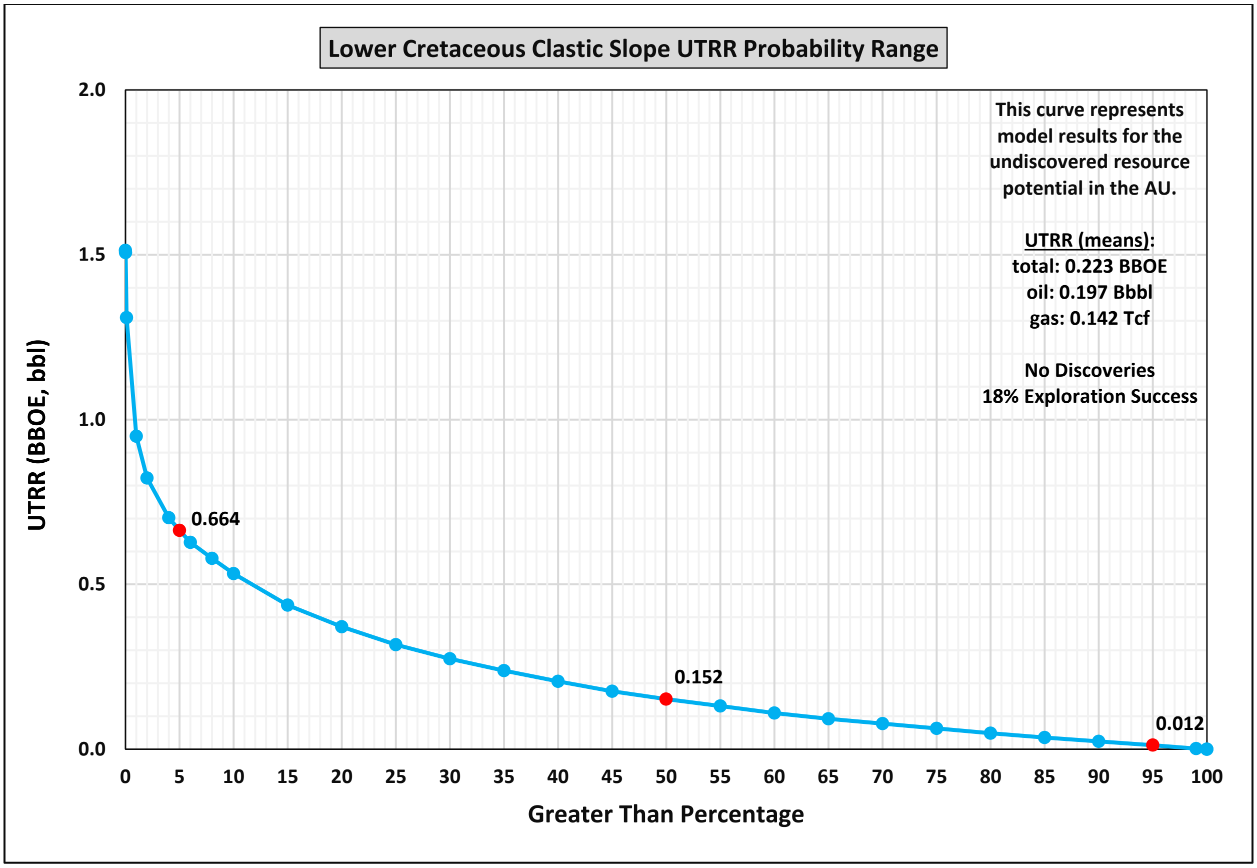

Figure 68. Lower Cretaceous Clastic Slope UTRR probability range based on total BOE.

Lower Tuscaloosa (eastern GOM)

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 GOM. 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 GOM 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 AUs. 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 AUs of this report.

Lower Tuscaloosa objectives in the offshore Shelf and Slope AU areas (**Figure 69**) were deposited in the full range of shelf-to-basin environments from their source areas, across the shelf margin, and into the deep basin.

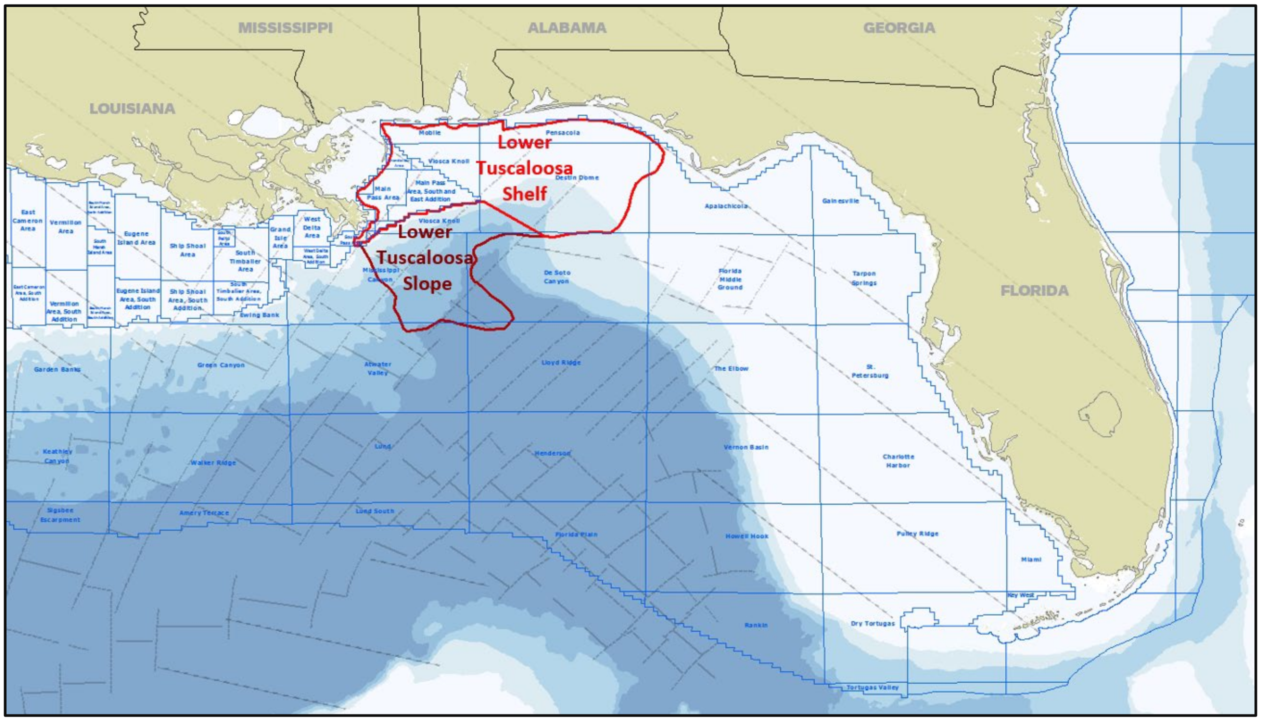

Figure 69. Lower Tuscaloosa Shelf and Slope locations.

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 estuarian 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 percent 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 and Jones, 2005).

Potential petroleum source rocks for the offshore Lower Tuscaloosa AUs 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, chances 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 offshore Shelf and Slope AUs.

Lower Tuscaloosa Shelf

Geology

The Lower Tuscaloosa Shelf AU 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 69**). West of the Mississippi Delta, the Shelf AU abuts the undifferentiated Mesozoic Shelf AU. Downdip, the Shelf AU onlaps 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 of the Lower Tuscaloosa Shelf AU 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). Within the Lower Tuscaloosa Shelf AU, Oxfordian (A157) or Tithonian (A148) sources are likely (**Figure 25**).

One Federal 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 in the offshore Shelf AU.

Risk

Because an active petroleum system has been established by the Main Pass Block 254 well, there is no play-level risk (**Figure 3**). At the prospect level, the highest risks are reservoir quality and effective seal mechanisms, resulting in an average conditional prospect chance of success of 25 percent (**Figure 4**). This equates to an overall exploration chance of success of 25 percent (**Figure 5**). 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 offshore, the pool-size distribution for this play was modeled with 24 Lower Tuscaloosa Formation discoveries in onshore Mississippi (**Figure 46**). These discoveries range in size from 0.030 to 242 MMBOE, with a mean size of 36 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 50 MMBOE.

The play was modeled as 50 percent oil and 50 percent gas. With no information on yields or GORs from the onshore analog discoveries, an average was calculated from eastern-GOM 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 0.005 to 0.132 Bbbl, and undiscovered gas resources range from 0.040 to 0.968 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 70**). Total BOE undiscovered resources range from 0.012 to 0.304 Bbbl at the 95th and 5th percentiles, respectively (**Figure 71**). Of all 30 assessment units in this study, the Lower Tuscaloosa Shelf Slope ranks 22nd based on mean-level undiscovered BOE resources (**Figure 10**).

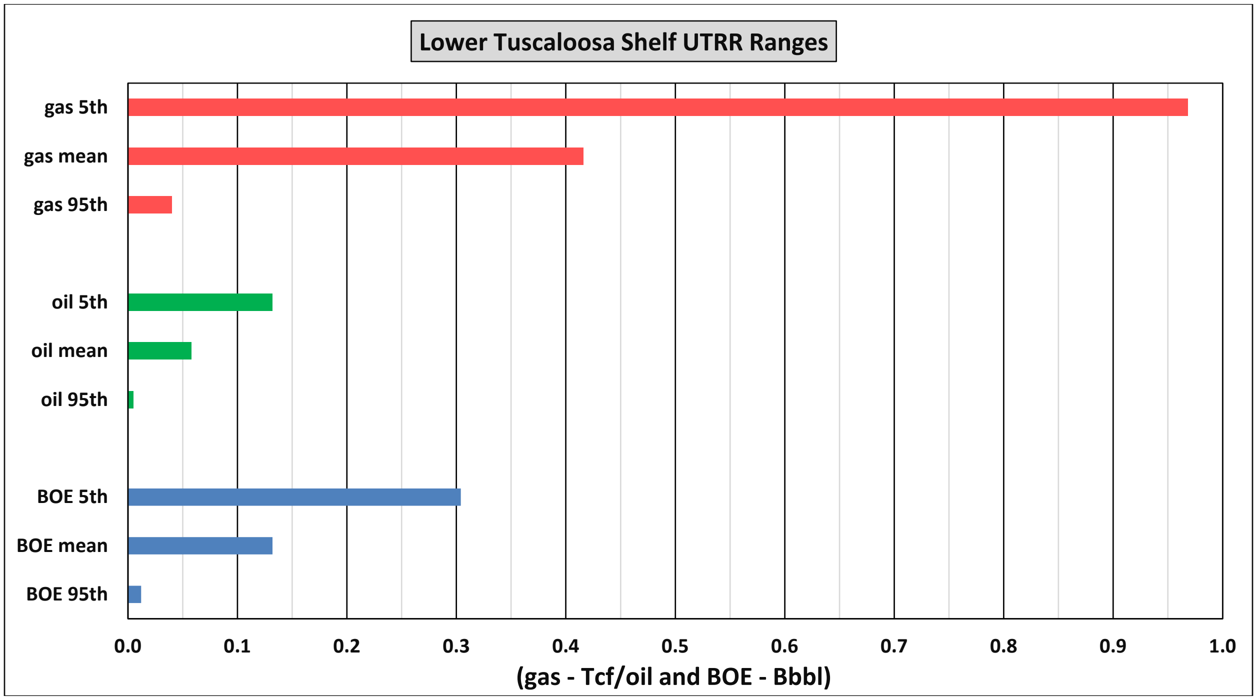

Figure 70. Lower Tuscaloosa Shelf gas, oil, and BOE UTRR ranges.

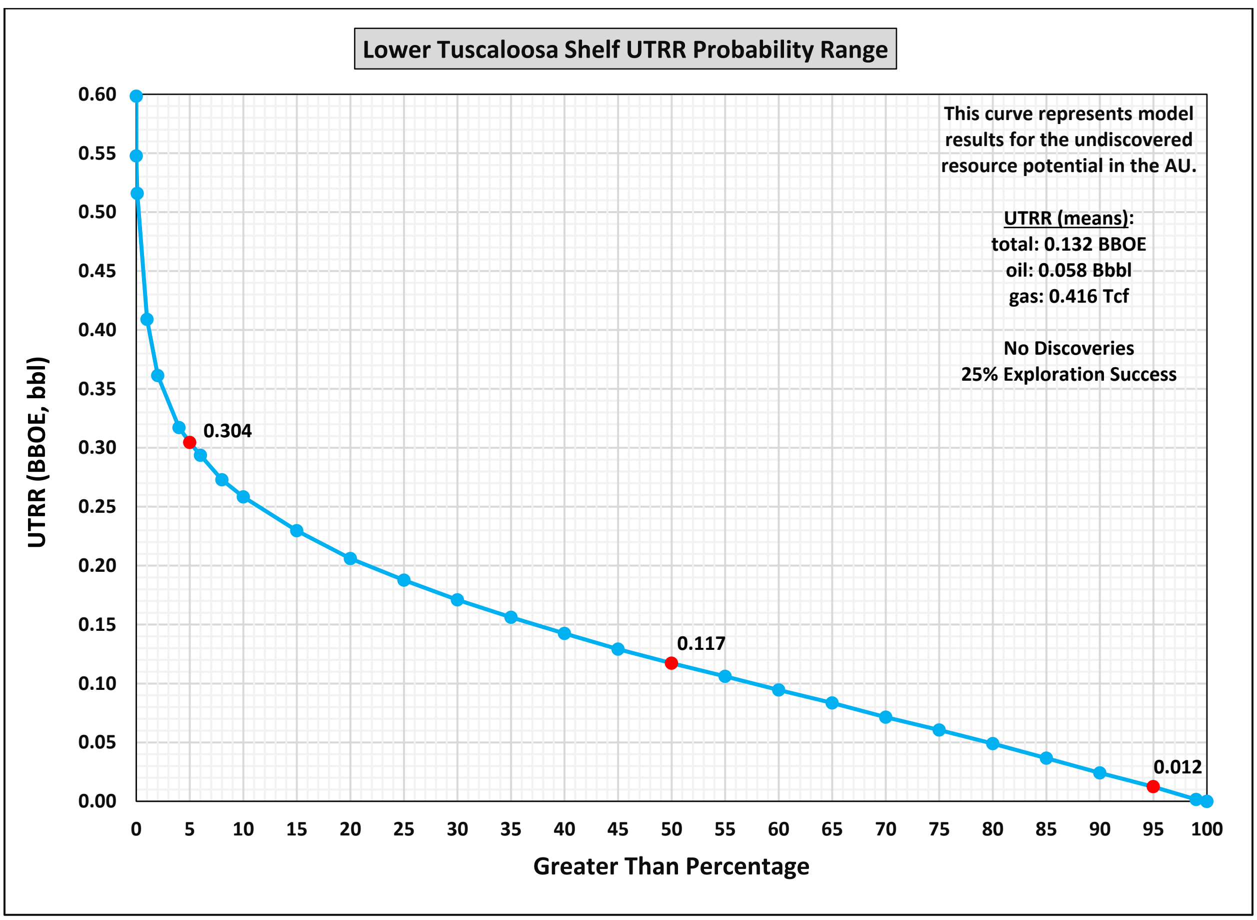

Figure 71. Lower Tuscaloosa Shelf UTRR probability range based on total BOE.

Lower Tuscaloosa Slope

Geology

The Lower Tuscaloosa 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 69**). To the north, the Slope AU abuts the Lower Tuscaloosa Shelf AU along the modern shelf-slope break. To the southeast, the Slope AU onlaps the Southern Platform (SP, **Figure 22**). To the southwest, it onlaps inflated salt of the Mesozoic salt nappes (**Figure 23**). To the west, the AU abuts the undifferentiated Mesozoic Slope AU along a NW-SE 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 because of increasing depth, structural complexity, and extensive allochthonous salt.

Potential reservoirs of the Lower Tuscaloosa Slope AU 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 (Snedden et al., 2016; Woolf, 2012).

The structural setting of the Lower Tuscaloosa Slope AU is similar to that of the underlying Lower Cretaceous Clastic Slope AU. The Lower Tuscaloosa 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). 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 Lower Tuscaloosa Slope AU (Harding et al., 2016; Weimer et al., 2016).

Risk

The riskiest components for the Slope AU at the play level are the presence and quality of a reservoir facies, resulting in a petroleum system chance of success of 54 percent (**Figure 3**). At the prospect level, again the highest risks are the presence and quality of a reservoir facies, resulting in an average conditional prospect chance of success of 25 percent (**Figure 4**). This equates to an overall exploration chance of success of 13 percent (**Figure 5**). 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 seven.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 24 Lower Tuscaloosa Formation discoveries in onshore Mississippi (**Figure 46**). These Lower Tuscaloosa discoveries range in size from 0.030 to 242 MMBOE, with a mean size of 36 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 185 MMBOE.

The play was modeled as 100 percent oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOM discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Because of the play-level petroleum system risk for the play, only 54 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil and gas resources are 0.707 Bbbl at the 5th percentile, with a mean of 0.182 Bbbl, and 0.508 Tcf at the 5th percentile, with a mean of 0.131 Tcf, respectively (**Table 9** and **Figure 72**). Total undiscovered BOE resources are 0.798 Bbbl at the 5th percentile, with a mean of 0.205

Bbbl (**Figure 73**). Based on mean-level undiscovered BOE resources, the Lower Tuscaloosa Slope ranks 21st of all 30 GOM assessment units (**Figure 10**).

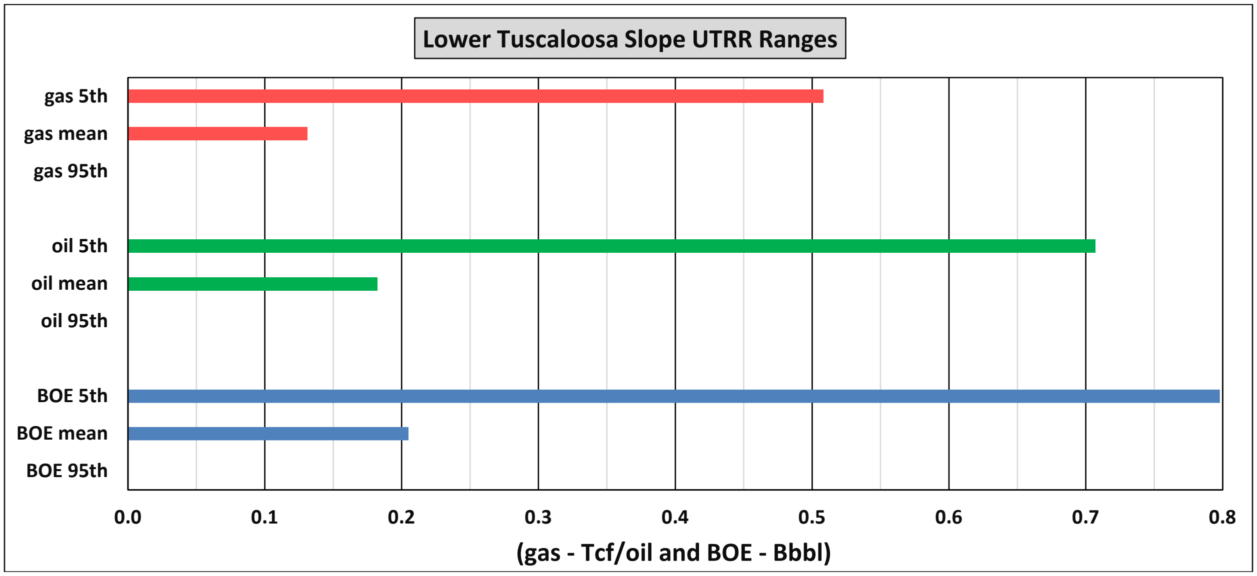

Figure 72. Lower Tuscaloosa Slope gas, oil, and BOE UTRR ranges.

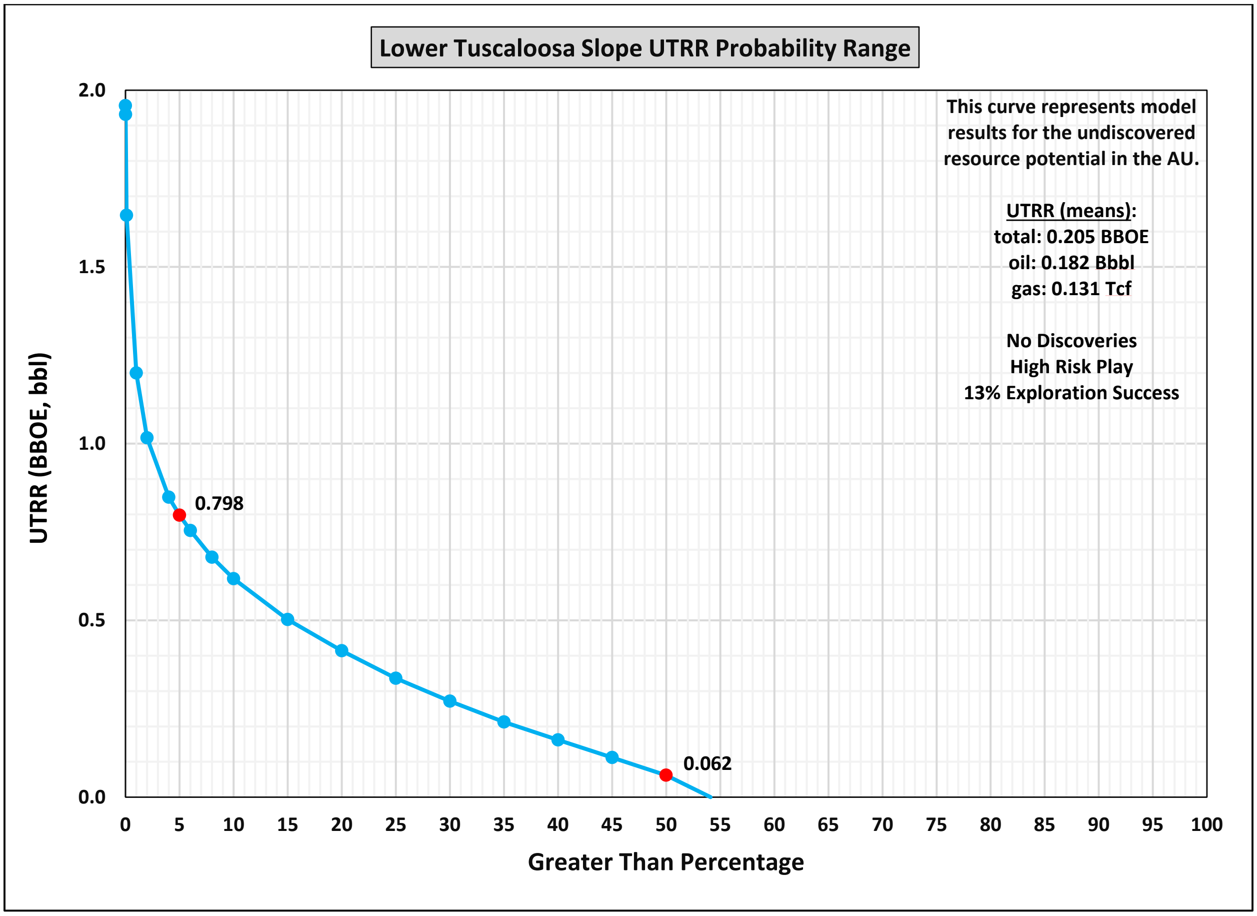

Figure 73. Lower Tuscaloosa Slope UTRR probability range based on total BOE.

Tuscaloosa Marine Shale (unassessed)

Geology

The Tuscaloosa Marine Shale (TMS) of southern Louisiana and Mississippi 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 AUs (**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 had 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.

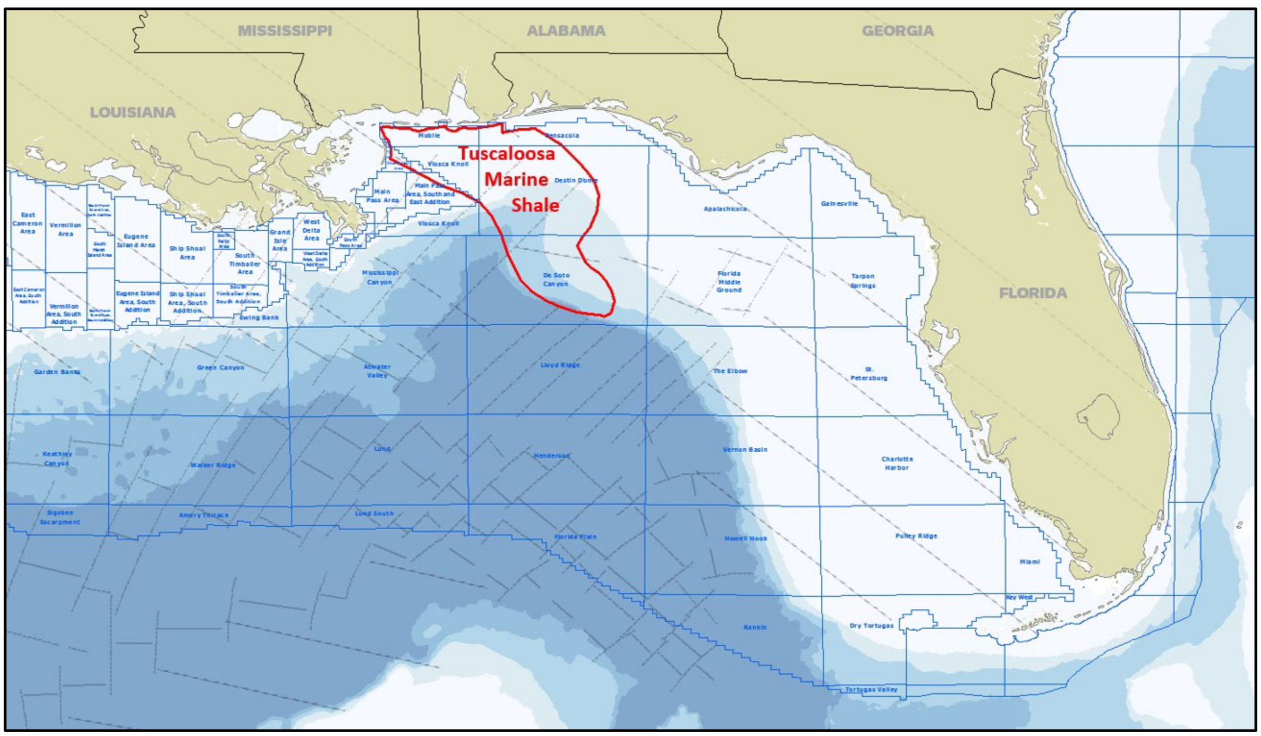

Figure 74. Tuscaloosa Marine Shale location.

The TMS Play in the Federal 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 74**).

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 offshore GOM, 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-Creany delta log Rt method (Passey et al., 1980). Mud log shows in De Soto Canyon Block 512 well in close proximity to the TMS suggest the presence of 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 geological 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 GOM)

The undifferentiated Mesozoic Shelf, Slope, and Basin Floor AUs (**Figure 75**) conceptually include all potential Mesozoic objectives recognized to the east of the modern Mississippi River Delta and included in the previously discussed Mesozoic AU areas. However, for the purpose of assessment, the play was modeled with Lower Tuscaloosa objectives analogous to the Lower Tuscaloosa AUs. It should be noted that the shelf, slope, and basin floor designations refer to modern bathymetry. Depositionally, all three Mesozoic play areas would have been in a slope to basinal setting at Lower Tuscaloosa time.

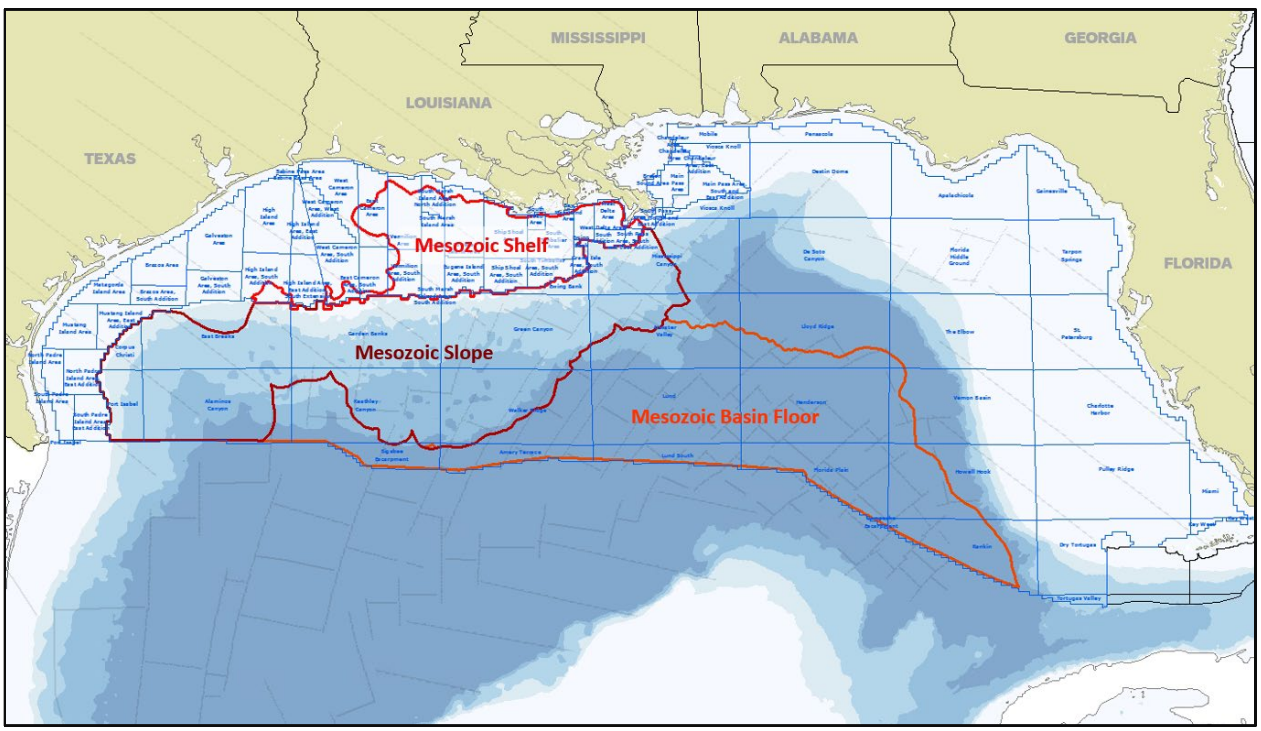

Figure 75. Mesozoic Shelf, Slope, and Basin Floor AU locations.

Potential Tuscaloosa reservoirs of the Mesozoic Shelf and Slope AUs are slope channels and basin-floor fans sourced from shelf margin deltas in onshore areas to the north or from the northeast (Snedden et al., 2016; Woolf, 2012). 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 objectives of the Deep Mesozoic Shelf Play of previous assessments were originally conceived as Jurassic through Cretaceous carbonate reservoirs situated on basement highs analogous to reservoirs in the Golden Lane Trend and Poza Rica Field in Mexico (Lore et al., 2001). The play concept was based on time-migrated 2D and 3D seismic surveys, potential field data, and the tectonic and stratigraphic understanding of the time. The play concepts have changed considerably with the subsequent acquisition of long-offset 2D seismic surveys, depth-migrated 3D seismic surveys, refinements in the understanding of the plate tectonic and salt tectonic evolution of the basin, and stratigraphic and petrophysical control from deep well tests.

The Mesozoic Shelf AU extends from state waters to the modern shelf-slope break (**Figure 75**). The Texas shelf and portions of the western-most Louisiana shelf are excluded from the play because of 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 243) Prospects both reached bottom-hole temperatures of 460^{o} F. A published map of subsurface temperature trends (Forrest et al., 2005) was used to delineate areas with anticipated temperatures 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 AU.

The Mesozoic section of the Shelf AU is situated beneath Paleogene and Neogene detachments, horizontal salt welds, and thick, complexly faulted Miocene and Plio–Pleistocene sediments filling salt-withdrawal minibasins (Diegel et al., 1995). Prospective structures include anticlinal closures above remnant autochthonous salt pillows and folds (Dooley et al., 2013; Philippe et al., 2005) 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 percent, and measured permeabilities averaging less than 0.1 millidarcies.

Most likely source rocks for the Mesozoic Shelf AU 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 Federal OCS well in Main Pass Block 254 has flowed hydrocarbons from the Lower Tuscaloosa in the stratigraphically equivalent Lower Tuscaloosa Shelf AU. Overlying tertiary reservoirs are charged predominantly by Tertiary source rocks (Hood et al., 2002).

Risk

The riskiest components for the Shelf AU at the play level are the presence and quality of a reservoir facies, resulting in a petroleum system chance of success of 50 percent (**Figure 3**). At the prospect level, the highest risks are reservoir quality and effective seals, resulting in an average conditional prospect chance of success of 18 percent (**Figure 4**). This equates to an overall exploration chance of success of only 9 percent (**Figure 5**). 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 results in 0 to 35 undiscovered pools, with a mean of five.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 24 Lower Tuscaloosa Formation discoveries in onshore Mississippi (**Figure 46**). These discoveries range in size from 0.030 to 242 MMBOE, with a mean size of 36 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 52 MMBOE.

This central Gulf of Mexico OCS deep shelf play was modeled as 100 percent gas. With no information on yields from the onshore analog discoveries, an average was calculated from eastern-GOM discovered data, with GRASP returning UTRR values for dry gas and condensate liquids (oil herein). Because of the play-level petroleum system risk for the play, only 50 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil and gas resources are 0.019 Bbbl at the 5th percentile, with a mean of 0.005 Bbbl, and 1.419 Tcf at the 5th percentile, with a mean of 0.372 Tcf, respectively (**Table 9** and **Figure 76**). Total undiscovered BOE resources are 0.271 Bbbl at the 5th percentile, with a mean of 0.071 Bbbl (**Figure 77**). Based on mean-level undiscovered BOE resources, the Mesozoic Shelf ranks 26th of all 30 GOM assessment units (**Figure 10**).

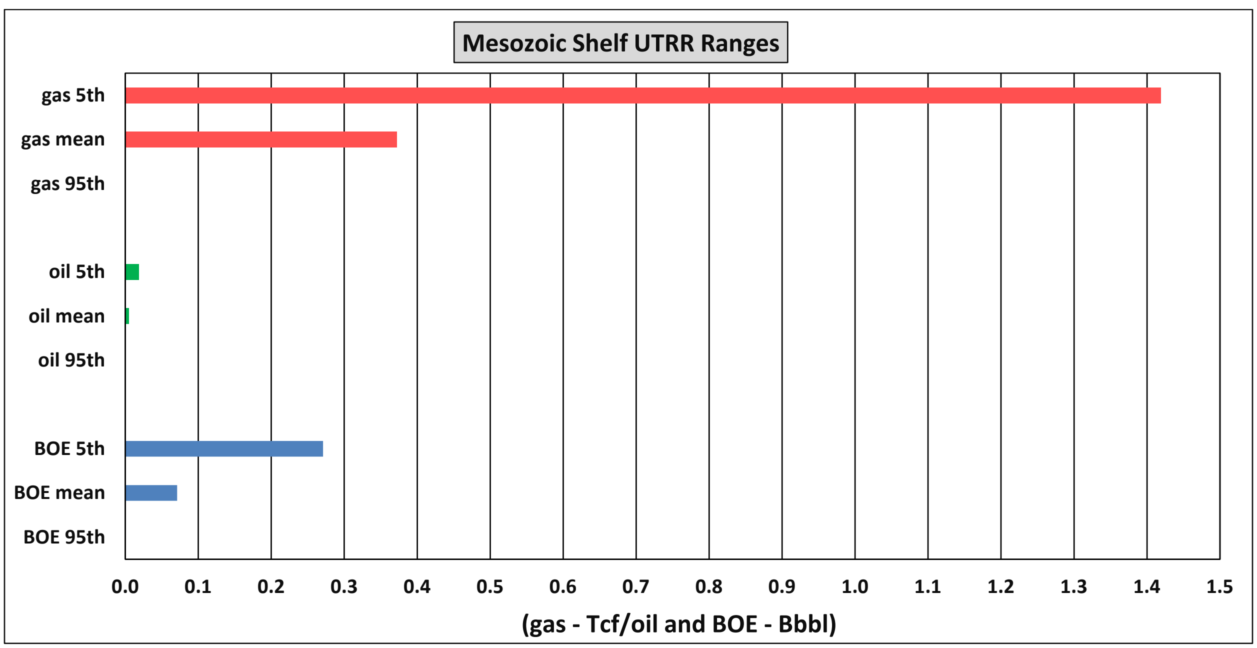

Figure 76. Mesozoic Shelf gas, oil, and BOE UTRR ranges.

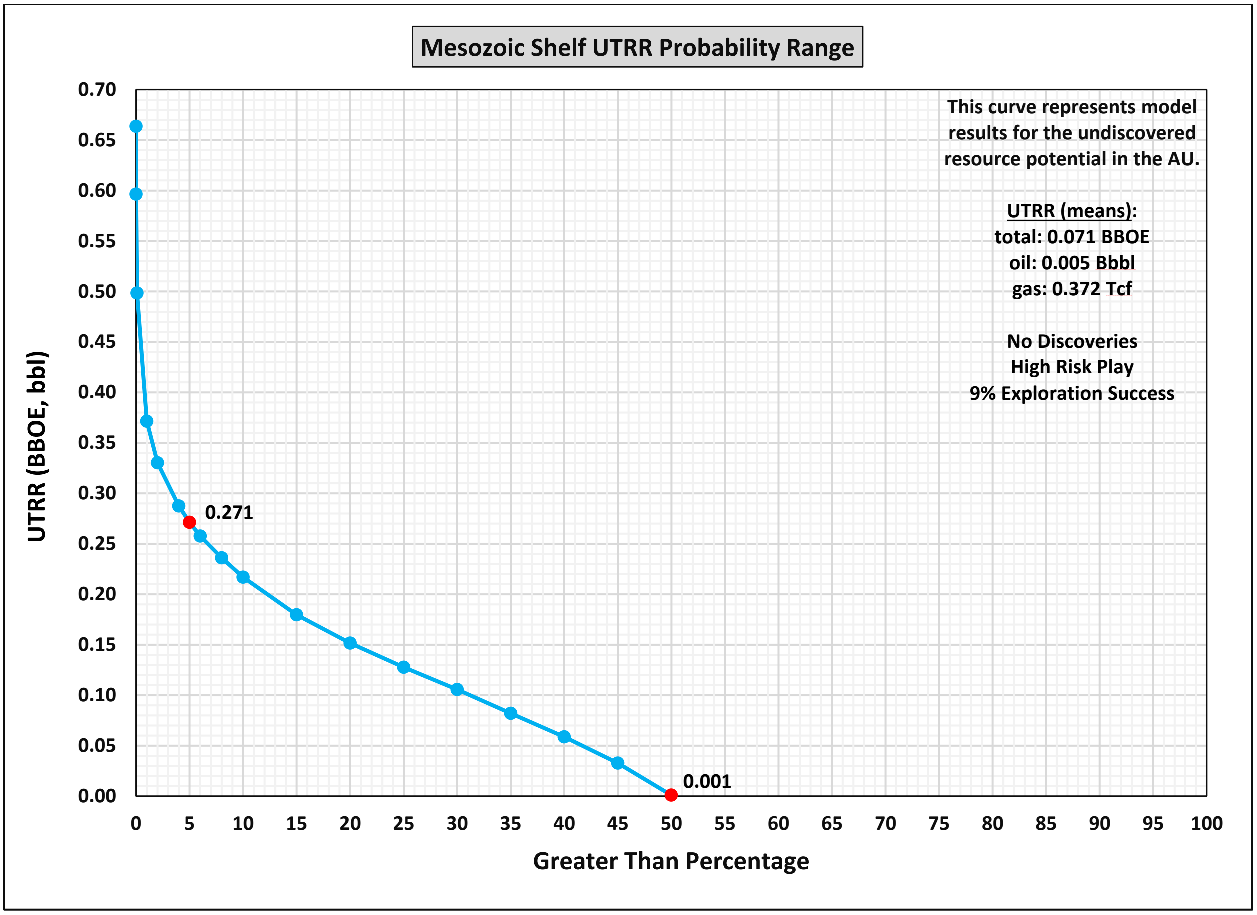

Figure 77. Mesozoic Shelf UTRR probability range based on total BOE.

Mesozoic Slope

Geology

The Mesozoic Slope AU 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 75**). The Mesozoic Slope AU abuts the Lower Tuscaloosa Slope AU 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 because of increasing depth, structural complexity, and extensive allochthonous salt. Well penetrations of the Mesozoic section are sparse.

The Mesozoic Slope AU is mostly subsalt, and subsurface temperatures are cooler relative to the Mesozoic Shelf AU because of the heat-wicking effect of the allochthonous salt canopy, which efficiently transfers heat from the deep subsurface to the sea floor, and also because of increasing water depth and less overburden. Only a small portion of the northern East Breaks Area was excluded because of anticipated high temperature. Because the Slope AU is situated in a cooler subsalt environment, Jurassic and Cretaceous source rocks remain in the oil-to-gas window, as evidenced by oil shows at 34,000 ft in the Tiber well (Keathley Canyon Block 102) and 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 thrusted, 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

Because of the portfolio of seismically defined subsalt structures and oil shows at the Tiber well, the hydrocarbon fill and trap components of the risking matrix at the play level carry no risk. Reservoir presence and quality are the riskiest components, resulting in a petroleum system chance of success of 60 percent (**Figure 3**). At the prospect level, the highest risks are reservoir quality and effective seals, resulting in an average conditional prospect chance of success of 18 percent (**Figure 4**). This equates to an overall exploration chance of success of 11 percent (**Figure 5**). 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 41 undiscovered pools, with a mean of eight.

With no BOEM-designated discoveries offshore, the pool-size distribution for this play was modeled with 24 Lower Tuscaloosa Formation discoveries in onshore Mississippi (**Figure 46**). These Lower Tuscaloosa discoveries range in size from 0.030 to 242 MMBOE, with a mean size of 36 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 190 MMBOE.

The play was modeled as 100 percent oil. With no information on GORs from the onshore analog discoveries, an average was calculated from eastern-GOM discovered data, with GRASP returning UTRR volumes for black oil and solution gas. Because of the play-level petroleum system risk for the play, only 60 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil and gas resources are 0.750 Bbbl at the 5th percentile, with a mean of 0.206 Bbbl, and 0.797 Tcf at the 5th percentile, with a mean of 0.219 Tcf, respectively (**Table 9** and **Figure 78**). Total undiscovered BOE resources are 0.892 Bbbl at the 5th percentile, with a mean of 0.245 Bbbl (**Figure 79**). Based on mean-level undiscovered BOE resources, the Mesozoic Slope ranks 16th of all 30 GOM assessment units (**Figure 10**).

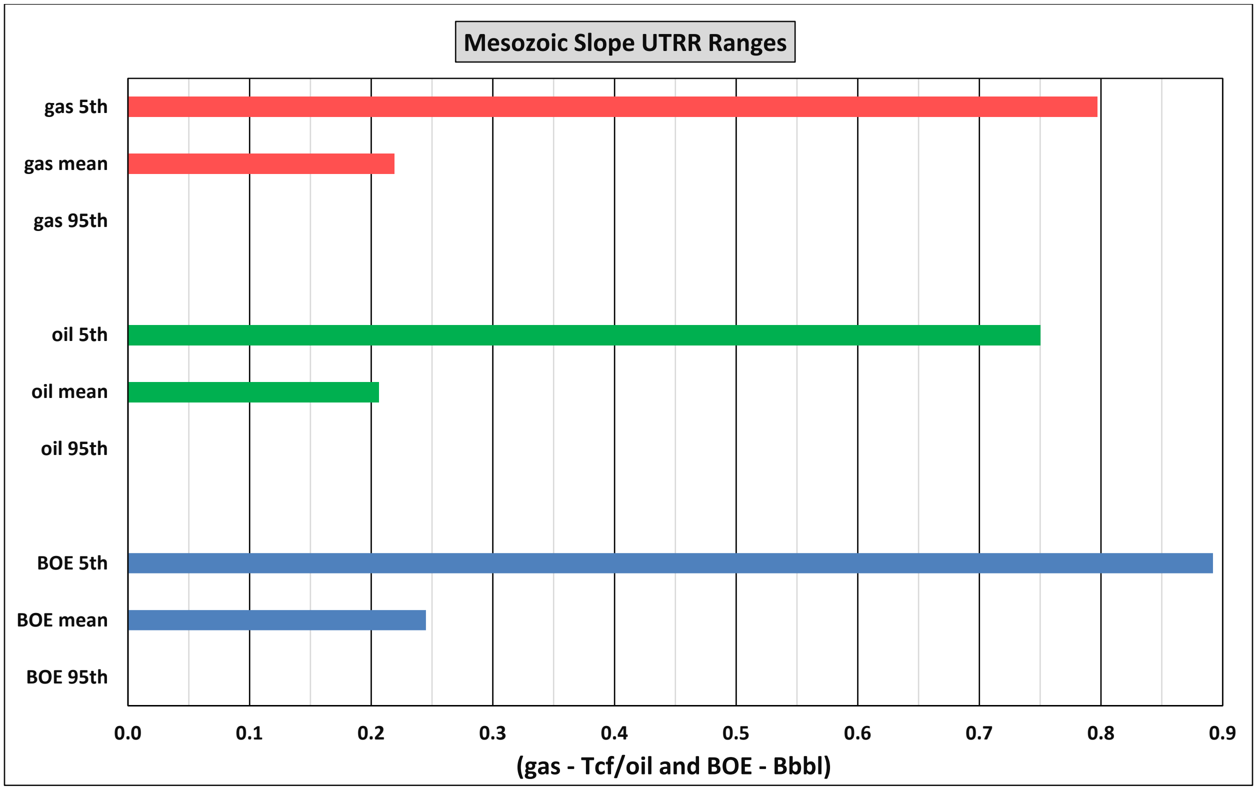

Figure 78. Mesozoic Slope gas, oil, and BOE UTRR ranges.

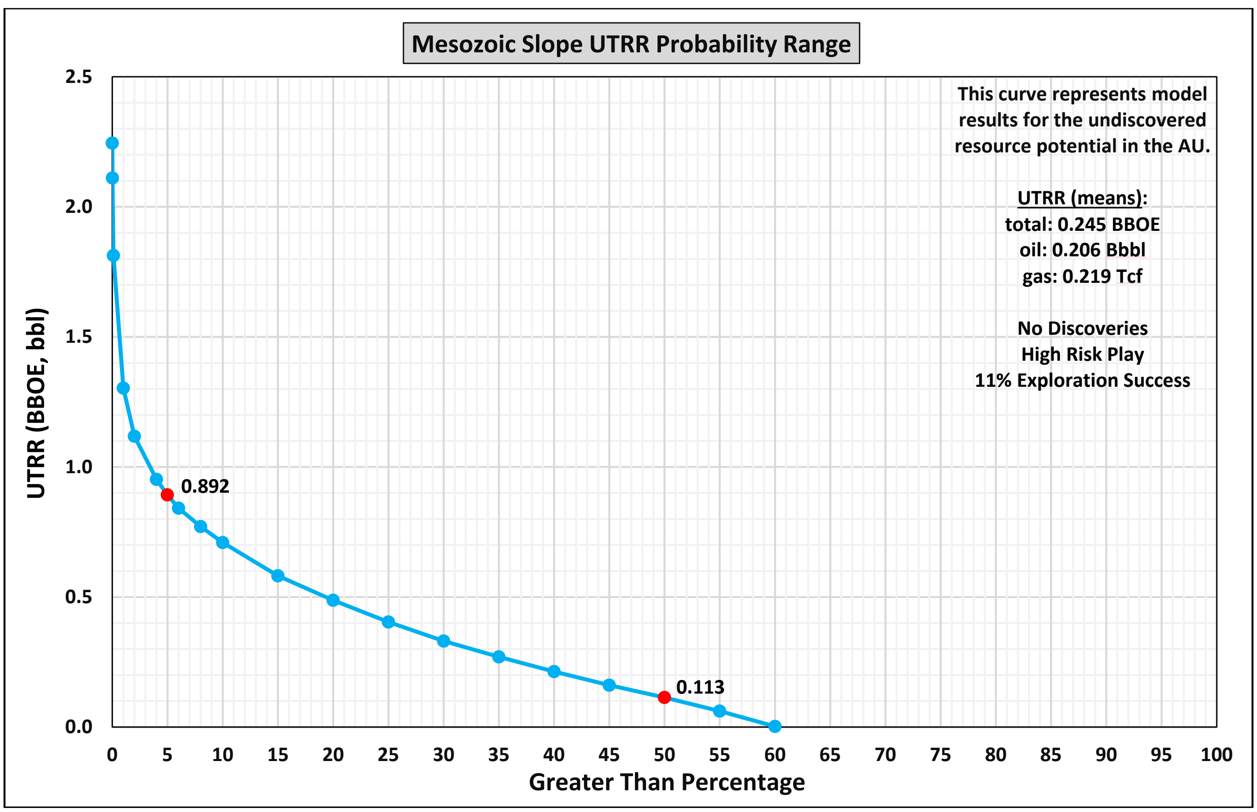

Figure 79. Mesozoic Slope UTRR probability range based on total BOE.

Mesozoic Basin Floor (unassessed)

Geology

The unassessed Mesozoic Basin Floor AU 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 75**).

Previous assessments included the region of the Mesozoic Basin Floor AU 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 actually sits astride a Jurassic mid-ocean ridge (Pindell et al., 2016; Sandwell et al., 2014; Snedden et al., 2014), 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 AU. Subsequent well tests and regional seismic correlation confirm that the unit originally identified as the Mid-Cretaceous Sequence Boundary was actually 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 AU.

Other Mesozoic Objectives

Other unassessed conceptual objectives of the Mesozoic AUs 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 GOM (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 GOM. Numerous penetrations in the deepwater areas of the northern GOM have penetrated the Chicxulub debrite layer (Scott et al., 2014), but none has 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 because of 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 GOM 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. There were no well penetrations of the Norphlet Formation in the Perdido Fold Belt area as of the January 1, 2019, cutoff date of this report.

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 Sunniland 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 because of 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 Federal 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 wells south of the platform area record oil shows. However, because it is considered high risk, this play was not assessed in the Federal OCS.

CENOZOIC ASSESSMENT UNITS

LOWER TERTIARY (PALEOGENE)

The Lower Tertiary Shelf (Wilcox and Frio), Frio Slope, Wilcox Slope, and Lower Tertiary Basin Floor AUs reference their modern bathymetric, rather than depositional setting (**Figure 80**). In the offshore areas of the GOM, all 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**).

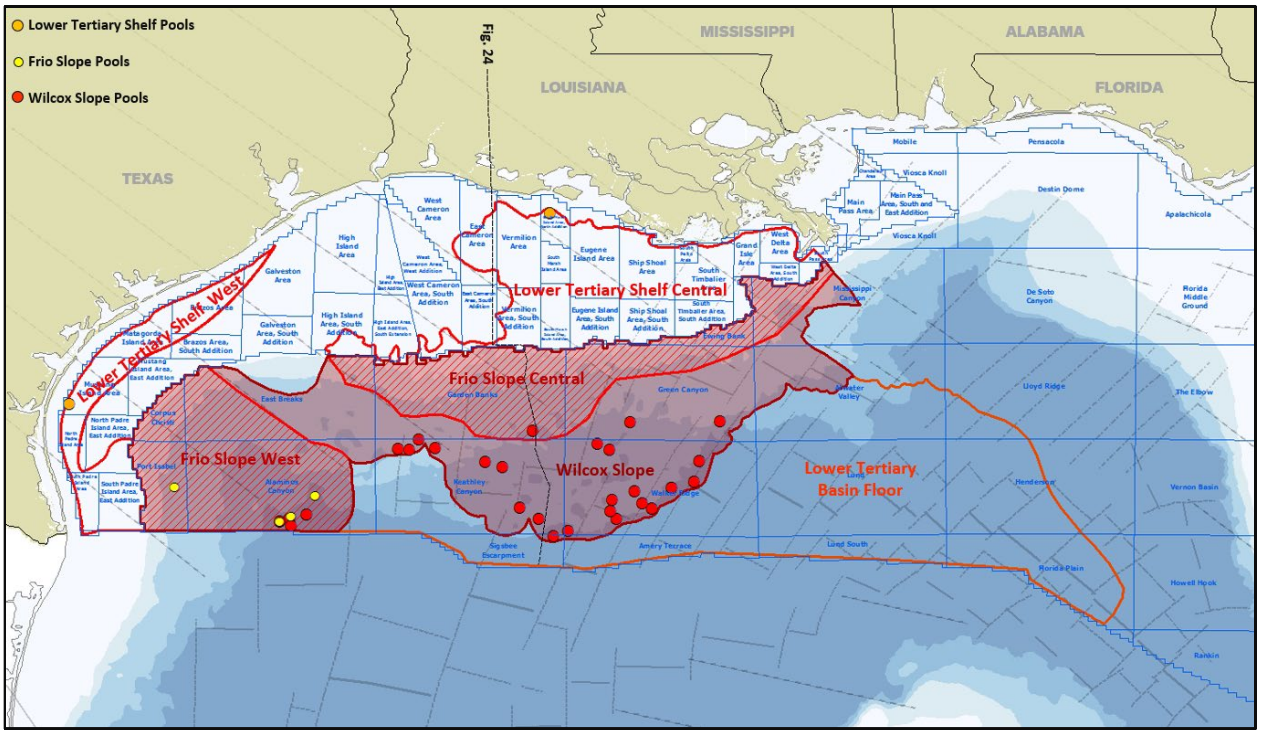

Figure 80. Lower Tertiary Shelf, Frio Slope, Wilcox Slope, and Lower Tertiary Basin Floor AU locations and associated discovered pools.

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 offshore GOM, and they are not included in this assessment. Production has been established from the Frio Formation in the deepwater GOM 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 GOM. 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 percent during the Paleocene (Sharman et al. 2017).

Lower Tertiary Shelf (Wilcox and Frio)

Geology

The undifferentiated Lower Tertiary Shelf AU 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 AU includes western and central GOM sectors (**Figure 80**) 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 AU. Wilcox sediments of the Lower Tertiary Shelf AU were deposited in slope canyons (McDonnell et al., 2008), intra-slope basins, and basin-floor fans. Frio-aged sediments of the Lower Tertiary Shelf AU were also deposited in slope and basin-floor settings.

The western sector of the Lower Tertiary Shelf AU extends along the Texas coast from the South Padre Island Area adjacent to Mexican waters and into the Galveston Area (**Figure 80**). 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 AU encompasses most of the central Louisiana shelf from the East Cameron Area eastward to the modern Mississippi River Delta (**Figure 80**). 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 AU is similarly situated to the Mesozoic Shelf AU beneath Paleogene and Neogene detachments, horizontal salt welds, and thick, complexly faulted Miocene and Plio–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 AU and include anticlinal closures above remnant autochthonous salt pillows and folds (Dooley et al., 2013; Philippe et al., 2005) 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 and South Marsh Island 243. Together, the two pools contain 0.001 Bbbl of oil and 0.050 Tcf of gas (total BOE of 0.010 Bbbl) (**Table 9**). The Frio pool in the Mustang Island 859 Field contains over 9 MMBOE, compared to the Wilcox pool in the South Marsh Island 243 Field, which only has about 0.2 MMBOE (**Figure 81**). Average subsea depths for the two discovered pools are 12,598 ft in Mustang Island and 26,789 ft in South Marsh Island, and water depths of the two pools are shallow, at less than 100 ft.

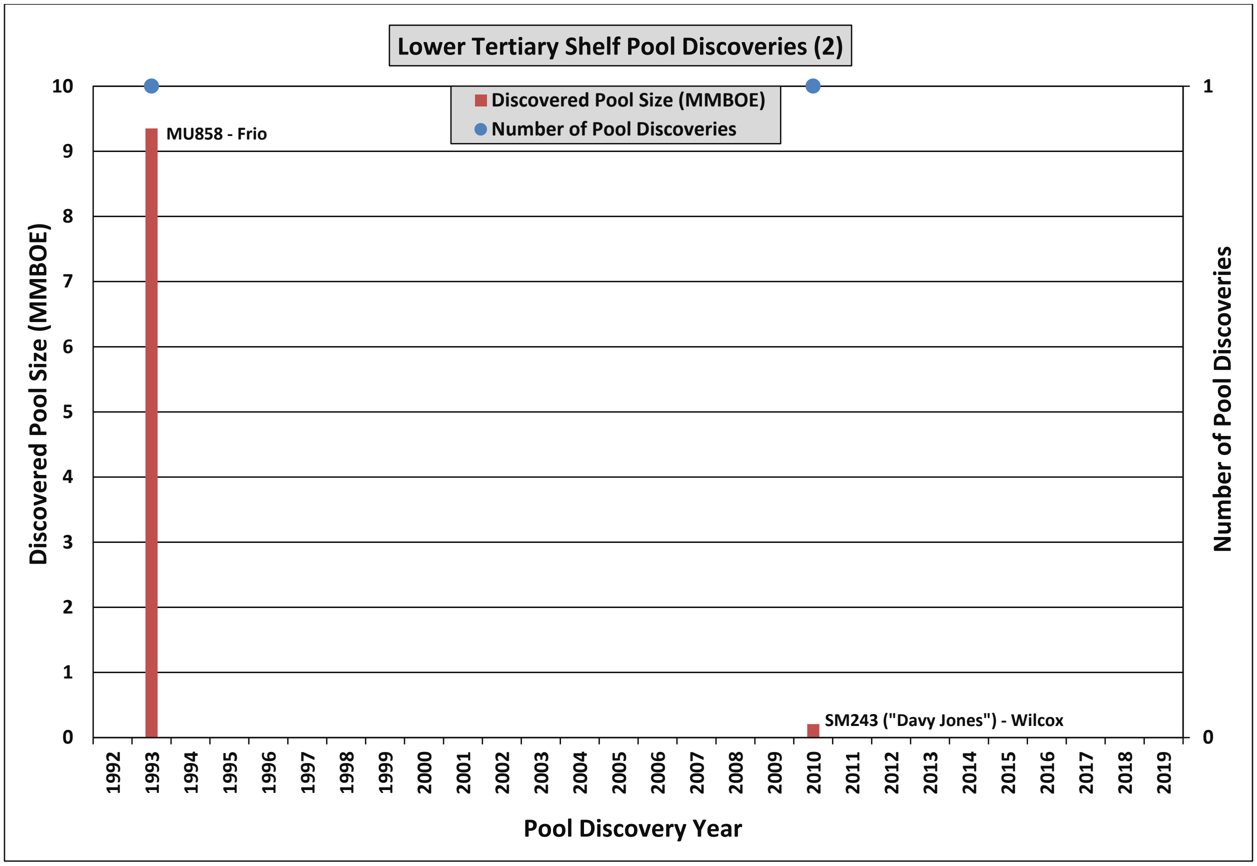

Figure 81. Lower Tertiary Shelf pool discovery history.

Risk

Most of the Galveston, High Island, West Cameron, and East Cameron Areas (**Figure 80**) were excluded from prospectivity in the Lower Tertiary Shelf AU because of high anticipated subsurface temperatures in excess of 460° F, 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. Unsuccessful flow rate tests due to "tight" reservoirs (because of the diagenetic effects of high pressures and temperatures) have caused downward revisions in the reserve estimates for the Davy Jones Prospect since BOEM's 2016 resource assessment (USDOI, 2017), which reduced the mean pool size significantly, from just under 800 MMBOE to only 0.2 MMBOE.

Even though a working petroleum system has been established for both Wilcox and Frio rocks on the shelf (**Figure 3**), the high pressure and temperature environments encountered condemn the prospect-level reservoir quality component of risking analysis (**Figure 4**), resulting in an overall exploration chance of success of 18 percent (**Figure 5**). 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 AU. 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 AU. From this pool-size distribution and the number of pools distribution, the largest six pools in the play are undiscovered, with the largest being approximately 54 MMBOE.

From the discovered data information, the play was modeled as 100 percent gas, with GRASP returning UTRR volumes for dry gas and condensate liquids (oil herein). Assessment results indicate that undiscovered oil resources range from 0.006 to 0.023 Bbbl, and undiscovered gas resources range from 0.491 to 1.887 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 82**). Total BOE undiscovered resources range from 0.093 to 0.359 BBOE at the 95th and 5th percentiles, respectively (**Figure 83**). Based on mean-level undiscovered BOE resources, the AU ranks 19th of all 30 GOM assessment units (**Figure 10**).

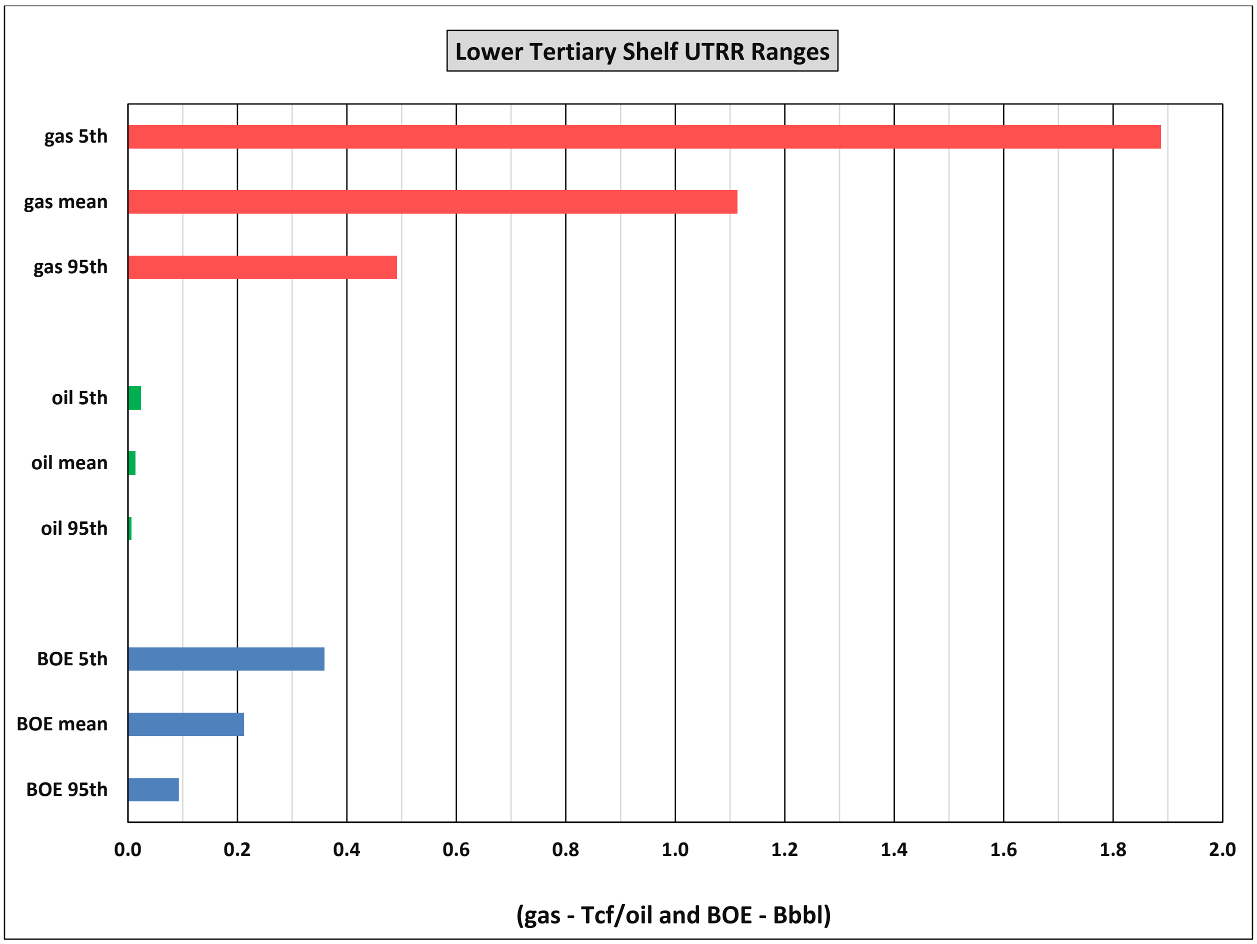

Figure 82. Lower Tertiary Shelf gas, oil, and BOE UTRR ranges.

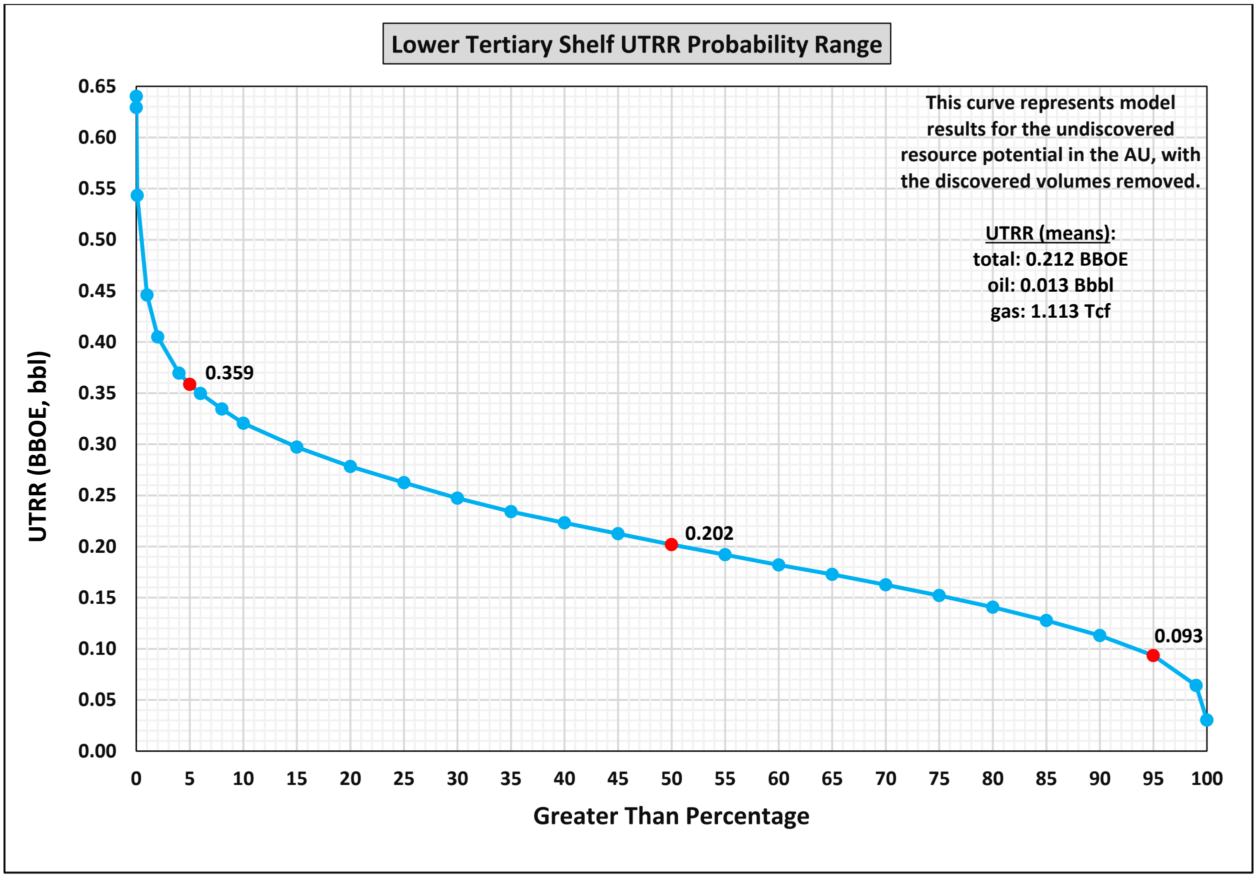

Figure 83. Lower Tertiary Shelf UTRR probability range based on total BOE.

Frio Slope

Geology

The Frio Slope AU is split into western and central GOM sectors (**Figure 80**) that are downdip equivalents of the Lower Tertiary Shelf AU 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 AU traverses the Port Isabel and Perdido Fold Belts (**Figure 80**), which are the sturctures 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 AU 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

Discovered Frio pools on the slope are contained in five BOEM-designated fields (**Figure 84**). Together they contain 0.187 Bbbl of oil and 0.108 Tcf of gas (total BOE of 0.206 Bbbl) (**Table 9**). Alaminos Canyon 857 and 859 are the only pools of Frio-age in the slope with significant volumes (**Figure 84**). 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

With a proven Frio petroleum system on the slope, there is no play-level risk for this AU (**Figure 3**). However, the reservoir quality of these Frio rocks and effective seal mechanisms were deemed the riskiest aspect at the prospect level (**Figure 4**), resulting in an overall exploration chance of 15 percent (**Figure 5**). See Appendix B for details.

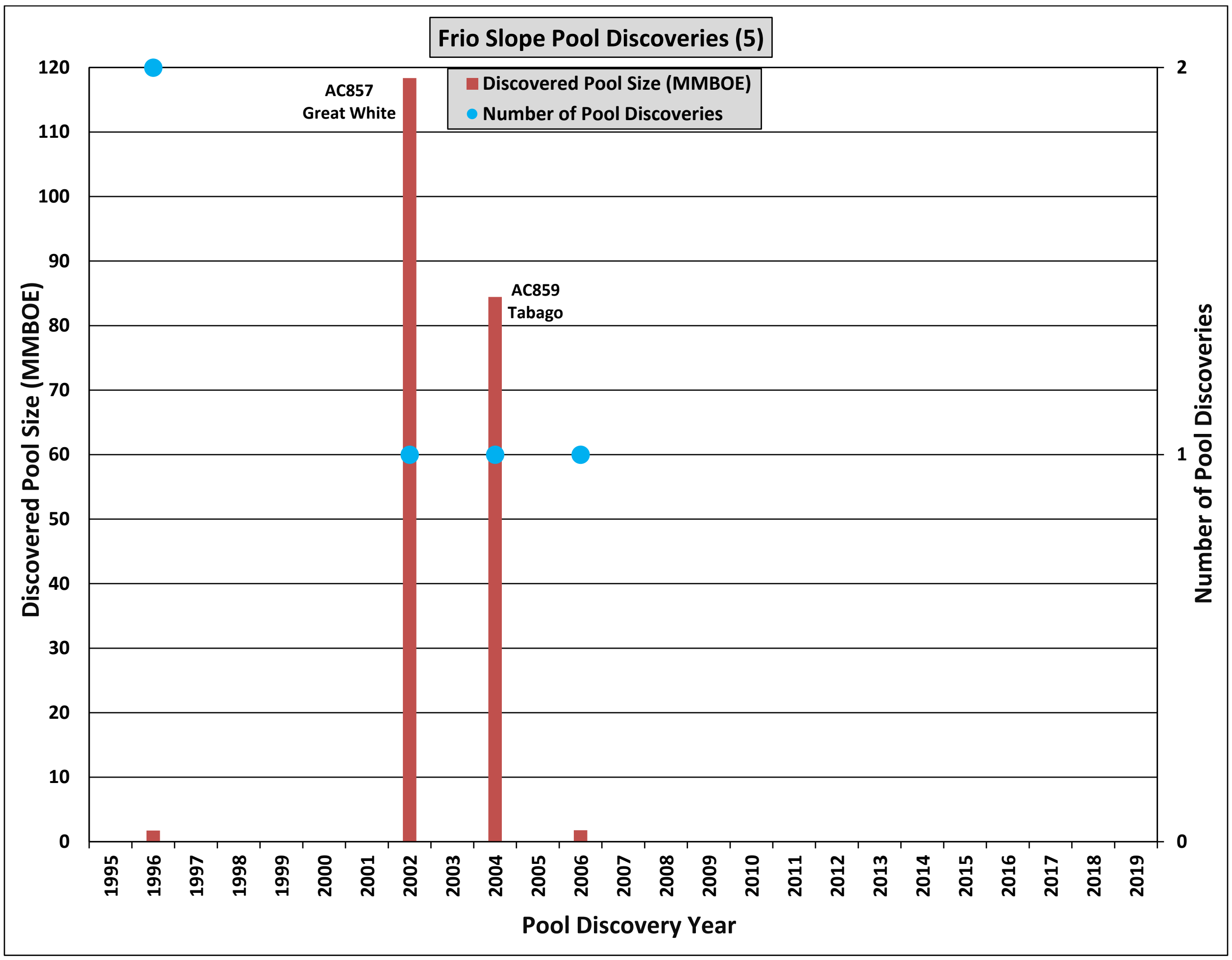

Figure 84. Frio Slope pool discovery history.

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 40 to 104. Applying risk results in 6 to 16 undiscovered pools, with a mean of 11.

The pool-size distribution was modeled with the discoveries and mapped prospects in the AU. From this pool-size distribution and the number of pools distribution, the largest two pools in the play are undiscovered, with the largest approximately 131 MMBOE in size.

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 0.030 to 0.473 Bbbl, and undiscovered gas resources range from 0.017 to 0.272 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 85**). Total BOE undiscovered resources range from 0.033 to 0.521 BBOE at the 95th and 5th percentiles, respectively (**Figure 86**). Based on mean-level undiscovered BOE resources, the AU ranks 20th of all 30 GOM assessment units (**Figure 10**).

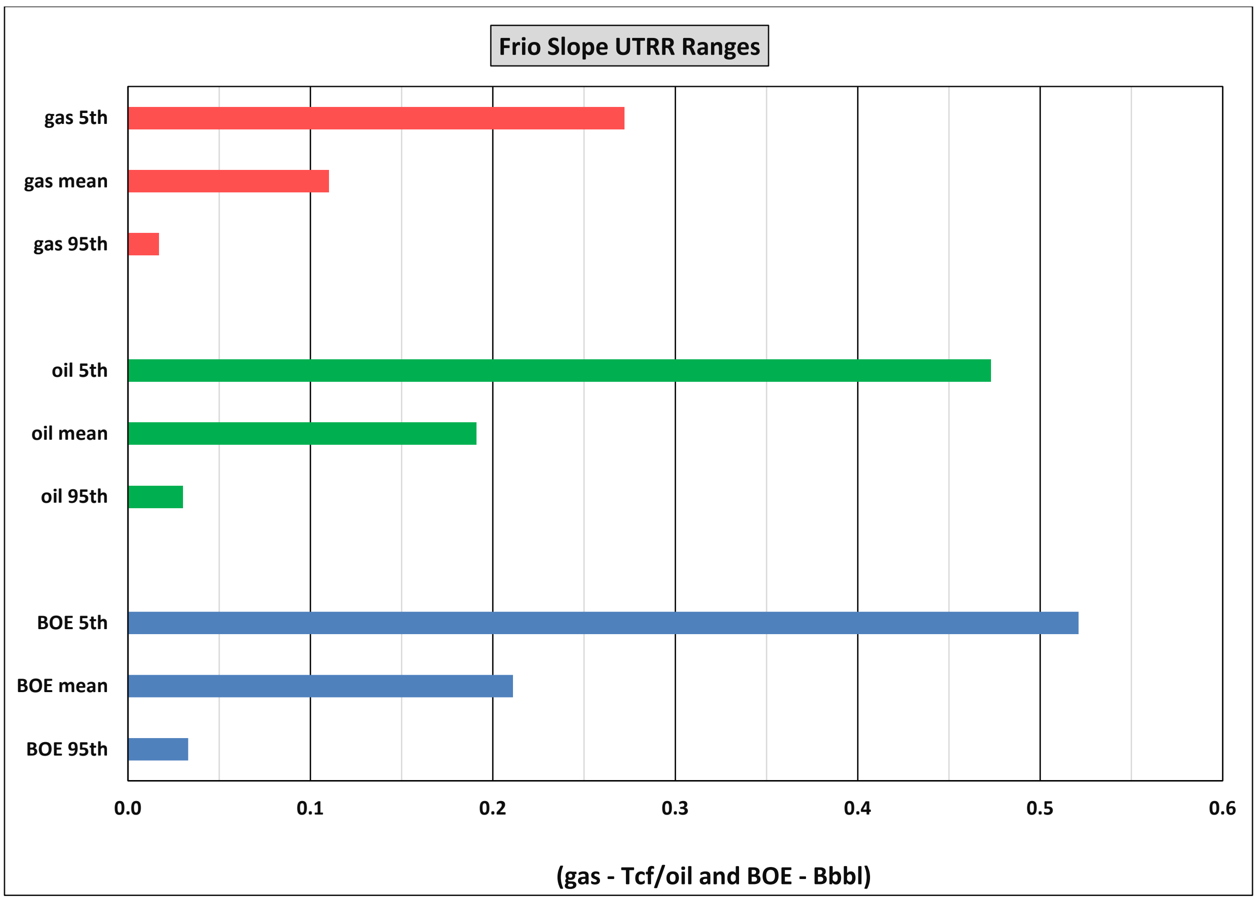

Figure 85. Frio Slope gas, oil, and BOE UTRR ranges.

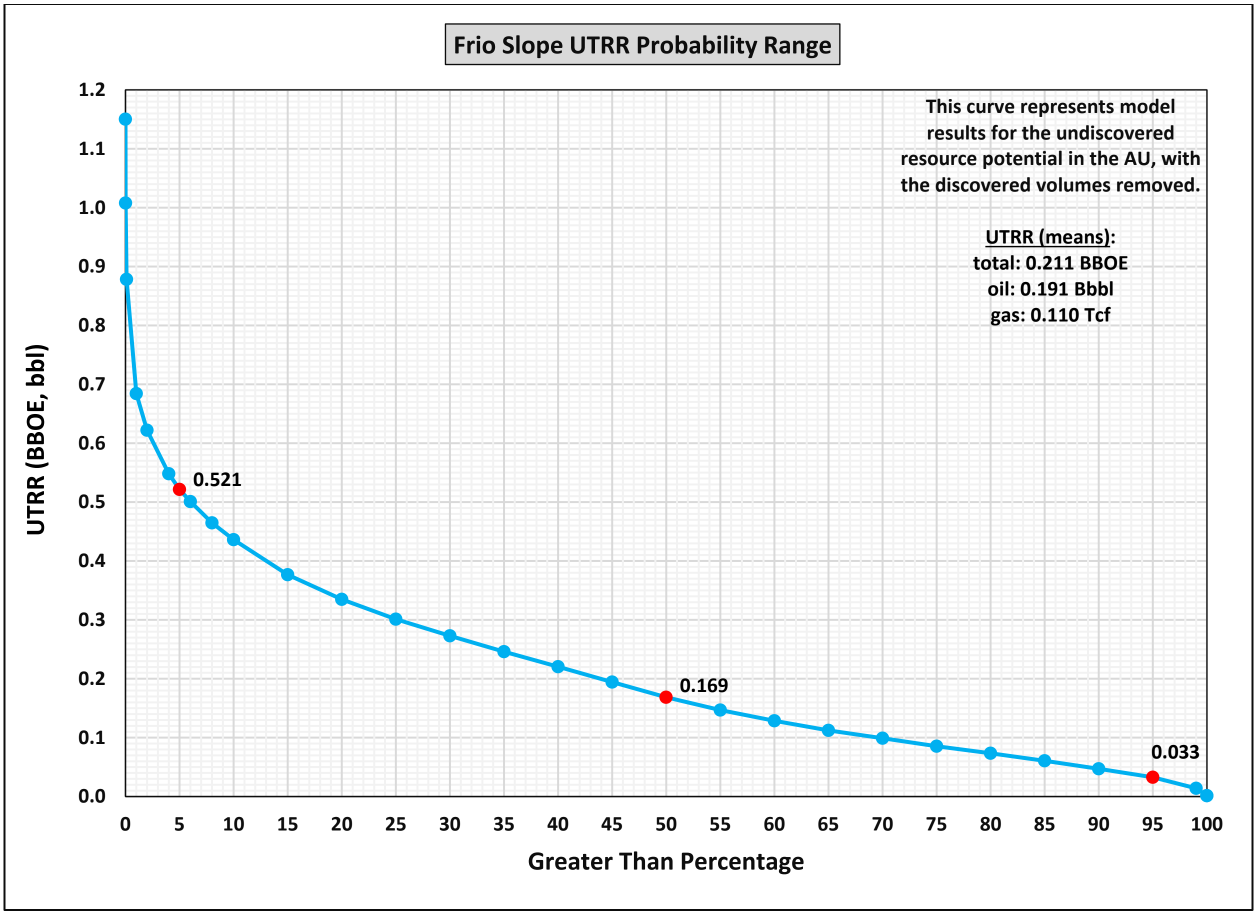

Figure 86. Frio Slope UTRR probability range based on total BOE.

Wilcox Slope

Geology

The Wilcox Slope AU 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 80**). The AU 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 Wilcox Slope AU 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 (<20,000 ft, with an average depth of approximately 14,000 ft) than in the central GOM (25,000 to 35,000 ft) (USDOI, 2021b). In spite of the shallower depths, subsurface temperatures are higher because of heat-wicking effects of the allochthonous salt canopy that has reduced the geothermal gradient in the central GOM and perhaps in part because of 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 AU in the central GOM (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/shelf-ward are increasingly complex structures related to salt withdrawal. Traps are typically three-way closures against salt feeders or vertical salt welds. Of particular 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 within the Wilcox Slope AU occur in the Alaminos Canyon, Garden Banks, Keathley Canyon, Walker Ridge, Green Canyon, and Sigsbee Escarpment Areas (**Figure 80**). As of the end of 2018, BOEM has estimated sizes of 28 pools, with discovery dates ranging from 2001 to 2016 (**Figure 87**). The AU contains 3.457 Bbbl of oil and 1.854 Tcf of gas (total BOE of 3.787 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 2008, Keathley Canyon 872 (Buckskin) is the largest pool, containing an estimated 461 MMBOE (**Figure 88**). Other sizeable discovered pools include Green Canyon 807 (Anchor), Alaminos Canyon 857 (Great White), Walker Ridge 678 (St. Malo), and Walker Ridge 759 (Jack), all estimated to contain approximately 300 MMBOE or more (**Figure 88**). Pools have been discovered in water depths ranging from 3,910 to 9,693 ft, and subsea depths of these pools range from 12,747 to 32,218 ft.

Figure 89 illustrates the pseudo-creaming curve for Wilcox Slope pool discoveries superimposed on the number and size of the discoveries through time. A creaming curve can be used as a measure of the maturity of a play, with a flat curve indicative of a mature play with little to no discoveries being added. Generally, the curve for the Wilcox Slope is still in an ascending phase, with the Anchor discovery adding substantial reserve volumes to the AU in 2014.

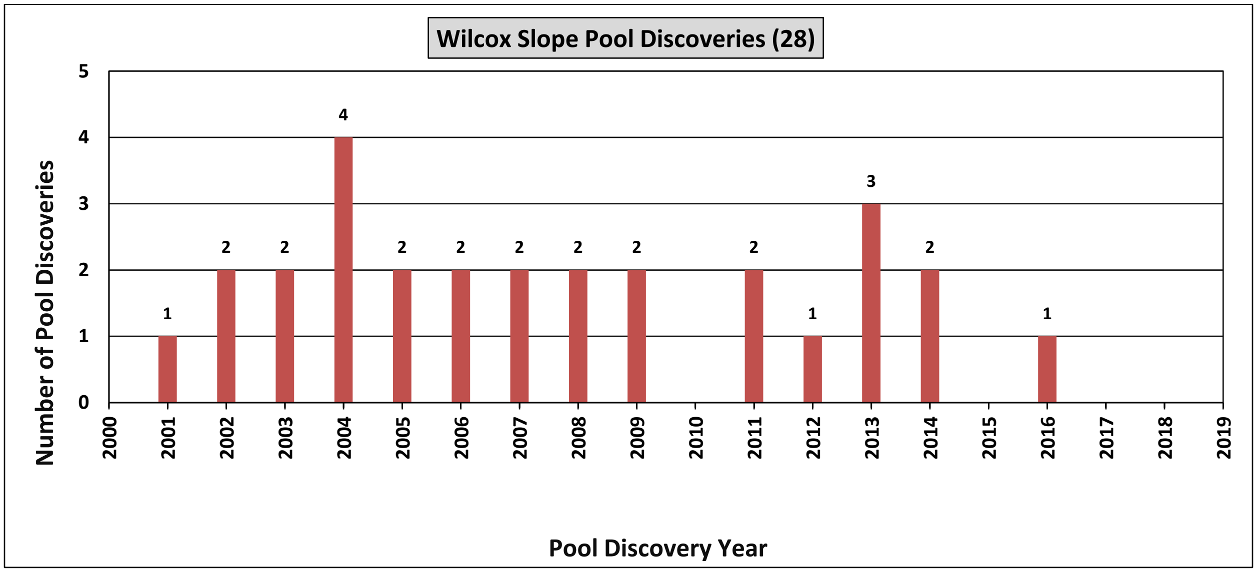

Figure 87. Wilcox Slope pool discovery history.

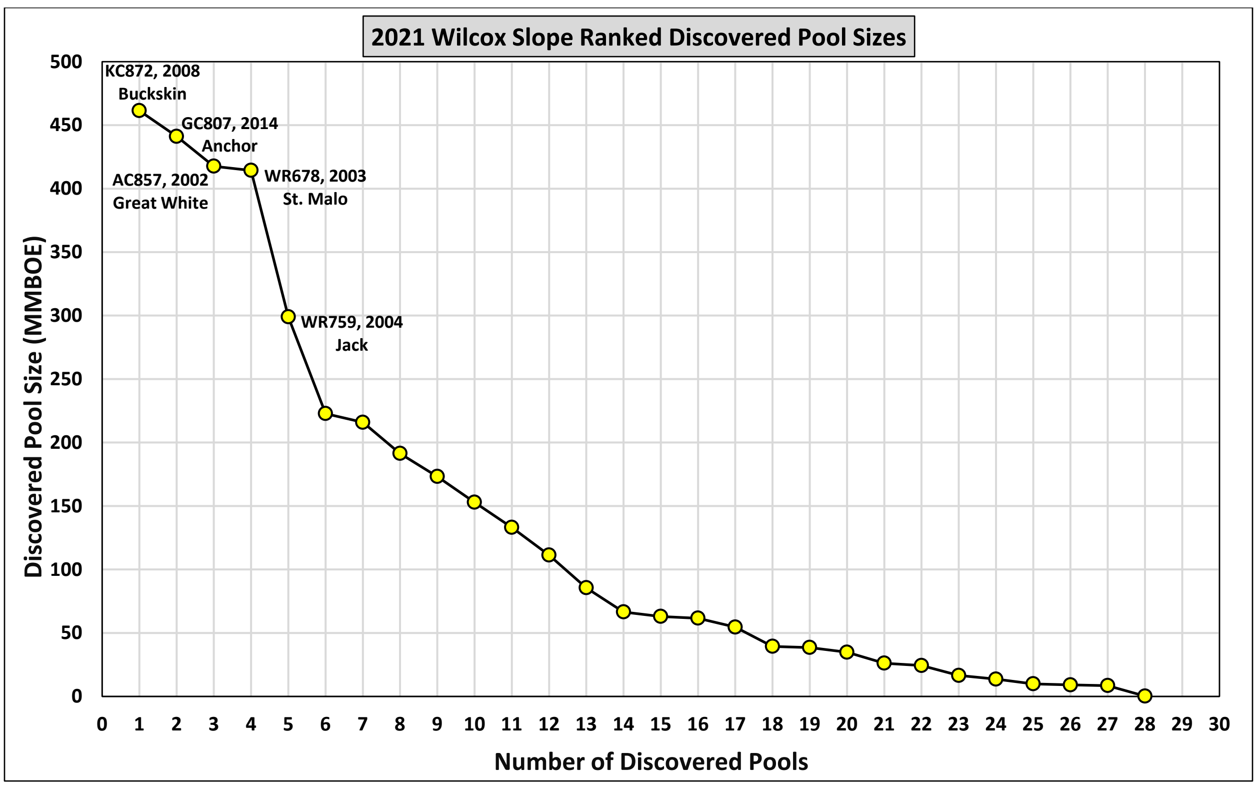

Figure 88. Wilcox Slope discovered pool-rank plot.

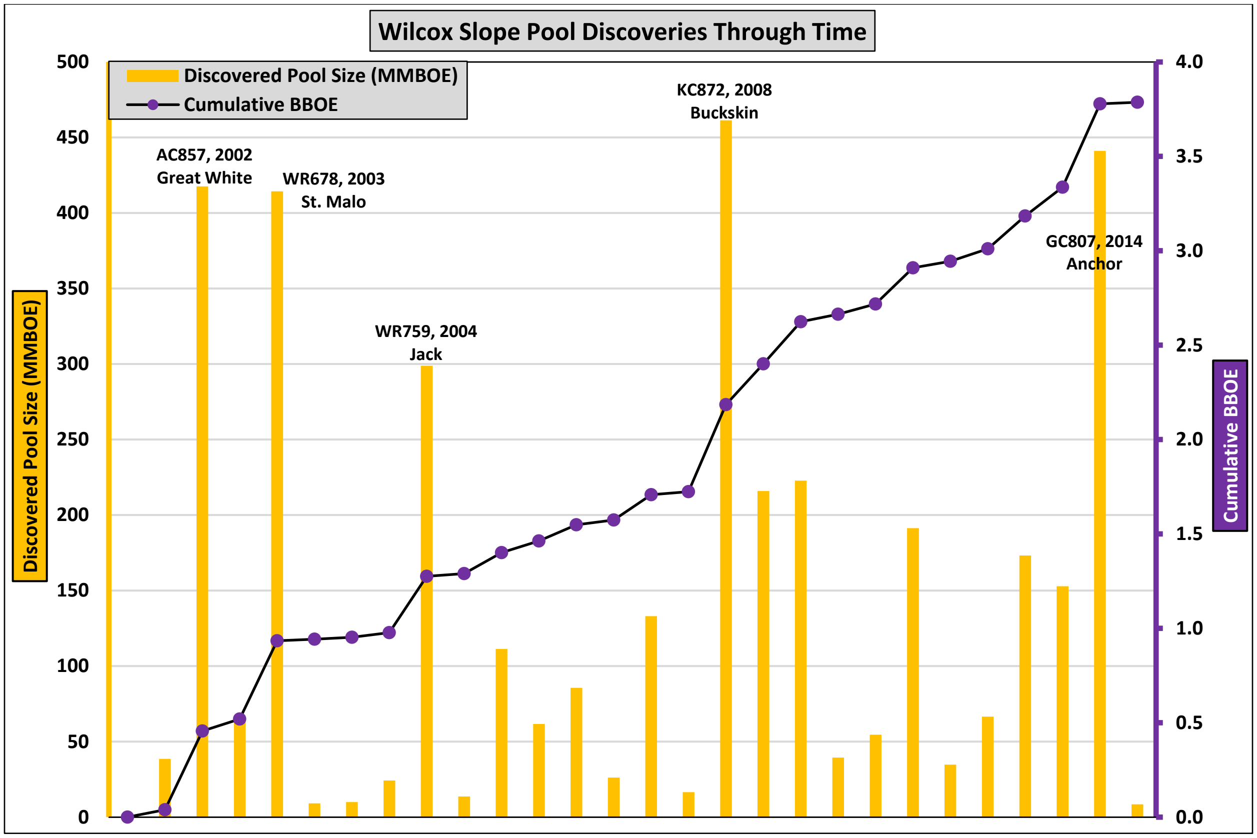

Figure 89. Wilcox Slope pseudo-creaming curve.

Risk

With numerous discoveries and hydrocarbon encounters in the AU, there is no play-level risk (**Figure 3**), as a working petroleum system has been well established for the Wilcox Formation onshore and offshore shelf and slope. At the average conditional prospect-level, it was deemed that the reservoir quality and effective seals were the most problematic (**Figure 4**). 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 GOM, with an overall exploration chance of success of 25 percent (**Figure 5**). 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 200 to 520. Applying risk results in 50 to 130 undiscovered pools, with a mean of 90.

The pool-size distribution was modeled with the discoveries in the AU, which range in size from 8 to 461 MMBOE, with a mean size of 140 MMBOE. From this pool-size distribution and the number of pools distribution, the two largest pools in the play are undiscovered, with the largest being approximately 563 MMBOE.

From the discovered data information, the play was modeled as 100 percent 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 4.760 to 12.806 Bbbl, and undiscovered gas resources range from 2.551 to 6.864 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 90**). Total BOE undiscovered resources range from 5.214 to 14.027 BBOE at the 95th and 5th percentiles, respectively (**Figure 91**). Based on mean-level undiscovered BOE resources, the Wilcox Slope is forecast to contain the most potential of all 30 GOM assessment units (**Figure 10**).

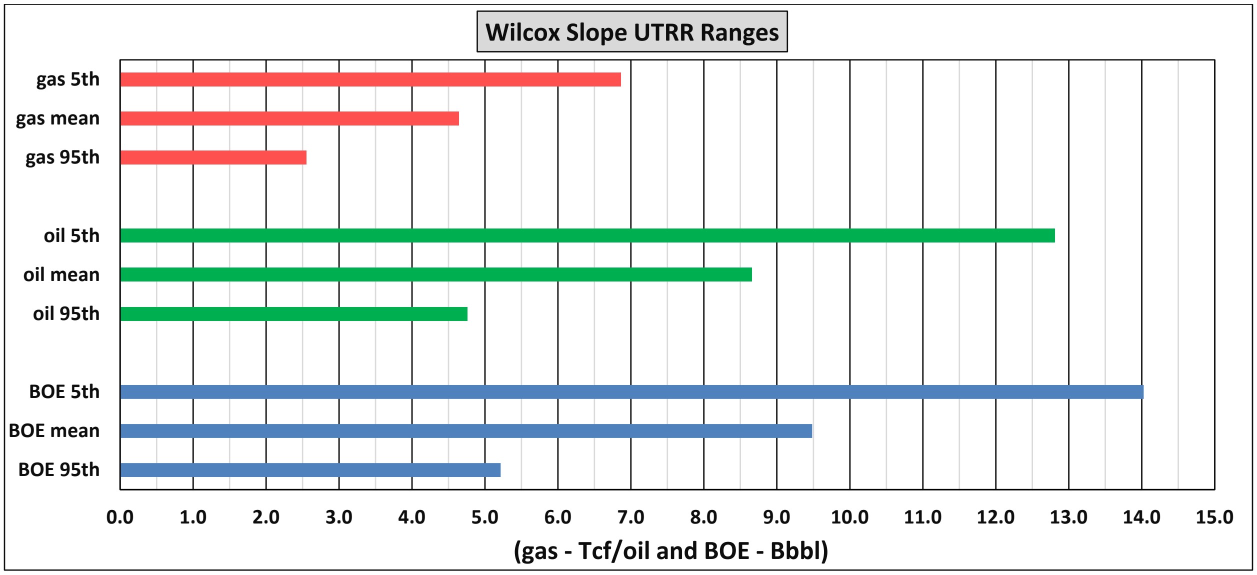

Figure 90. Wilcox Slope gas, oil, and BOE UTRR ranges.

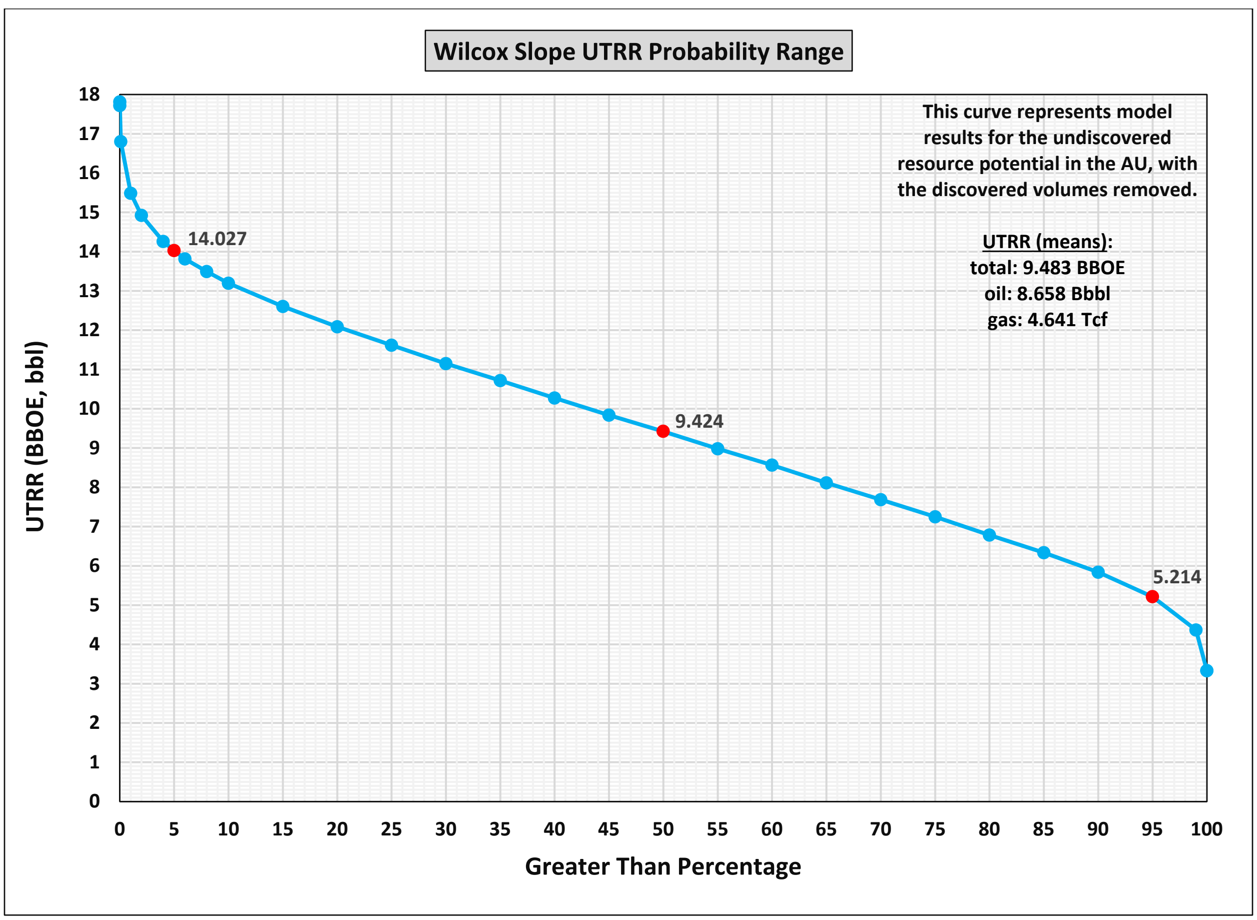

Figure 91. Wilcox Slope UTRR probability range based on total BOE.

Lower Tertiary Basin Floor

Geology

The undifferentiated Lower Tertiary Basin Floor AU contains no discoveries and conceptually includes all Paleocene, Eocene, and Oligocene strata. The AU 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 80**). It is generally coincident 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. An inventory of subtle compactional drape closures associated with underlying basement structures had been included in the Buried Hills Drape Play of previous assessments (e.g., Lore et al., 2001). New to the current assessment is a portfolio of large stratigraphic traps inferred from seismic facies that are syncline-separated from discoveries in the outboard Wilcox Slope AU. 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 because of 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 Basin Floor AU, 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 (Lonergan 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

With no proven petroleum system, the presence and quality of a reservoir were deemed the riskiest components, resulting in a play-level chance of success of 56 percent (**Figure 3**). The same determination was made at the prospect level, leading to an average conditional prospect chance of success of 18 percent (**Figure 4**). The resulting overall exploration chance of success is just 10 percent, making the Lower Tertiary Basin Floor one of the riskiest AUs assessed (**Figure 5**). 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 eight.

The pool-size distribution for this conceptual play was modeled with 14 outboard Wilcox Slope discoveries in the deepwater GOM. These pools range in size from 9 to 461 MMBOE, with a mean size of

127 MMBOE. From this pool-size distribution and the number of pools distribution, the largest pool in the play is approximately 485 MMBOE.

The play was modeled as 100 percent oil. Based on GORs from the 14 Wilcox Slope pool volumes, GRASP returned UTRR volumes for black oil and solution gas. Because of the play-level petroleum system risk for the play, only 56 percent of the probabilistic trials in the assessment model returns successful case values. Assessment results indicate that undiscovered oil and gas resources are 2.999 Bbbl at the 5th percentile, with a mean of 0.991 Bbbl, and 0.777 Tcf at the 5th percentile, with a mean of 0.257 Tcf, respectively (**Table 9** and **Figure 92**). Total undiscovered BOE resources are 3.137 Bbbl at the 5th percentile, with a mean of 1.036 Bbbl (**Figure 93**). Based on mean-level undiscovered BOE resources, the play ranks 8th of all 30 GOM assessment units (**Figure 10**).

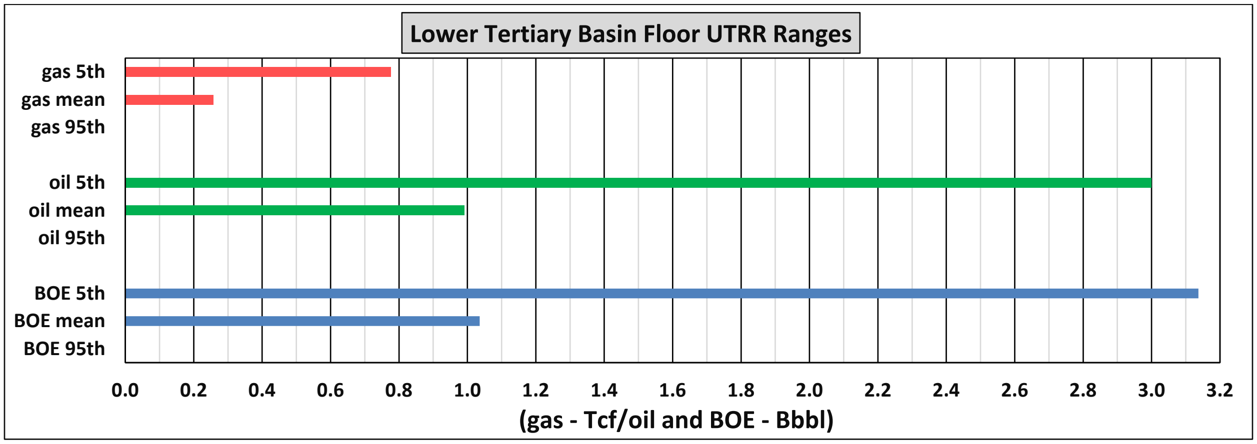

Figure 92. Lower Tertiary Basin Floor gas, oil, and BOE UTRR ranges.

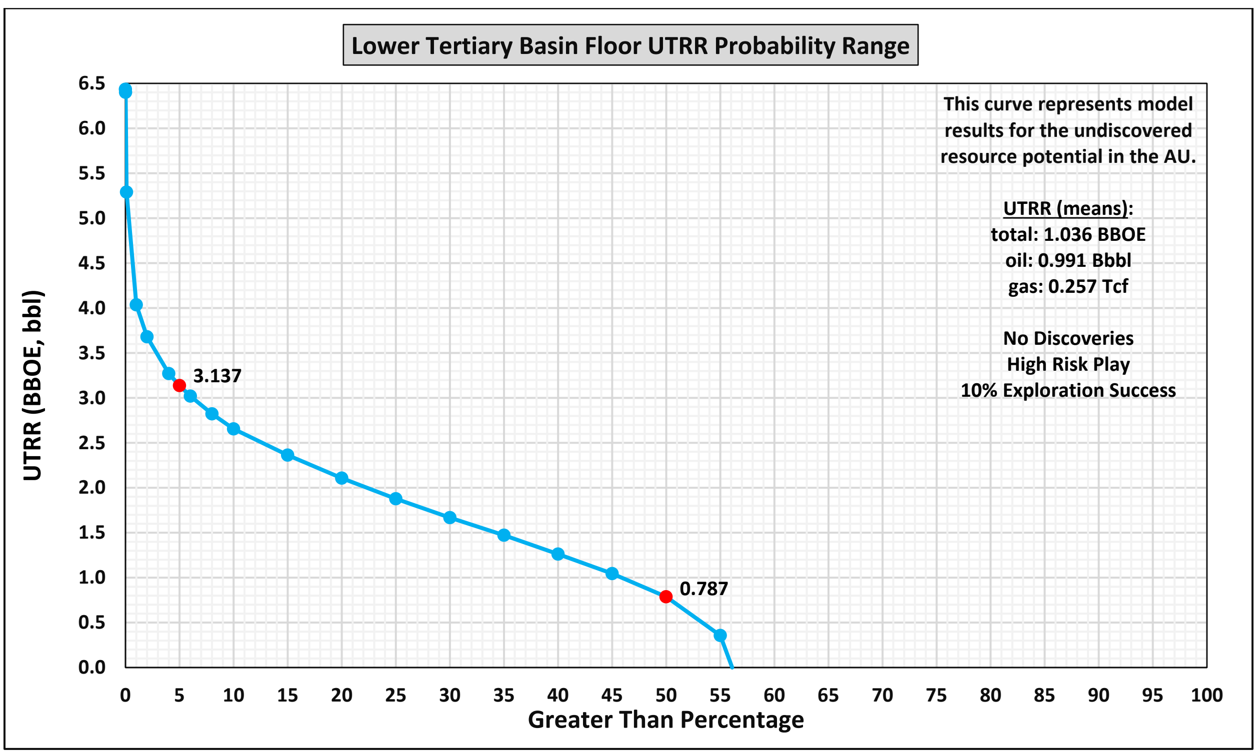

Figure 93. Lower Tertiary Basin Floor UTRR probability range based on total BOE.

Neogene and Quaternary

The Neogene and Quaternary Shelf, Slope, and Basin Floor AU locations reference their modern 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 thrusted 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 present-day GOM shelf. The stratigraphic framework within the GOM Basin for Lower 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 94**).

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.

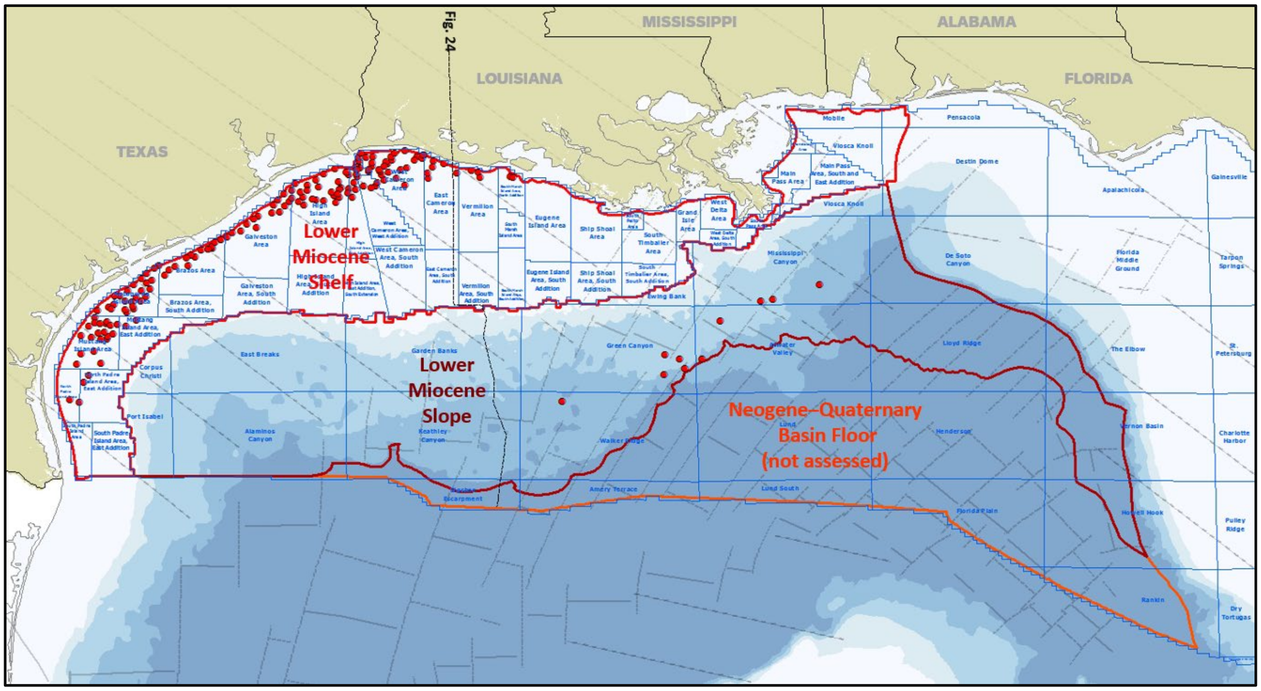

Figure 94. Lower Miocene Shelf and Slope locations and associated discovered pools.

The Lower Miocene Shelf AU in the western GOM 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 Lower Miocene Shelf 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 within the Lower Miocene Shelf AU lie in shallow OCS waters of offshore Texas and the southwest Louisiana coast (**Figure 94**). As of the end of 2018, 159 pools have been discovered, with discovery dates ranging from 1949 to 2013 (**Figure 95**). The AU contains 0.223 Bbbl of oil and 19.935 Tcf of gas (total BOE of 3.770 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 1980, Matagorda Island 623 is the largest pool, containing an estimated 0.322 BBOE (**Figure 96**). Other sizeable discovered pools include West Cameron 71, West Cameron 45, and Matagorda Island 668, all estimated to contain more than 0.150 BBOE (**Figure 96**). Pools have been discovered in water depths ranging from 13 to 214 ft, and subsea depths of these pools range from 4,664 to 19,632 ft.

Figure 97 illustrates the pseudo-creaming curve for Lower Miocene Shelf pool discoveries superimposed on the number and size of the discoveries through time. The largest pools were found in the early history exploration, with little resources being added present day.

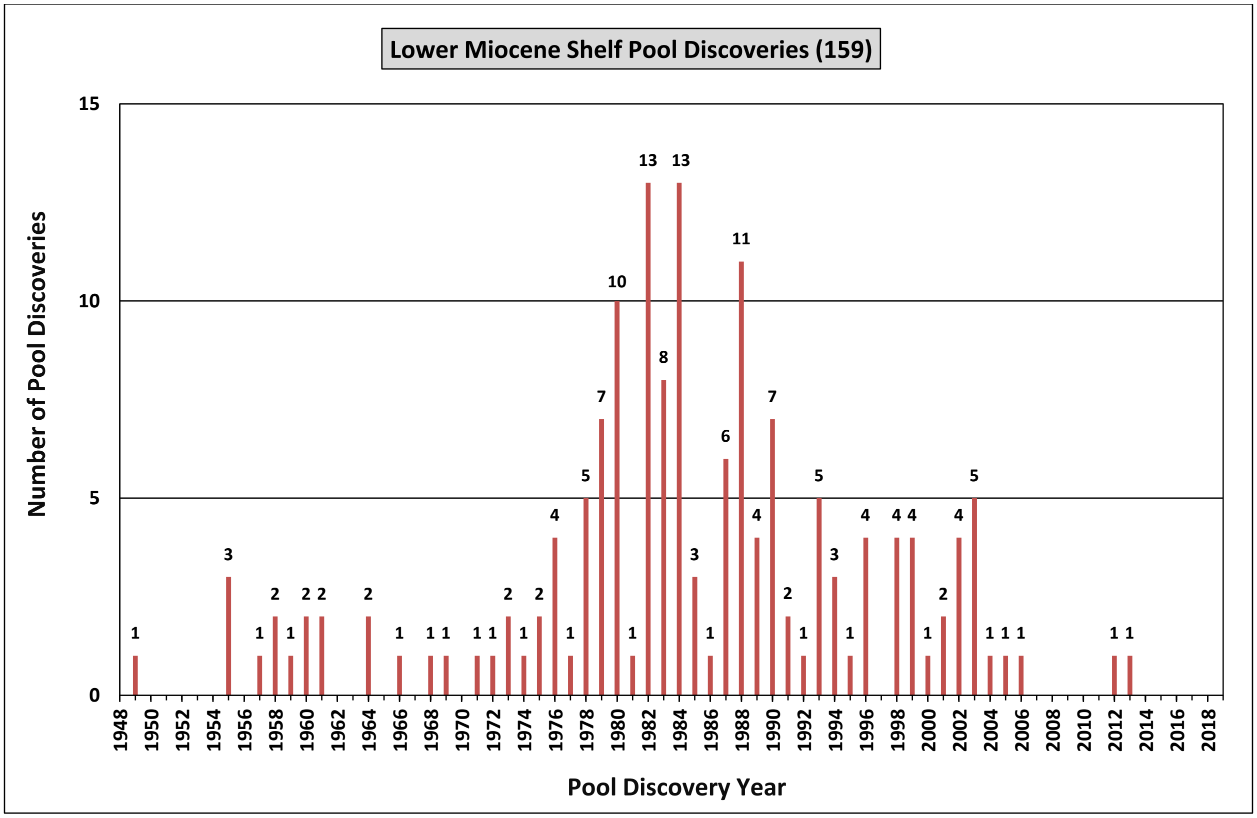

Figure 95. Lower Miocene Shelf pool discovery history.

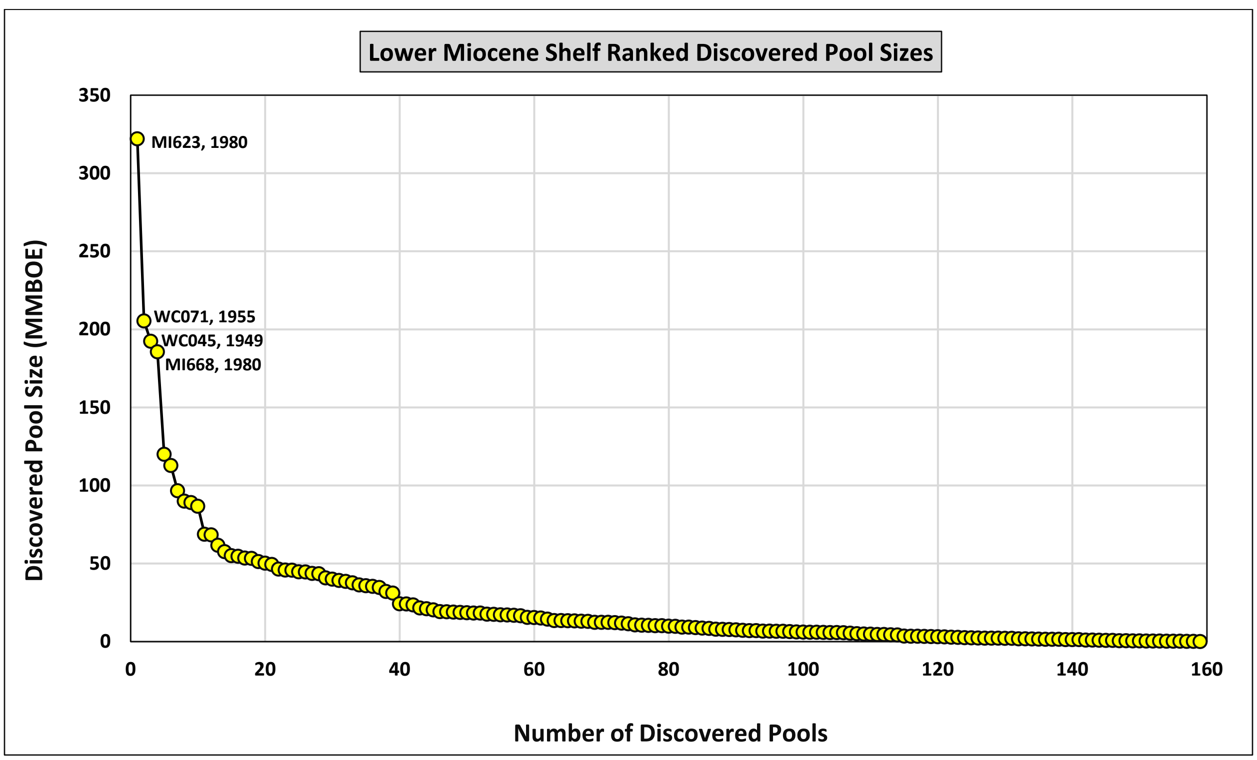

Figure 96. Lower Miocene Shelf discovered pool-rank plot.

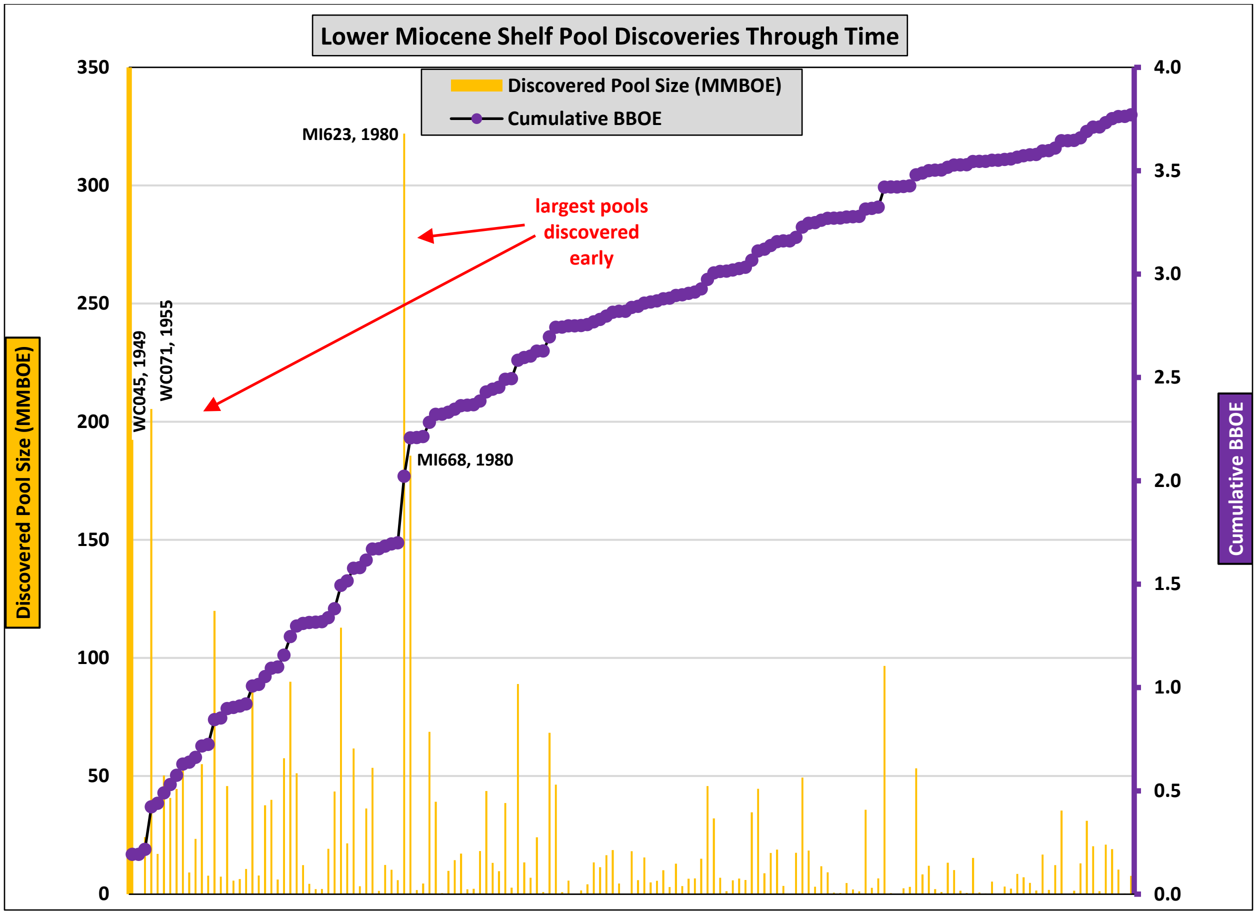

Figure 97. Lower Miocene Shelf pseudo-creaming curve.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factor for successful hydrocarbon accumulations is the trap component, resulting in a prospect-level chance of success of 21 percent (**Figure 4**). This makes the overall exploration chance of success 21 percent (**Figure 5**). See Appendix B for details.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 195 to 386. Applying risk results in 41 to 81 undiscovered pools, with a mean of 61.

The pool-size distribution was modeled with the 159 discoveries in the AU. These pools range in size from 0.031 to 322 MMBOE, with a mean size of 24 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 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 0.007 to 0.087 Bbbl, and undiscovered gas resources range from 0.622 to 7.972 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 98**). Total BOE undiscovered resources range from 0.118 to 1.505 BBOE at the 95th and 5th percentiles, respectively (**Figure 99**). Based on mean-level undiscovered BOE resources, the AU ranks 13th of all 30 GOM assessment units (**Figure 10**).

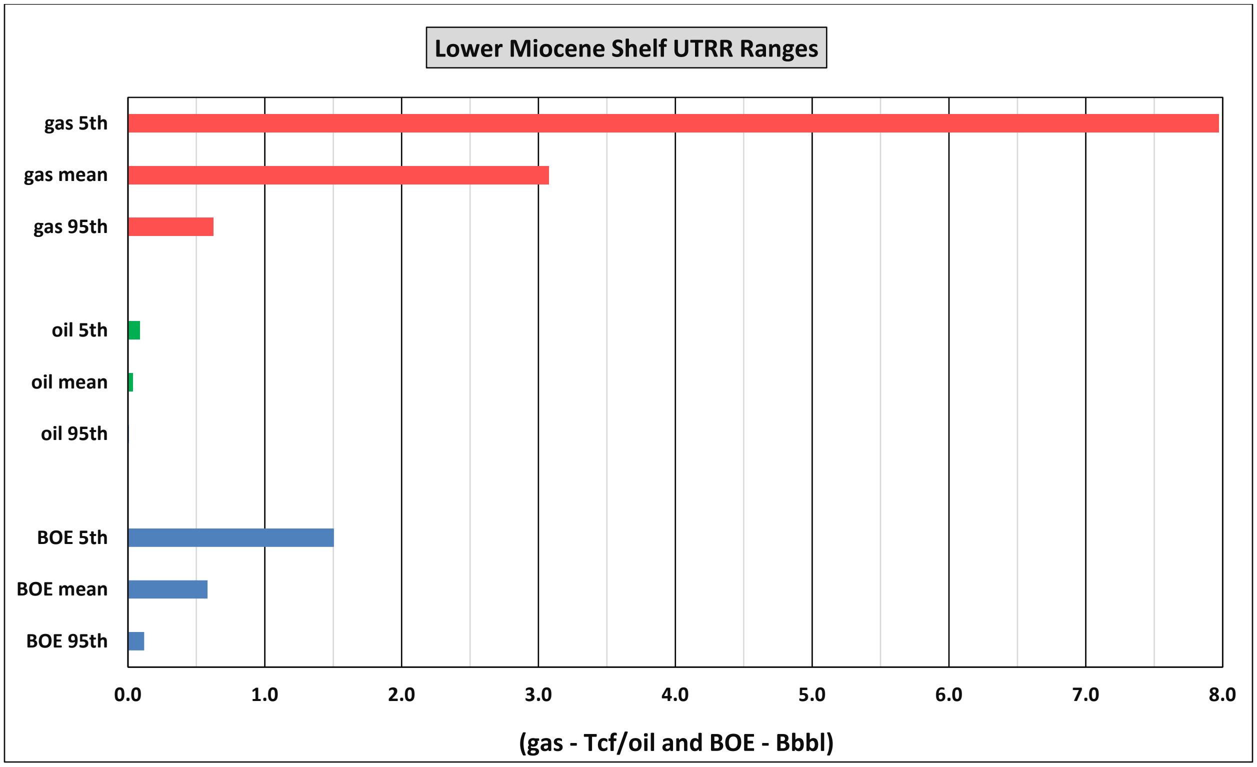

Figure 98. Lower Miocene Shelf gas, oil, and BOE UTRR ranges.

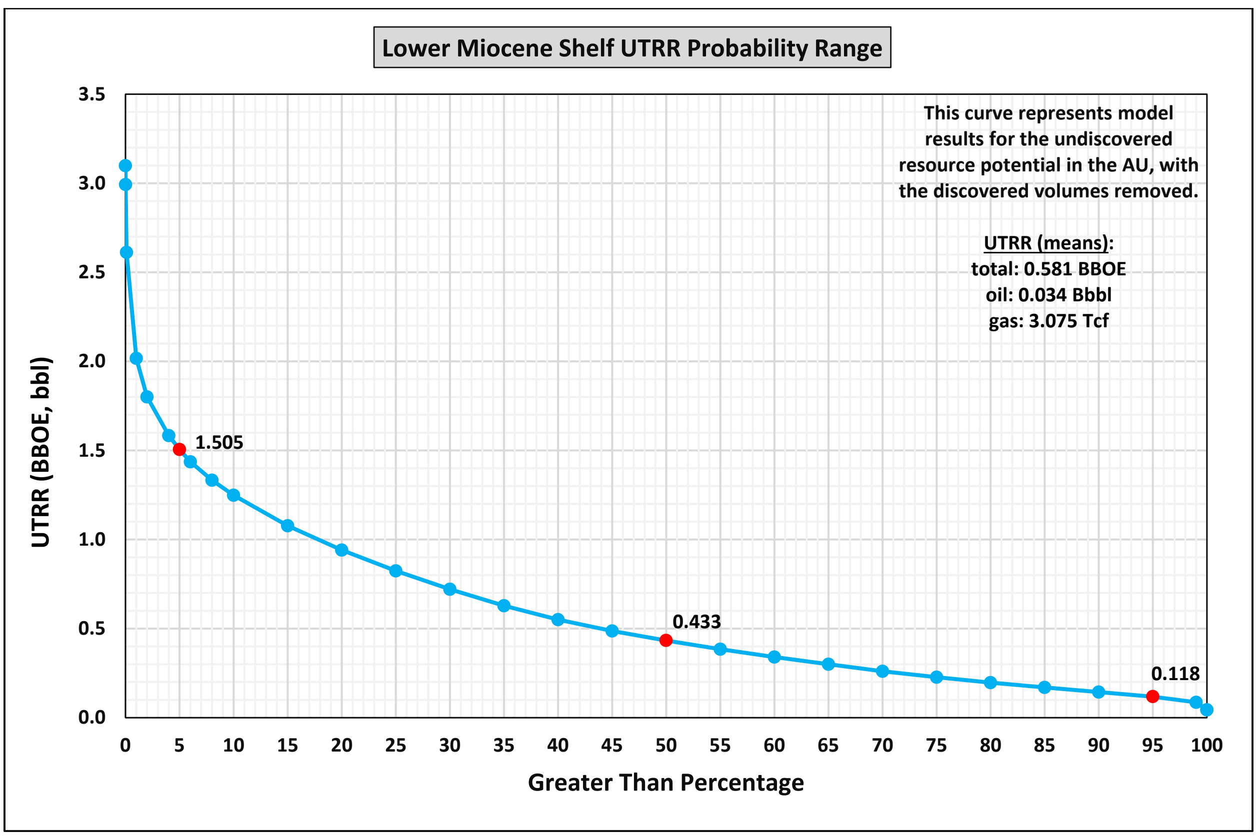

Figure 99. Lower Miocene Shelf UTRR probability range based on total BOE.

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 GOM slope. The stratigraphic framework for Lower Miocene strata 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 94**). 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 GOM 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 Lower Miocene 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

Hydrocarbon-bearing pools within the Lower Miocene Slope have been discovered in the Walker Ridge, Green Canyon, Atwater Valley, and Mississippi Canyon Areas (**Figure 94**). As of the end of 2018, 10 hydrocarbon-bearing pools have been discovered, with discovery dates ranging from 1998 to 2014 (**Figure 100**). The AU contains 3.494 Bbbl of oil and 1.526 Tcf of gas (total BOE of 3.765 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 1998, Green Canyon 826 (Mad Dog) is the largest pool, containing an estimated 1.398 BBOE (**Figure 101**). Other sizeable discovered pools include Mississippi Canyon 940 (Vito), Green Canyon 654 (Shenzi), and Mississippi Canyon 778 (Thunder Horse), all estimated to contain more than 0.5 BBOE (**Figure 101**). Pools have been discovered in water depths ranging from 3,710 to 6,303 ft, and subsea depths of these pools range from 17,324 to 30,065 ft.

Figure 102 illustrates the pseudo-creaming curve for Lower Miocene Slope pool discoveries superimposed on the number and size of the discoveries through time. With only 10 discovered pools so far, the curve stairsteps through time, rising with each relatively large discovery.

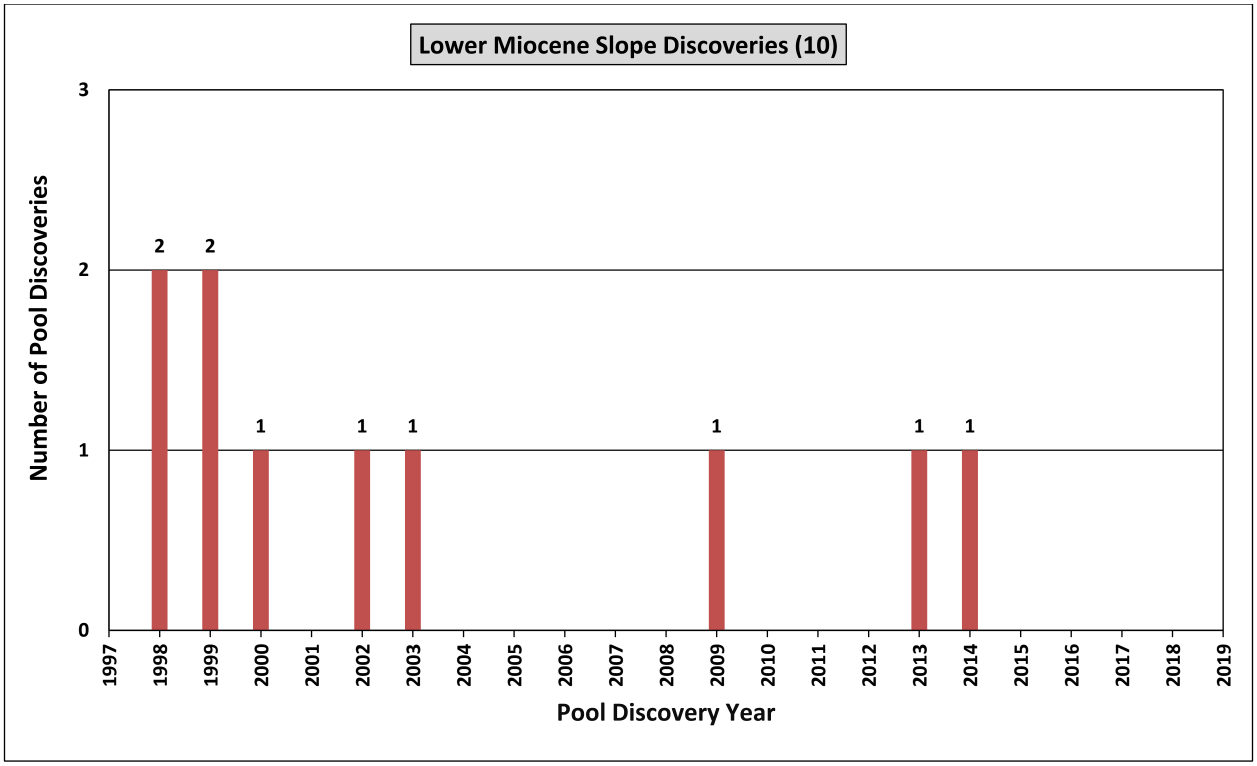

Figure 100. Lower Miocene Slope pool discovery history.

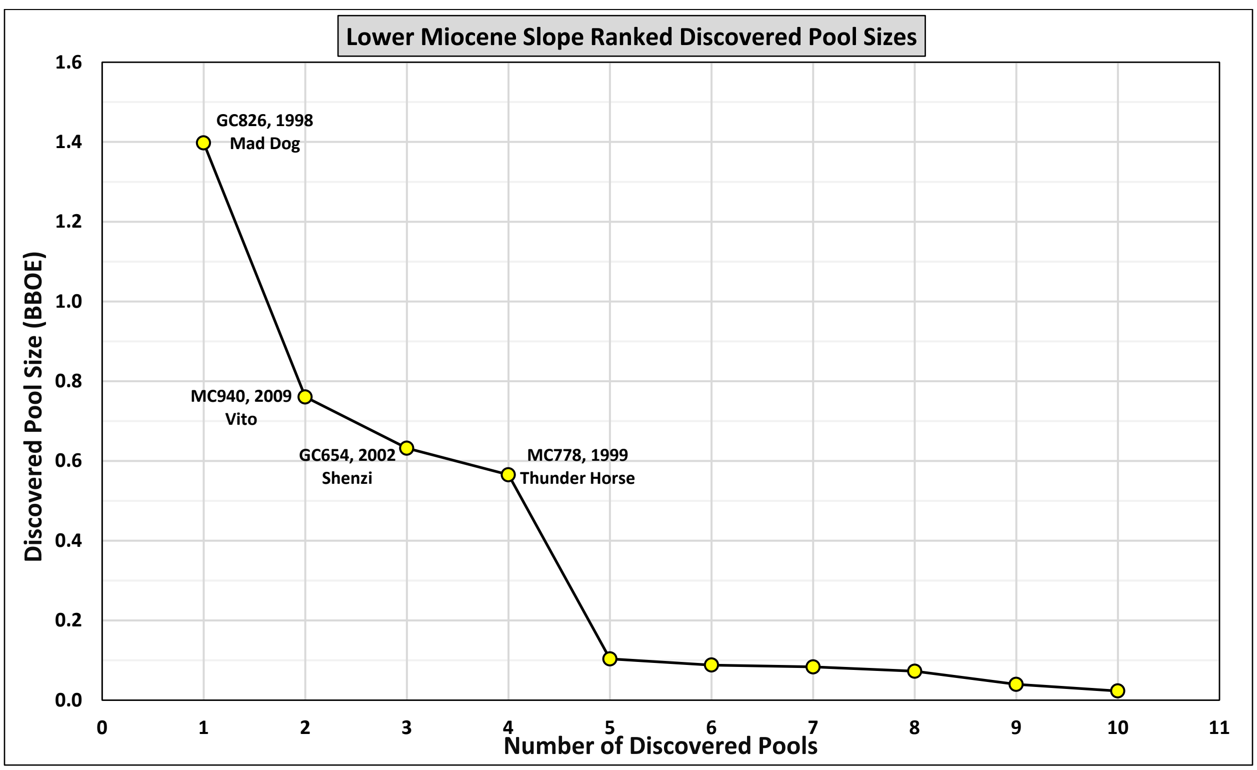

Figure 101. Lower Miocene Slope discovered pool-rank plot.

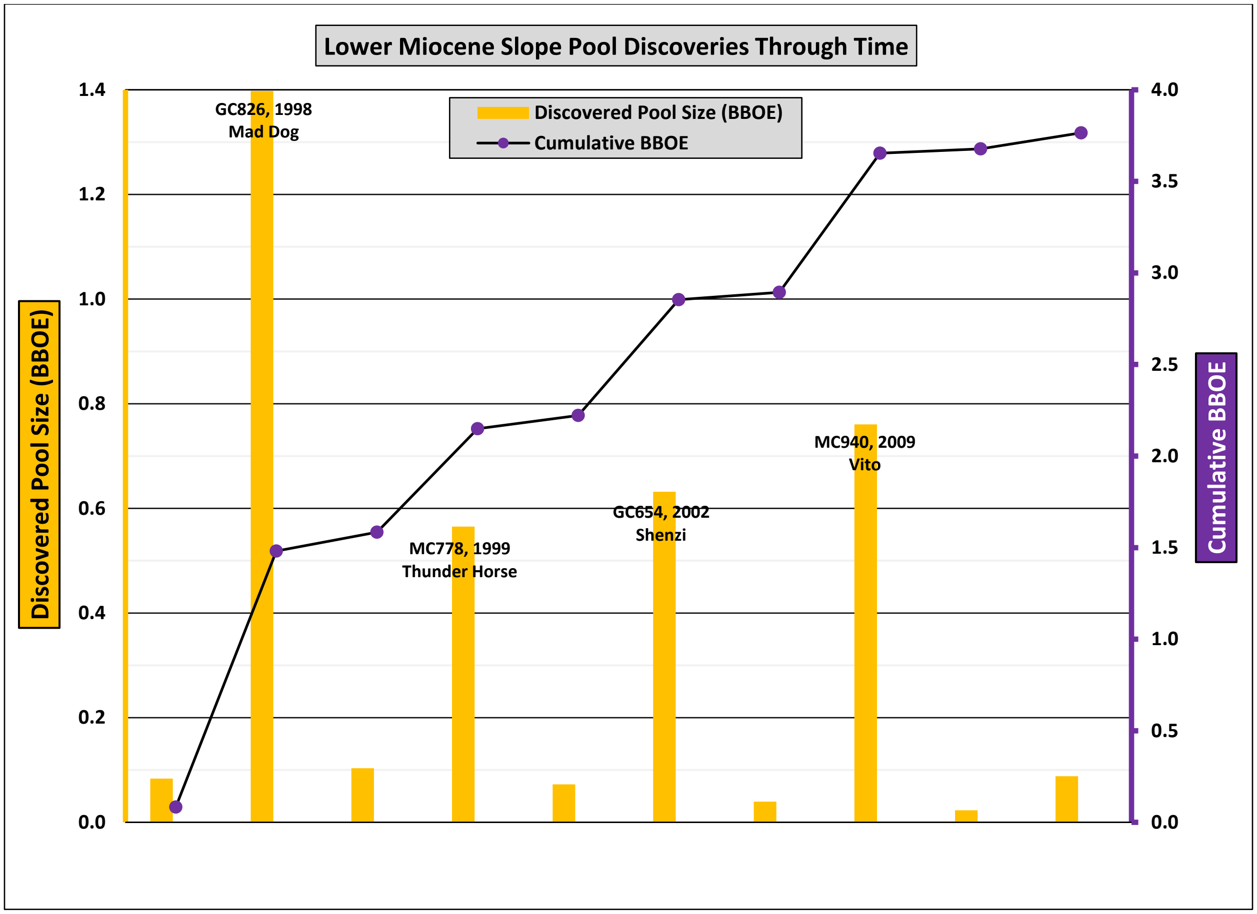

Figure 102. Lower Miocene Slope pseudo-creaming curve.

Risk

With 10 discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factor for successful hydrocarbon accumulations is the trap component, resulting in a prospect-level chance of success of 21 percent (**Figure 4**). This makes the overall exploration chance of success 21 percent (**Figure 5**). See Appendix B for details.

Undiscovered Resources

The Lower Miocene Slope AU was modeled with high undiscovered potential based on (1) only 10 discoveries so far in a vast exploration area, (2) numerous, untested, positive structures where deep-sea fan sediments could have ponded behind inflated salt, and (3) an immature pseudo-creaming curve (**Figure 102**).

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 286 to 476. Applying risk results in 60 to 100 undiscovered pools, with a mean of 80.

The pool-size distribution was modeled with the 10 discoveries in the AU. These pools range in size from 23 to 1,398 MMBOE, with a mean size of 377 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 1,110 MMBOE in size.

From the discovered data information, GRASP returned UTRR volumes for black oil and solution gas. Assessment results indicate that undiscovered oil resources range from 2.097 to 7.441 Bbbl, and undiscovered gas resources range from 0.916 to 3.249 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 103**). Total BOE undiscovered resources range from 2.260 to 8.019 BBOE at the 95th and 5th percentiles, respectively (**Figure 104**). Based on mean-level undiscovered BOE resources, the AU ranks 4th of all 30 GOM assessment units (**Figure 10**).

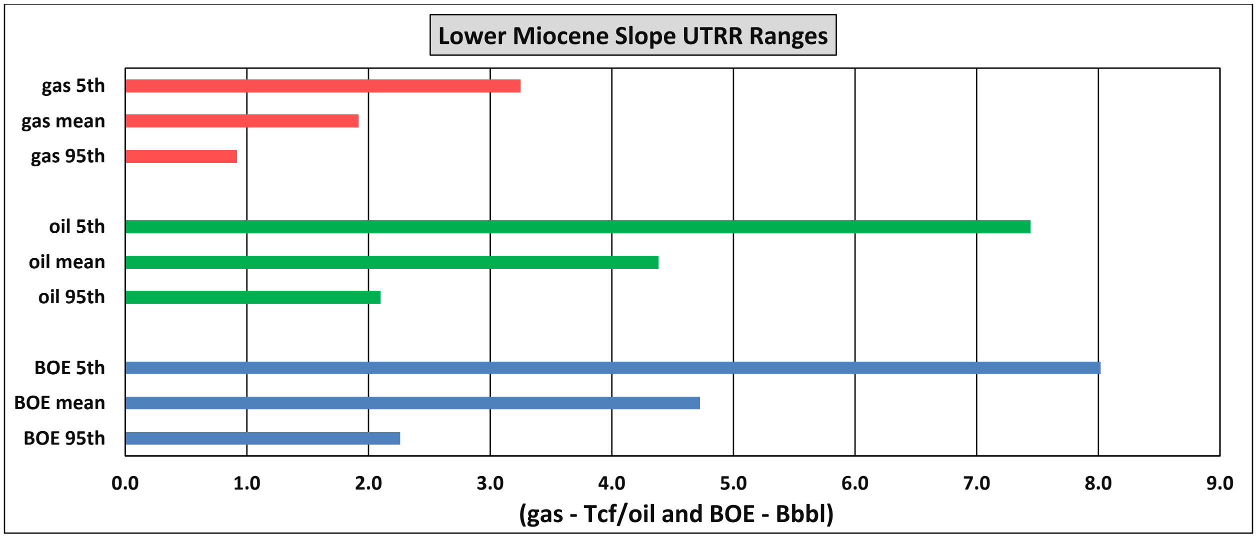

Figure 103. Lower Miocene Slope gas, oil, and BOE UTRR ranges.

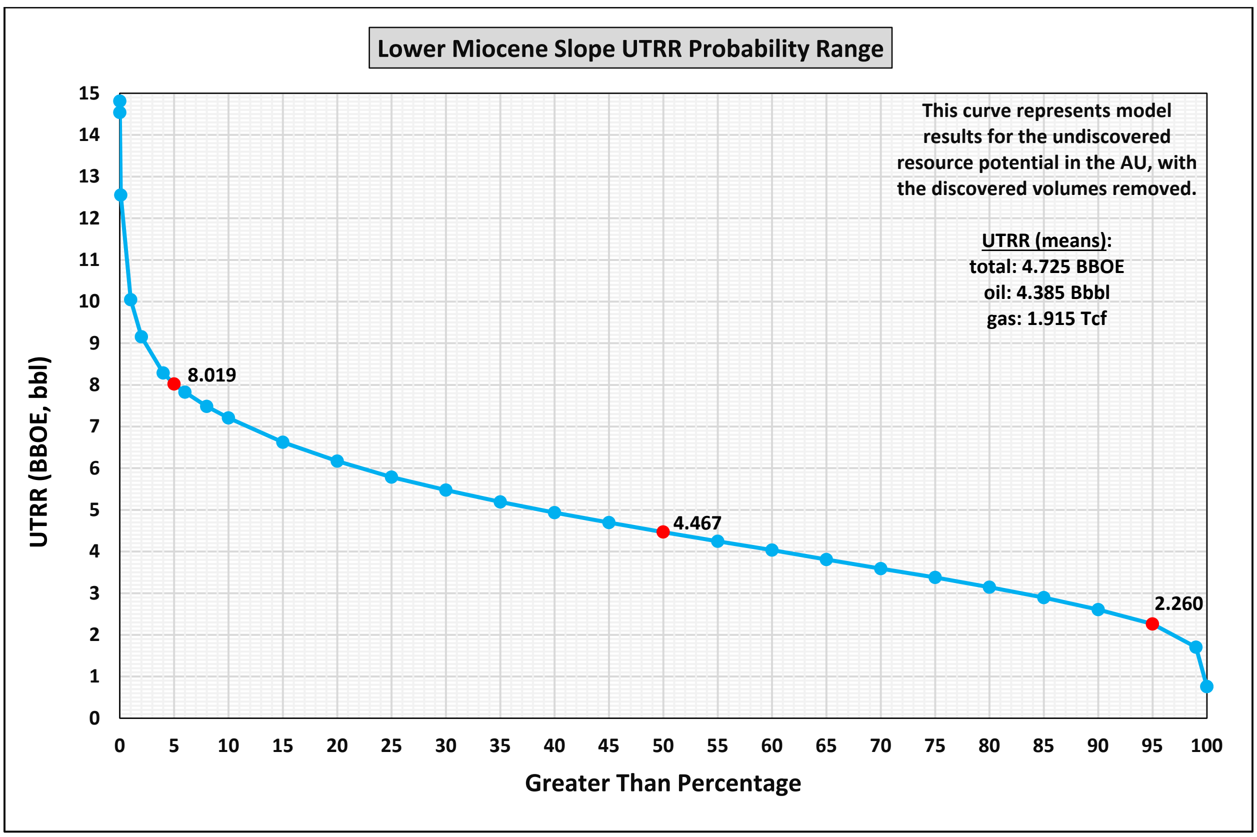

Figure 104. Lower Miocene Slope UTRR probability range based on total BOE.

Middle Miocene Shelf

Geology

The Middle Miocene Shelf AU is defined by sediments deposited in the Langhian and Serravallian Stages (**Table 4**) within the present-day GOM shelf. The stratigraphic framework within the GOM 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 105**).

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 Middle Miocene Shelf AU in the western GOM 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 Middle Miocene Shelf 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.

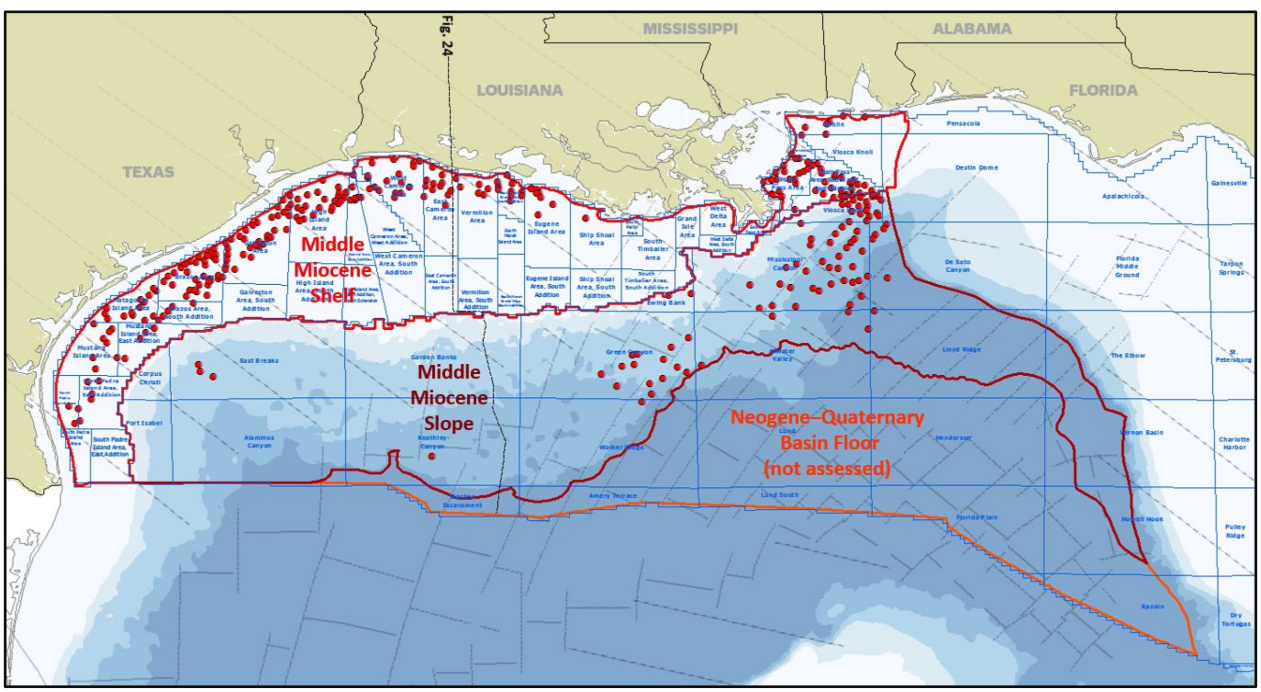

Figure 105. Middle Miocene Shelf and Slope locations and associated discovered pools.

Discoveries

BOEM-designated hydrocarbon discoveries within the Middle Miocene Shelf AU 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 105**). As of the end of 2018, 246 pools have been discovered, with discovery dates ranging from 1948 to 2017 (**Figure 106**). The AU contains 0.617 Bbbl of oil and 30.792 Tcf of gas (total BOE of 6.096 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 1958, the Tiger Shoal pool in the South Marsh Island Area is the largest, containing an estimated 0.612 BBOE in Middle Miocene rocks (**Figure 107**). Other sizeable discovered pools include Vermilion 39, Vermilion 14, East Cameron 64, and West Cameron 180, all estimated to contain more than 0.250 BBOE (**Figure 107**). Pools have been discovered in water depths ranging from 10 to 588 ft, and subsea depths of these pools range from 2,212 to 18,464 ft.

Figure 108 illustrates the pseudo-creaming curve for Middle Miocene Shelf pool discoveries superimposed on the number and size of the discoveries through time. The largest pools were found in the early history exploration, with little resources being added present day.

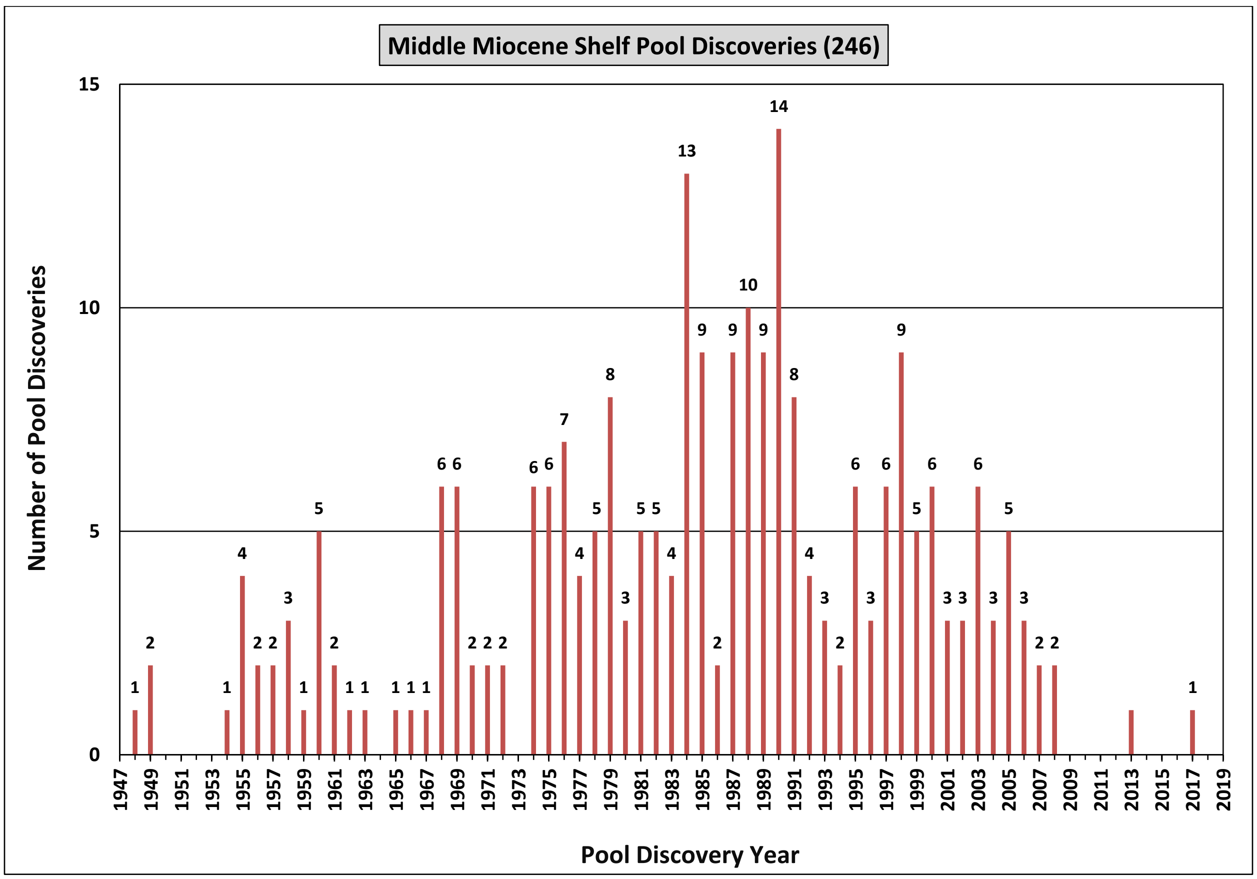

Figure 106. Middle Miocene Shelf pool discovery history.

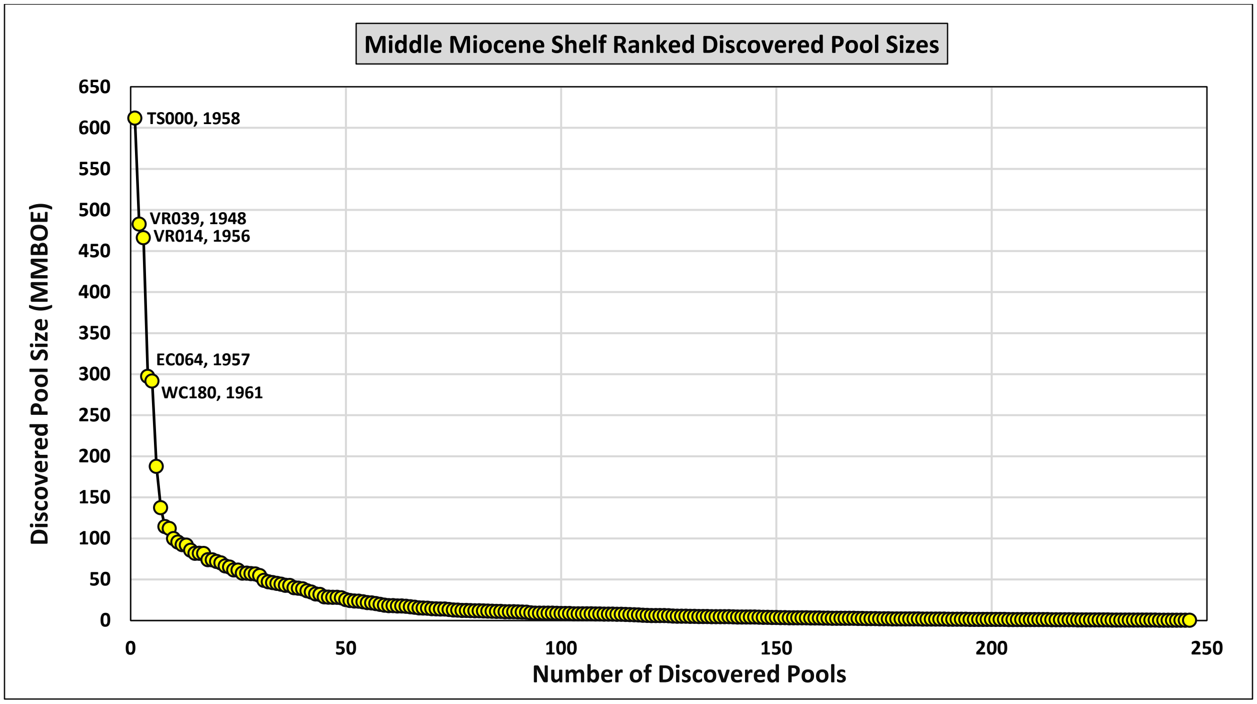

Figure 107. Middle Miocene Shelf discovered pool-rank plot.

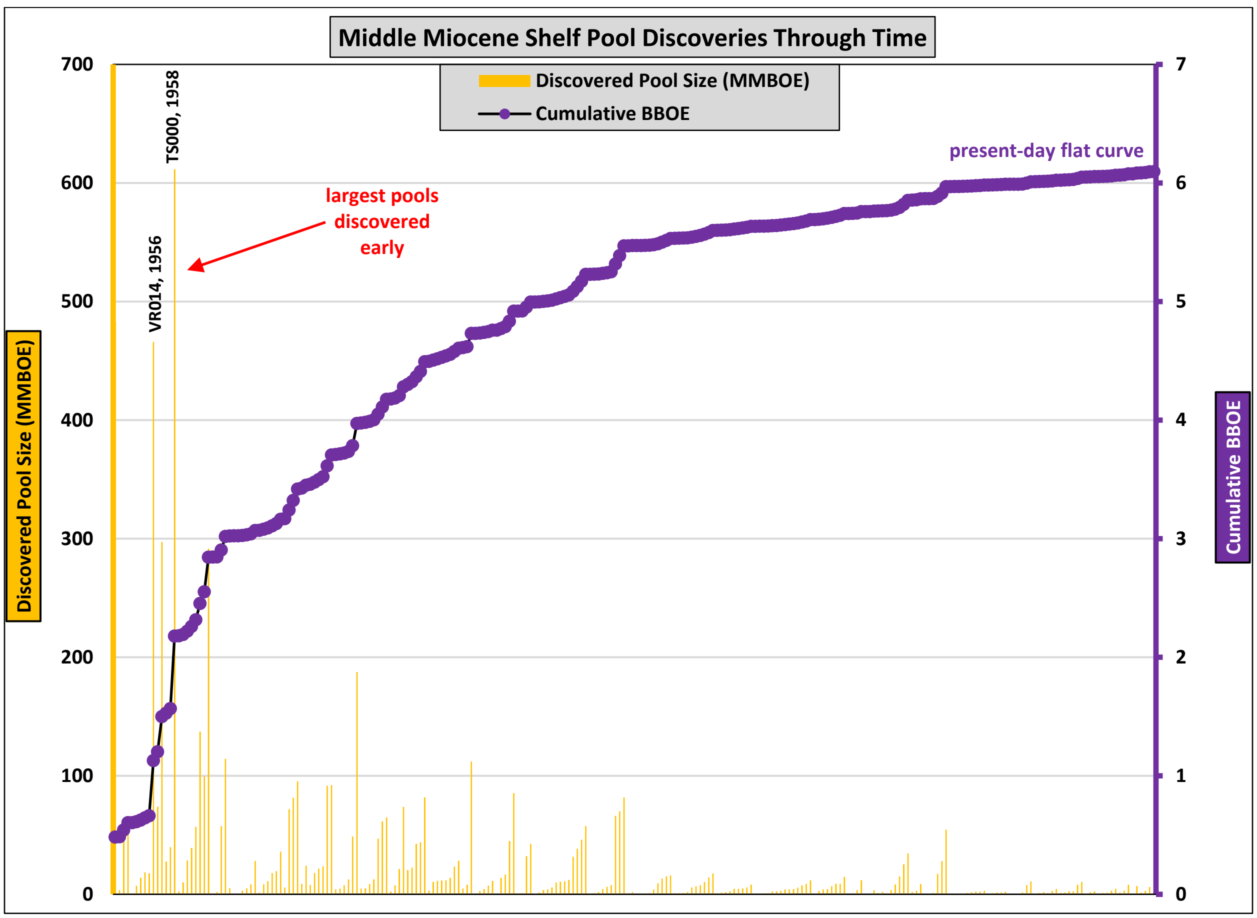

Figure 108. Middle Miocene Shelf pseudo-creaming curve.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factor for successful hydrocarbon accumulations is the trap component, resulting in a prospect-level chance of success of 25 percent (**Figure 4**). This makes the overall exploration chance of success 25 percent (**Figure 5**). See Appendix B for details.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 340 to 500. Applying risk results in 85 to 125 undiscovered pools, with a mean of 105.

The pool-size distribution was modeled with the 246 discoveries in the AU. These pools range in size from 0.127 to 612 MMBOE, with a mean size of 25 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 30 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 0.046 to 0.189 Bbbl, and undiscovered gas resources range from 2.260 to 8.376 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 109**). Total BOE undiscovered resources range from 0.449 to 1.680 BBOE at the 95th and 5th percentiles, respectively (**Figure 110**). Of all 30 assessment units in this study, the Middle Miocene Shelf AU ranks 10th based on mean-level undiscovered BOE resources (**Figure 10**).

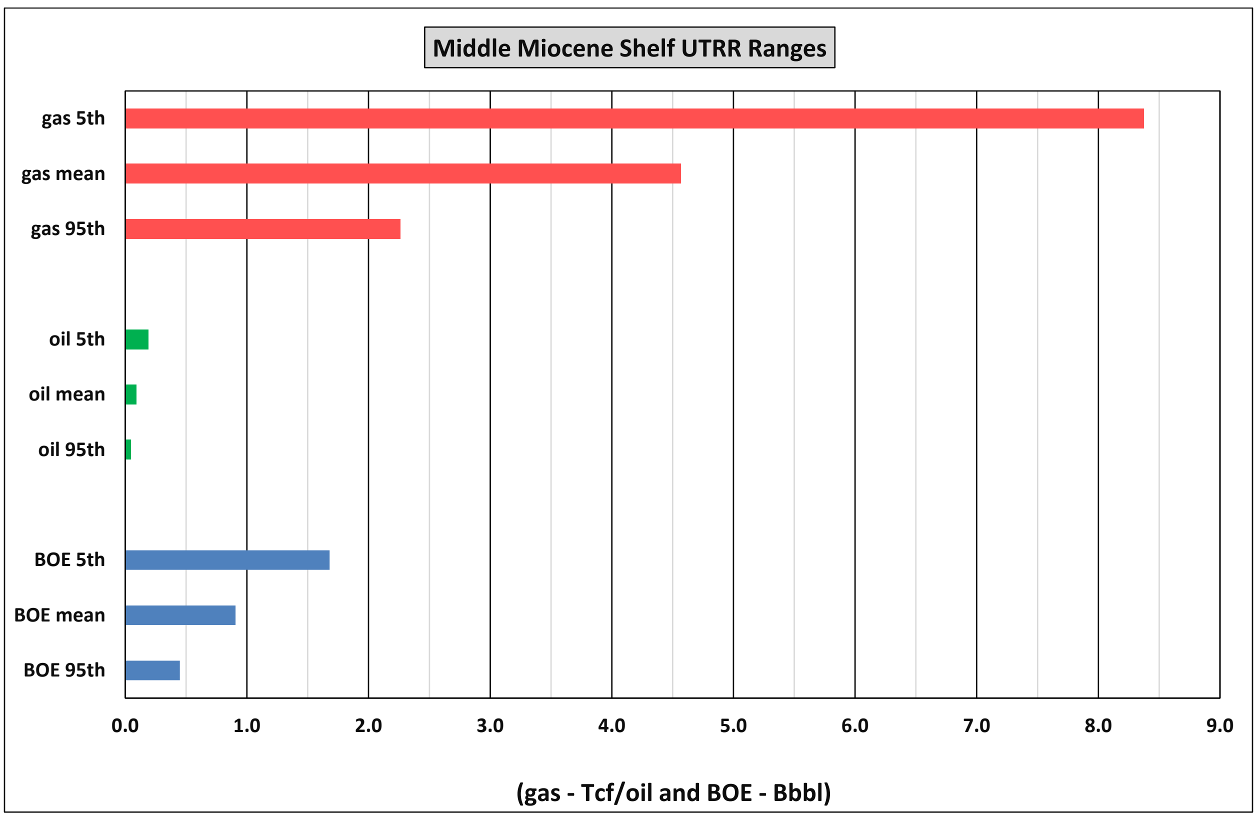

Figure 109. Middle Miocene Shelf gas, oil, and BOE UTRR ranges.

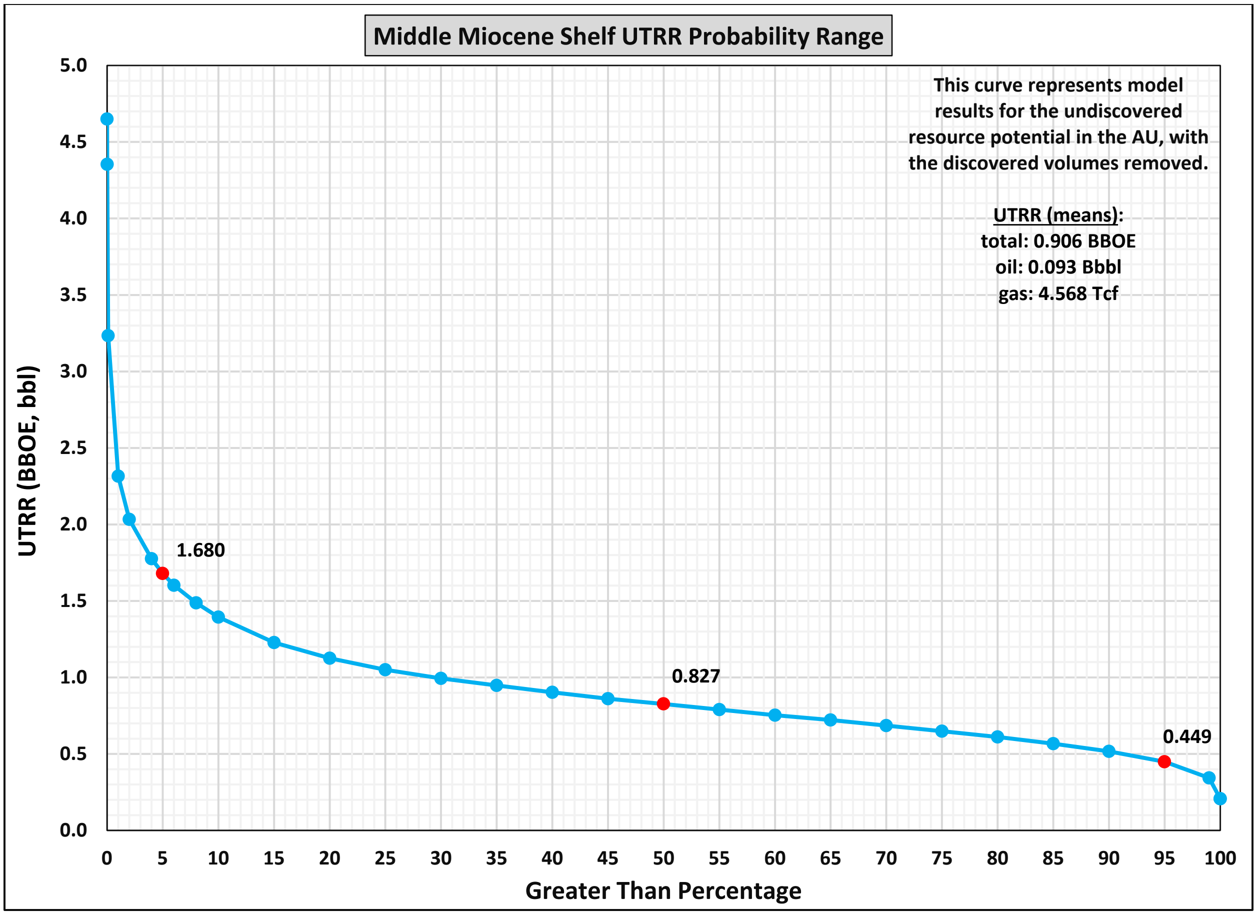

Figure 110. Middle Miocene Shelf UTRR probability range based on total BOE.

Middle Miocene Slope

Geology

The Middle Miocene Slope AU is defined by sediments deposited in the Langhian and Serravallian Stages (**Table 4**) within the present-day GOM slope. The stratigraphic framework within the GOM 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 105**). 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 in the Middle Miocene Slope AU 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 Middle Miocene 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 within the Middle Miocene Slope AU occur from the East Breaks Area to the De Soto Canyon Area (**Figure 105**). As of the end of 2018, 84 pools have been discovered, with discovery dates ranging from 1982 to 2016 (**Figure 111**). The AU contains 5.636 Bbbl of oil and 9.611 Tcf of gas (total BOE of 7.346 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. The two largest pools in the AU—Green Canyon 640 (Tahiti) and Green Canyon 743 (Atlantis)—both contain more than 0.900 BBOE (**Figure 112**). Other large discovered pools include Mississippi Canyon 776 (North Thunderhorse) and Green Canyon 468 (Stampede), both estimated to contain more than 0.450 BBOE (**Figure 112**). Pools have been discovered in water depths ranging from 689 to 8,351 ft, and subsea depths of these pools range from 8,297 to 29,578 ft.

Figure 113 illustrates the pseudo-creaming curve for Middle Miocene Slope pool discoveries superimposed on the number and size of the discoveries through time. As recently as 2012, the Mississippi Canyon 300 discovery (Marmalard) added over 0.200 BBOE to the discovered resource base of the AU.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factors for successful hydrocarbon accumulations are the reservoir and trap components, resulting in a prospect-level chance of success of 25 percent (**Figure 4**). This makes the overall exploration chance of success 25 percent (**Figure 5**). See Appendix B for details.

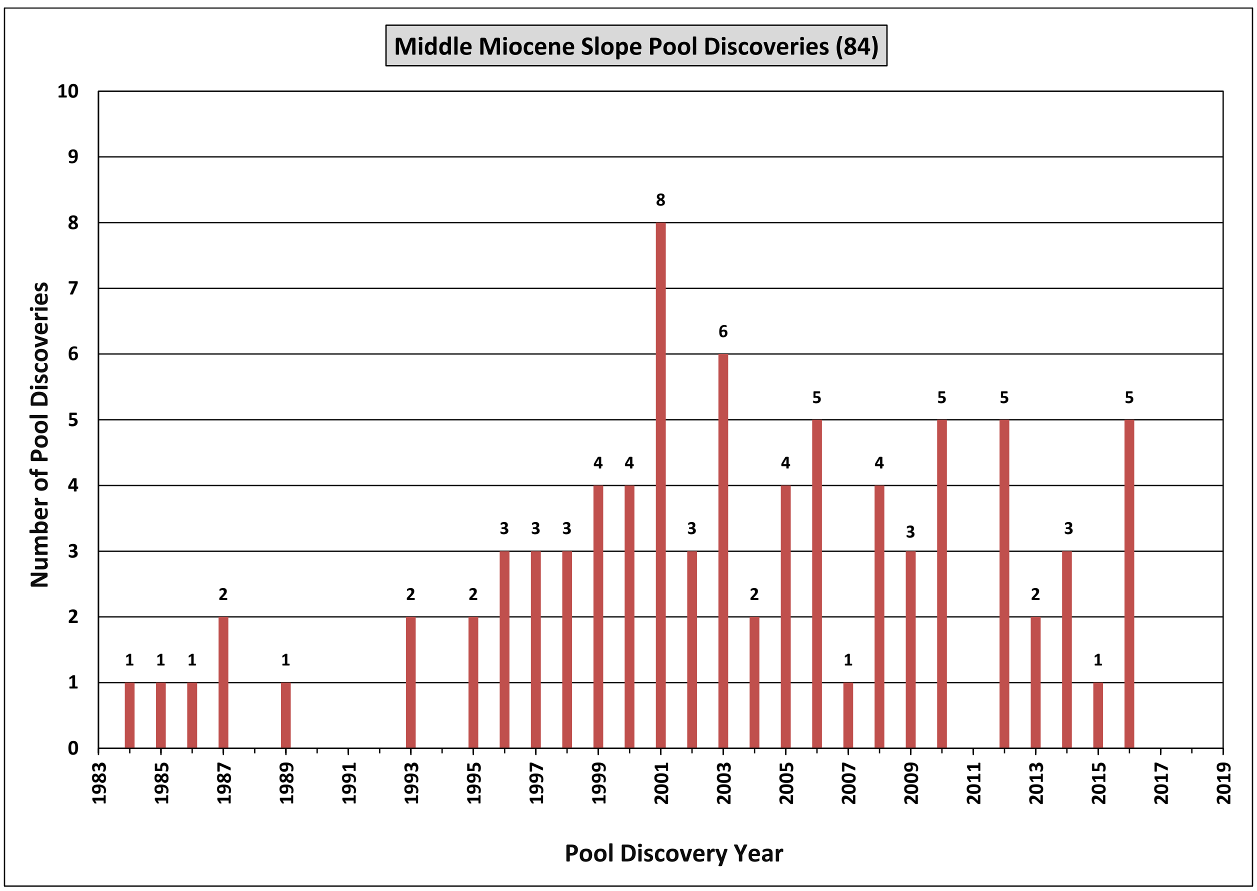

Figure 111. Middle Miocene Slope pool discovery history.

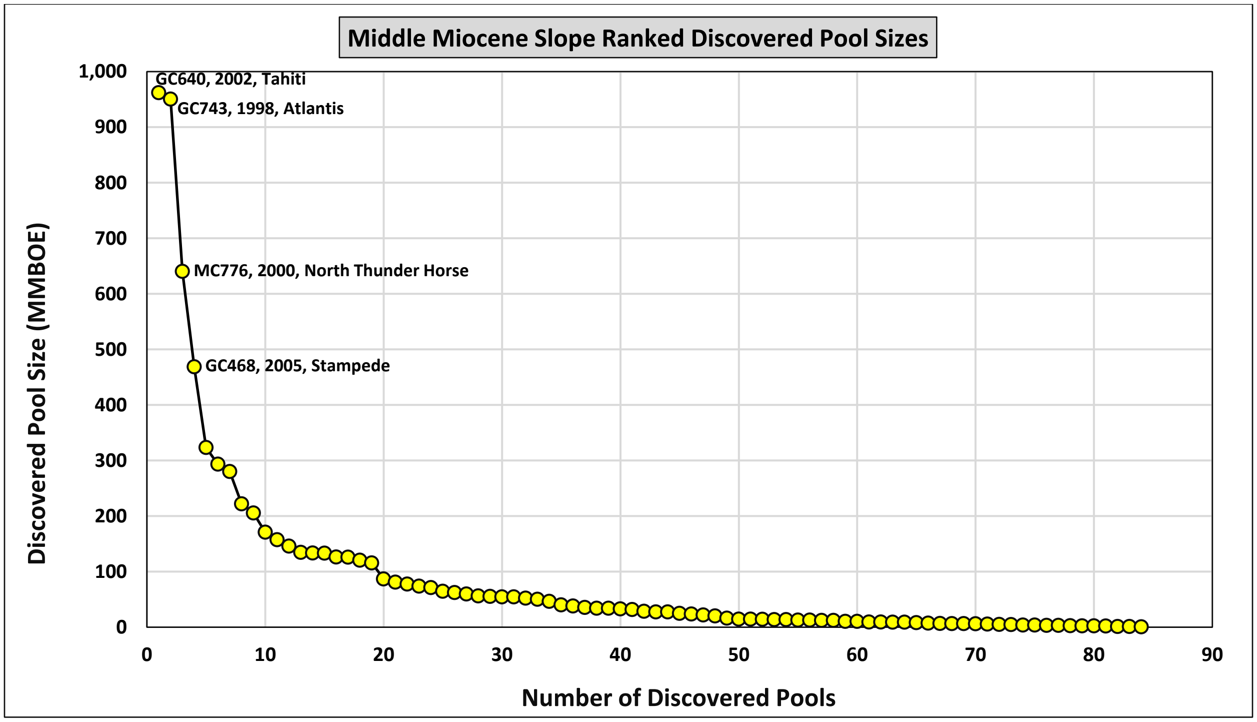

Figure 112. Middle Miocene Slope discovered pool-rank plot.

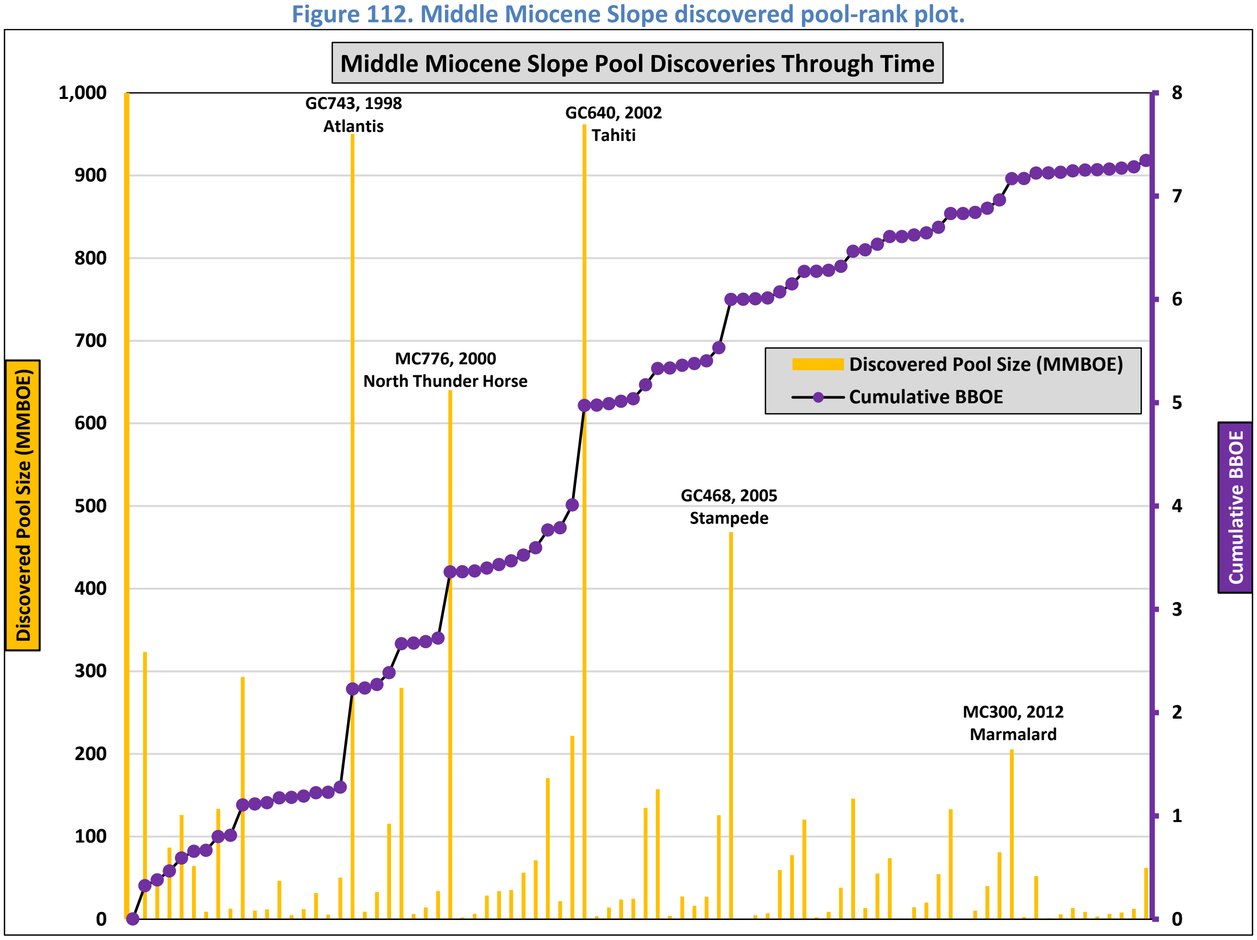

Figure 113. Middle Miocene Slope pseudo-creaming curve.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 704 to 864. Applying risk results in 176 to 216 undiscovered pools, with a mean of 196.

The pool-size distribution was modeled with the 84 discoveries in the AU. These pools range in size from 0.124 to 962 MMBOE, with a mean size of 87 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 208 MMBOE in size.

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 2.049 to 6.306 Bbbl, and undiscovered gas resources range from 3.325 to 10.363 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 114**). Total BOE undiscovered resources range from 2.641 to 8.150 BBOE at the 95th and 5th percentiles, respectively (**Figure 115**). Of all 30 assessment units in this study, the Middle Miocene Slope AU ranks 3rd based on mean-level undiscovered BOE resources (**Figure 10**).

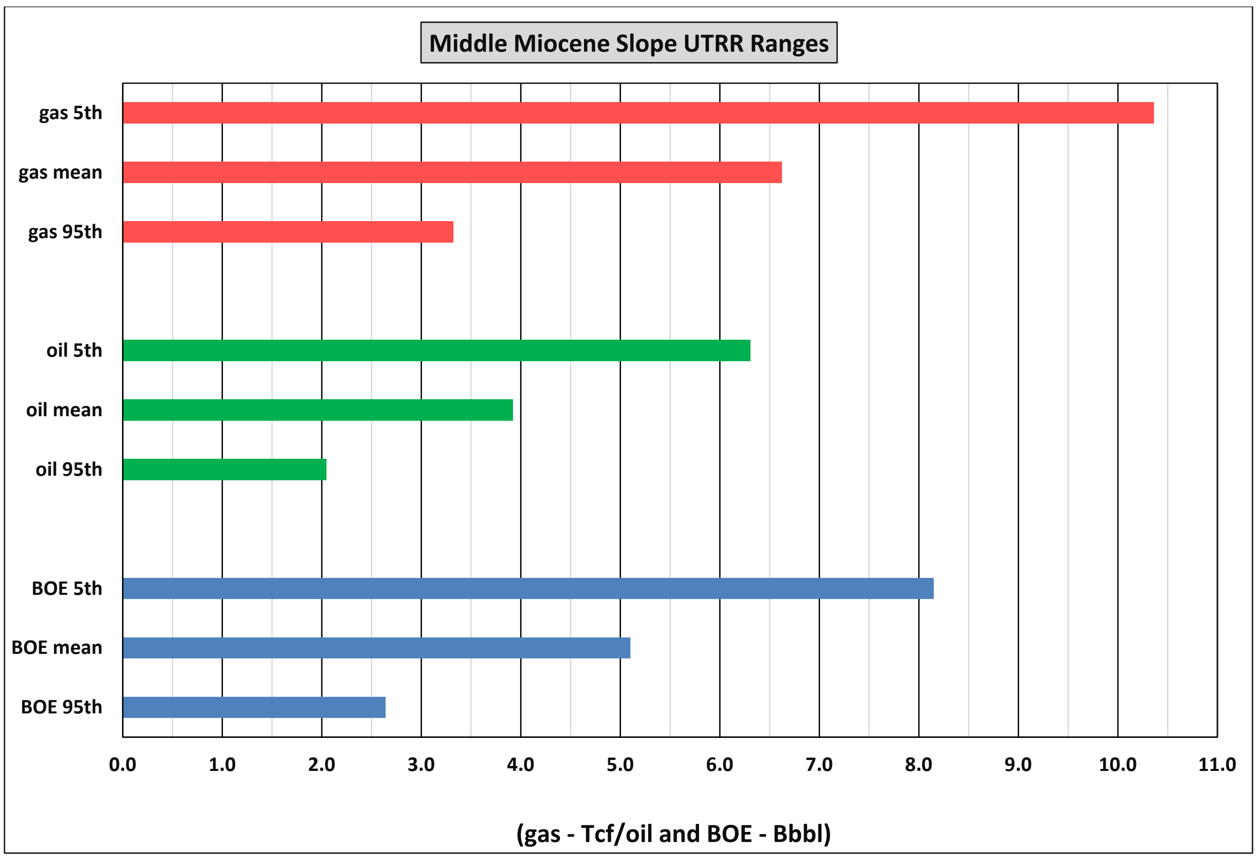

Figure 114. Middle Miocene Slope gas, oil, and BOE UTRR ranges.

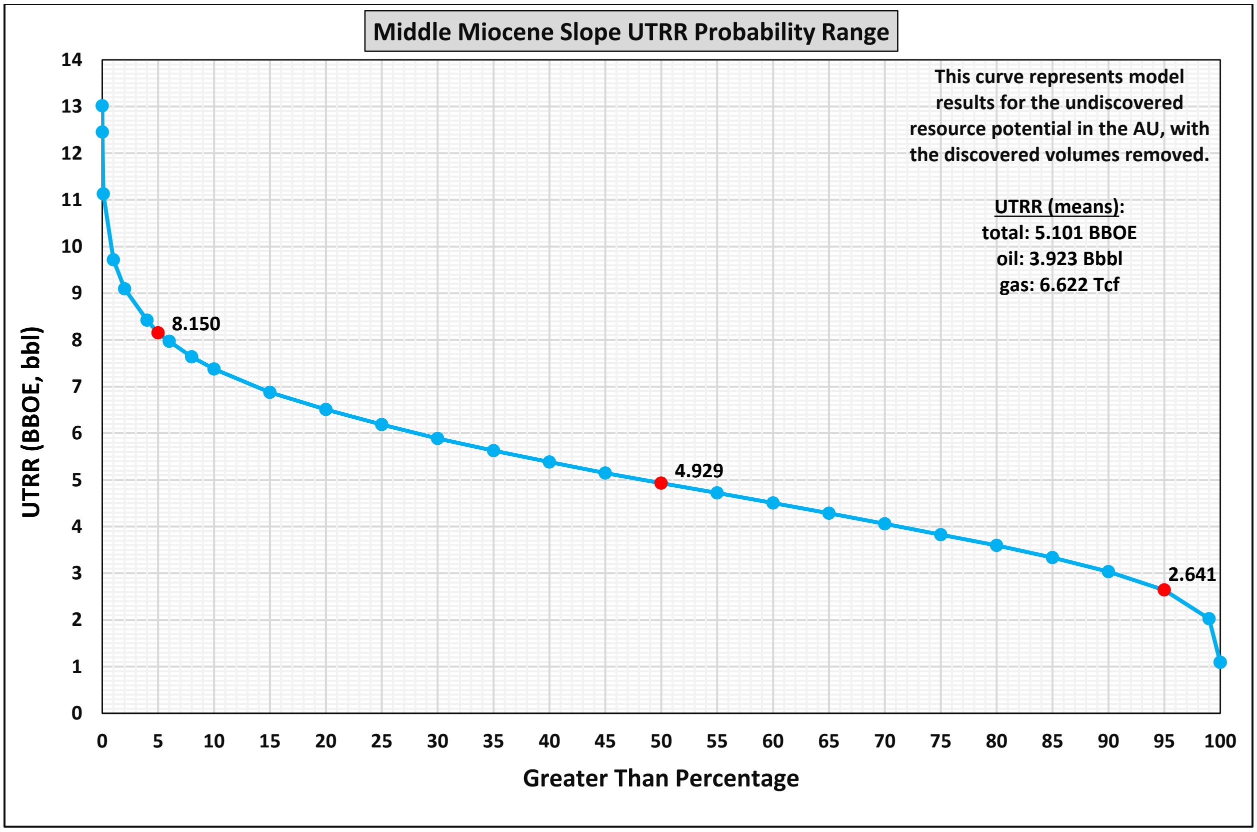

Figure 115. Middle Miocene Slope UTRR probability range based on total BOE.

Upper Miocene Shelf

Geology

The Upper Miocene Shelf AU is defined by sediments deposited in the Tortonian and Messinian Stages (**Table 4**) within the present-day GOM shelf. The stratigraphic framework within the GOM Basin for Upper 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 116).**

The Upper Miocene shelf margin advanced beyond the modern coastline from Texas to Florida. Extensive fluvial-dominate 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 Gaudalupe 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 Upper Miocene shelf margin on the upper and lower slopes and in topographically low areas between salt highs and onto the abyssal plain.

The Upper Miocene Shelf AU in the western GOM 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 Upper Miocene Shelf 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.

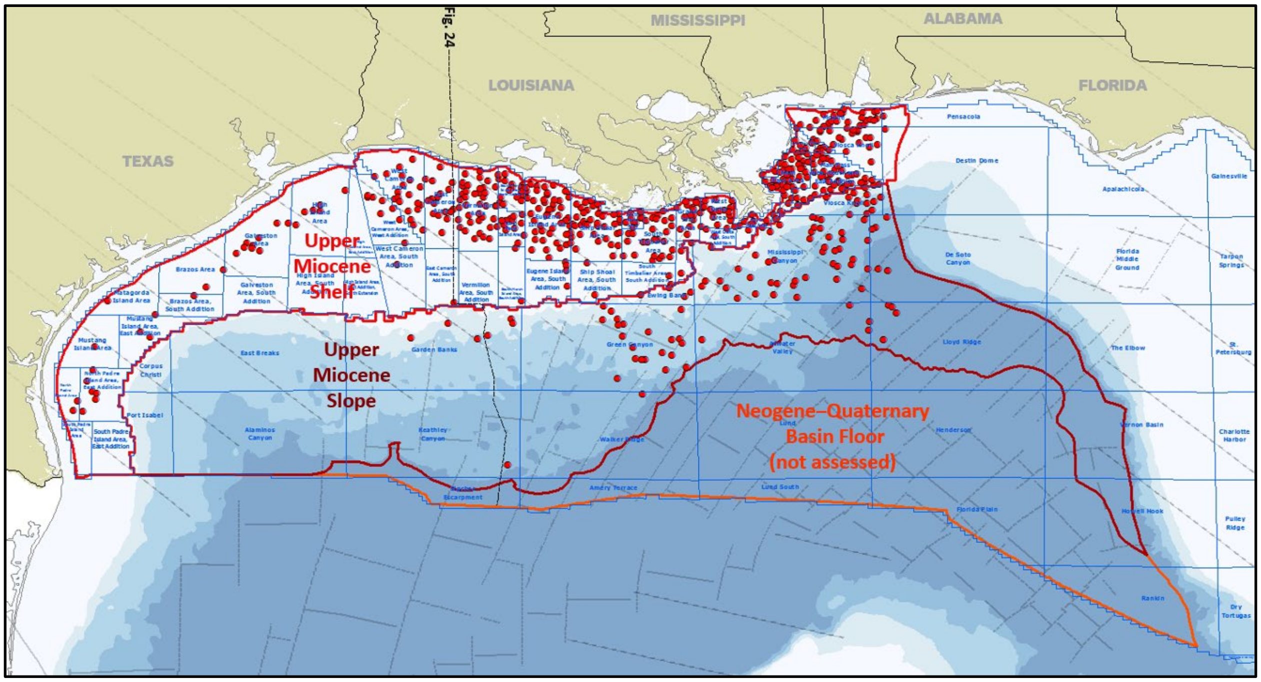

Figure 116. Upper Miocene Shelf and Slope locations and associated discovered pools.

Discoveries

Upper Miocene Shelf deposition and exploration in the GOM has been extensively studied, explored, and developed back to 1947 with the first shelf discovery in Federal waters at Vermillion Block 71 (**Figure 117**). As of the end of 2018, 473 hydrocarbon-bearing pools have been discovered. The pools contain 6.444 Bbbl of oil and 48.307 Tcf of gas (total BOE of 15.039 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 1956, Grand Isle 43 is the largest pool, containing an estimated 0.653 BBOE (**Figure 118**). Other sizable discovered pools include Bay Marchand 2, West Delta 30, and Main Pass 41, all estimated to contain more than 0.450 BBOE (**Figure 118**). Pools have been discovered in water depths ranging from 9 to 625 ft, and subsea depths of these pools range from 1,283 to 21,273 ft.

Figure 119 illustrates the pseudo-creaming curve for Upper Miocene Shelf pool discoveries superimposed on the number and size of the discoveries through time. The present-day flattening of the pseudo-creaming curve and decreasing discovery sizes through time reflect a well-established, highly explored assessment unit, where the largest discoveries were found early in its exploration history.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factor for successful hydrocarbon accumulations is the trap component, resulting in a prospect-level chance of success of 29 percent (**Figure 4**). This makes the overall exploration chance of success 29 percent (**Figure 5**). See Appendix B for details.

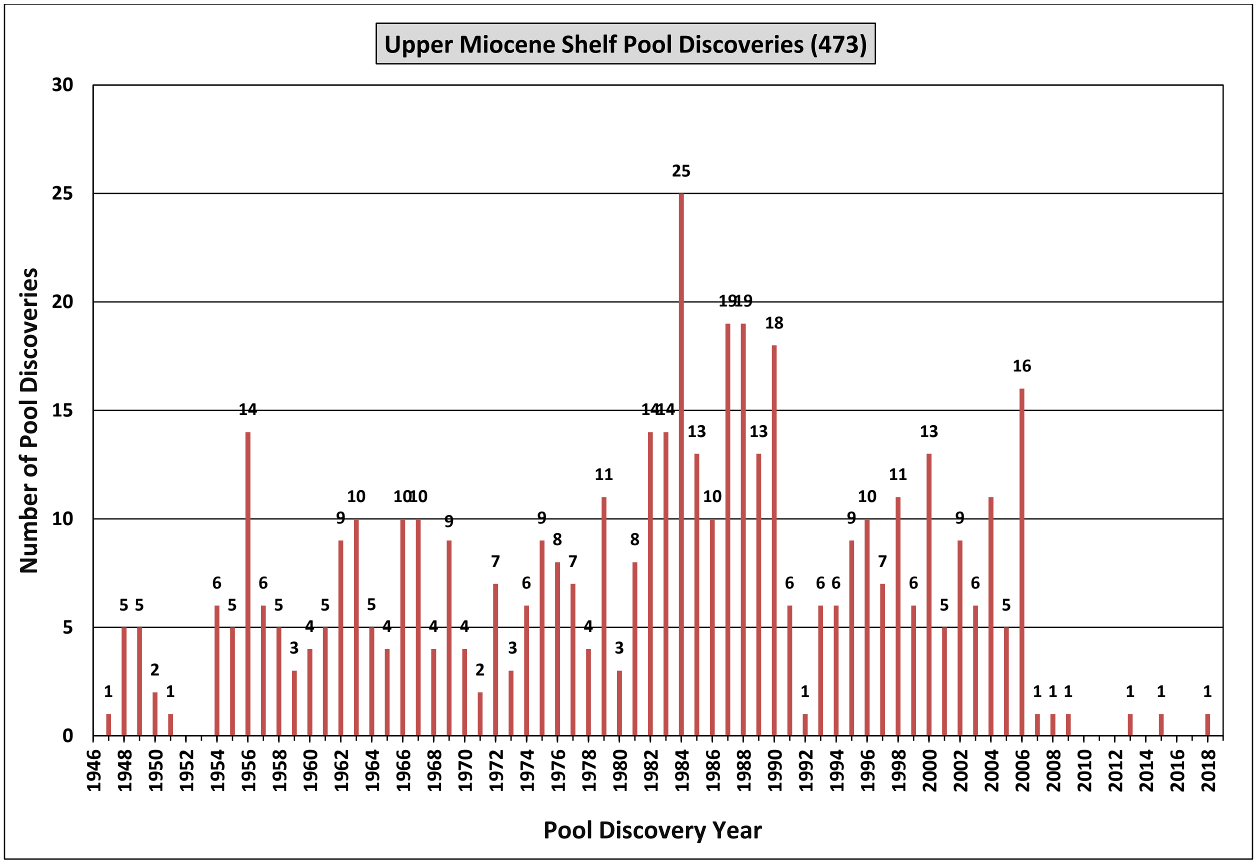

Figure 117. Upper Miocene Shelf pool discovery history.

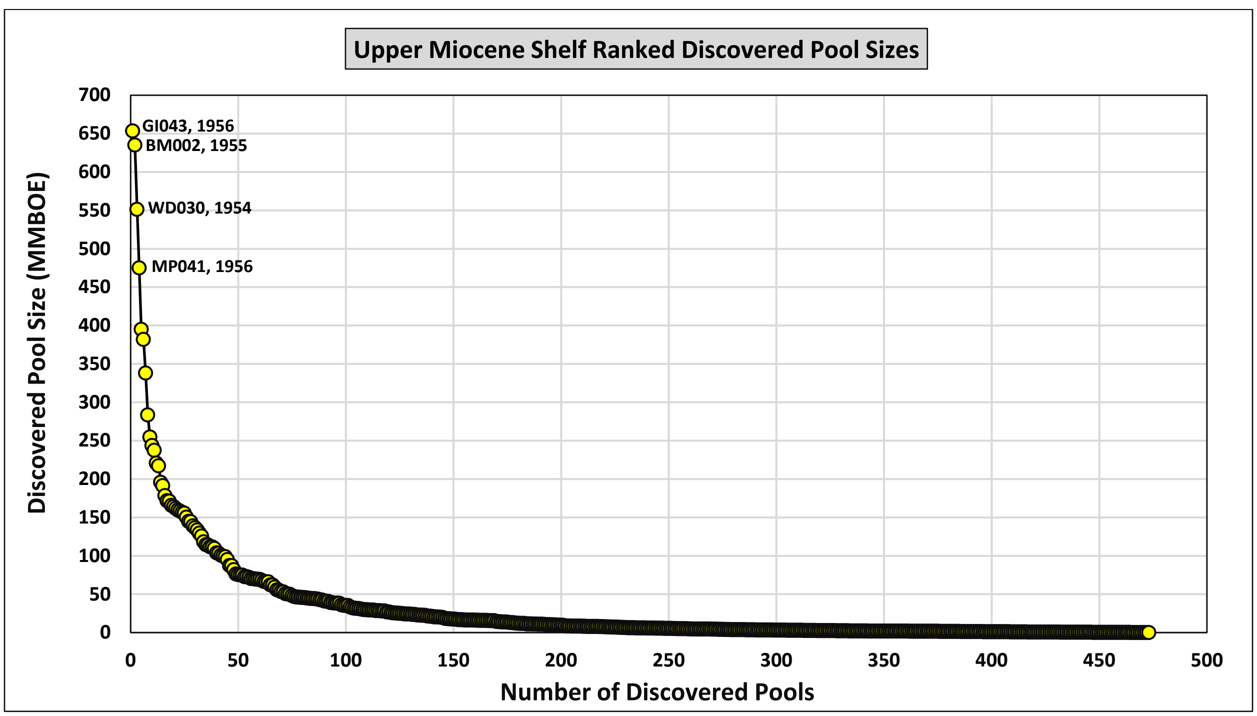

Figure 118. Upper Miocene Shelf discovered pool-rank plot.

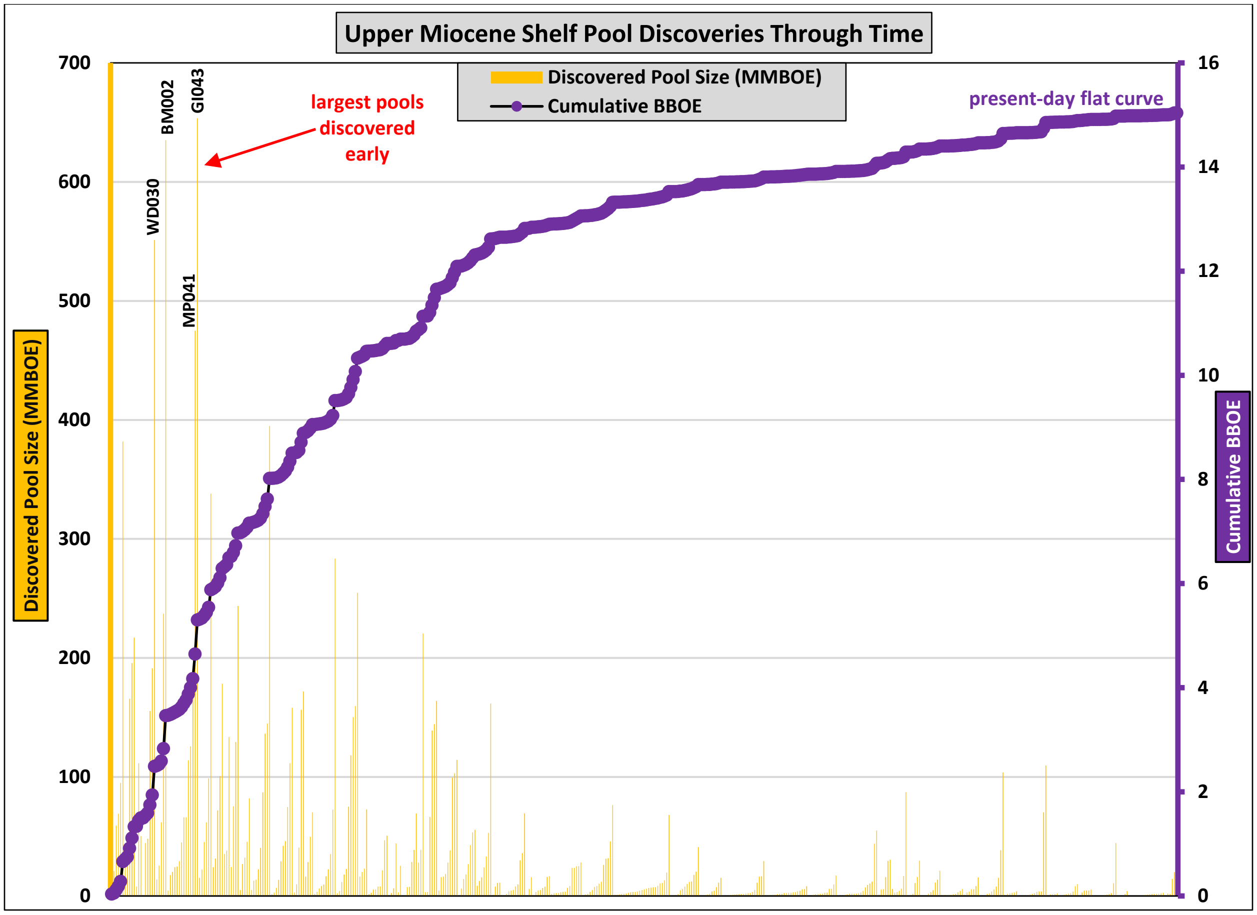

Figure 119. Upper Miocene Shelf pseudo-creaming curve.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 541 to 679. Applying risk results in 157 to 197 undiscovered pools, with a mean of 177.

The pool-size distribution was modeled with the 473 discoveries in the AU. These pools range in size from 0.001 to 653 MMBOE, with a mean size of 32 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 36 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 0.264 to 0.746 Bbbl, and undiscovered gas resources range from 1.974 to 5.552 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 120**). Total BOE undiscovered resources range from 0.616 to 1.734 BBOE at the 95th and 5th percentiles, respectively (**Figure 121**).

The Upper Miocene Shelf has been heavily explored and has had significant development and production for over 60 years. However, the discovered Upper Miocene fields continue to be extensively studied and explored to assess unproduced resources and other potential traps and opportunities. In fact, of all 30 assessment units in this study, the Upper Miocene Shelf AU ranks 7th based on mean-level undiscovered BOE resources (**Figure 10**), containing the most remaining potential of any Cenozoic shelf assessment unit.

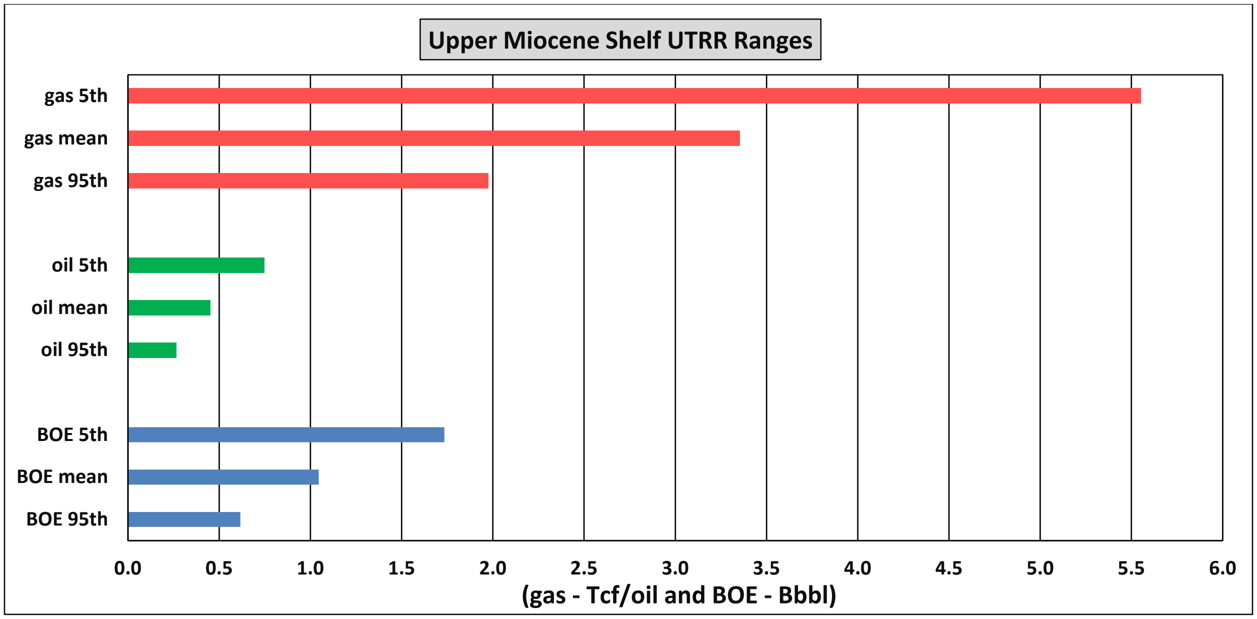

Figure 120. Upper Miocene Shelf gas, oil, and BOE UTRR ranges.

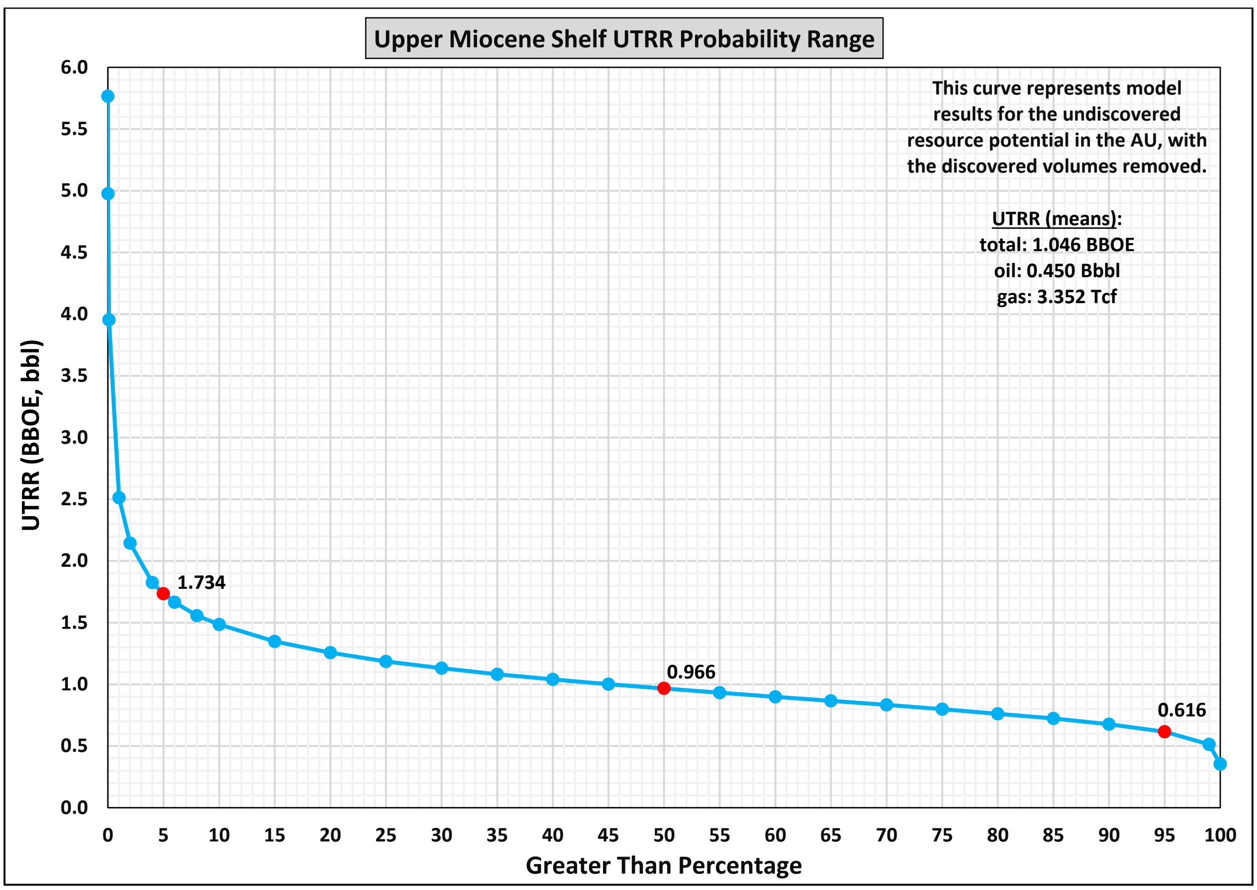

Figure 121. Upper Miocene Shelf UTRR probability range based on total BOE.

Upper Miocene Slope

Geology

The Upper Miocene Slope AU is defined by sediments deposited in the Tortonian and Messinian Stages (**Table 4**) within the present-day GOM slope. The stratigraphic framework within the GOM Basin for the Upper 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 116**). 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 Upper Miocene 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 Upper Miocene 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

Upper Miocene Slope deposition and exploration has been extensively studied, 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 Upper Miocene Slope AU occur from the Garden Banks/Keathley Canyon Areas in the western portion of the AU to the De Soto Canyon/Lloyd Ridge Areas in the eastern portion of the AU (**Figure 116**). As of the end of 2018, a total of 103 hydrocarbon-bearing pools have been discovered (**Figure 122**). The Upper Miocene Slope AU contains some of the largest pools ever discovered in the GOM deep water, including the discoveries associated with the Mars-Ursa geologic complex in the Mississippi Canyon Area (**Figure 123**).

Upper Miocene Slope discoveries account for 5.067 Bbbl of oil and 14.433 Tcf of gas (total BOE of 7.635 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Pools have been discovered in water depths ranging from 697 to 9,112 ft, and subsea depths of these pools range from 4,965 to 26,192 ft.

Figure 124 illustrates the pseudo-creaming curve for the pool discoveries superimposed on the number and size of the discoveries through time. Numerous large pool discoveries have resulted in sharp upticks in volumes added to the AU through time. The most recent example is the Kaikias discovery in 2014, which added 348 MMBOE to the discovered resource base in the AU.

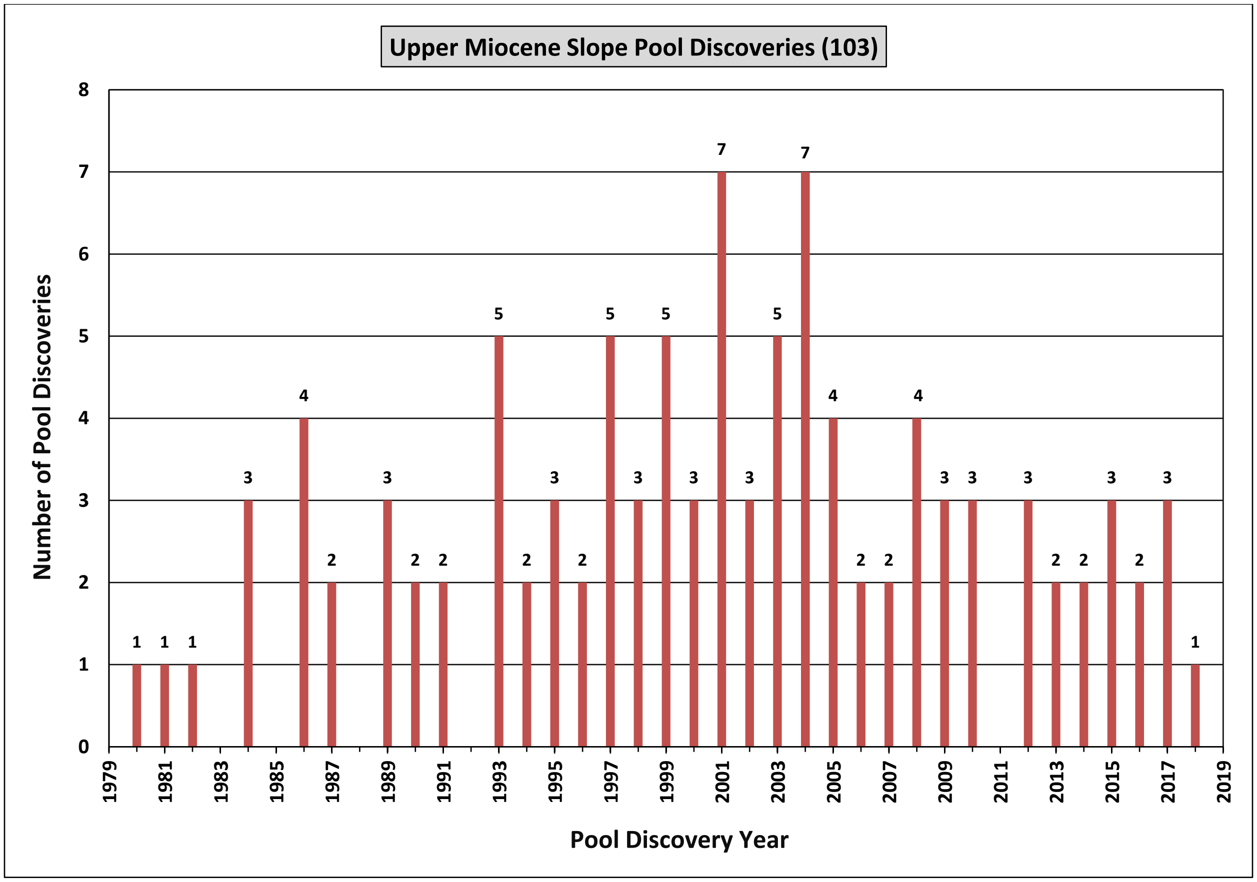

Figure 122. Upper Miocene Slope pool discovery history.

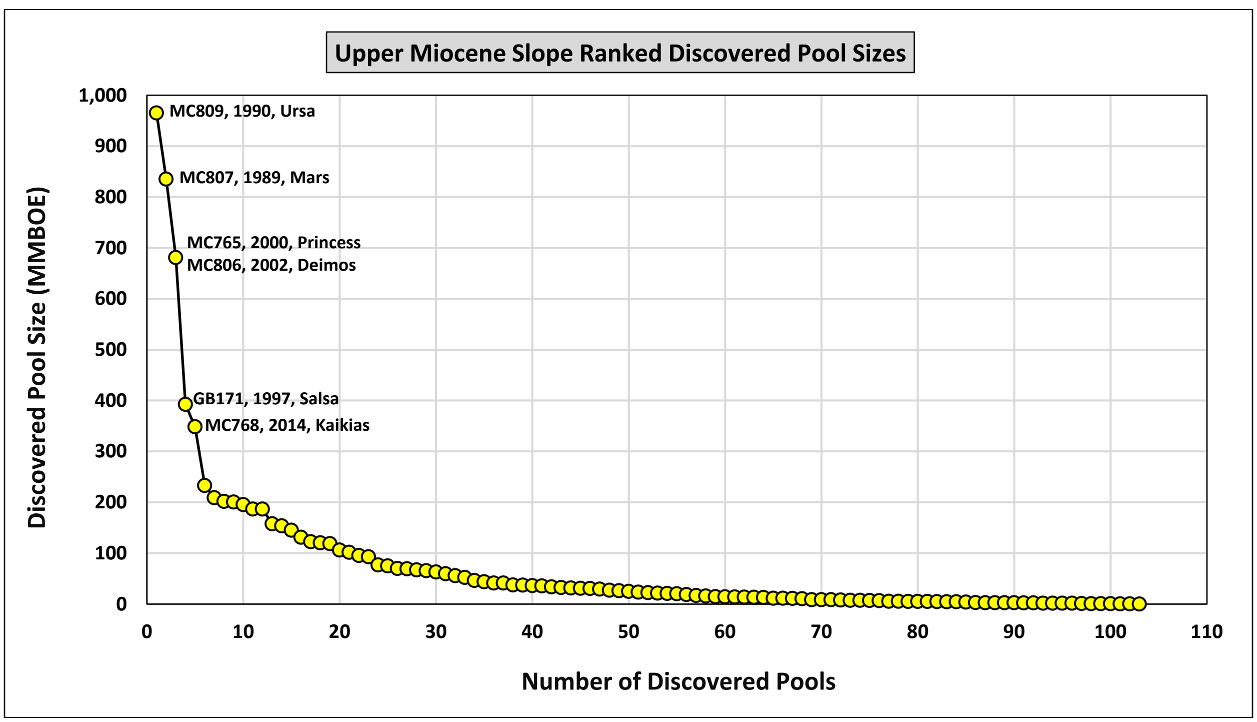

Figure 123. Upper Miocene Slope discovered pool-rank plot.

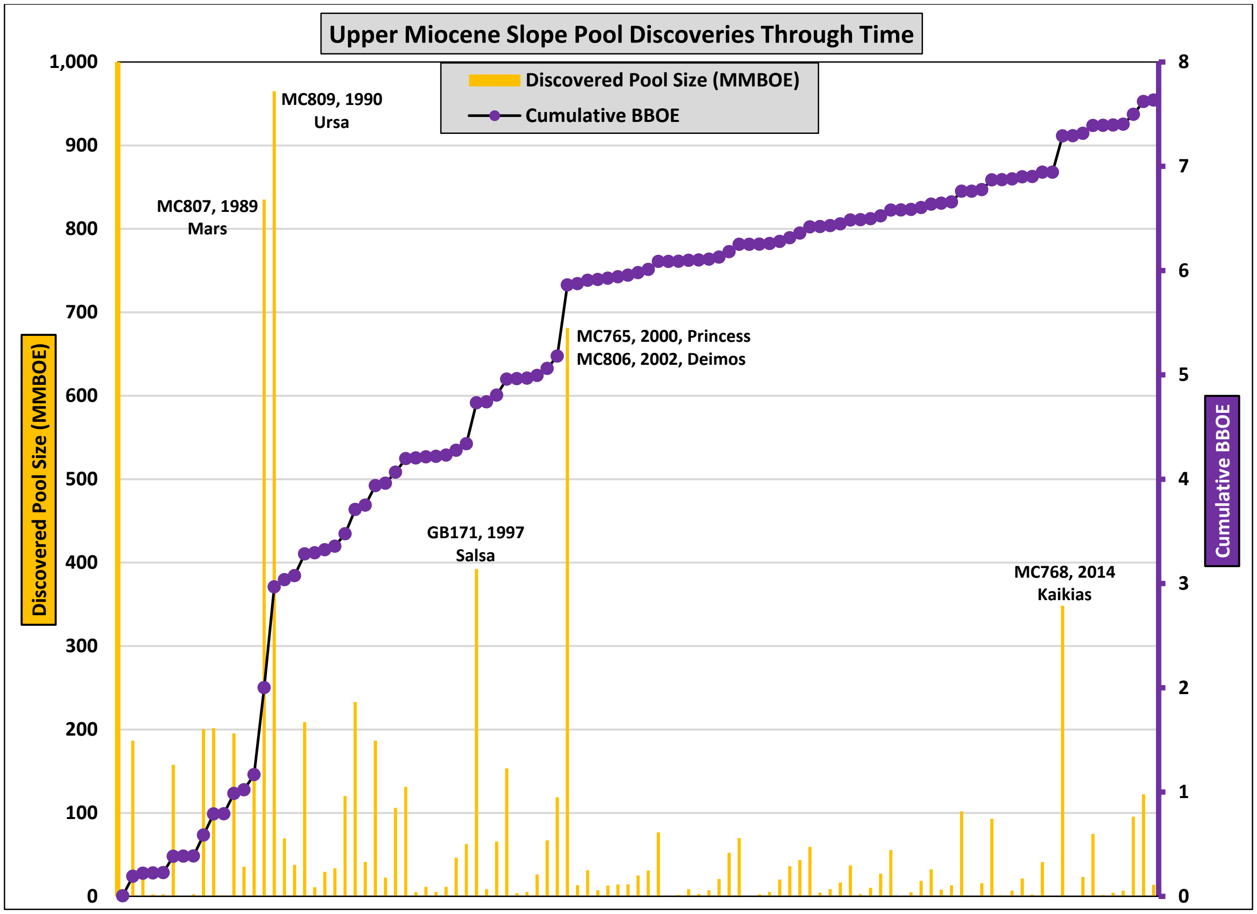

Figure 124. Upper Miocene Slope pseudo-creaming curve.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factor for successful hydrocarbon accumulations is the trap component, resulting in a prospect-level chance of success of 29 percent (**Figure 4**). This makes the overall exploration chance of success 29 percent (**Figure 5**). See Appendix B for details.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 438 to 576. Applying risk results in 127 to 167 undiscovered pools, with a mean of 149.

The pool-size distribution was modeled with the 103 discoveries in the AU. These pools range in size from 0.026 to 965 MMBOE, with a mean size of 74 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 426 MMBOE in size.

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 2.300 to 5.336 Bbbl, and undiscovered gas resources range from 6.321 to 15.563 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 125**). Total BOE undiscovered resources range from 3.424 to 8.105 BBOE at the 95th and 5th percentiles, respectively (**Figure 126**).

Although the Upper Miocene Slope AU has been explored for a long time historically, it still offers significant opportunities for exploration and continues to provide discoveries. In fact, of all 30 assessment units in this study, the AU ranks 2nd behind the Wilcox Slope based on mean-level undiscovered BOE resources (**Figure 10**). The potential of the Upper Miocene Slope continues to be extensively explored as far south as Keathley Canyon.

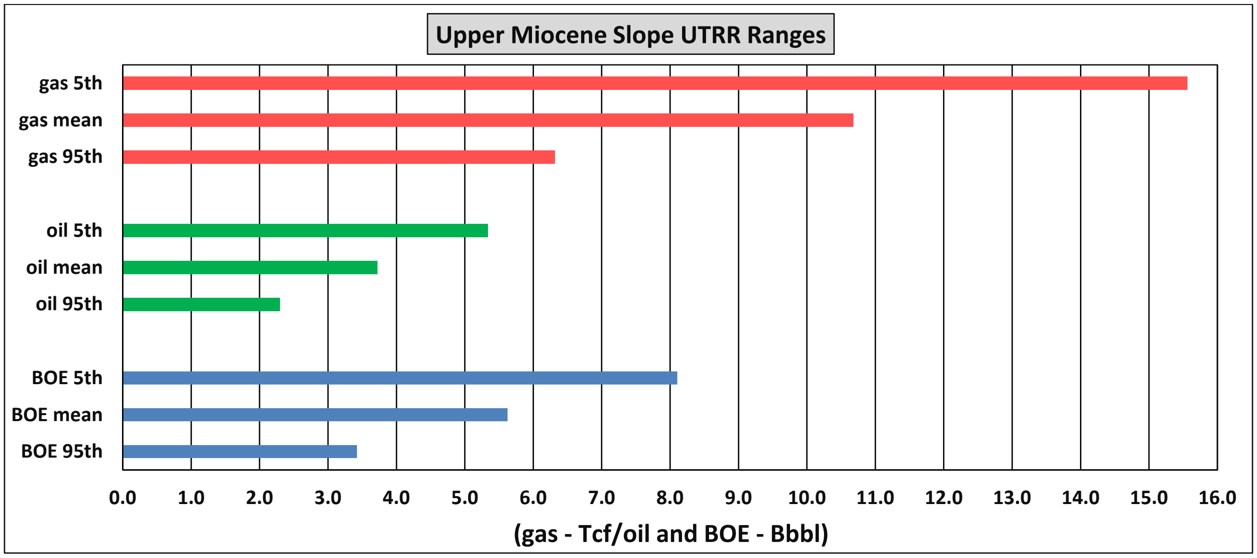

Figure 125. Upper Miocene Slope gas, oil, and BOE UTRR ranges.

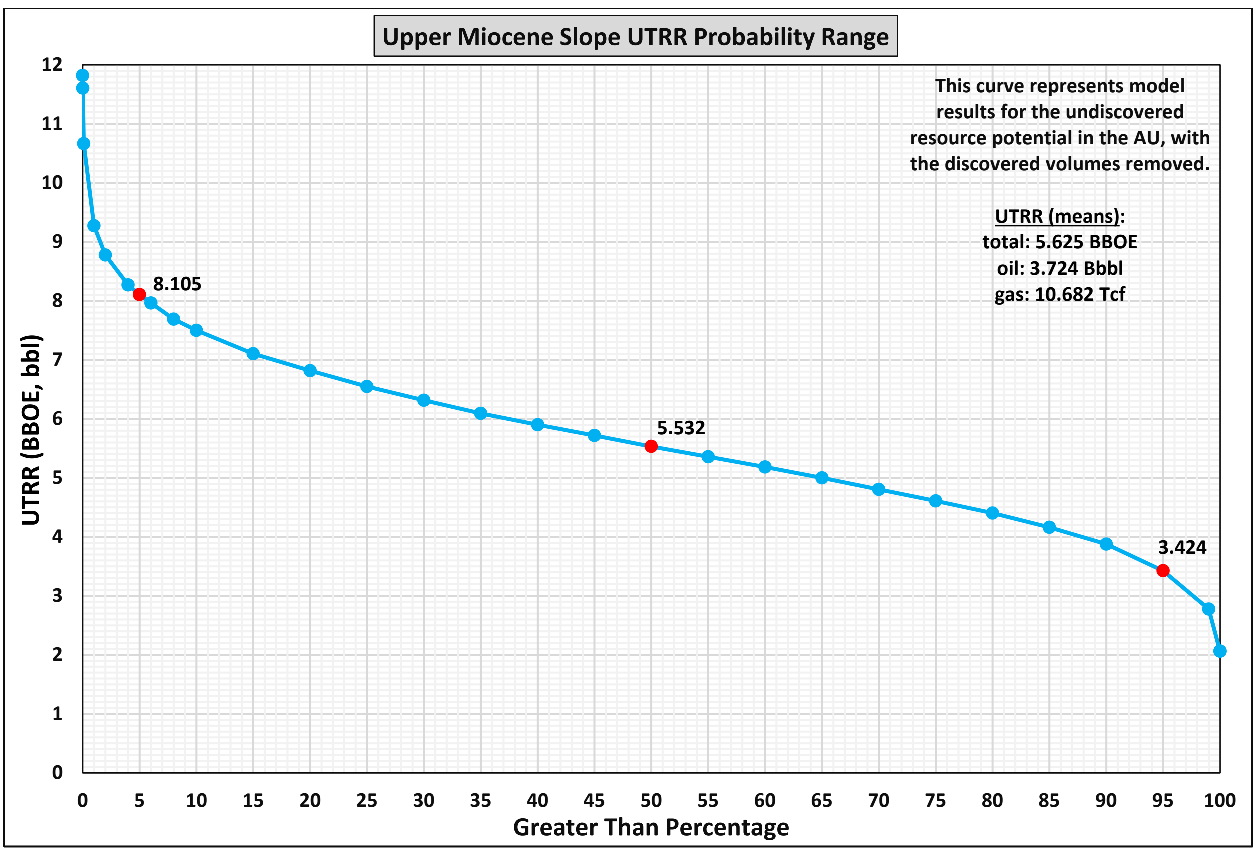

Figure 126. Upper Miocene Slope UTRR probability range based on total BOE.

Pliocene Shelf

Geology

The Pliocene Shelf AU is defined by sediments deposited in the Zanclean and Piacenzian Stages (**Table 4**) within the present-day GOM shelf. The stratigraphic framework within the GOM 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, 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 127**).

The Pliocene shelf margin advanced to the limit of the 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 stacked, blocky, sand-dominated sediments deposited in fluvial channel-levee complexes, crevasse splays, and point bars; in deltaic distributary channel-levee complexes, crevasse splays, distributary mouth bars, bay fill, beaches and barrier islands; and in shallow marine shelf delta fringes and slumps. Deepwater fan systems include channel-levee systems and sheet sand lobes.

The Pliocene 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.

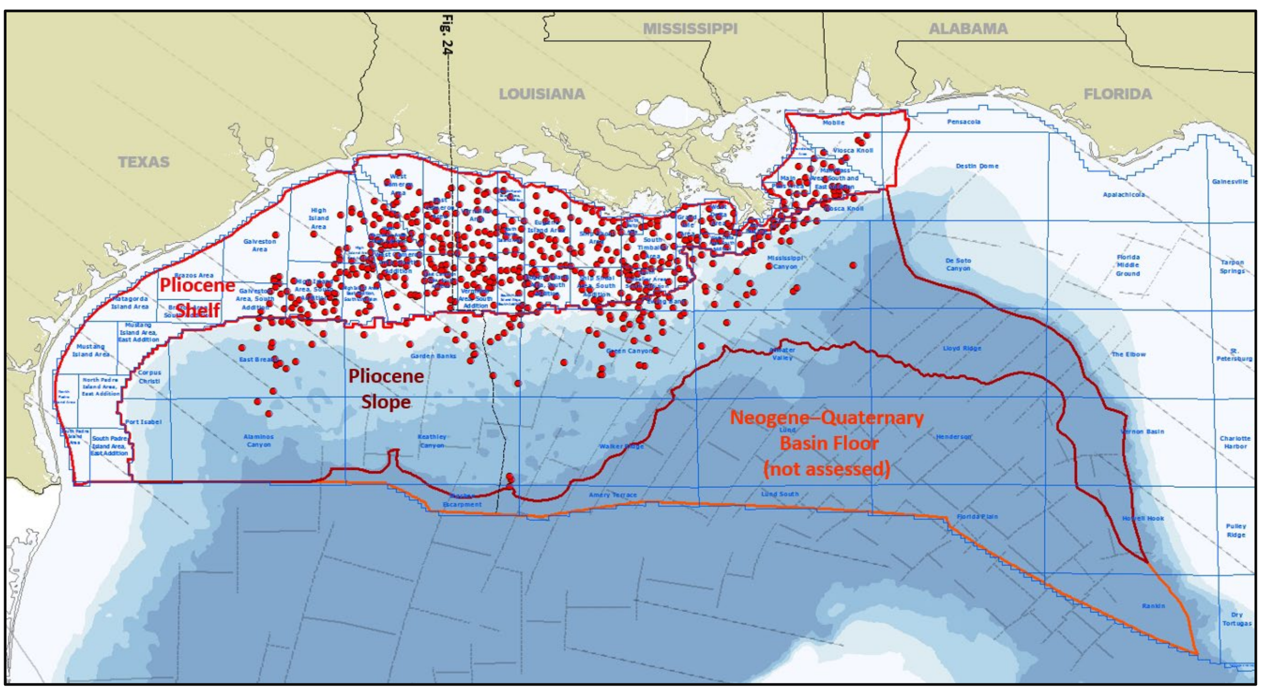

Figure 127. Pliocene Shelf and Slope locations and associated discovered pools.

Discoveries

Hydrocarbon-bearing pools within the Pliocene Shelf AU 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 127**). As of the end of 2018, there are 481 BOEM-designated hydrocarbon discoveries in the Shelf AU. Discovery dates range from 1948 to 2009 and peaked in the 1980s (**Figure 128**). The Shelf AU contains 4.768 Bbbl of oil and 48.824 Tcf of gas (total BOE of 13.456 Bbbl) (**Table 9**). These totals include cumulative production, remaining reserves, and contingent resources. Discovered in 1960, Ship Shoal 208 is the largest discovered pool, containing an estimated 0.484 BBOE (**Figure 129**). Other sizable pools include Eugene Island 238, South Pass 89, and Ship Shoal 169, all of which contain more than 0.3 BBOE (**Figure 129**). Pools have been discovered in water depths ranging from 12 to 650 ft, and subsea depths of these pools range from 1,115 to 16,145 ft.

Figure 130 illustrates the pseudo-creaming curve for Pliocene Shelf pool discoveries superimposed on the number and size of the discoveries through time. The flattening of the pseudo-creaming curve and decreasing discovery sizes through time clearly reflect a well-established, mature assessment unit with the largest pools found early in its exploration history.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factor for successful hydrocarbon accumulations is the trap component, resulting in a prospect-level chance of success of 29 percent (**Figure 4**). This makes the overall exploration chance of success 29 percent (**Figure 5**). See Appendix B for details.

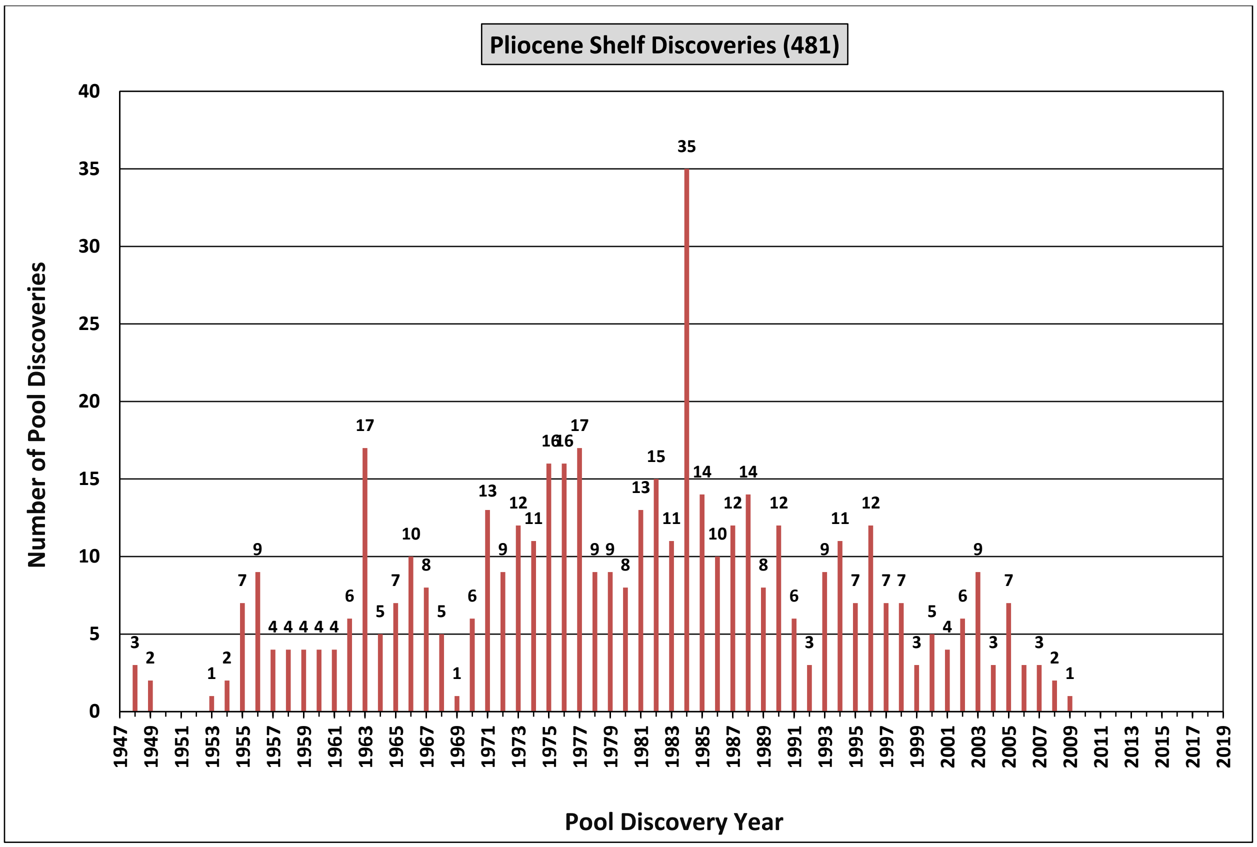

Figure 128. Pliocene Shelf pool discovery history.

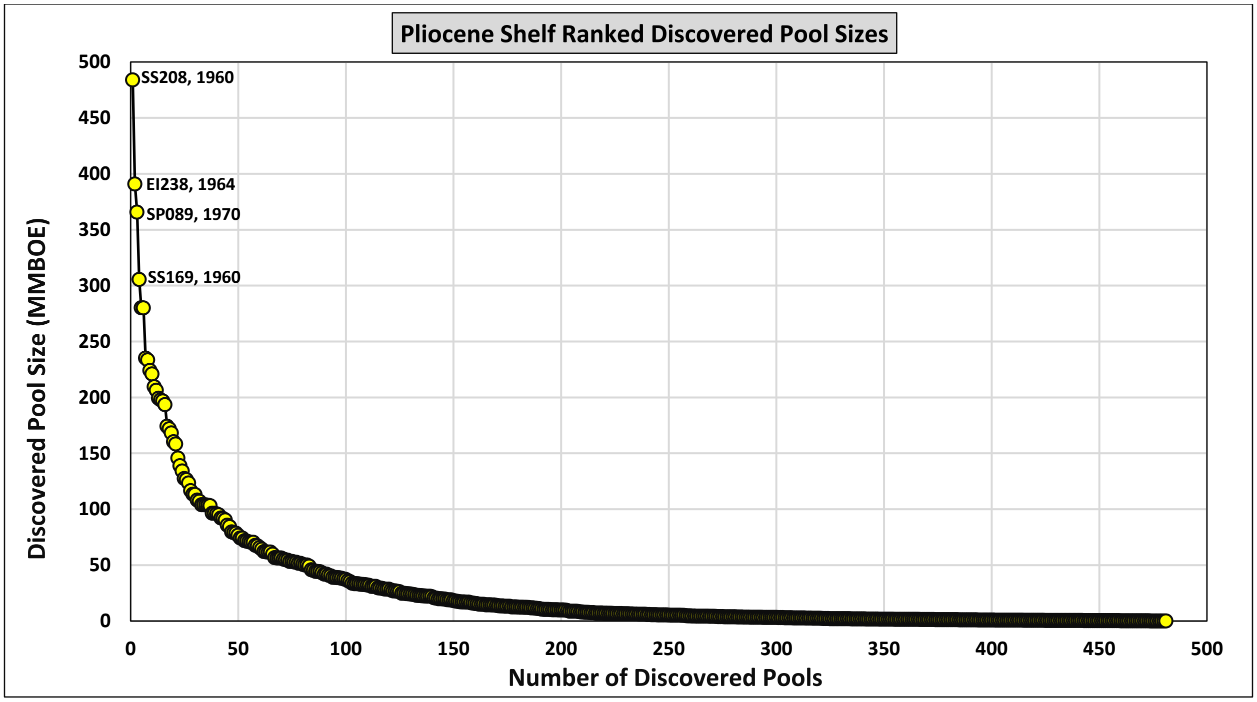

Figure 129. Pliocene Shelf discovered pool-rank plot.

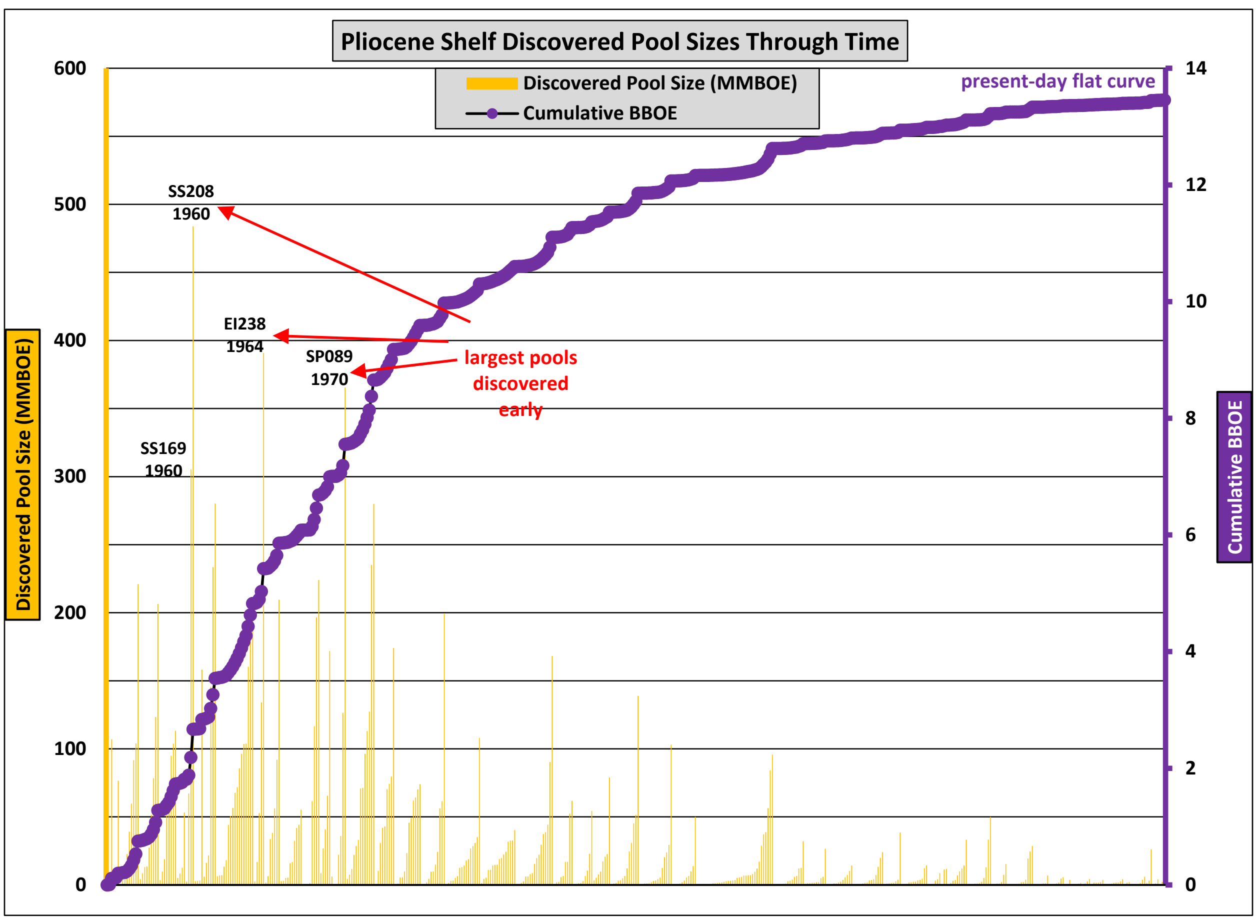

Figure 130. Pliocene Shelf pseudo-creaming curve.

Undiscovered Resources

The Pliocene 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 flat pseudo-creaming curve indicative of very mature and highly explored plays (**Figure 130**).

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 238 to 376. Applying risk results in 69 to 109 undiscovered pools, with a mean of 89.

The pool-size distribution was modeled with the 481 discoveries in the AU. These pools range in size from 0.005 to 484 MMBOE, with a mean size of 28 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 5 MMBOE in size.

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 0.009 to 0.084 Bbbl, and undiscovered gas resources range from 0.095 to 0.835 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 131**). Total BOE undiscovered resources range from 0.026 to 0.233 BBOE at the 95th and 5th percentiles, respectively (**Figure 132**). 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. Based on mean-level undiscovered BOE resources, the AU ranks 25th of all 30 GOM assessment units (**Figure 10**).

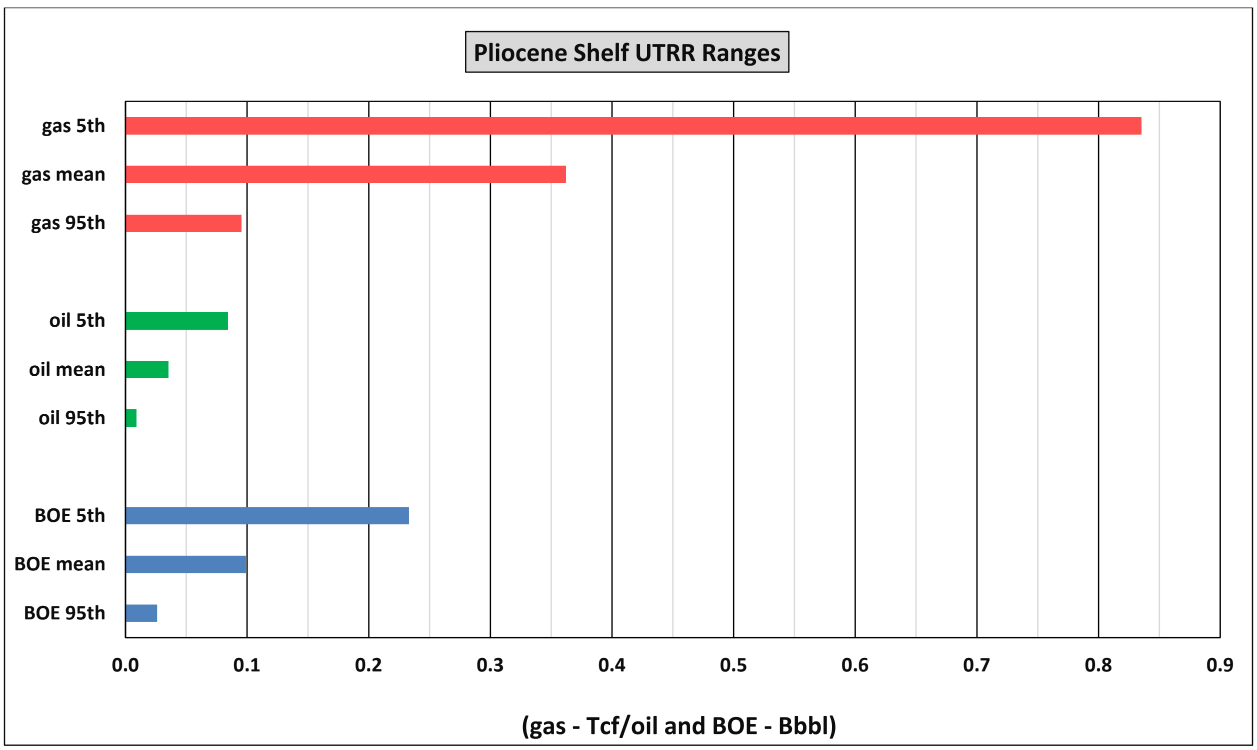

Figure 131. Pliocene Shelf gas, oil, and BOE UTRR ranges.

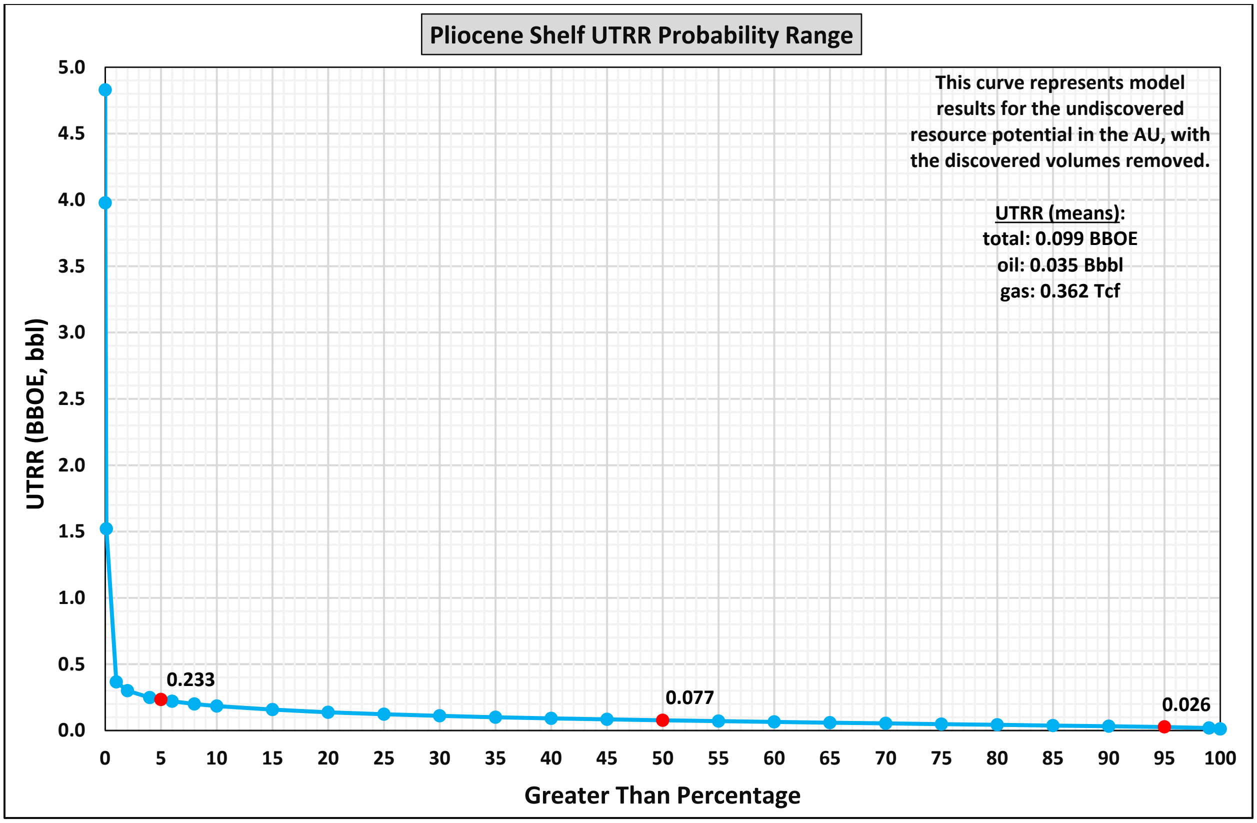

Figure 132. Pliocene Shelf UTRR probability range based on total BOE.

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 GOM slope (**Figure 24**). The stratigraphic framework within the GOM 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 127**). 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 Pliocene Slope AU is underlain by large Pliocene submarine fan systems which advanced across the Sigsbee Salt Canopy in the central GOM (**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 Pliocene 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. Thus, it is a relatively mature play for the modern slope. As of the end of 2018, there are 111 BOEM-designated hydrocarbon discoveries. Discovery dates range from 1975 to 2014 (**Figure 133**). The Slope AU contains 4.669 Bbbl of oil and 12.044 Tcf of gas (total BOE of

6.812 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in late 2009/early 2010, the subsalt Lucius discovery (Keathley Canyon 875) is the largest pool in the Slope AU, containing an estimated 0.764 BBOE (**Figure 134**). Other sizable discovered pools include Mississippi Canyon 807 (Mars-Ursa complex), Garden Banks 426 (Auger), Mississippi Canyon 194 (Cognac), and Green Canyon 244 (Troika), all estimated to contain more than 0.3 BBOE (**Figure 134**). Pools have been discovered in water depths ranging from 659 to 8,566 ft, and subsea depths of these pools range from 2,750 to 23,994 ft.

Figure 135 illustrates the pseudo-creaming curve for the pool discoveries superimposed on the number and size of the discoveries through time. Numerous large pool discoveries have resulted in sharp upticks in volumes added to the AU through time. The most recent example is the aforementioned Lucius discovery.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factors for successful hydrocarbon accumulations are the reservoir and trap components, resulting in a prospect-level chance of success of 25 percent (**Figure 4**). This makes the overall exploration chance of success 25 percent (**Figure 5**). See Appendix B for details.

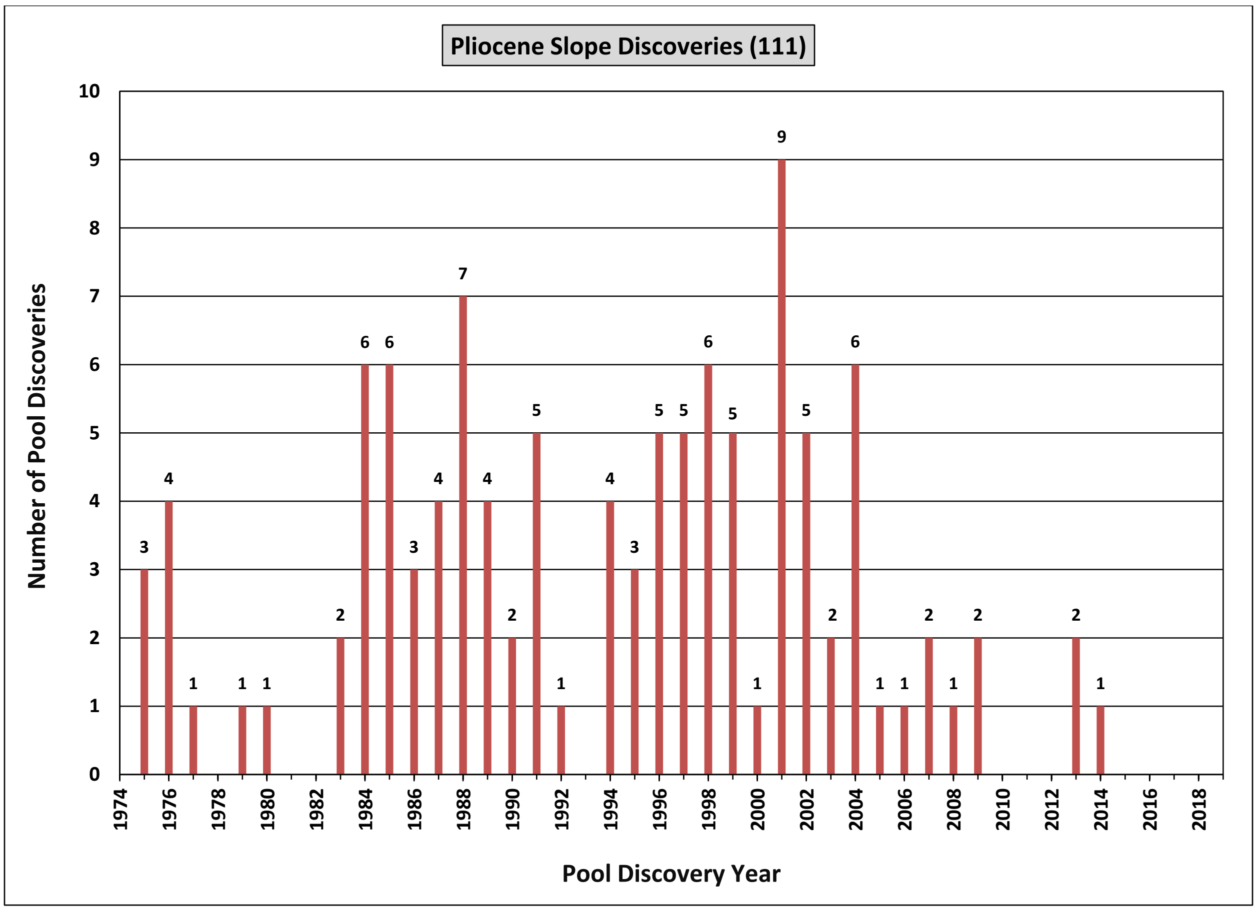

Figure 133. Pliocene Slope pool discovery history.

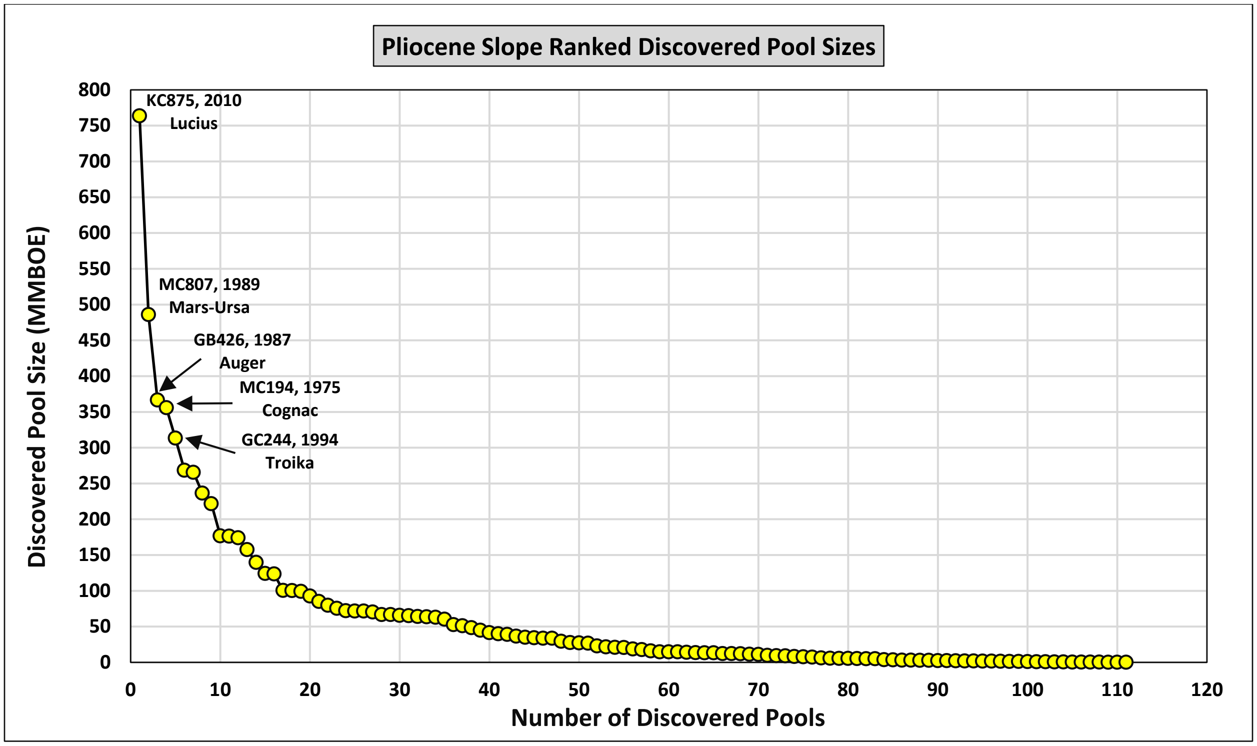

Figure 134. Pliocene Slope discovered pool-rank plot.

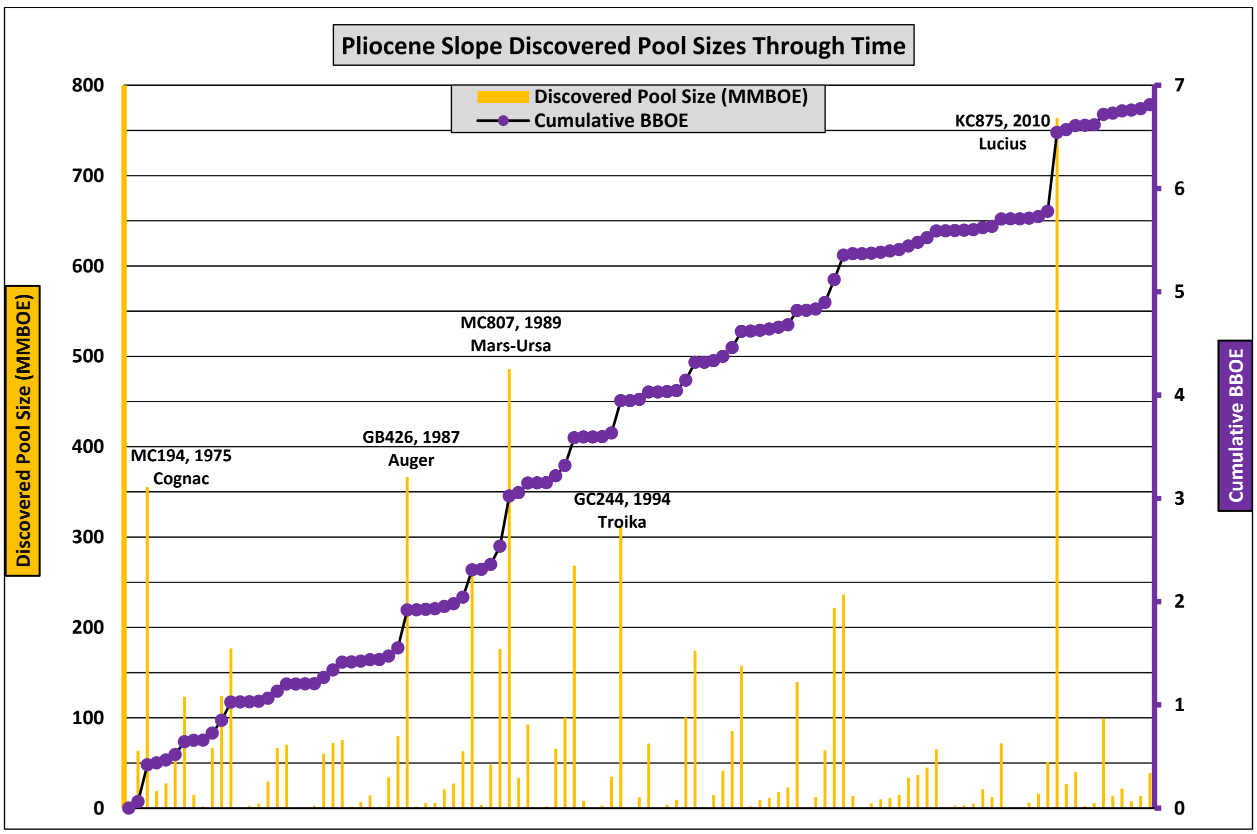

Figure 135. Pliocene Slope pseudo-creaming curve.

Undiscovered Resources

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 316 to 476. Applying risk results in 79 to 119 undiscovered pools, with a mean of 99.

The pool-size distribution was modeled with the 111 discoveries in the AU. These pools range in size from 0.105 to 764 MMBOE, with a mean size of 61 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 24 MMBOE in size.

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 0.141 to 1.103 Bbbl, and undiscovered gas resources range from 0.369 to 2.997 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 136**). Total BOE undiscovered resources range from 0.207 to 1.637 BBOE at the 95th and 5th percentiles, respectively (**Figure 137**). Based on mean-level undiscovered BOE resources, the AU ranks 14th of all 30 GOM assessment units (**Figure 10**).

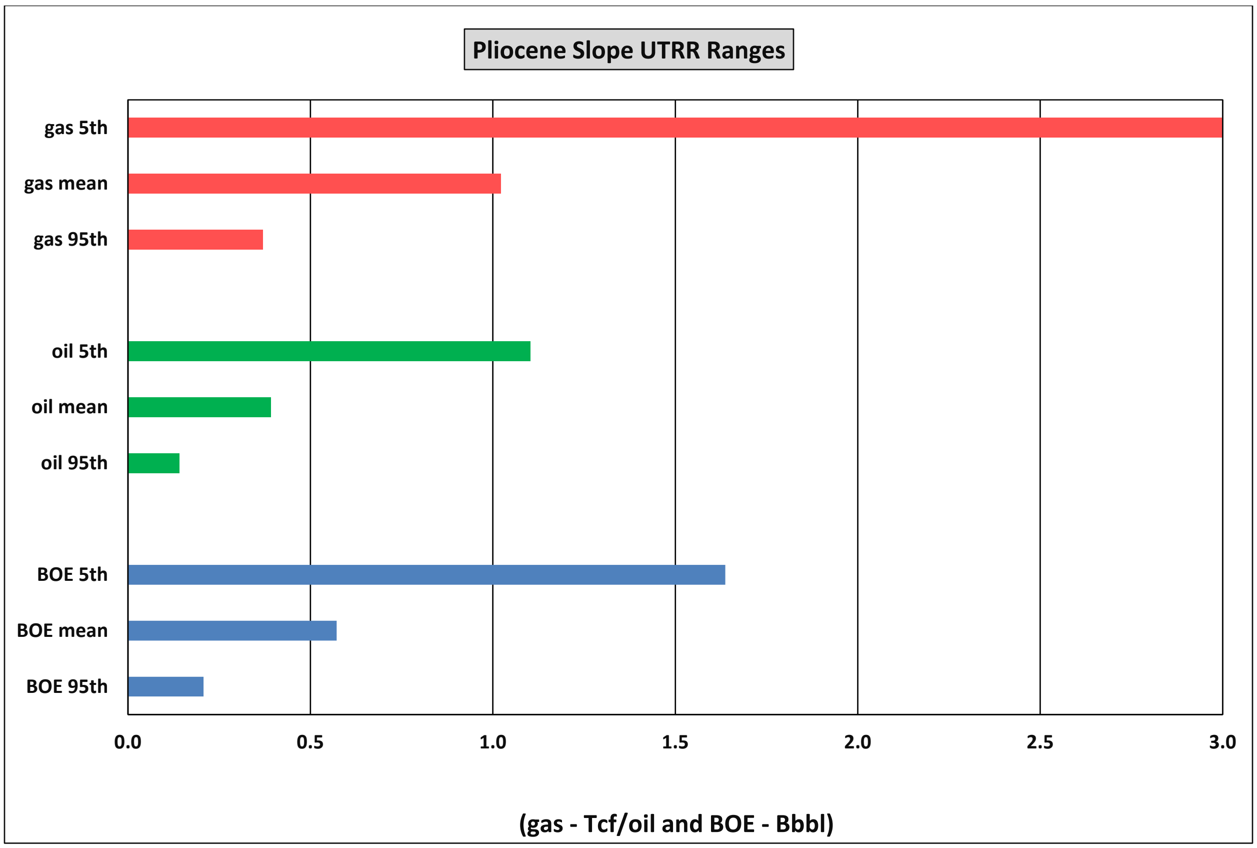

Figure 136. Pliocene Slope gas, oil, and BOE UTRR ranges.

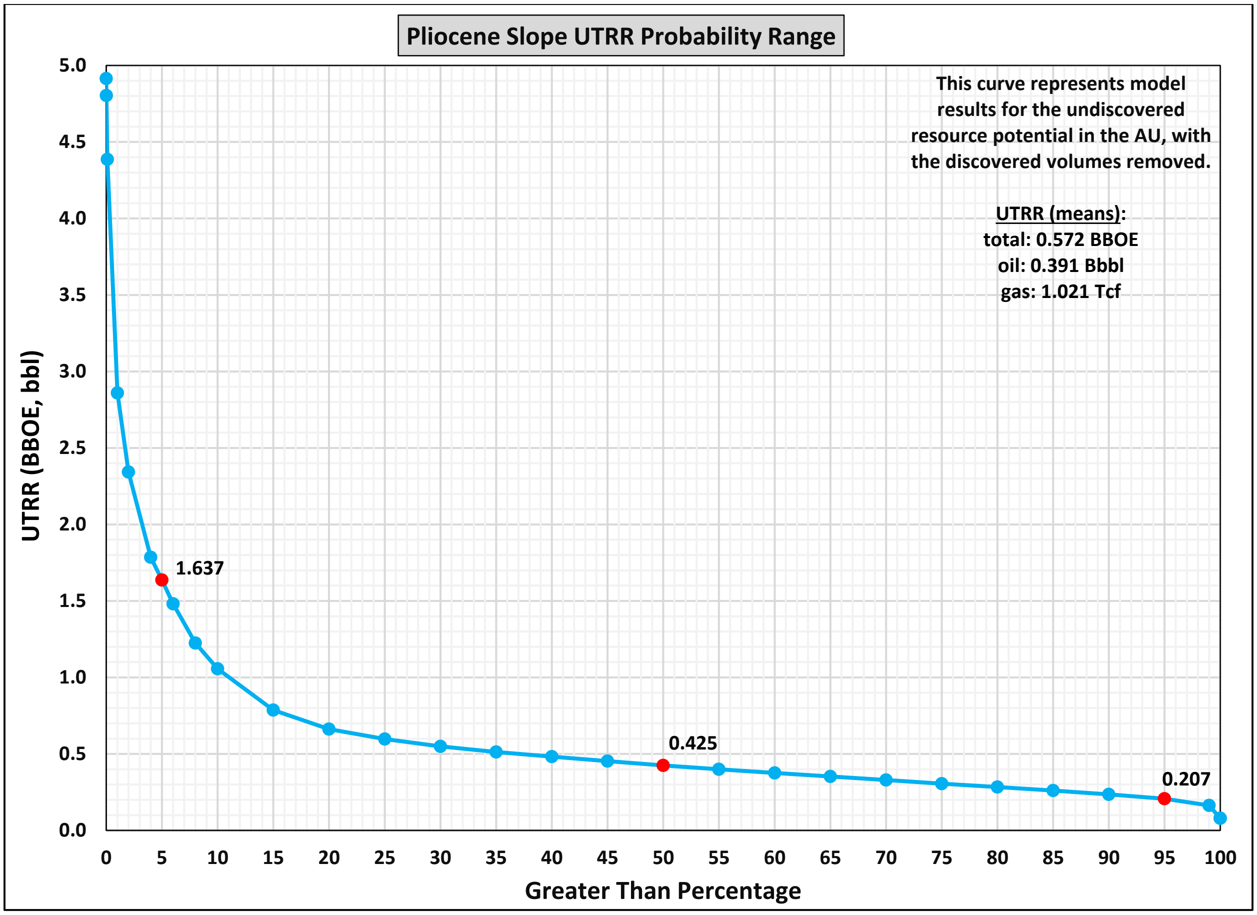

Figure 137. Pliocene Slope UTRR probability range based on total BOE.

Pleistocene Shelf

Geology

The Pleistocene Shelf AU is defined by sediments deposited in the Gelasian, Calabrian, Ionian, and Tarantian Stages (**Table 4**) within the present-day GOM shelf. These sediments represent the youngest prospective stratigraphy in the GOM Basin (**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 138**).

The Pleistocene Shelf AU including eastern-most offshore Texas and the western and central Louisiana shelf are 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**). Reservoirs of the Pleistocene Shelf AU were deposited in fluvial-deltaic, coastal, and shallow marine environments. Shallow-water facies include stacked, blocky, sand-dominated sediments deposited in fluvial channels, levees, crevasse splays, and point bars; in deltaic distributary channels, crevasse splays, distributary mouth bars, bay fill, beaches and barrier islands; and in shallow marine shelf sand bodies.

The Pleistocene 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.

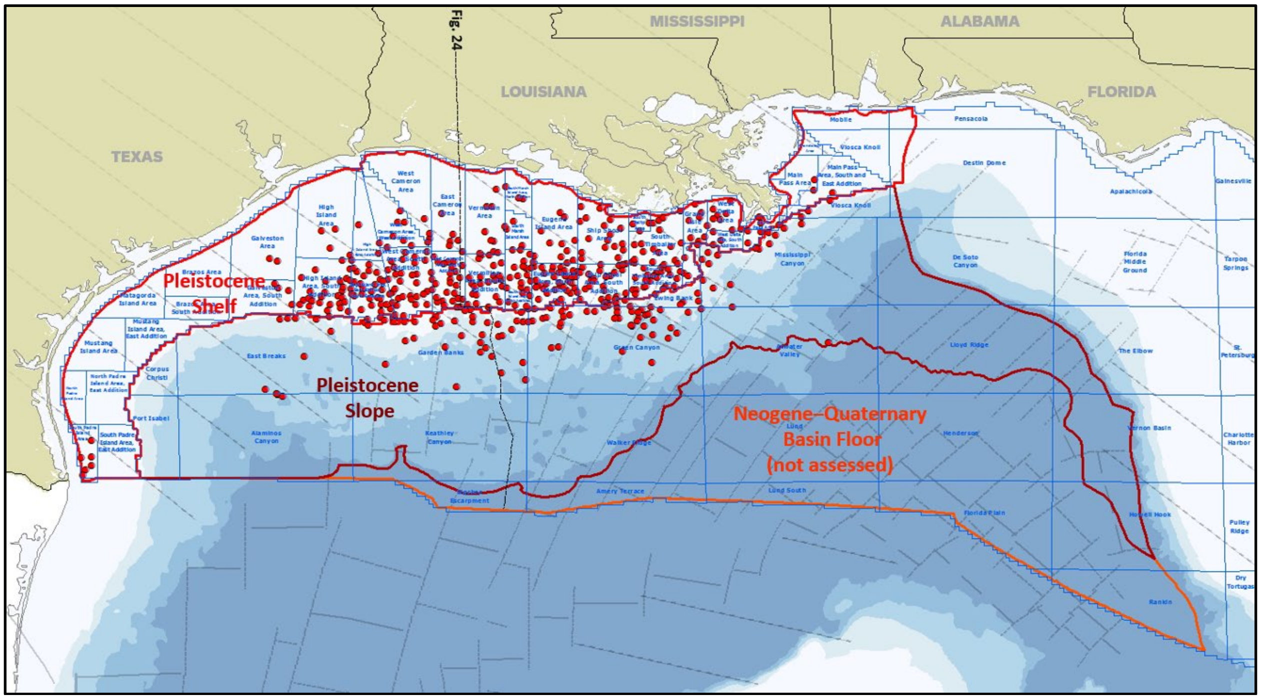

Figure 138. Pleistocene Shelf and Slope locations and associated discovered pools.

Discoveries

The Pleistocene Shelf is very mature, as these sediments overlie older targets. Hydrocarbon-bearing pools within the AU 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 138**). As of the end of 2018, 392 hydrocarbon-bearing pools have been discovered, with discovery dates ranging from 1947 to 2009, with the peak of discoveries occurring in the mid-1970s (**Figure 139**). The AU contains 1.816 Bbbl of oil and 36.279 Tcf of gas (total BOE of 8.272 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 1971, Eugene Island 330 is the largest pool, containing an estimated 0.575 BBOE (**Figure 140**). Other sizable discovered pools include Eugene Island 292, South Marsh Island 130, Eugene Island 296, and West Cameron 587, all estimated contain more than 0.2 BBOE (**Figure 140**). Pools have been discovered in water depths ranging from 12 to 638 ft, and subsea depths of these pools range from 882 to 12,835 ft.

Figure 141 illustrates the pseudo-creaming curve for Pleistocene Shelf pool discoveries superimposed on the number and size of the discoveries through time. The flattening of the pseudo-creaming curve and decreasing discovery sizes through time clearly reflect a well-established, mature assessment unit in its end-of-life phase.

Risk

With numerous discoveries, the play-level chance of success for the AU is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factor for successful hydrocarbon accumulations is the trap component, resulting in a prospect-level chance of success of 43 percent (**Figure 4**). This makes the overall exploration chance of success 43 percent (**Figure 5**). See Appendix B for details.

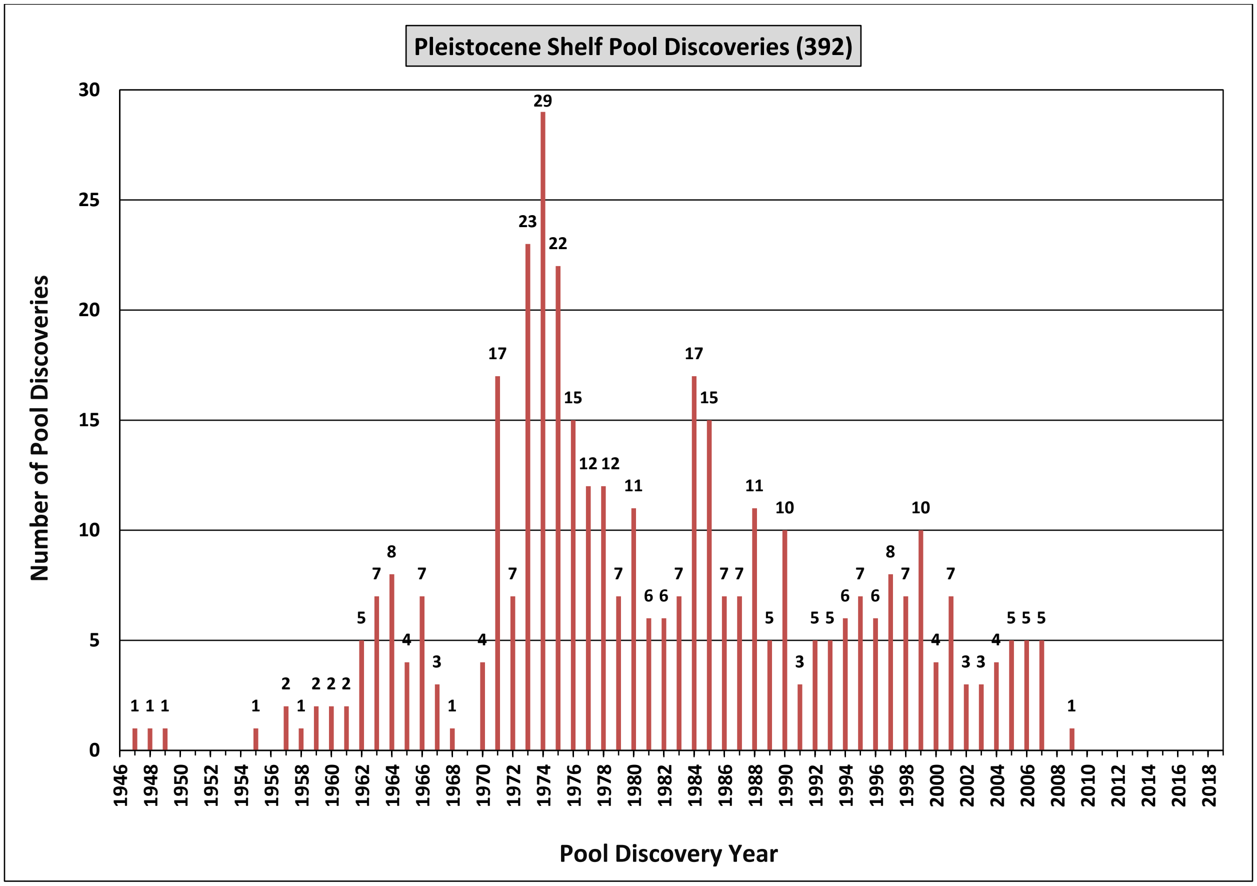

Figure 139. Pleistocene Shelf pool discovery history.

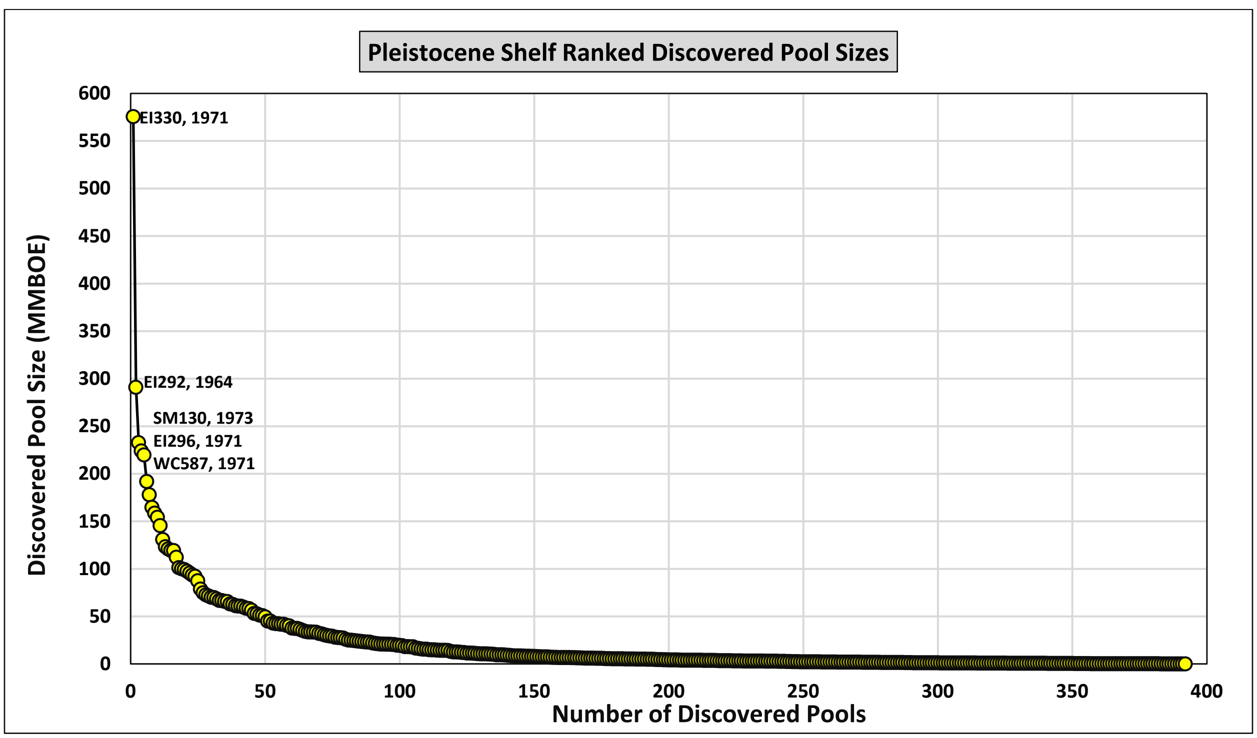

Figure 140. Pleistocene Shelf discovered pool-rank plot.

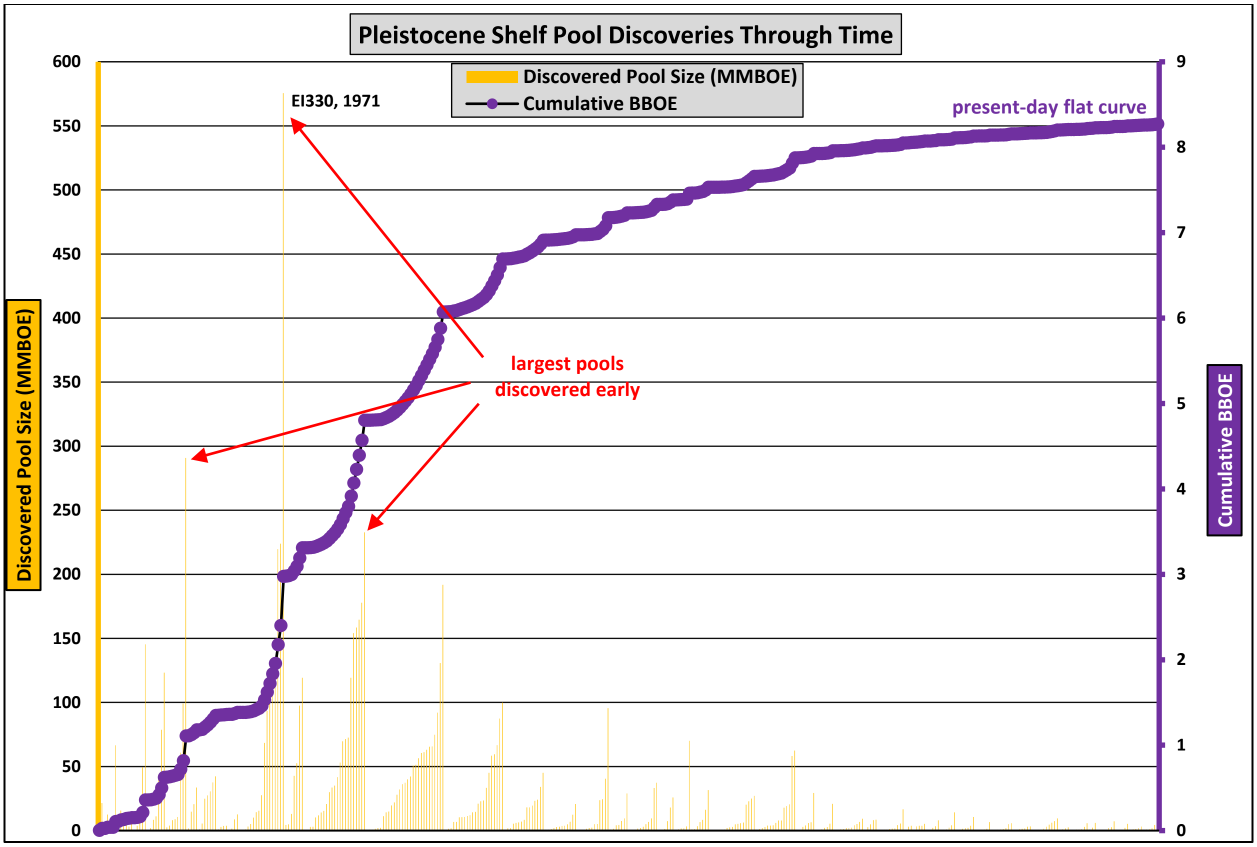

Figure 141. Pleistocene Shelf pseudo-creaming curve.

Undiscovered Resources

The Pleistocene 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 2009, and (4) a present-day flat pseudo-creaming curve indicative of mature, highly explored plays (**Figure 141**).

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 19 to 112. Applying risk results in 8 to 48 undiscovered pools, with a mean of 28.

The pool-size distribution was modeled with the 392 discoveries in the AU. These pools range in size from 0.001 to 575 MMBOE, with a mean size of 21 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 1 MMBOE in size.

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 0.001 to 0.037 Bbbl, and undiscovered gas resources range from 0.014 to 0.787 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 142**). Total BOE undiscovered resources range from 0.003 to 0.177 BBOE at the 95th and 5th percentiles, respectively (**Figure 143**). 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. Based on mean-level undiscovered BOE resources, the AU ranks 27th of all 30 GOM assessment units (**Figure 10**).

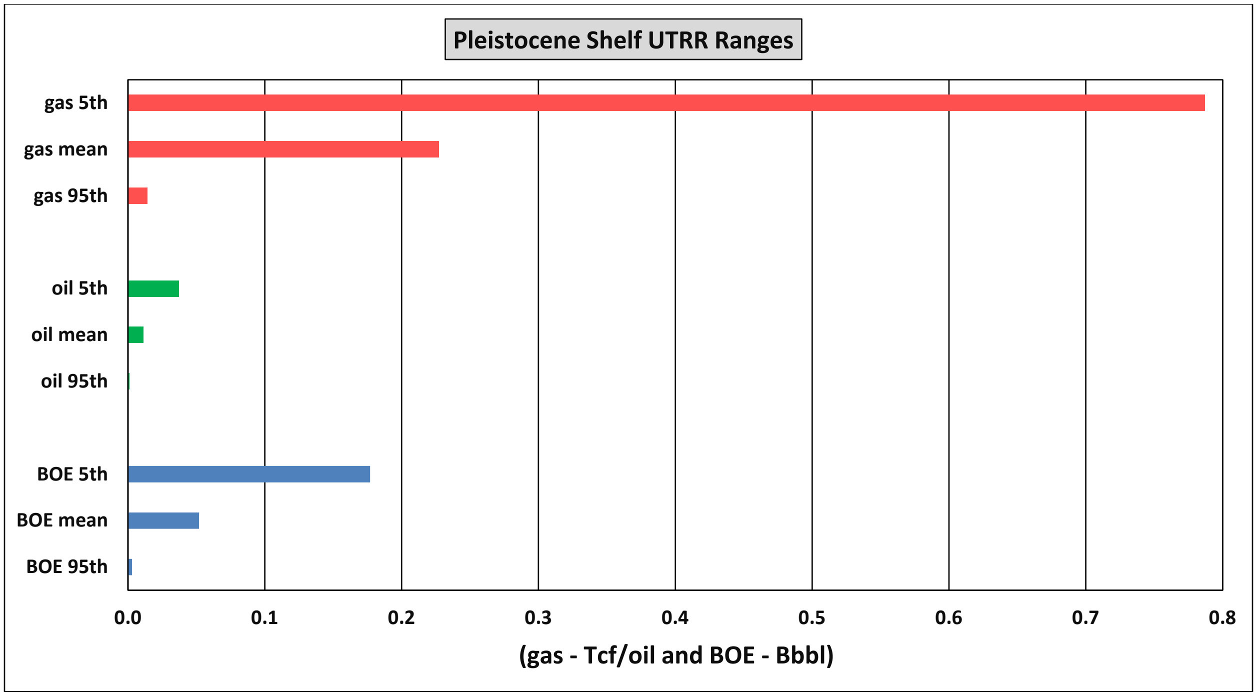

Figure 142. Pleistocene Shelf gas, oil, and BOE UTRR ranges.

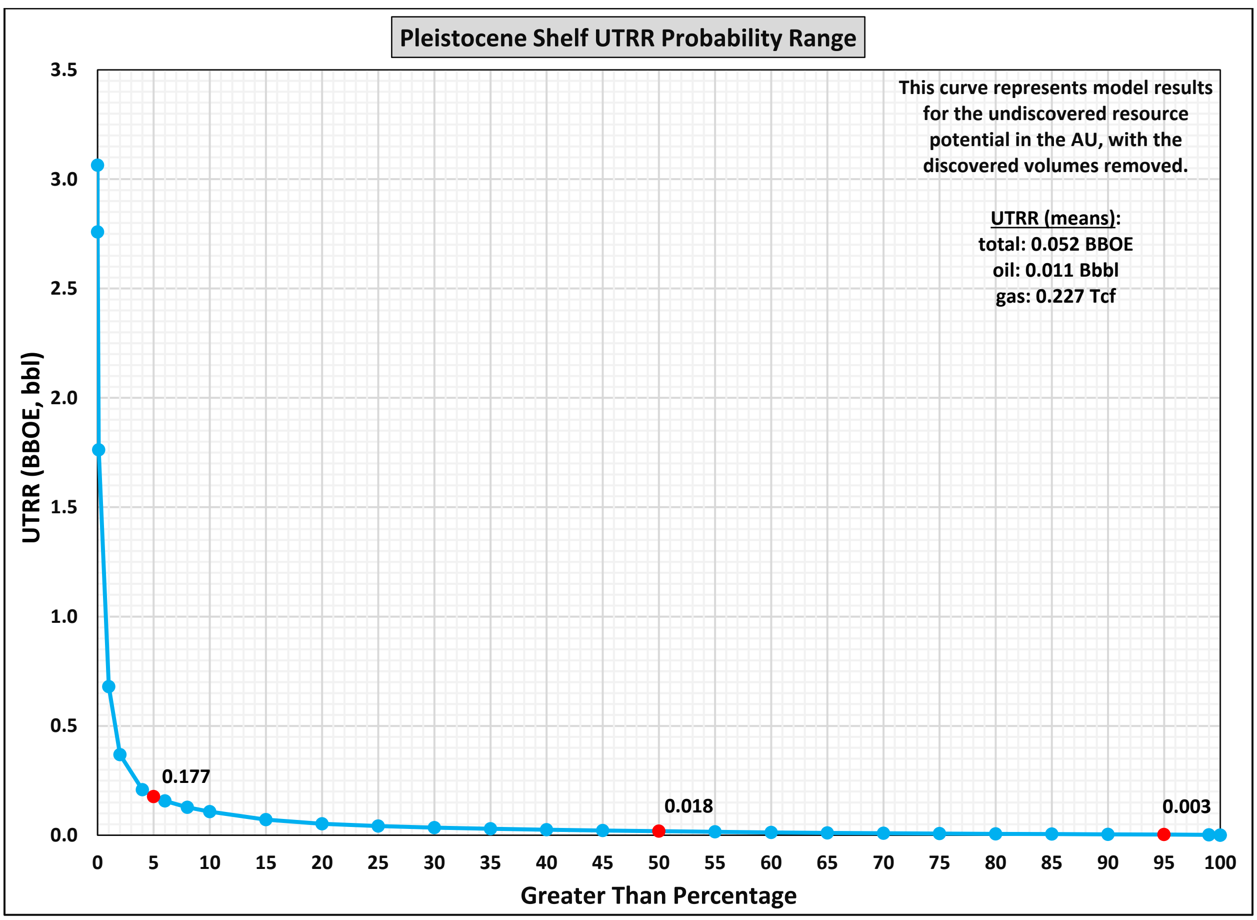

Figure 143. Pleistocene Shelf UTRR probability range based on total BOE.

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 GOM slope (**Figure 24**). These sediments represent the youngest prospective stratigraphy in the GOM Basin (**Figure 25**). The AU extends along strike from Mexican waters in the west and onlaps the Cretaceous shelf margin in the east (**Figure 138**). 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 Pleistocene 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 Pleistocene Slope AU is very mature, as these sediments overlie older targets. Hydrocarbon-bearing pools within the AU have been discovered from the East Breaks/Alaminos Canyon Areas in the west along strike to the Viosca Knoll Area in the east (**Figure 138**). As of the end of 2018, 107 hydrocarbon-bearing pools have been discovered, with discovery dates ranging from 1975 to 2009, with bimodal peaks occurring in the 1980s and late 1990s/early 2000s (**Figure 144**). The AU contains 1.075 Bbbl of oil and 7.238 Tcf of gas (total BOE of 2.363 Bbbl) (**Table 9**). These discovered resources include cumulative production, remaining reserves, and contingent resources. Discovered in 1987, Garden Banks 426 (Auger) is the largest pool, containing an estimated 0.219 BBOE (**Figure 145**). Other sizable discovered pools include Alaminos Canyon 25 (Hoover), East Breaks 945 (Diana), Garden Banks 668 (Gunnison), and Garden Banks 783 (Magnolia), all estimated to contain more than 0.1 BBOE (**Figure 145**). Pools have been discovered in water depths ranging from 659 to 6,623 ft, and subsea depths of these pools range from 2,355 to 21,023 ft.

Figure 146 illustrates the pseudo-creaming curve for Pleistocene Slope pool discoveries superimposed on the number and size of the discoveries through time. The flattening of the pseudo-creaming curve and decreasing discovery sizes through time clearly reflect a well-established, mature assessment unit in its end-of-life phase.

Risk

With numerous discoveries, the play-level chance of success for the Pleistocene Slope is 100 percent (zero risk) (**Figure 3**). The most crucial limiting factors for successful hydrocarbon accumulations are the reservoir and trap components, resulting in a prospect-level chance of success of 25 percent (**Figure 4**). This makes the overall exploration chance of success 25 percent (**Figure 5**). See Appendix B for details.

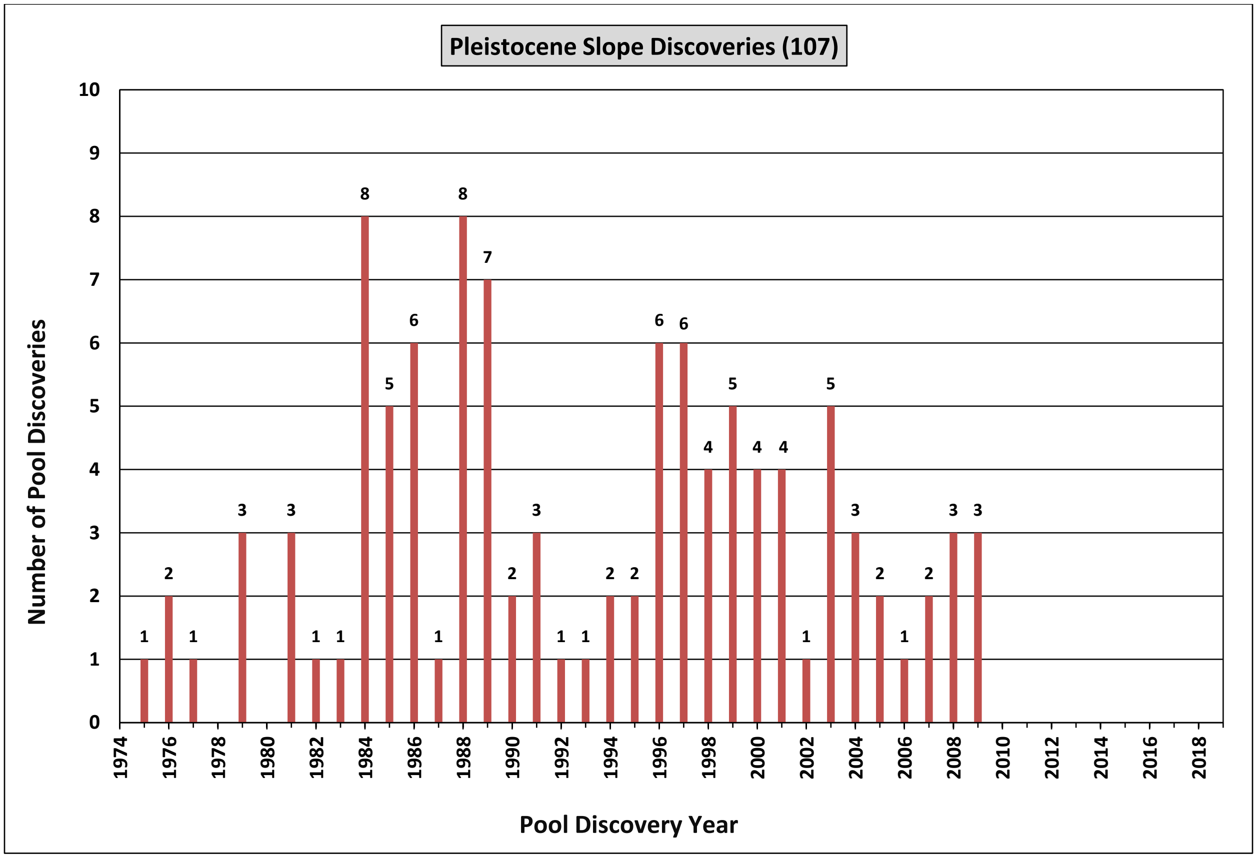

Figure 144. Pleistocene Slope pool discovery history.

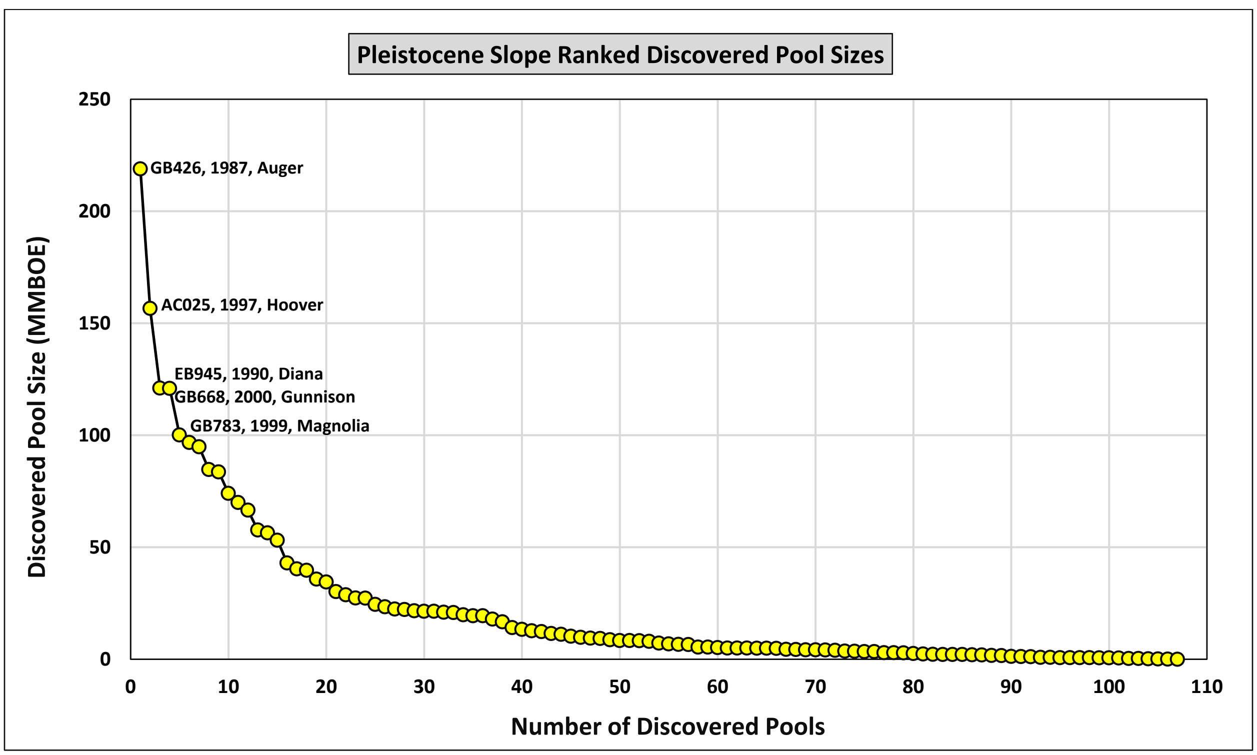

Figure 145. Pleistocene Slope discovered pool-rank plot.

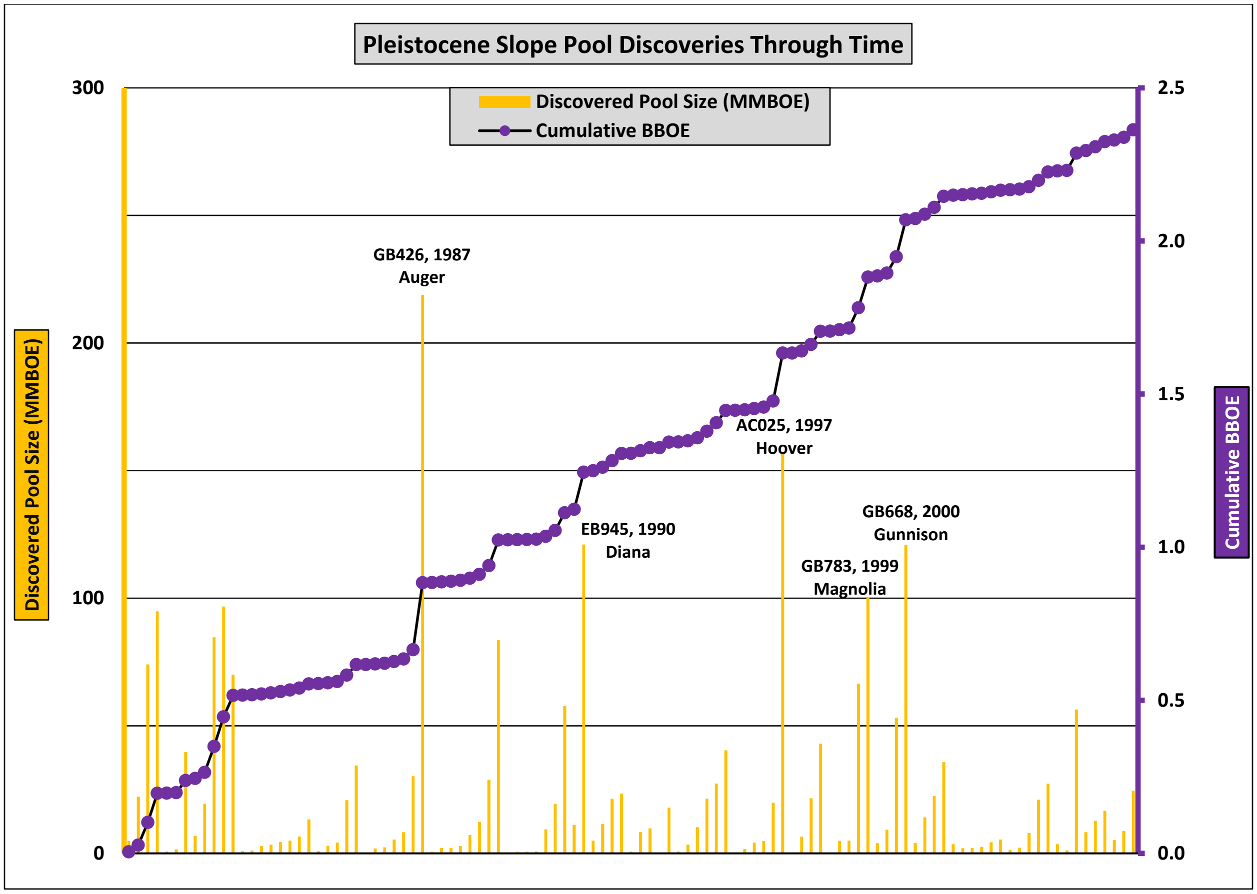

Figure 146. Pleistocene Slope pseudo-creaming curve.

Undiscovered Resources

The Slope AU was modeled with relatively little opportunity for undiscovered resources based on (1) a long discovery and production history dating back to 1975, (2) no discoveries greater than 50 MMBOE since 2000, and (3) no discoveries at all since 2009.

The number of remaining prospects for this established play was estimated based on discoveries, mapped prospects, and regional structures. From this, the assessors determined that the number of prospects ranges from 236 to 396. Applying risk results in 59 to 99 undiscovered pools, with a mean of 79.

The pool-size distribution was modeled with the 107 discoveries in the AU. These pools range in size from 0.009 to 219 MMBOE, with a mean size of 22 MMBOE. From this pool-size distribution and the number of pools distribution, the largest undiscovered pool in the play is approximately 6 MMBOE in size.

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 0.016 to 0.130 Bbbl, and undiscovered gas resources range from 0.112 to 0.905 Tcf at the 95th and 5th percentiles, respectively (**Table 9** and **Figure 147**). Total BOE undiscovered resources range from 0.036 to 0.291 BBOE at the 95th and 5th percentiles, respectively (**Figure 148**). Based on mean-level undiscovered BOE resources, the AU ranks 24th of all 30 GOM assessment units (**Figure 10**).

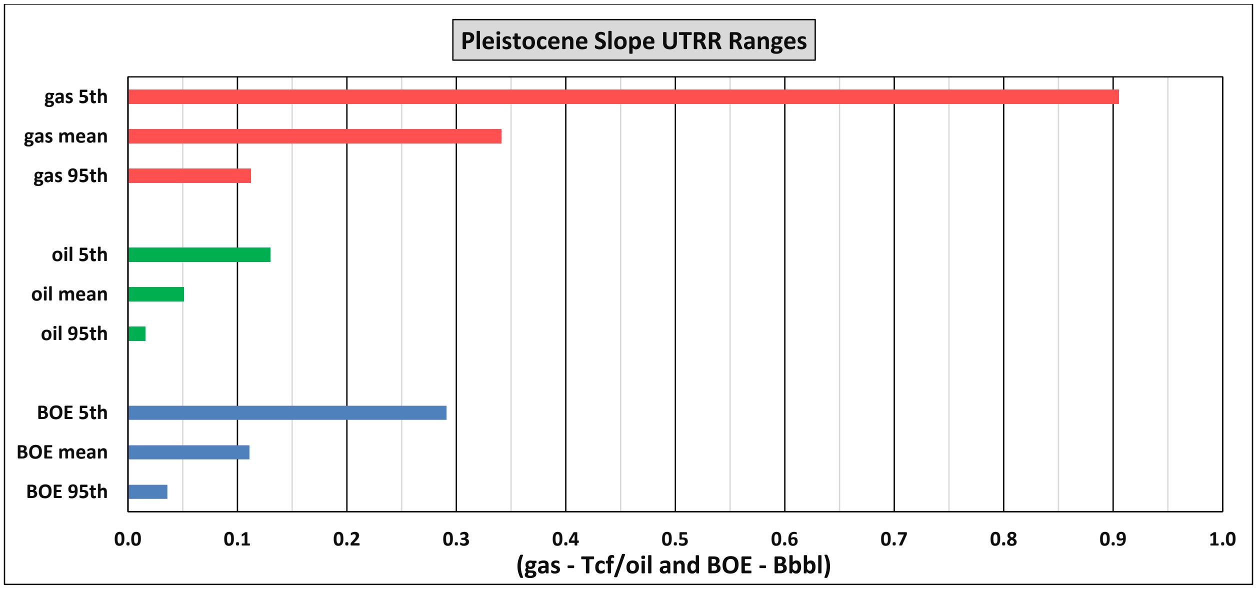

Figure 147. Pleistocene Slope gas, oil, and BOE UTRR ranges.

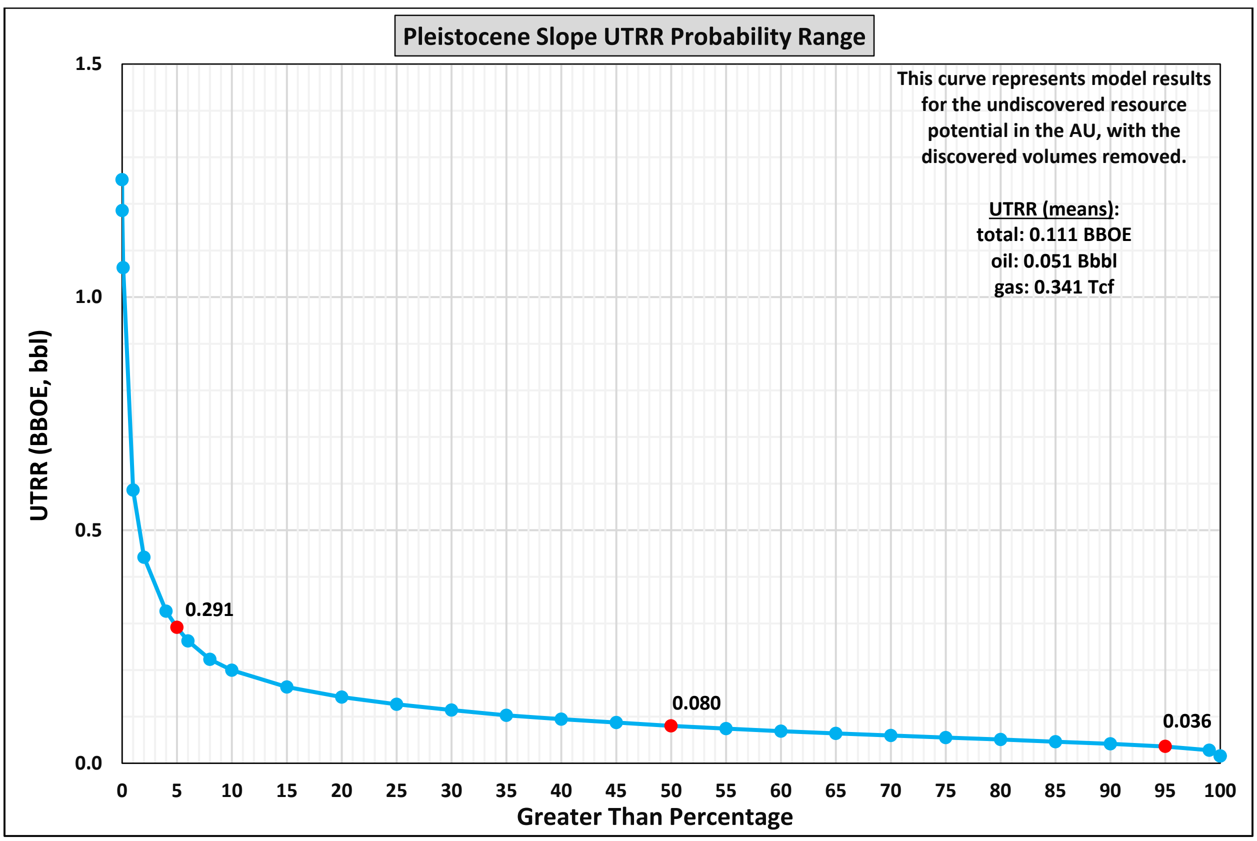

Figure 148. Pleistocene Slope UTRR probability range based on total BOE.

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 play, 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 Mezozoic 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 play 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 Play was not assessed because of a high degree of perceived geologic risk and a relatively small prospect inventory.

GLOSSARY

Assessment Unit: All hydrocarbon reservoirs of a specific geologic age in a specified geographic area.

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

Slope: An assessment unit in water depths greater than or equal to 656 ft (≥200 m). Synonymous with "deep water" 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 occur in the same play.

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

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

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

Conceptual Play: A play hypothesized 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.

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

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

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

Reserves Appreciation (a.k.a., Reserves Growth): 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 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 can conceivable by 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**) depending upon economic, technical, contractual, or regulatory criteria. (Discovered resource definitions taken from Burgess et al., 2020.)

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/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 Mexico	Assessment Unit Name:	Pre-Salt or Equivalent
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARBK
Date:	March 2020	Assessment:	2021 National 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**		***0.7000***		***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	**2**		***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	**3**		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.4480**		
Average Conditional Prospect Chance[1] (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**	***0.0806***

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 GOM 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 Mexico	Assessment Unit Name:	Expanded Jurassic
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARBJ
Date:	March 2020	Assessment:	2021 National 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		***0.6000***		***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***
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***
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 (1 * 2 * 3) ***Product of All Subjective Play Chance Factors***			**0.3360**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) ***Product of All Subjective Conditional Prospect Chance Factors***					**0.2100**
Exploration Chance ***Product of Overall Play Chance and Average Conditional Prospect Chance***				**Overall Exploration Chance**	***0.0706***

[1] Assumes that the play exists (where all play chance factors = 1.0)

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:	Norphlet Shelf
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARBH
Date:	March 2020	Assessment:	2021 National 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		***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***		***0.7000***
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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] *Assumes that the play exists (where all play chance factors = 1.0)*					**0.2940**
Exploration Chance *Product of Overall Play Chance and Average Conditional Prospect Chance*				**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:	Norphlet Slope			
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARBI			
Date:	March 2020	Assessment:	2021 National 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		***1.0000***		***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***
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***		***0.7000***
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 **(1 * 2 * 3)** ***Product of All Subjective Play Chance Factors***			**1.0000**		
Average Conditional Prospect Chance[1] **(1 * 2 * 3)** ***Product of All Subjective Conditional Prospect Chance Factors*** [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					**0.2100**
Exploration Chance ***Product of Overall Play Chance and Average Conditional Prospect Chance***				**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

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:	Smackover
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARBF
Date:	March 2020	Assessment:	2021 National 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		*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*		*0.5000*
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*
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 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] *Assumes that the play exists (where all play chance factors = 1.0)*					**0.2450**
Exploration Chance *Product of Overall Play Chance and Average Conditional Prospect Chance*				**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:

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 Mexico	Assessment Unit Name:	Florida Basement Clastic
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARBE
Date:	March 2020	Assessment:	2021 National 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		***0.7000***		***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***
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***
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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.3430**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] *Assumes that the play exists (where all play chance factors = 1.0)*					**0.2160**
Exploration Chance *Product of Overall Play Chance and Average Conditional Prospect Chance*				**Overall Exploration Chance**	***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 Mexico**	**Assessment Unit Name:**	**Cotton Valley Clastic Shelf**
Assessor(s):	**Mesozoic Team**	**Assessment Unit UAI:**	**AAACARBC**
Date:	**March 2020**	**Assessment:**	**2021 National 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**		***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***		***0.5000***
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***
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 * 2 * 3) ***Product of All Subjective Play Chance Factors***			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) ***Product of All Subjective Conditional Prospect Chance Factors*** [1] *Assumes that the play exists (where all play chance factors = 1.0)*					**0.2100**
Exploration Chance ***Product of Overall Play Chance and Average Conditional Prospect Chance***				**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**

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 Mexico	Assessment Unit Name:	Cotton Valley Clastic Slope
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARBD
Date:	March 2020	Assessment:	2021 National 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		*0.9000*		*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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.4320		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] *Assumes that the play exists (where all play chance factors = 1.0)*					0.2100
Exploration Chance *Product of Overall Play Chance and Average Conditional Prospect Chance*				Overall Exploration Chance	*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 Mexico	Assessment Unit Name:	Sunniland
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAZ
Date:	March 2020	Assessment:	2021 National 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		***0.9000***		***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		0.7000	
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***
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***
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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.5040**		
Average Conditional Prospect Chance[1] (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**	***0.1270***

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 Mexico	Assessment Unit Name:	Lower Cretaceous Carbonate
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAY
Date:	March 2020	Assessment:	2021 National 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		***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		0.7000	
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***
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		0.5000	
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 * 2 * 3) ***Product of All Subjective Play Chance Factors***			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) ***Product of All Subjective Conditional Prospect Chance Factors*** [1] *Assumes that the play exists (where all play chance factors = 1.0)*					**0.2100**
Exploration Chance ***Product of Overall Play Chance and Average Conditional Prospect Chance***				**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

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 Cretaceous Clastic Shelf
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAV
Date:	March 2020	Assessment:	2021 National 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		***0.8000***		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.5760**		
Average Conditional Prospect Chance[1] (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**	***0.1452***

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 Mexico	Assessment Unit Name:	Lower Cretaceous Clastic Slope
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAW
Date:	March 2020	Assessment:	2021 National 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		***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***		***0.5000***
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***
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 **(1 * 2 * 3)** ***Product of All Subjective Play Chance Factors***			**1.0000**		
Average Conditional Prospect Chance[1] **(1 * 2 * 3)** ***Product of All Subjective Conditional Prospect Chance Factors*** ***[1] Assumes that the play exists (where all play chance factors = 1.0)***					**0.1750**
Exploration Chance ***Product of Overall Play Chance and Average Conditional Prospect Chance***				**Overall Exploration Chance**	***0.1750***

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 Mexico	Assessment Unit Name:	Lower Tuscaloosa Shelf
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAR
Date:	March 2020	Assessment:	2021 National 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		***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***		***0.6000***
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 Chance[1] **(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 system.
Therefore, there is no play risk.

BOEM Play and Prospect Risk Analysis Form			
Assessment Province:	Gulf of Mexico	Assessment Unit Name:	Lower Tuscaloosa Slope
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAS
Date:	March 2020	Assessment:	2021 National 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		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	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
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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.5400		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] *Assumes that the play exists (where all play chance factors = 1.0)*					0.2450
Exploration Chance *Product of Overall Play Chance and Average Conditional Prospect Chance*				Overall Exploration Chance	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 Mexico	Assessment Unit Name:	Mesozoic Shelf
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAT
Date:	March 2020	Assessment:	2021 National 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		*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	2		*0.5000*		*0.4000*
a. Presence of Reservoir Facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.8000		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*
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*			**0.5000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors*					**0.1800**

[1] *Assumes that the play exists (where all play chance factors = 1.0)*

Exploration Chance

Product of Overall Play Chance and Average Conditional Prospect Chance

Overall Exploration Chance: ***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 Mexico	Assessment Unit Name:	Mesozoic Slope
Assessor(s):	Mesozoic Team	Assessment Unit UAI:	AAACARAU
Date:	March 2020	Assessment:	2021 National 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		*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	0.8000		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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.6000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors*					**0.1750**
Exploration Chance *Product of Overall Play Chance and Average Conditional Prospect Chance*				**Overall Exploration Chance**	*0.1050*

[1] Assumes that the play exists (where all play chance factors = 1.0)

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 Mexico	Assessment Unit Name:	Lower Tertiary Shelf
Assessor(s):	Lower Tertiary Team	Assessment Unit UAI:	AAACARAK
Date:	December 2019	Assessment:	2021 National 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		***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	2		***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	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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (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 Mexico	Assessment Unit Name:	Frio Slope
Assessor(s):	Lower Tertiary Team	Assessment Unit UAI:	AAACARAL
Date:	March 2020	Assessment:	2021 National 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		***1.0000***		***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***
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***
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 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					**0.1500**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***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 Mexico	Assessment Unit Name:	Wilcox Slope
Assessor(s):	Lower Tertiary Team	Assessment Unit UAI:	AAACARAM
Date:	March 2020	Assessment:	2021 National 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		***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		0.8000	
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 Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors*					**0.2520**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***0.2520***

[1] ***Assumes that the play exists (where all play chance factors = 1.0)***

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 Tertiary Basin Floor				
Assessor(s): Mesozoic Team		**Assessment Unit UAI:** AAACARAO				
Date: March 2020		**Assessment:** 2021 National 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		***1.0000***		***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***	
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***	
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 (1 * 2 * 3) ***Product of All Subjective Play Chance Factors***			**0.5600**			
Average Conditional Prospect Chance[1] (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** ***0.1008***		

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):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAI
Date:	December 2019	Assessment:	2021 National 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		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					**0.2100**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**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

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 Slope
Assessor(s):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAJ
Date:	December 2019	Assessment:	2021 National 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		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					**0.2100**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**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**

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:**	**Middle Miocene Shelf**
Assessor(s):	**Mio-Plio-Pleistocene Team**	**Assessment Unit UAI:**	**AAACARAG**
Date:	**December 2019**	**Assessment:**	**2021 National 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**		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					**0.2450**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**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:	Middle Miocene Slope
Assessor(s):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAH
Date:	December 2019	Assessment:	2021 National 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		*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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					**0.2450**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**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):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAE
Date:	December 2019	Assessment:	2021 National 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		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors*					**0.2940**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***0.2940***

[1] ***Assumes that the play exists (where all play chance factors = 1.0)***

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):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAF
Date:	December 2019	Assessment:	2021 National 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		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors*					**0.2940**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***0.2940***

[1] ***Assumes that the play exists (where all play chance factors = 1.0)***

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:	Pliocene Shelf
Assessor(s):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAC
Date:	December 2019	Assessment:	2021 National 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		*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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			1.0000		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					0.2940
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**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:**	Pliocene Slope
Assessor(s):	Mio-Plio-Pleistocene Team	**Assessment Unit UAI:**	AAACARAD
Date:	December 2019	**Assessment:**	2021 National 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		***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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (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:

BOEM Play and Prospect Risk Analysis Form			
Assessment Province:	Gulf of Mexico	Assessment Unit Name:	Pleistocene Shelf
Assessor(s):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAA
Date:	December 2019	Assessment:	2021 National 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		***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		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***
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***
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 * 2 * 3) *Product of All Subjective Play Chance Factors*			**1.0000**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the play exists (where all play chance factors = 1.0)***					**0.4320**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***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**

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:	Pleistocene Slope
Assessor(s):	Mio-Plio-Pleistocene Team	Assessment Unit UAI:	AAACARAB
Date:	December 2019	Assessment:	2021 National 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		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 (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			1.0000		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors*					0.2520

[1] ***Assumes that the play exists (where all play chance factors = 1.0)***

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:

Department of the Interior (DOI)

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

Bureau of Ocean Energy Management (BOEM)

The Bureau of Ocean Energy Management works to manage the exploration and development of the Nation's offshore resources in a way that appropriately balances economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development, and environmental reviews and studies.