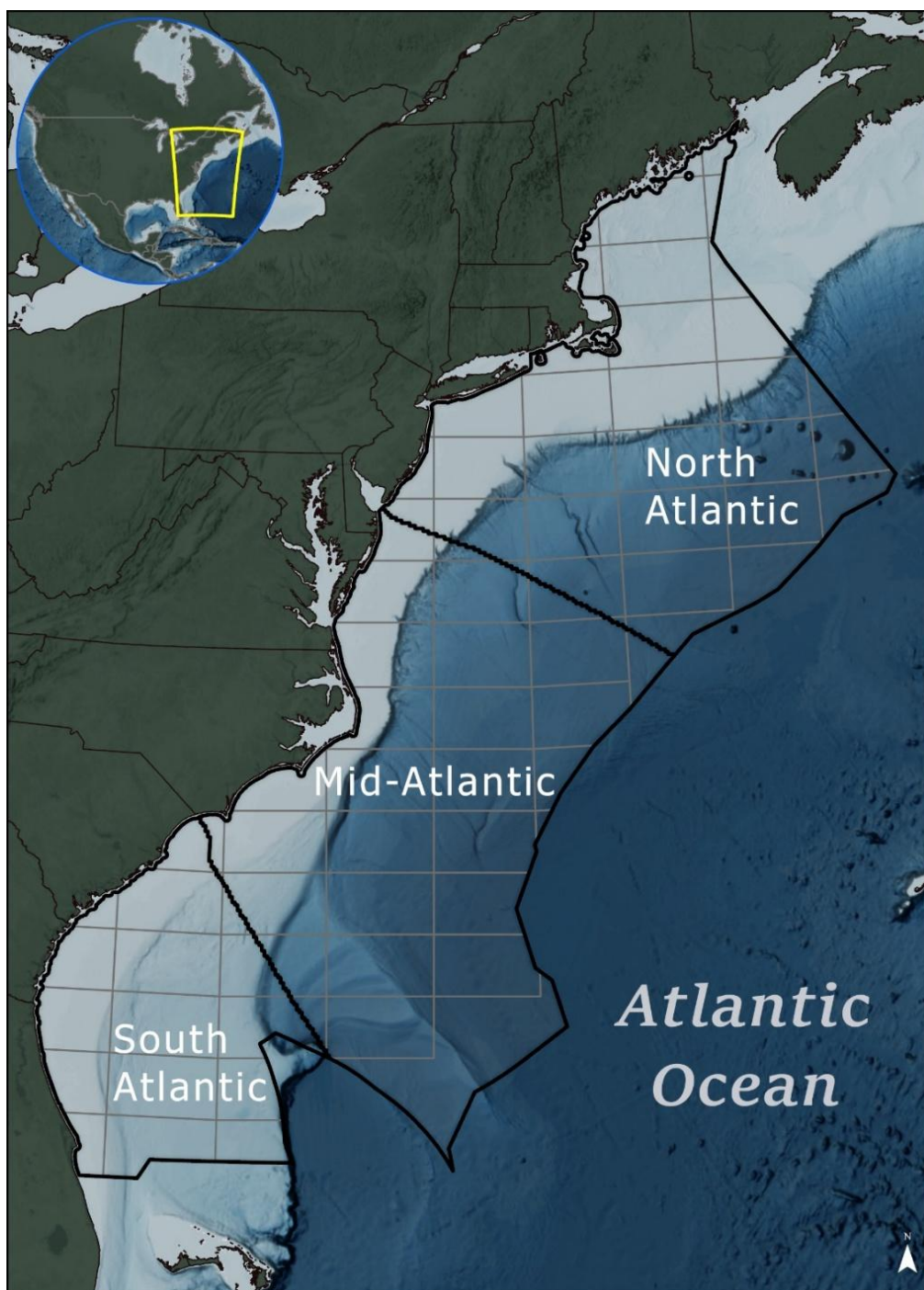


2026 Assessment of Technically and Economically Recoverable Oil and Natural Gas Resources of the U.S. Atlantic Outer Continental Shelf



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Published by:

U.S. Department of the Interior

Bureau of Ocean Energy Management

Gulf of America OCS Region

Office of Resource Evaluation

New Orleans, Louisiana

September 2026



TABLE OF CONTENTS

FIGURES.....	ii
TABLES.....	ii
ABBREVIATIONS AND ACRONYMS.....	iii
1.0 INTRODUCTION.....	1
2.0 THE ATLANTIC OCS.....	1
2.1 REGIONAL SETTING.....	3
2.2 STRATIGRAPHIC SUMMARY OF THE U.S. ATLANTIC OCS	5
2.3 EXPLORATION HISTORY	9
2.4 REGION LEVEL ENGINEERING, TECHNOLOGY, AND TRANSPORTATION.....	10
2.5 METHODOLOGY.....	11
3.0 ATLANTIC ASSESSMENT UNITS.....	15
3.1 MARGINAL FAULT BELT (JURASSIC–CRETACEOUS) AU	17
3.2 CAROLINA TROUGH SALT BASIN (JURASSIC–CENOZOIC) AU	19
3.3 CARBONATE MARGIN LATE JURASSIC–EARLY CRETACEOUS) AU.....	23
3.4 PALEOSLOPE SILICICLASTIC CORE AU AND EXTENSION (JURASSIC–CENOZOIC) AU	26
3.5 BLAKE PLATEAU BASIN (JURASSIC–CRETACEOUS) AU.....	31
3.6 SHELF STRATIGRAPHIC (JURASSIC) AU	33
3.7 INTERIOR SHELF STRUCTURE (CRETACEOUS AND JURASSIC) AU	35
3.8 RIFT BASIN (TRIASSIC–JURASSIC) AU	38
3.9 HYDROTHERMAL DOLOMITE (JURASSIC–CRETACEOUS) AU	41
4.0 UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES.....	43
5.0 UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES.....	47
6.0 UNASSESSED RESOURCES.....	51
7.0 ACKNOWLEDGEMENTS.....	54
8.0 GLOSSARY.....	55
9.0 REFERENCES.....	56
10.0 APPENDICES.....	76
10.1 APPENDIX A. ATLANTIC HISTORICAL TIMELINE.....	76
10.2 APPENDIX B. PLAY AND PROSPECT RISK ANALYSIS FORMS	77
10.3 APPENDIX C. HISTORIC UTRR: REPORTED RESOURCES 1995–2026.....	87

FIGURES

Figure 1. Generalized sedimentary thickness map.	2
Figure 2. Generalized stratigraphy of the U.S. Atlantic.	6
Figure 3. Well locations along with labels for those discussed in this report.	8
Figure 4. AU locations for the U.S. Atlantic OCS.	16
Figure 5. Marginal Fault Belt (Jurassic–Cretaceous) AU location	18
Figure 6. Carolina Trough Salt Basin (Jurassic–Cenozoic) AU location	21
Figure 7. Carbonate Margin (Late Jurassic–Early Cretaceous) AU location.	25
Figure 8. Paleoslope Siliciclastic Core (Jurassic–Cenozoic) AU location.	27
Figure 9. Paleoslope Siliciclastic Extension (Jurassic–Cenozoic) AU location.	30
Figure 10. Blake Plateau Basin (Jurassic–Cretaceous) AU location.	32
Figure 11. Shelf Stratigraphic (Jurassic) AU location	34
Figure 12. Interior Shelf Structure (Jurassic–Cretaceous) AU location.....	37
Figure 13. Rift Basin (Triassic–Jurassic) AU location.....	39
Figure 14. Hydrothermal Dolomite (Jurassic–Cretaceous) AU location	42
Figure 15. Atlantic OCS AUs ranked by mean UTRR.	44
Figure 16. The combined Atlantic AU areas and the 200 m and 800 m isobaths.....	46
Figure 17. Percentage of UTRR in shallow, deep, and ultra-deepwater for 5 Assessments.	47
Figure 18. The mean UTRR and mean UERR (for 5 oil-gas price pairs) for the Atlantic OCS.....	48
Figure 19. The mean UTRR and mean UERR (for 5 oil-gas price pairs) for the 3 Atlantic planning areas.	49
Figure 20. Methane seeps, BSR locations, and research wells with known or possible gas hydrates.	53

TABLES

Table 1. U.S. Atlantic AUs with probability of success at the play (petroleum system) and prospect level. The probable hydrocarbon type is listed as a percentage for each AU.....	13
Table 2 AU characteristics and inputs for the GRASP models.....	14
Table 3 UTRR by AU for oil, gas, and total BOE.....	17
Table 4. UTRR by planning area and water depth.....	45
Table 5. UERR by planning area and water depth. The gas market value adjustment is 0.3.....	50

ABBREVIATIONS AND ACRONYMS

2D	two-dimensional
3D	three-dimensional
AU	assessment unit
Bbbl	billion barrels
bbl	barrels
bbl/d	barrels per day
BBOE	billion barrels of oil equivalent
BCFG	billion cubic feet of gas
BCFGE	billion cubic feet of gas equivalent
BCT	Baltimore Canyon Trough
BPB	Blake Plateau Basin
BOE	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management
BSR	bottom simulating reflector
CTSB	Carolina Trough Salt Basin
CBM	coalbed methane
COST	continental offshore stratigraphic test
DOI	Department of the Interior
DOE	Department of Energy
DSDP	deep sea drilling project
DST	drillstem tests
EEZ	Exclusive Economic Zone
FEED	front-end engineering design
FERC	Federal Energy Regulatory Commission
FID	final investment decision
FIS	fluid inclusion study
FIT	Fluid Inclusion Technologies, Inc.
FLNG	floating liquified natural gas
FPS	floating production and storage
FPSO	floating production storage and offloading
Fm	formation
ft	feet
GBB	Georges Bank Basin
GOA	Gulf of America
GOR	gas-oil ratio
GRASP	Geologic Resource Assessment Program
HC	Hudson Canyon
LNG	liquified natural gas
m	meters
Ma	million years ago
mbsf	meters below seafloor
mD	millidarcies

mi	miles
mi ²	square miles
MMbbl	million barrels of oil
MMBOE	million barrels of oil equivalent
MMCFG	million cubic feet of gas
MMBNGL	million barrels of natural gas liquids
MSGBC	Mauritania –Senegal–The Gambia–Guinea Bissau–Conakry
MTPA	million tons per annum
MYR	million years
NCEI	National Centers for Environmental Information
NOAA	National Oceanic and Atmospheric Administration
OAE	oceanic anoxic events
OCS	outer continental shelf
ODP	ocean drilling program
PRU	post-rift unconformity
PETRIMES	Petroleum Resources Information Management and Evaluation System
SAR	synthetic aperture radar
SBs	sequence boundaries
SDR	seaward-dipping reflector
SEGE	Southeast Georgia Embayment
Tcf	trillion cubic feet
TOC	total organic carbon
UERR	undiscovered economically recoverable resources
U.S.	United States
UTRR	undiscovered technically recoverable resources

Please note that all colors within the maps, charts, and graphs of this document may not be fully 508-compliant. If you require a specific map, chart, or graph in an accessible format, please contact [BOEM](#).

As of July 10, 2026, the Department of the Interior has reunified the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement into the Marine Minerals Administration, which oversees the responsible development of the nation’s offshore energy and marine mineral resources with an integrated focus on safety, environmental protection and efficient oversight. For more information, visit [DOI.gov/mma-reunification](https://doi.gov/mma-reunification).

1.0 INTRODUCTION

This report summarizes the results of the 2026 Bureau of Ocean Energy Management (BOEM) assessment of undiscovered, technically recoverable oil and gas resources of the U.S. Atlantic Outer Continental Shelf (OCS), the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction ([Figure 1](#)). It complies with and fulfills requirements of the Energy Policy Act of 2005. This resource assessment represents a comprehensive appraisal of data and information populating a distribution of pool/field sizes from an Atlantic analog database. This assessment incorporates and applies modern exploration concepts and key learnings based on industry exploration activities in northeast-adjacent Nova Scotia, conjugate Northwest Africa, the West African and its conjugate South American Transform Margins, and the East African Transform Margin. It also provides comments on significant exploration and production activity on the international analogs used in this assessment's inventory.

Enhanced and reprocessed deep-penetration reflection seismic, modern potential field data (gravity and magnetic), digital wireline logs for 51 wells, and biostratigraphic data were used to make this report. A sequence framework developed by GeoSpec (2003) served as the primary framework, and when integrated with the seismic data, provided reasonable consistency throughout the region. Originally available and recent geochemical data were assessed, aggregated, and incorporated. All data were integrated to develop a comprehensive, petroleum system-focused assessment of potential resources.

Additional discoveries in the analog settings within Northwest Africa (Mauritania and Senegal), the Guyana-Suriname basin of Northern South America, and East Africa (Tanzania) continue to improve our understanding of discovery size and petroleum systems in those analogs. Corresponding Atlantic assessment units (AUs) that utilize these analogs were updated based on the new data.

2.0 THE ATLANTIC OCS

Located on the eastern margin of the continental United States (U.S.), the Atlantic OCS extends ~1,300 miles (mi) from the Canadian province of Nova Scotia (northeast) to The Bahamas (southwest). The Atlantic OCS is divided into the North, Mid-, and South Atlantic Planning Areas ([Figure 1](#)). The Atlantic OCS in this report excludes the Straits of Florida Planning Area as it is included with the Gulf of America (GOA) assessment. AUs within the GOA extend into the Straits of Florida Planning Area (BOEM, 2026a; BOEM, 2026b). Atlantic planning area boundaries were redesigned in 2005 (MMS, 2006) and 2025 (Federal Register, 2025). In 2023, the Extended Continental Shelf boundary was updated (BOEM, 2023). See [Appendix A](#) for a historical timeline of Atlantic events. Water depths in the Atlantic OCS range from less than 30 ft to >15,000 ft.

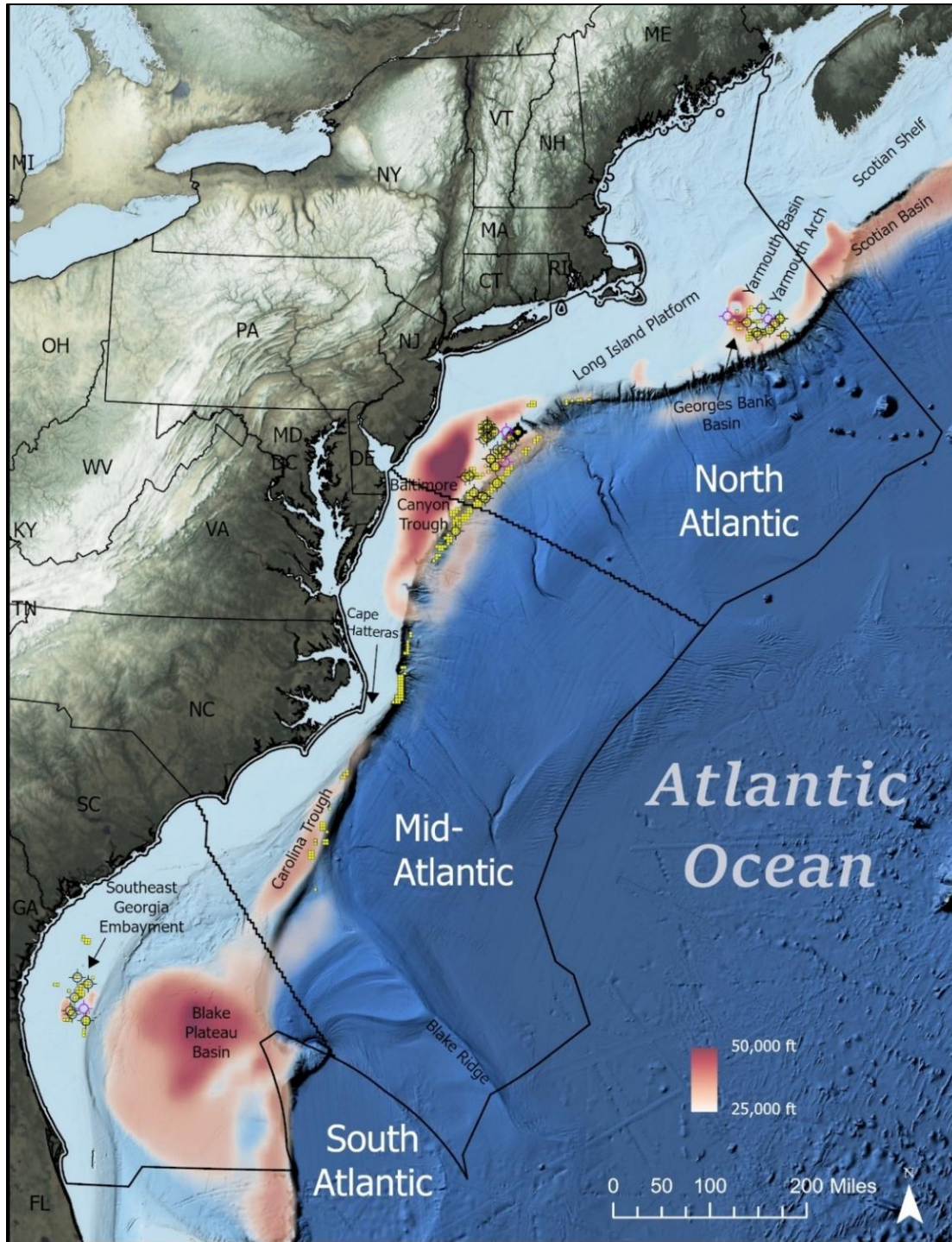


Figure 1. The sediment thickness raster layer in white to red graded shading comes from ‘GlobSed’, a grid published in 2019 by the National Centers for Environmental Information (NCEI) within the National Oceanic and Atmospheric Administration (NOAA) (Straume et al., 2019). The black outlines offshore are the planning area boundaries. Expired oil and gas leases are yellow boxes. The 46 industry wells are shown in black using the standard symbol for a dry hole (hollow circles with outside dashes). The 5 COST wells are shown in purple using the same symbology. Planning area names and geologic features are labeled. The light black outlines onshore are the state boundaries. State abbreviations are labeled. The background is a seafloor bathymetry and onshore topography derived from GEBCO (2024).

2.1 REGIONAL SETTING

Terrane accretions sutured at the end of the last Wilson cycle closed the Iapetus and Rheic seas during formation of the Pangea supercontinent (Nance et al., 2012; van Staal et al., 2009). In the late Triassic, rift basins developed in Eastern North America (Withjack et al., 2024). A brief period (~1.5 million years (Myr)) of shallow volcanic intrusives (diabase) and volcanic extrusives (basalt) known as the Central Atlantic Magmatic Province (CAMP) was $^{40}\text{Ar}/^{39}\text{Ar}$ radiometric dated to ~200 million years ago (Ma) (Nomade et al., 2007). Estimated to have been the most aerially extensive (Marzen et al., 2020) large igneous province (LIP) in geologic history, it is the purported cause of the Triassic-Jurassic mass extinction (Kent et al., 2024; Ruiz-Martinez et al., 2012; Olsen, 1999; Perkins, 2013). The CAMP flood basalts were likely sourced from the partial melting of shallow mantle beneath accreted terranes of different compositions (Labails et al., 2010; McHone, 2000).

Post-CAMP dike intrusions continued for 6-30 Myr forming a wedge that rotated during continental breakup to form what are called seaward-dipping reflectors (SDRs) (Davis et al., 2018). SDRs are seen in seismic reflection and magnetic data where they correspond to a ~1,500-mile-long positive magnetic anomaly called the East Coast Magnetic Anomaly (ECMA) (Labails et al., 2010). These igneous emplacements coincided with thinning of the continental lithosphere and may have assisted with fracturing by reducing the effective stress required to rupture the lithosphere (Shuck et al., 2019). Basinward of ECMA is the earliest oceanic crust, dating to the Early Jurassic ~190 Ma (Labails et al., 2010) and marking the beginning of seafloor spreading (Withjack et al., 2024). Further basinward of ECMA is the Blake Spur Magnetic Anomaly (BSMA), another positive magnetic amplitude lineament that is interpreted as the onset of normal seafloor spreading via the creation of thicker oceanic crust (Shuck et al., 2019). Both ECMA and BSMA correspond to features on the conjugate African side, the West African Coastal Magnetic Anomaly (WACMA) and the African Blake Spur Anomaly (ABSMA), respectively (Biari et al., 2017). All four are segmented by transform faults that formed from asymmetric spreading due to variations in tectonic inheritance and pre-existing crustal compositions (Withjack et al., 2024; Greene et al., 2020; Behn and Lin, 2000). Rifting ceased during the Middle Jurassic (Hutchinson, 2005) and post-rift sediments were deposited onto syn-rift strata, SDRs, or pre-rift basement. Accommodation space and thus the location of the post-rift sedimentary basins that are the targets for oil and gas, are controlled by this tectonic history.

The Atlantic margin is comprised of magma-dominated and magma-poor terranes (Reston, 2009). The magma-poor or non-volcanic areas such as the Meguma terrane seen more offshore Northeast Canada (Lang et al., 2020) have hyperextended crusts that are often more brittle and exhumed mantle that created hydrated minerals like serpentine (Reston, 2009). The U.S. OCS terranes are magma-rich (volcanic) and are responsible for the abundant SDRs. The volcanic Avalon terrane in the North and Mid- Planning Areas behaved more ductile and required less stress to rift resulting in a quicker transition to drifting and a thicker crust (Lang et al., 2020; Shuck et al., 2019). In the Northern OCS, the Georges Bank Basin (GBB) ([Figure 1](#)) formed multiple syn-

rift structures and experienced earlier crustal thinning that predated major volcanism. This resulted in a wider, shallower basin (Lang et al., 2020) with post-rift sediments ~9km thick ([Figure 1](#), Hutchinson, 2005). Located at the edge of the GBB, the Continental Offshore Stratigraphic Test (COST) G1 well reached Paleozoic metamorphic basement at 16,071' MD (Edson et al., 2000). To the south the Baltimore Canyon Trough (BCT) was more magma-influenced, forming a narrow, thick basin (>15km) ([Figure 1](#); Hutchinson, 2005) with few rift basins and a sharp basement hinge (Lang et al., 2020).

Igneous activity after the Atlantic Ocean formation includes an Early Cretaceous lamprophyre dike swarm located within the Hudson Canyon protraction area (Turney et al., 2026). This intrusion was the target of several unsuccessful exploration wells. Additionally, a lineament of alkaline basalt volcanoes called the New England seamount chain formed episodically during the Late Cretaceous, ~100-83 Mya (NOAA, 2021). Cenozoic canyons are common on the shelf edge and slope in the North and Mid- Planning Areas with the biggest channels having eroded and transported hundreds of meters of sediment to their basinal fans (Shor and McClennen, 1988). These are modern analogs to potential reservoirs in older strata within the Paleoslope Siliciclastic Core and Extension AUs.

South of Cape Hatteras ([Figure 1](#)), the southern half of the OCS is dominated by the Carolina Trough and the Blake Plateau Basin (BPB). The former is a narrow basin that formed quickly with a fast extension rate (Dillon and Popenoe, 1988). Salt deposition was early, ending in the Early Jurassic (Labails et al., 2010; Hutchinson, 2005). Subsequent passive loading of sediment drove diapirism in the basin and accommodation faulting updip. This faulted and expanded section of Jurassic and Early Cretaceous sections comprises BOEM's Marginal Fault Belt AU. The halokinetic area is BOEM's Carolina Trough Salt Basin (CTSB) AU. These AUs are the most prospective in the Southern OCS. The BPB had a slow extension rate (Hutchinson, 2005) forming a wider basin with more carbonate deposition and less siliciclastic sedimentation. The deepwater plateau drowned during the Late Cretaceous when subsidence outpaced carbonate deposition (Dillon and Popenoe, 1988). However, non-photosynthetic, cold-water corals persist in deepwater on the modern Blake Plateau. With a high-density mound area of ~150 by ~25 miles, this is the largest known province globally (Sowers et al., 2024).

Seamounts formed in the abyssal plain ~300 miles offshore Carolina but with much less volcanism than the long chains in the North Planning Area. Only two volcanoes are visible on available bathymetry. Unsampled, their age is constrained to be younger than the formation of the oceanic crust they pierced.

Erosional forces have been dominant on the Blake Plateau since the end of the Paleocene as the Gulf stream currents along the Florida straits replaced the Suwannee strait current that had cut across the Florida panhandle and southern Georgia since the Late Cretaceous (Pinet and Popenoe, 1985). The Gulf current in its modern form began ~2.8 Ma when the Panamanian Isthmus closed (O'Dea et al., 2016). The low sedimentation rates and high erosional rates resulted in large, well-imaged contourite features like the Blake Ridge ([Figure 1](#)) as well as significant

quantities of polymetallic nodules on BPB (NOAA, 2022). Additionally, the straight lineaments seen on seafloor bathymetry that appear more characteristic of anthropogenic features are Quaternary iceberg scours. Over 700 iceberg scours were identified on the shelf south of Cape Hatteras. Radiocarbon dating demonstrated scour groupings around the Heinrich Event 3 (~31,000 years before present) when large, brief meltwater flows transported ~1,000 ft thick icebergs over 3,000 miles (Condon and Hill, 2021).

2.2 STRATIGRAPHIC SUMMARY OF THE U.S. ATLANTIC OCS

The generalized stratigraphy of the U.S. Atlantic margin ([Figure 2](#)), based in part on modern data collected offshore Nova Scotia, is calibrated with the Geologic Time Scale of 2004 (Ogg et al., 2008) and the eustatic sea level curve from Haq et al. (1987). The lithostratigraphic framework uses nomenclature derived from the Scotian shelf and slope offshore (CNSOPB, 2009a and b). Late Triassic–Early Jurassic syn-rift sediments consist primarily of interbedded fluvial and lacustrine red beds, shales, basalts, and in some locations, evaporites (Post et al., 2012). A post-rift or breakup unconformity (PRU) overlies the syn-rift sequence. This diachronous ‘base Jurassic’ sequence boundary (SB) marks the boundary between post-rift sediments above and pre-rift and syn-rift strata, SDRs, and oceanic crust below. Within the post-rift sediments, BOEM recognizes eight (8) SBs. Derived from the GeoSpec (2003) interpretation of the western Central Atlantic, this framework was used in BOEM’s interpretation of the region’s geology, stratigraphy, and hydrocarbon prospectivity.

A marine transgression above the SB1 unconformity resulted in a shallow marine environment ([Figure 2](#)) within which updip siliciclastics (Mohican Formation (Fm) and equivalents) and downdip limestones, dolomites, and minor evaporites (Iroquois Fm and equivalents) were deposited (CNSOPB, 2009a and b). Source rocks offshore Nova Scotia are interpreted to be within some of these Jurassic Fms. The Atlantic OCS also likely includes Jurassic age source rocks. Diamondoids from the Hudson Canyon (HC) area wells 598-1 and 642-2 ([Figure 3](#)) indicate an Early to Middle Jurassic source (Sassen and Post, 2008). Autochthonous evaporites formed in post-rift, sag-phase settings of the GBB (Elliott and Post, 2012; Post et al., 2012; Wade and MacLean, 1990; Amato and Simonis, 1980) and BCT (McKinney et al., 2005). Further south in the Carolina Trough, increased salt volumes formed salt-cored structures in post-rift sediments. (Dillon et al., 1982) Salt deposition initiated early in the Atlantic formation and concluded at the onset of seafloor spreading (Early Jurassic) for the Carolina Trough (Labails et al., 2010; Hutchinson, 2005).

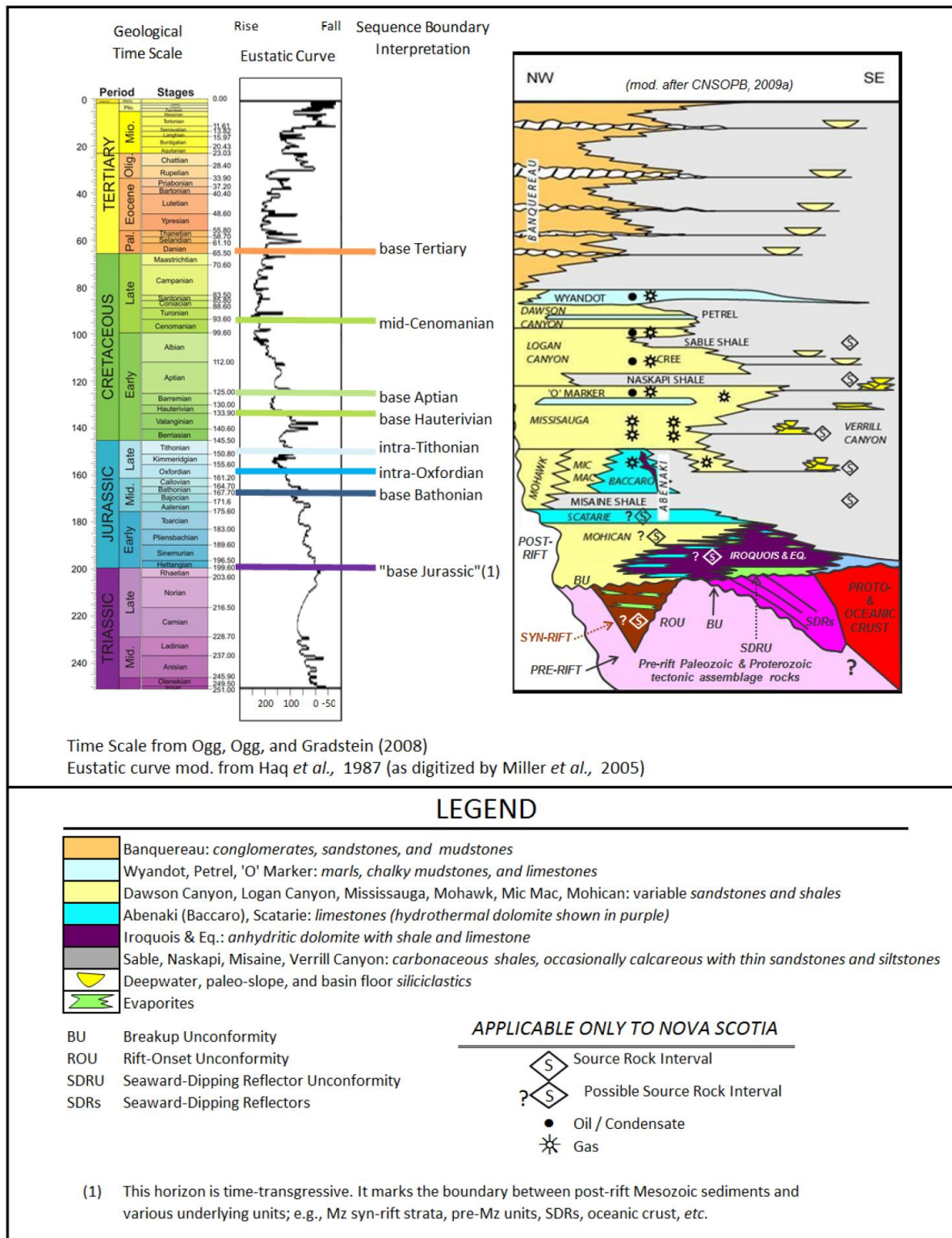


Figure 2. Generalized stratigraphy of the U.S. Atlantic OCS based on the more heavily explored, northeast-adjacent Nova Scotian shelf and slope. Calibrated using ages from the Geologic Time Scale of 2004 (Ogg et al., 2008) and integrated with the Haq et al. (1987) eustatic sea level curve. Key seismic horizons interpreted by BOEM staff represent sequence boundaries initially identified and interpreted by GeoSpec, a Viridien company, on GeoSpec's seismic interpretation of the U.S. Atlantic OCS (GeoSpec, 2003).

As new oceanic crust formed between drifting continental and transitional crusts, margin subsidence led to deepening seas and increasing accommodation space for sediment deposition. Along the shelf edge, a carbonate gigaplatform had formed by the Middle Jurassic, extending from the Grand Banks offshore Newfoundland, Canada to the Bahama Bank offshore Florida (Poag, 1991). Its development was affected by contemporaneous Late Jurassic–Early Cretaceous siliciclastic deltaic depocenters that locally restricted carbonate sedimentation (Eliuk and Wach, 2014). Siliciclastic sedimentation bypassed the reefs forming channels that segmented the margin and created fan complexes on the continental slope and rise. The steep slope helped transport and deposit significant sediment resources including reservoir quality sediments far from shore, as seen in the DSDP 603b well ([Figure 3](#)). When sedimentation outpaced sea level rise and accommodation space, progradation buried the carbonate reefs. In the Early Cretaceous, sea level rose faster than carbonate formation, drowning the reefs. Both mechanisms were active in the northern OCS before progressing south. By Late Cretaceous the BPB was inundated as sea level continued to rise, forming the deepwater carbonate platform present today (Hutchinson, 2005; Dillon and Popenoe, 1988). Further south in the Bahama Basin, carbonate reefs are still active (Poag, 1991).

A cooler climate and an increased polar ice cap were common for much of the Cenozoic and thereby produced a lower eustasy. Fluvial erosion on the mostly unconsolidated shelf during low-stand stages transported sediments onto the deepwater slope and abyssal environments (CNSOPB, 2009b). Mass wasting and other debris flows on the shelf edge led to turbidite deposition downslope. Known bolide impacts like the Montagnais on the Scotian shelf and the Chesapeake Bay impact may have caused partial collapse of the continental margin leading to channelized gravity deposits that could have deposited sediments hundreds of feet thick at locations over one hundred miles downslope (Dypvik and Jansa, 2003; Deptuck, 2011). These potentially well-sorted shelf sediments could have formed deepwater reservoirs in Atlantic AUs like the Paleoslope Siliciclastic Core and Extension. See the [2021 Assessment](#) for more detail on the Atlantic stratigraphy (BOEM, 2021). For a more chronostratigraphic-based framework for the Mid- and North Planning Areas shelf, see the [final technical report](#) for the Mid-Atlantic U.S. Offshore Carbon Storage Assessment Project (Battelle, 2019) funded by the U.S. Department of Energy (DOE).

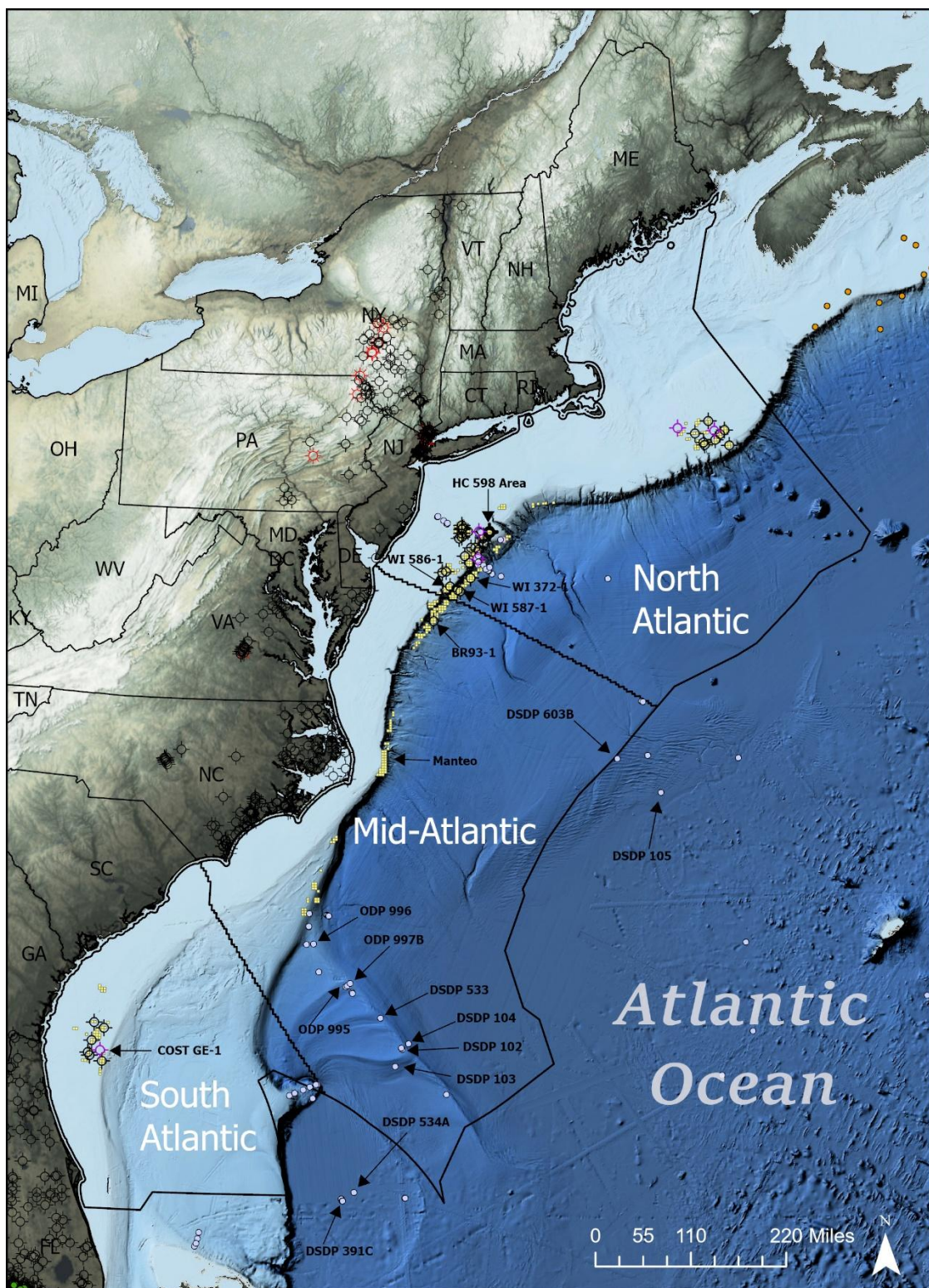


Figure 3. Locations of the Hudson Canyon 598 area and wells referenced in the text of this report. Solid, light purple circles are DSDP or ODP scientific wells. Onshore wells are hydrocarbon exploration wells shown with standard oil and gas symbology. Oil discoveries are solid green circles, gas discoveries are red outline circles with outside hashes, and dry holes are black outline circles with hashes. Scotian shelf and slope exploration wells are solid orange circles. Other cartographic elements are as labeled in Figure 1.

2.3 EXPLORATION HISTORY

From the first seismic survey in 1966 until today, the Atlantic OCS has experienced periods of robust activity and dormancy. Approximately 239,000 line miles of 2D seismic were acquired, processed, and interpreted between 1966 and 1988. The BOEM seismic data set in the Atlantic OCS consists of ~170,000 line miles of 2D data. This data has been made available online at the National Archive of Marine Seismic Surveys (NAMSS, 2016). From 1976–1983, 410 blocks were leased during 9 lease sales. A total of 51 wells were drilled with five COST wells drilled between 1975 and 1979, and 46 industry wells drilled between 1978 and 1984 ([Figure 3](#)). In 2000, the last lease was relinquished at the undrilled Manteo prospect ([Figure 3](#)). A potentially new phase of exploration was abandoned in 2010 with the cancellation of a proposed new lease sale, Virginia Sale 220 (BOEM, 2010). To date, there has been no commercial hydrocarbon production in the U.S. Atlantic OCS. The only discovery was a non-commercial gas condensate reservoir within compartmentalized siliciclastic reservoirs in the HC 598 area ([Figure 3](#)).

Since the last hydrocarbon wells were drilled in the early 1980s, new data has been collected, legacy data has been reprocessed, administrative and methodological practices have been updated, and our understanding of Atlantic prospectivity has evolved, supported in part by new analog fields from newly accessible deepwater plays. BOEM licensed ~12,400 line miles of reprocessed reflection seismic data and ~185,000 line miles of depth-converted, time-migrated data in SEG-Y format from GeoSpec (a Viridien company) prior to the 2016 Assessment. An additional ~40,000 line miles of reprocessed seismic and an updated sequence framework interpretation were licensed from CGG (a Viridien company) between 2018 and 2021. A DOE funded feasibility study for carbon sequestration led to the reprocessing of ~2,500 line miles of 2D seismic and ~80 new porosity and permeability measurements from 40 core plugs in 17 legacy wells (Battelle, 2019). This data was mostly in the North Atlantic Planning Area and was shared with BOEM. In 2018, 1,250 line miles of new 2D seismic were acquired by USGS and BOEM to better delineate bottom simulating reflections (BSRs) related to gas hydrates (USGS, 2018). Additional seismic surveys conducted between 2010 and 2012 provided shallow imaging in support of the Integrated Ocean Drilling Program (IODP) research wells. Like the Deep Sea Drilling Project (DSDP) and the Ocean Drilling Program (ODP) research legs before IODP, these wells ([Figure 3](#)) were drilled for research unrelated to hydrocarbons and typically reached total depths of only a few hundred meters (NCEI, 2026).

The Atlantic OCS remains largely unexplored with only the Interior Shelf Structure, Carbonate Margin, and Paleoslope Siliciclastic Core AUs tested via drilling. Industry wells included 39 exploration wells and 7 appraisal wells (HC 598 area). This equates to 1 exploration well for every ~1.5 Atlantic protraction. For comparison, 124 exploration wells have been drilled offshore Nova Scotia (CNSOER, 2018). As the U.S. wells and most of the seismic coverage are concentrated in 3 basins on the shelf, hydrocarbon prospective areas remain underexplored.

2.4 REGION LEVEL ENGINEERING, TECHNOLOGY, AND TRANSPORTATION

Technology has advanced significantly since the exploration of the late 1970s and early 1980s when only 5 of the 51 Atlantic OCS wells were drilled in water depths greater than 500 ft. In the last 40 years drillship capabilities have progressed to allow hydrocarbon exploration in ~12,000 ft of water and drill to total vertical depths >35,000 ft (Sorkhabi, 2025). The GOA hosts the world's deepest discovery well at Bandit (American Press, 2026) and the greatest water depth production facility at Perdido Spar (Offshore Mag, 2010). The GOA is also home to the deepest operating floating production storage and offloading (FPSO) vessel with Turritella, producing in ~9,500 ft of water (SBM Offshore, 2016). The current record for floating liquified natural gas (FLNG) is the Coral Sul FLNG operating in ~6,500 ft of water within Mozambique's Rovuma basin (ENI, 2022). The ability to produce from such depths is valuable as this report estimates 19% of the Atlantic's undiscovered technically recoverable resources (UTRR) lie in deepwater and 71% in ultra-deepwater. BOEM (2019) defines water depths as less than 1,000 ft for shallow water, 1,000–5,000 ft for deepwater, and greater than or equal to 5,000 ft for ultra-deepwater. The majority of the prospective Atlantic OCS is accessible to FPSO and FLNG facilities, given the water depths in which these vessels currently operate.

Hydrocarbon exploration has increasingly shifted towards frontier and underexplored basins similar to the U.S. Atlantic margin. Focus on high-value, ultra-deepwater targets have resulted in the discovery and rapid development of large fields in areas without preexisting infrastructure via the increasing utilization of FPSOs and FLNGs. The time from initial discovery to first production can be under 5 years for FPSO as demonstrated by the 2015 Liza-1 discovery offshore Guyana to its 2019 first production (ExxonMobil, 2019). In some cases, this timeline can be even shorter with the Baleine field offshore Côte d'Ivoire reaching first production in under two years (ENI, 2023). New construction of an FLNG vessel currently takes just under 3 years with designs becoming increasingly standardized. Conversions from repurposed LNG carriers are also becoming common (Rystad, 2026). Both vessel types can also relocate to other fields as needed. From the first FPSO introduced in 1977 to the 185 vessels operating worldwide as of 2025, FPSOs now support production across a wide range of water depths and offshore environments (Kaiser, 2026).

The first FLNG was the *Petronas Satu* with its first cargo shipped in early 2017 (PETRONAS, 2017). Today that has grown to 13 vessels operating, under construction, or in planning, and with a current production of 14.1 million tons per annum (Mtpa) (Rystad, 2026). The cost overruns and delays from the initial years have been resolved with cost per ton now comparable to LNG facilities (Rystad, 2026). The capacity gap between the average onshore LNG facility of 8 Mtpa (Kelleher, 2019) and FLNG is decreasing with the ongoing construction of a 4.2 Mtpa FLNG facility (Offshore Technology, 2025). FLNG is forecast to continue its rapid growth, reaching a global capacity of 42 Mtpa by 2030 and 55 Mtpa by 2035 (Rystad, 2026).

FPSOs can be collaboratively used to produce oil and/or condensate while natural gas is transported to onshore facilities via pipeline as seen in Brazil's Santos Basin (Offshore Energy,

2026) and Western Australia's Browse Basin (Total Energies, 2026). Other hybrid scenarios are seen in gas dominant basins like Rovuma where both LNG (ExxonMobil, 2026) and FLNG (ENI, 2022) were planned. The speed of FLNG fast-tracking generated first cargo in 2022 for the Coral gas field (ENI, 2022), while the onshore LNG production in the Rovuma Basin is still in development. Conversely, other recently developed frontier gas fields like Egypt's 30 trillion cubic feet (Tcf) Zohr field (Offshore Technology, 2021) and Israel's ~23 Tcf Leviathan field (Offshore Energy, 2025) utilized pipelines to transport to LNG facilities onshore.

All options would be available in the US Atlantic OCS. The smaller infrastructure footprint of Floating Production and Storage (FPS) vessels could avoid environmentally sensitive areas and help deconflict with competing OCS interests such as fishing and shipping or other resource extraction activities like sand or critical mineral mining. In the U.S., 2 of the 8 LNG export terminals (Cove Point, MD and Elba Island, GA) and multiple petroleum refineries are located on the Atlantic coast (FERC, 2026; EIA, 2025a). The U.S. has been the global leader in natural gas exports since 2023 (EIA, 2025b), is the world's largest oil producer (EIA, 2026a), a net petroleum exporter since 2020 (EIA, 2024), and the second largest global petroleum exporter (Investopedia, 2026). Modifications to enable export at pre-existing import LNG terminals (Kelleher, 2019) and the large price spread between global natural gas markets (Henry Hub, Dutch Title Transfer Facility, Japan Korea Marker, etc.) facilitated this quick growth from first U.S. LNG export in 2016 (EIA, 2026b; EIA, 2026c). An export advantage of FLNG is direct transport from the producing field to the market of choice. Commercial viability of future discoveries could be enhanced with FLNG and FPSO. Advances in technology and current exploration trends position the Atlantic OCS for its most promising outlook in decades.

2.5 METHODOLOGY

For the 2026 Atlantic resource assessment, BOEM staff used an enhanced reflection seismic database, gravity and magnetic data sets, and subsurface well data from existing offshore and onshore U.S. and offshore Nova Scotian wells. Geochemical data and sea surface slicks identified on updated satellite-derived synthetic aperture radar (SAR) data helped to constrain BOEM's understanding of potential hydrocarbon source rocks. Since the 2011 Atlantic Assessment, BOEM has used global analogs including the conjugate Northwest African margin and other Atlantic passive margins that are geologically comparable to the U.S. Atlantic Margin. A global database created from literature-based research, government websites, and a licensed Wood Mackenzie dataset (Wood Mackenzie, 2020) provided appropriate analogs and guidance for potential field sizes and hydrocarbon volumes. Analogs were selected on similar or equivalent tectonic or structural settings, with comparable petroleum system components, such as source, reservoir, seal, and overburden. A petroleum system was defined by Magoon and Dow in 1994 as the components and processes required to generate, expel, migrate, accumulate, and preserve hydrocarbons. Environment of deposition, lithology, depth of burial, diagenetic history, porosity and permeability, and trap type also influenced analog selection. A reservoir of the same geologic

age was preferable but less important. Taken holistically, these data facilitate a play-based approach to define the assessment units (AUs). An AU is a group of pools with a shared geologic history within a petroleum system. BOEM makes no distinction between an AU and a play, with the terms used interchangeably in this report. An AU can be conceptual if a petroleum system is hypothesized to exist. The AU is established if a hydrocarbon accumulation has been discovered, irrespective of its economic recoverability. A pool is defined as an accumulation of hydrocarbons, typically within a single stratigraphic interval. It can be discovered or in the case of most of the Atlantic AUs, undiscovered. Pools within a given play are assessed collectively. A prospect is a potential pool, a geologic feature with the potential to trap an accumulation of hydrocarbons. Both play and prospect risk encompass the elements and processes of hydrocarbon generation, expulsion, migration, accumulation, and preservation. Risk is assessed at both the play and prospect level. A proven petroleum system removes play risk, with discovery success only constrained by the prospect risk. An established AU therefore greatly increases its UTRR.

BOEM assigned risk to petroleum system components for each AU on the Atlantic OCS. These components include risk factors and appropriate timing that result in a hydrocarbon accumulation. The specific risk components assessed are:

- Hydrocarbon fill;
 - ✓ Presence of a quality, effective, mature source rock, and
 - ✓ Effective expulsion and migration.
- Reservoir;
 - ✓ Presence of reservoir facies, and
 - ✓ Reservoir quality.
- Trap;
 - ✓ Presence of trap, and
 - ✓ Effective seal mechanism.

The outcome of these assessments is summarized in [Table 1](#). The assessed scores for each AU are in [Appendix B](#).

The multiple risks are integrated by taking the product of all 3 component (source, reservoir, and trap) risks. As these numbers are the chance of success, the lower numbers equate to a higher risk for a given play or prospect. As there are subcomponents for each component, the number from the lowest valued subcomponent is the one used as it is the most likely to be absent. All components need to be present for the assessed play or prospect to exist. Any absence will make that essential component a 0 resulting in 0 UTRR. The product of the play and prospect risk is the total exploration risk, or chance of success. The total exploration risk along with the area of the play and the distribution of possible pools are the most impactful for an AU's UTRR. For this assessment, the risks were rounded at the tenth decimal place. In Atlantic assessment reports prior, the rounding was done at the whole percentage number. The rest of the methodology was unchanged since the 2021 Assessment.

Atlantic Assessment Units	Probability of Success			Probability	
	Play	Prospect	Total Exploration	Gas	Oil
Marginal Fault Belt (Jurassic - Cretaceous)	0.441	0.140	0.062	0.70	0.30
Carolina Trough Salt Basin (Jurassic - Cenozoic)	0.504	0.288	0.145	0.60	0.40
Carbonate Margin (Late Jurassic - Early Cretaceous)	0.336	0.175	0.059	0.80	0.20
Paleoslope Siliciclastic Core (Jurassic - Cenozoic)	0.336	0.175	0.059	0.50	0.50
Paleoslope Siliciclastic Extension (Jurassic - Cenozoic)	0.288	0.096	0.028	0.50	0.50
Blake Plateau Basin (Jurassic - Cretaceous)	0.288	0.140	0.040	0.20	0.80
Shelf Stratigraphic (Jurassic)	0.288	0.112	0.032	0.70	0.30
Interior Shelf Structure (Jurassic - Cretaceous)	1.000	0.108	0.108	0.80	0.20
Rift Basin (Triassic - Jurassic)	0.336	0.252	0.085	0.20	0.80
Hydrothermal Dolomite (Jurassic - Cretaceous)	0.240	0.140	0.034	0.20	0.80

Table 1. U.S. Atlantic AUs with probability of success at the play (petroleum system) and prospect level. The overall chance of success or total exploration risk is the product between these two risk components. Gas and oil probability is the estimated likelihood of hydrocarbon type should the AU become proven. Their sum is 1.

As part of this 2026 resource inventory, all play and prospect level risks were reviewed and modified based on updates to the risking methodology and the continued evolution of the analogs. The subjective assessment methodology models a range of pool sizes on a truncated lognormal distribution populated using analog discoveries for the conceptual Atlantic AUs. These inputs are restricted with a lower limit of 1 MMBOE, as typical for USGS international assessments (Klett et al., 2000), due to their trivial contribution to the total UTRR. The upper limit is usually equal to the largest field discovered in the play or analog(s), but consideration is given to the exploration maturity of each analog and whether it's reasonable for larger fields to have remained undiscovered. No distributions exceeded the largest analog fields for this assessment. Fields/pools outside the upper and lower limits were removed from the distribution. The distributed volume is sampled over 10,000 trials using BOEM's Geologic Resource Assessment Program (GRASP). The current version of GRASP was adapted by BOEM from the Petroleum Resources Information Management and Evaluation System (PETRIMES) suite of programs developed by the Geological Survey of Canada (Lore et al., 2001). GRASP defines plays as either subjective/conceptual or discovered/established. [Table 2](#) includes the pool and prospect numbers, AU area, and a pool density that is derived from the analogs for the conceptual AUs. GRASP uses these inputs in its models and reports pool outputs as 4 hydrocarbon streams; oil, condensate, non-associated gas, and solution gas. Additionally, a total of all hydrocarbons is reported as barrel of oil equivalent (BOE). Oil is reported as stock tank barrels and gas as standard cubic feet. One barrel of oil has the energy equivalence of 5,620 cubic feet of gas, either associated with liquid hydrocarbons or non-associated. Gas converted to barrels of oil equivalent are combined with liquid barrels to arrive at the total UTRR in BOE. UTRR are limited to what can be produced via natural pressure, artificial lift, pressure maintenance, or other secondary conventional recovery methods. Therefore, resources within gas hydrates or those that otherwise require enhanced recovery techniques to produce, are not included in this assessment.

The portion of UTRR that are economically recoverable under a given set of economic and technological conditions are undiscovered economically recoverable resources (UERR). UERR are always a fraction of what is physically recoverable as UTRR. UERR are greatly influenced by the total hydrocarbon volume, extraction cost, and market prices. Assumptions on the timing and cost of exploration, development, and operation are highly consequential but also difficult to constrain. Therefore, BOEM's proprietary model uses Monte Carlo simulation to stochastically model a range of input variables over many iterations until a single UERR output is reached for each oil-gas price pair for a given gas market adjustment. Both UTRR and UERR are reported at the 95 percent probability (a 19 in 20 chance of occurrence), the mean, and the 5 percent probability (a 1 in 20 chance of occurrence). All probabilities denote a model occurrence whereby the BOE value is met or surpassed. Lastly, the Atlantic UTRR and UERR are aggregated with the other 3 BOEM regions to comprise the total U.S. OCS resources (BOEM, 2026a).

Atlantic Assessment Units	Area		Pool	# Prospects			# Pools		
	Mi ²	Blocks	Density	Min	Mean	Max	Min	Mean	Max
Marginal Fault Belt (Jurassic - Cretaceous)	7376	820	18	167	335	502	0	21	101
Carolina Trough Salt Basin (Jurassic - Cenozoic)	4926	547	15	63	127	190	0	18	80
Carbonate Margin (Late Jurassic - Early Cretaceous)	7615	846	25	97	193	290	0	11	77
Paleoslope Siliciclastic Core (Jurassic - Cenozoic)	16833	1870	18	305	611	916	0	36	202
Paleoslope Siliciclastic Extension (Jurassic - Cenozoic)	55164	6129	120	266	532	798	0	15	109
Blake Plateau Basin (Jurassic - Cretaceous)	36551	4061	60	242	483	725	0	19	136
Shelf Stratigraphic (Jurassic)	7680	853	15	254	508	762	0	16	118
Interior Shelf Structure (Jurassic - Cretaceous)	2807	312	25	58	116	173	0	12	38
Rift Basin (Triassic - Jurassic)	4443	494	40	24	49	73	0	4	34
Hydrothermal Dolomite (Jurassic - Cretaceous)	1701	189	30	23	45	68	0	2	22

Table 2. The area, pool density, and estimates of the number of pools and prospects (minimum, mean, and maximum) for each AU. Pool density is the estimated average number of blocks per pool. A block is 9 mi². The larger the pool density number, the fewer the pools expected for a given area.

BOEM uses independent ordered aggregation methods to sum assessment volumes from the Assessment Unit level to planning areas and water depths categories. This method sums the oil and gas resources on a trial-by-trial basis naturally dispersing the zeros, individual simulations with no hydrocarbon resources, throughout the trial distribution. After summation, the 10,000 trials are sorted, and percentiles are taken from the sorted list. Independent aggregation tends to narrow the uncertainty range. Because independent aggregation methods keep zero values and variable outcomes dispersed throughout the distribution, summing multiple assessment units smooths out the extremes and compresses the percentiles band. Independent aggregation assumes independent variation between assessment units. For example, Play A's low does not always occur in the same trial as Play B's low. Because trials are not tied to the same underlying trial outcome, percentiles cannot be added. This applies for all 5th and 95th resource aggregations in this report including individual AUs ([Table 3](#)), as well as planning areas and water depth categories ([Table 4](#)).

3.0 ATLANTIC ASSESSMENT UNITS

[Figure 4](#) shows the areal extent of each AU defined by BOEM in the U.S. Atlantic OCS. Descriptions and discussions of each AU will be addressed in the following order:

1. Marginal Fault Belt (Jurassic–Cretaceous)
2. Carolina Trough Salt Basin (Jurassic–Cenozoic)
3. Carbonate Margin (Late Jurassic–Early Cretaceous)
4. Paleoslope Siliciclastic Core (Jurassic–Cenozoic)
5. Paleoslope Siliciclastic Extension (Jurassic–Cenozoic)
6. Blake Plateau Basin (Jurassic–Cretaceous)
7. Shelf Stratigraphic (Jurassic)
8. Interior Shelf Structure (Jurassic–Cretaceous)
9. Rift Basin (Triassic–Jurassic)
10. Hydrothermal Dolomite (Jurassic–Cretaceous)

The first 5 AUs contain 90% of the total estimated UTRR in the U.S. Atlantic OCS. The remaining 5 AUs contain 10% of the UTRR in the region ([Table 3](#)). The Paleoslope Siliciclastic Core and Extension AUs are discussed together. For 2026, 9 AUs are conceptual and 1, the Interior Shelf Structure, is established. Additional play concepts are discussed but not assessed in this report. Representative seismic lines for 7 of the 10 AUs have been published with interpretations by BOEM staff (Post et al., 2012).

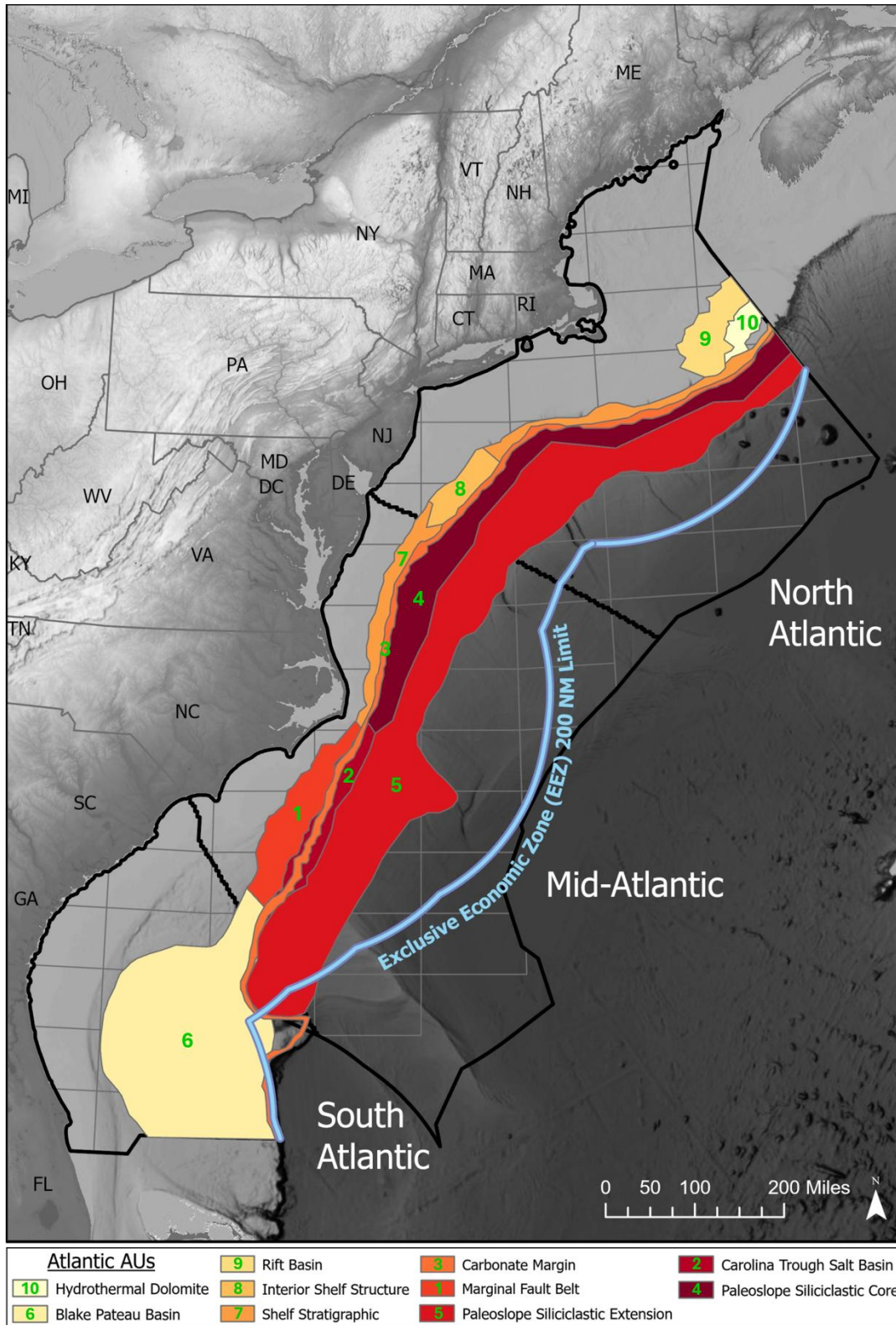


Figure 4. The 10 Atlantic AU outlines labeled on the map with their corresponding number from the legend. Shading is color-graded by mean UTRR from light yellow for low values to dark red for high. Note that the Carbonate Margin area overlaps geographically with other AUs. Protraction areas are the gray outlines offshore. The Exclusive Economic Zone (EEZ) boundary is the thick blue line. Other cartographic elements are as labeled in Figure 1.

Basin Assessment Unit	2026 Undiscovered Technically Recoverable Resources (UTRR)								
	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Atlantic OCS	0.539	4.498	11.070	3.403	34.355	78.302	1.145	10.611	25.003
Marginal Fault Belt (Jurassic – Cretaceous)	0.000	0.296	0.882	0.000	3.495	12.905	0.000	0.918	3.179
Carolina Trough Salt Basin (Jurassic – Cenozoic)	0.000	0.899	2.496	0.000	7.836	25.009	0.000	2.293	6.946
Carbonate Margin (Late Jurassic – Early Cretaceous)	0.000	0.173	0.622	0.000	2.882	12.381	0.000	0.686	2.825
Paleoslope Siliciclastic Core (Jurassic – Cenozoic)	0.000	1.849	10.527	0.000	12.021	34.398	0.000	3.988	16.648
Paleoslope Siliciclastic Extension (Jurassic – Cenozoic)	0.000	0.769	3.433	0.000	4.891	25.957	0.000	1.640	8.052
Blake Plateau Basin (Jurassic – Cretaceous)	0.000	0.130	0.656	0.000	0.347	1.319	0.000	0.192	0.890
Shelf Stratigraphic (Jurassic)	0.000	0.098	0.492	0.000	1.155	5.193	0.000	0.304	1.415
Interior Shelf Structure (Jurassic – Cretaceous)	0.034	0.069	0.078	0.393	1.159	2.250	0.104	0.275	0.478
Rift Basin (Triassic – Jurassic)	0.000	0.169	0.374	0.000	0.450	4.412	0.000	0.249	1.159
Hydrothermal Dolomite (Jurassic – Cretaceous)	0.000	0.045	0.367	0.000	0.120	0.450	0.000	0.067	0.447

Table 3. UTRR by AU for oil, gas, and total BOE. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

3.1 MARGINAL FAULT BELT (JURASSIC–CRETACEOUS) AU

Confined to the Mid-Atlantic Planning Area, the undrilled Marginal Fault Belt conceptual AU ([Figure 5](#)) occurs in a seismically defined area of ~7,400 mi² in the updip region of the undrilled Carolina Trough ([Figure 1](#)). Water depths in the AU range from ~1,000–4,000 ft. Productive analogs to the seismically identified features in the AU are located in the updip areas of the onshore GOA Mesozoic basins of East Texas, South Arkansas, and Mississippi-Alabama-Florida (Wendlandt and Shelby, 1948; Sigsby, 1976; Foote et al., 1988; and Halvatzis, 2000). Field sizes, based on current cumulative production in analog fields, range from less than 1 MMBOE to more than 500 MMBOE according to production records from Alabama (Geological Survey of Alabama, State Oil and Gas Board, 2026), Florida (Florida Dept. of Environmental Protection, 2026), and various production sources from Mississippi (including Frew, 1992). Faulting and associated oil and gas traps in this updip setting were recognized along the updip margin of the onshore northern GOA in the early 1900s (Foley, 1926). Subsequently, it was determined that down structural dip salt movement was the primary cause of this faulting and the resulting hydrocarbon traps (Hughes, 1968; Jackson and Wilson, 1982; and Frew, 1992). Dillion et al. (1982) recognized a similar down-to-the basin fault system in the most updip part of the Carolina Trough Salt Basin and inferred that faulting was caused by seaward salt flow.

Marginal Fault Belt (Jurassic–Cretaceous)

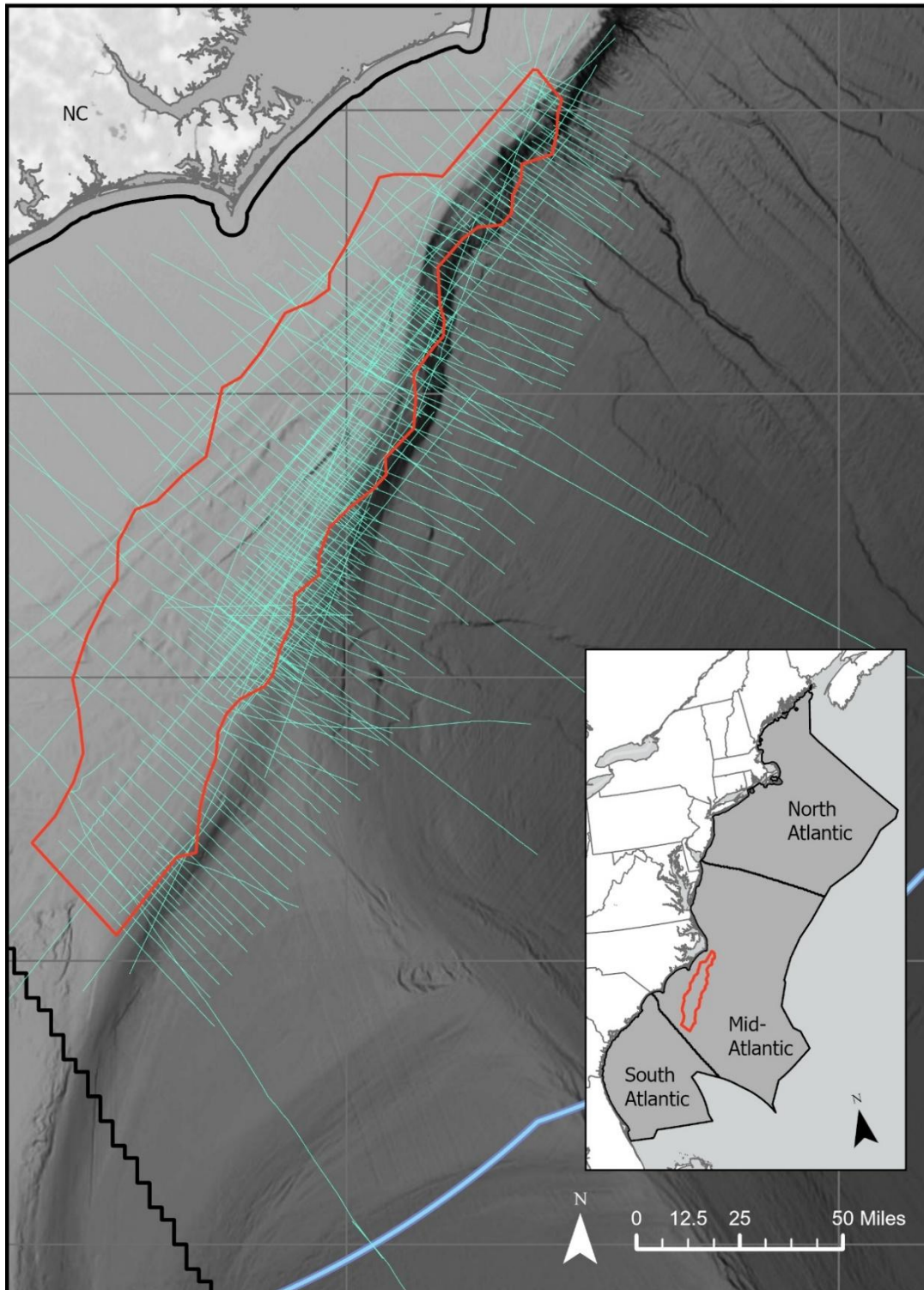


Figure 5. The Marginal Fault Belt (Jurassic–Cretaceous) AU is show in a red-orange outline. 2D seismic coverage is shown as bright blue-green lines. Other cartographic elements are as labeled in earlier figures. No industry or COST wells are visible in the area around the play. The inset map is a simplified image showing the AU location at a scale of the entire Atlantic OCS.

For this resource assessment, the enhanced depth-converted, time-migrated, deep-penetration, reflection seismic data often provides better delineation of the faults and the graben system(s), and therefore potential hydrocarbon traps. Source rocks in the analog area are Oxfordian age, laminated lime mudstones with predominately algal- and bacterially-derived organic matter (Sassen et al., 2005). Source rocks have yet to be identified in this undrilled AU. However, indirect hydrocarbon indicators suggest source rocks are present and that generation–expulsion–migration can be interpreted as having occurred. These hydrocarbon indicators include sea surface slick anomalies identified on SAR data and seismically identified possible gas chimneys and fault-related amplitude anomalies in the sedimentary strata adjacent to faults identified by BOEM staff. Anticipated reservoirs are siliciclastics and carbonates in rollover structures, fault traps, or combination structural-stratigraphic traps (Hughes, 1968; Ottmann et al., 1973; Locklin, 1984; Frew, 1992). Regionally sealing lithologies in the updip paleo-shelf area may not be as effective as farther basinward due to a higher percentage of sandstone rich intervals. However, regional marine transgressions in the Jurassic and Cretaceous ([Figure 2](#)) indicate the presence of potential sealing intervals. On their poster panels, Coleman et al. (2014) show sealing intervals even farther updip in the Pamlico Sound of North Carolina based on wireline log character.

The Marginal Fault Belt has a mean of 918 MMBOE ([Table 3](#)) due to a good pool density ([Table 2](#)). It has an average geographical size ([Table 2](#)) with a chance of success that is also in the middle at 6.2% ([Table 1](#)). Analogs for this play contain large fields and therefore the lognormal distribution in GRASP has a high truncation on the upper pool limit and the possibility for larger pools to be sampled in the model. This results in a higher UTRR for the play. All comparisons described here and in the subsequent play sections are made within the 10 Atlantic AUs and descriptive evaluations are in this relative context.

3.2 CAROLINA TROUGH SALT BASIN (JURASSIC–CENOZOIC) AU

The conceptual Carolina Trough Salt Basin (CTSB) AU ([Figure 6](#)) is located downdip from the related Marginal Fault Belt AU ([Figure 5](#)) and updip of the Paleoslope Siliciclastic Extension AU ([Figure 9](#) and [Figure 4](#)). This undrilled play is nearly 5,000 mi², entirely within the Mid-Atlantic Planning Area. Present-day water depths in this AU range from ~8,000 ft to greater than 9,000 ft. The Carbonate Margin AU that overlaps part of the play area ([Figure 4](#)) is a different play type and its resources are assessed separately.

The Carolina Trough and the Scotian Basin are the only locations offshore eastern North America where salt diapirism is abundant. Similar to the magma-poor Scotian Basin, the Carolina Trough is interpreted to have had greater continental stretching during the rifting phase. The thinner basement allowed more accommodation space for salt early in the Atlantic’s history (Early Jurassic). As basin development continued, salt migrated downdip forming diapirs while the overlying sediment block subsided and was faulted (Dillon et al., 1982; Dillon et al., 1983).

The offset of shallow strata near the seafloor and the seafloor expression of diapirs indicate that development is still active.

Using 2D seismic reflection data and side-scan sonar data, between 25 and 30 salt diapirs have been interpreted in the CTSB area (Dillon et al., 1982; Popenoe, 1984; Carpenter and Amato, 1992). The exact number of salt structures interpreted depends on the volume and quality of seismic data available to delineate these salt structures and the confidence level of the interpreter. Structures have been confirmed as salt and not a ductile formation like mobilized shale. Evidence includes elevated pore water salinities at the ODP 996 wells (Leg 164) (Egeberg, 2000) and high heat flow measurements (Ruppel et al., 1995).

No information is provided in Dillon et al. (1982), Popenoe (1984), or Carpenter and Amato (1992) regarding the processing sequence that was applied to the reflection seismic data they used. The lack of information on processing is significant, because 2D seismic data imaging is substantially improved by migration which attempts to put reflected energy into its proper location. Depth-conversion of seismic data also improves its imaging. In the case of the U.S. Atlantic OCS, improved, accurate imaging is especially important in areas where the present-day water bottom dips steeply on the continental slope, and correspondingly the water depth increases substantially over a short distance. In areas of steep dip, 2D seismic data is generally processed with insufficient velocity analyses to accurately image the structure of the area.

Unfortunately, because of the steep, near vertical nature of the salt bodies, even the best-acquired and processed 2D seismic reflection data cannot accurately depict their geometry. This is because the 2D data are recorded in a single vertical plane, rather than as an infilled volume or cube of data as is done in 3D seismic acquisition and processing. With a 2D seismic line, it is not always possible to determine how far in or out of the plane the reflected energy on the line originated. 3D seismic data provides a more precise, though imperfect, salt body depiction. As no 3D data has been acquired to date for the Atlantic OCS, the exact location, size, and geometry of these features are subject to some uncertainty. Acquisition of the existing 2D seismic commonly used cables 3,500–4,000 meters in length collected with a nominal fold of 48 (NAMSS, 2016). Modern acquisition parameters would greatly improve upon these short offset, low fold, and low frequency datasets.

The “regional” 2D seismic grid spacing available to BOEM throughout much of this play ranges from ~1.25 to ~3.25 miles in a “dip” (~NW–SE) direction, and from ~3 to ~7 miles in a “strike” (~NE–SW) direction. In some cases, subsequent surveys were acquired on grids oriented slightly differently. As a result, the reflection seismic data density grid on some salt features is ~1 mile or less. Most of the salt bodies interpreted by BOEM staff for this resource assessment are controlled by two or more 2D seismic lines. Those lines, although 2D, have been depth-converted and time-migrated.

Carolina Trough Salt Basin (Jurassic–Cenozoic)

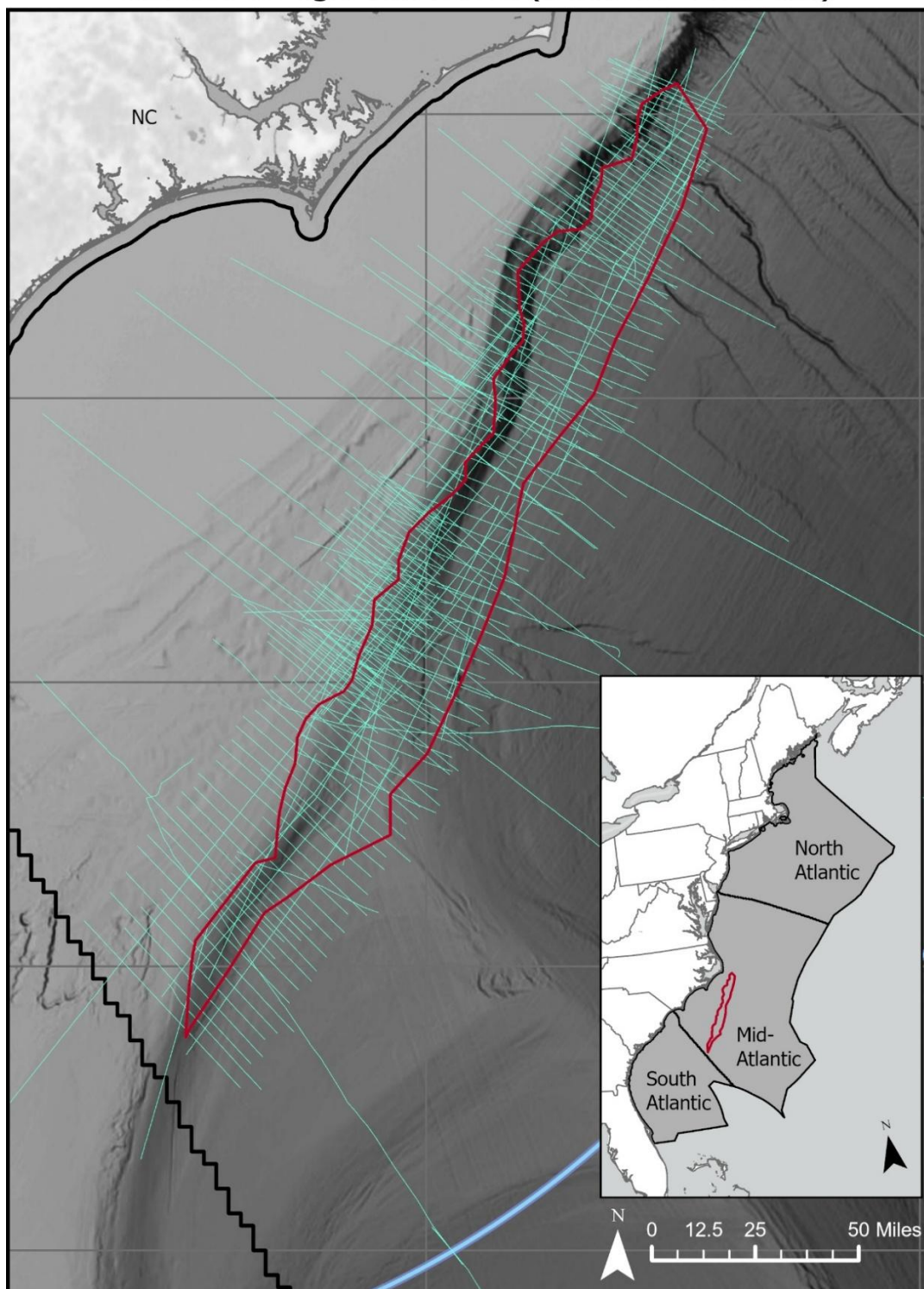


Figure 6. The Carolina Trough Salt Basin (Jurassic–Cenozoic) is shown in a red outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures. No industry or COST wells are visible in the area around the play.

Source rocks for the play are supported by SAR identified sea surface slicks within the play (NPA, 2018) and methane seeps over the Cape Fear and Blake Ridge diapirs (Ruppel et al., 2024), both domes having bathymetric expression. Additional evidence of methane includes the gas chimneys seen on the seismic data, and the chemosynthetic communities and associated authigenic carbonate on the seafloor (Paull et al., 1995; Paull et al., 1996; Taylor et al., 2000; Ruppel et al., 2024).

Siliciclastic reservoirs are interpreted to be the primary targets, although carbonates deposited in high-energy environments may also occur. Regional correlations suggest that reservoirs may occur but have not been confirmed due to the lack of drilling. Vertical salt movement is interpreted to provide cross-stratal migration conduits connecting deeper, mature oil and gas source rocks with younger reservoirs.

Multiple salt bodies have bathymetric expression, either reaching the sea floor or being close enough to deform it. Because of possible trap breaching, the crests of these salt bodies are interpreted to be less prospective than their flanks. Deeper salt bodies, such as those more than 5,000 ft below the seafloor, may provide hydrocarbon traps on their crests or their flanks. The largest salt bodies would be preferred targets because of their potential for larger hydrocarbon traps. Several important questions with respect to geologic interpretation remain: Are the depicted salt bodies connected to autochthonous salt or are they detached? Are some of the salt bodies actually high-angle toe thrusts? Are there overhangs of salt under which prospective hydrocarbons traps may exist? Are there salt features near the paleo-carbonate margin?

On the northwest African conjugate margin, the Mauritania–Senegal–The Gambia–Guinea Bissau–Conakry (MSGBC) basin, contains similar salt-related structures such as diapirs, toe thrusts, detached salt bodies, etc., that are productive and prospective (Brownfield, 2016) making the area an excellent analog for this AU. Additionally, the two regions have a shared geologic history as conjugate margins separated during the breakup of Pangea, with syn-rift to early post-rift Triassic to Early Jurassic evaporites that would later form the salt structures common to both. However, the Albian (Early Cretaceous) and Late Cretaceous age sources and younger siliciclastic reservoirs of MSGBC (USGS Senegal, 2016) were deposited after several hundred miles of drift separated the North American and African plates (Blakey, 2020). Any potential Jurassic source rocks or carbonate reservoirs common to both would have been in syn-rift strata or early in the post-rift phase when plate separation between the plates was minimal. Analog resources came from a Wood Mackenzie database and operator reports. Using the selection criteria for analogs described in the [METHODOLOGY](#), those selected for this AU resulted in a range of discovery size from ~4 MMBOE to 890 MMBOE and totaled nearly 7.5 BBOE (PetroView, 2020).

The CTSB has a mean of 2.293 BBOE giving it the second largest UTRR ([Table 3](#)) in the Atlantic OCS. It has a good pool density ([Table 2](#)) and the best overall chance of success at 14.5% ([Table 1](#)). Its acreage is less than the median ([Table 2](#)), but its analogs contain numerous large fields allowing for the potential discovery of similarly large pools within the CTSB.

3.3 CARBONATE MARGIN LATE JURASSIC–EARLY CRETACEOUS) AU

With an area of ~7,600 mi² in water depths from ~3,500–6,500 ft, the conceptual Carbonate Margin AU spans all 3 planning areas ([Figure 7](#)). The play is the continuation of the Nova Scotia carbonate margin which includes the Deep Panuke field, the analog for this AU. A bank edge play is long and narrow with an average width of ~10 miles or less as interpreted from seismic and subsurface data. The underlying Late Jurassic–Early Cretaceous carbonate shelf is predominantly limestone with intervals of terrigenous siliciclastic material, both as interbeds and as disseminated sand, silt, and clay (Edson and Carpenter, 1986).

On the U.S. OCS three unsuccessful exploration wells targeted this play, the Wilmington Canyon (WI) 586-1, WI 587-1, and WI 372-1 ([Figure 3](#)), making this AU the second most explored on the Atlantic OCS. All wells were drilled in the southern BCT within the modern boundary of the North Planning Area ([Figure 1](#)).

The WI 587-1 ([Figure 3](#)) well tested slightly argillaceous, chalk or chalk-like domal or plateau-like features on the near-shelf margin. The deposits had high porosity but low permeability and were interpreted to have formed in deepwater (Eliuk and Prather, 2005). Fluid Inclusion Technologies, Inc. (FIT), a Schlumberger company, provided insights into the petroleum systems in this AU as part of a 2015 fluid inclusion stratigraphic (FIS) analysis on the WI 587-1, WI 372-1, and WI 586-1 wells ([Figure 3](#)). At well WI 587-1, FIS analysis on 251 cuttings samples from 8,560–14,500 ft found indications of anomalous dry gas, wet gas, oil inclusions, intermittent sulfur species of probable thermal origin, and likely hydrocarbon migration events (Fluid Inclusion Technologies, Inc., 2015a).

A few miles updip of WI 587-1, the shelf WI 586-1 well ([Figure 3](#)) targeted a thin, Early Cretaceous age, high energy carbonate facies situated over a prograding “clastic wedge” (Edson and Carpenter, 1986). The well encountered trace methane, ethane, and propane on the chromatograph but no significant shows seen in the conventional cores and petrophysical analysis of the well logs (Nichols, 1986). Conventional geochemical analysis determined low source rock potential and thermal immaturity to a depth of ~12,000 ft. Below that depth, palynomorph colors suggest borderline maturity (Miller et al., 1986; Fry, 1986). No cross-stratal migration conduits between the reservoir objectives and deeper, more thermally mature zones are visible on the seismic. Therefore, a lack of hydrocarbon charge may be responsible for this dry hole. FIS analysis was performed on a total of 382 drill cutting samples from 7,970–16,000 ft in WI 586-1. Dry gas spectra with trace wet gas species encountered below 9,060 ft., and dry gas anomalies with acetic acid below 11,650 ft, could be indicative of nearby oil or condensate. Trace sulfur species of probable thermal origin were also seen in the deeper section. Migration events are suggested (Fluid Inclusion Technologies, Inc., 2015b).

Well WI 372-1 was drilled on the basinward edge of the Abenaki carbonate margin to test a high-relief build-up of Early Berriasian age (Eliuk and Prather, 2005). The “pinnacle-like” feature was interpreted as a *keep-up* feature formed during a relatively rapid rate of carbonate

accumulation (Sarg, 1988) after which deposition had ceased in the updip area of WI 587-1 (Eliuk and Prather, 2005). The mud log chromatograph indicated only minor occurrences of methane, ethane, and propane with no other significant shows. Abandoned as a dry hole, potential source rocks in the well were found to be organic-lean, gas-prone, and thermally immature. FIS analysis on 143 cuttings samples from 9,170–11,631 ft in WI 372-1 indicate minor migration events of oil and condensate with a possible separate gas charge (Fluid Inclusion Technologies, Inc., 2015c). Prather (1991) noted downlap of the upper Albian sequence boundary (LKI) on the upper Berriasian sequence boundary (LKIII) at the WI 372-1 location implying that the Berriasian shelf-margin carbonates and any contained hydrocarbons were exposed locally on the sea floor during this nonconformity. If a breached seal from local erosion was responsible for the lack of hydrocarbons at WI 372-1, then prospectivity may be unaffected elsewhere in the play.

Microthermometry was measured at 14,460 ft and 15,480 ft by FIT for the WI 586-1 well. Both samples indicated higher maximum burial temperatures of 105–110° C compared to the estimate for current burial temperatures of 70–75° C (Fluid Inclusion Technologies, Inc., 2015d). For a more detailed analysis on the FIS and microthermometry for the wells in this report, see BOEM's [2016 Atlantic Assessment](#) (BOEM, 2016).

On the Canadian side, 15 exploration wells targeted Abenaki carbonate margin traps offshore Nova Scotia. Seven wells drilled the interpreted bank edge and nine wells drilled in carbonates shoreward or siliciclastics basinward of the bank edge. All were dry holes (Kidston et al., 2005). These wells showed geology similar with the Carbonate Margin AU wells. Therefore, the Canadian formation nomenclature is used in this report also. Carbonate sands were, however, more common in the strata of the BCT wells (Eliuk and Prather, 2005). Shallowing-upwards sequences record the Abenaki margin's progradation and aggradation with the most prospective being the youngest member of the Abenaki Fm., the Bacarro member (Kidston et al., 2005; Offshore Energy Research Association, 2011). Changes along strike from northeast to southwest record a margin evolution from a progradational, gently dipping ramp-like margin with interfingering carbonate and clastic facies, to a steeper sigmoidal bank margin, to an eroded margin, and to a faulted and eroded margin (Kidston et al., 2005). Potential reservoirs are limestone and dolostone (dolomite), the latter likely forming from secondary alteration of limestone as in the Deep Panuke reservoir. Geochemical analysis of biomarkers from Deep Panuke condensates indicated a Jurassic age marine shale source, possibly of a paralic-deltaic environment, derived from a mix of algal and terrestrial organic matter. The predominately gas field is more thermally mature than Scotian shelf condensates and oils such as at the Panuke field as determined from terpane/sterane and diamondoid methyladamantane/methyldiamantane ratios (Zumberge, 2010).

Carbonate Margin (Late Jurassic–Early Cretaceous)

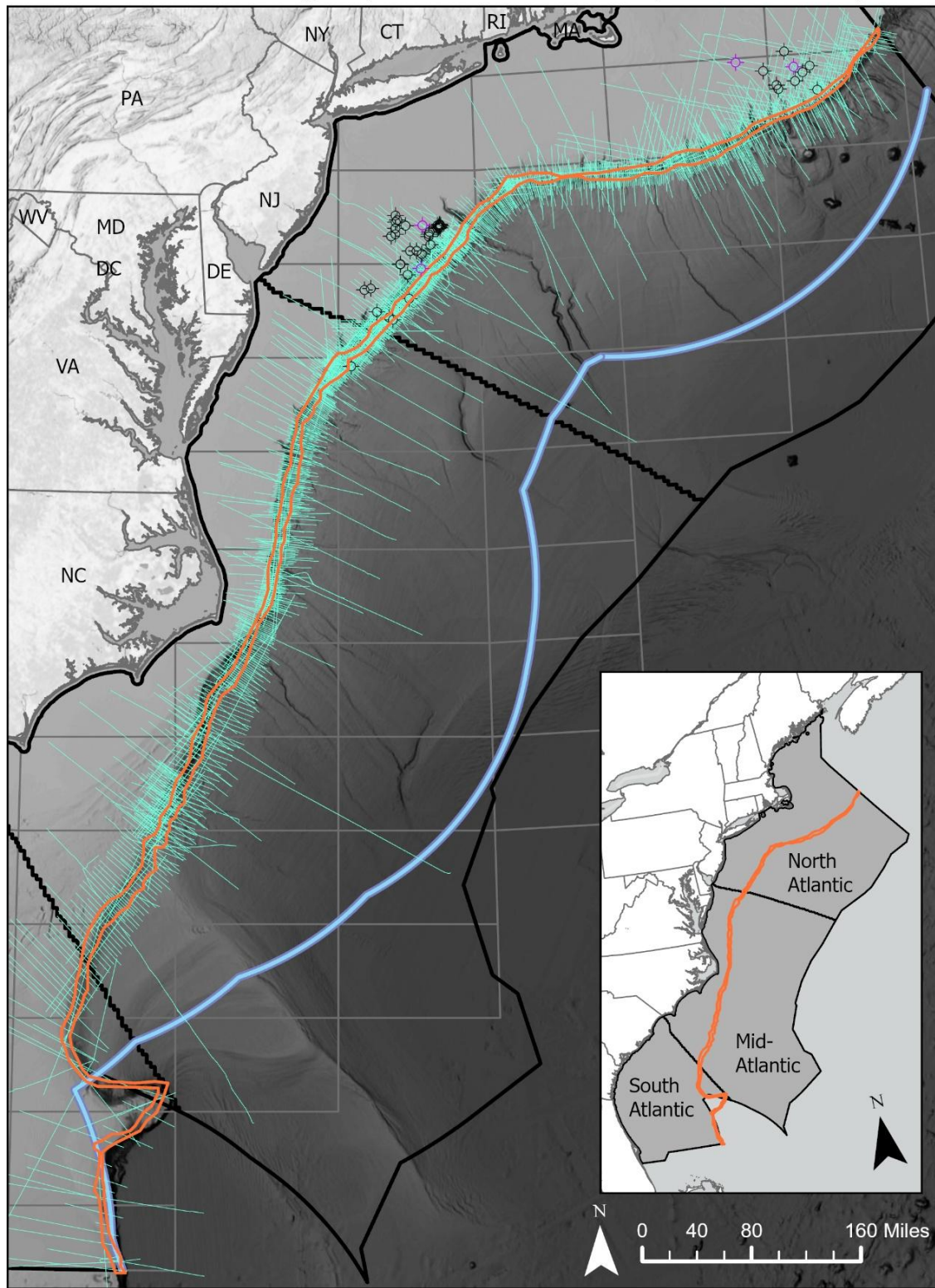


Figure 7. The Carbonate Margin (Late Jurassic–Early Cretaceous) is shown in a dark orange outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

The preservation of trapped hydrocarbons is a significant risk for this AU. Top seals would likely be impermeable carbonates, shales, or a marly mix. At the Deep Panuke analog, hydrocarbons were trapped via an intra-Abenaki seal. Identifying and risking this type of seal would require analysis on a prospect-by-prospect basis. Hydrocarbon indicators were interpreted by BOEM in this AU including flat spots within the shelfward dipping carbonate margin beds, and amplitude anomalies similar to those identified pre-discovery at Deep Panuke (Harvey, 1999; Harvey and MacDonald, 1990; Harvey and MacDonald, 2012). Where present, these may help better assess prospect risk. Due to play's extensive geography, any of the petroleum system elements and processes may be risks for a given location. Additionally, vertical cross-stratal migration conduits are likely to be necessary to connect the mature source rocks with shallower, younger reservoirs.

Deep Panuke, the single field in Nova Scotia that has been used as the analog for this AU, is now plugged and abandoned (CNSOER, 2021; Wierzbicki et al., 2006). The field came online in August 2013 and was shut in May 2018. Over 5 years it produced 147 billion cubic feet of gas (BCFG) or just a quarter of the operator's mean estimate of 632 BCFG (CNSOER, 2021; Encana, 2006). This underperformance led to a significant decrease in the Carbonate Margin AU's 2026 UTRR estimates compared to the values from the 2016 Atlantic Assessment.

The Carbonate Margin AU has a mean of 686 MMBOE ([Table 3](#)), middle rank at 5th largest UTRR. Its pool density is also average for the Atlantic plays ([Table 2](#)) along with its total chance of success of 5.9% ([Table 1](#)).

3.4 PALEOSLOPE SILICICLASTIC CORE AU AND EXTENSION (JURASSIC–CENOZOIC) AU

The conceptual Paleoslope Siliciclastic Core and Extension AUs ([Figure 4](#)), herein referred simply as the Core and Extension, are geographically large, high UTRR plays within deep and ultra-deepwater. The Core is ~17,000 mi² in 4,500–8,000 ft water depths. The larger, more basinward Extension is ~55,000 mi² in 8,500–10,500 ft water depths. The Core extends from the U.S.–Canadian border in the North Planning Area to halfway through the Mid- ([Figure 8](#)). The Extension covers the continental slope and upper rise across all 3 planning areas ([Figure 9](#)). Grant et al. (2013), Erlich and Inniss (2014), Hodgson and Rodriguez (2015), and others have described comparable, deep and ultra-deepwater plays, often using similar differentiating characteristics to those used by BOEM to define the Core and Extension as independent AUs. Their respective locations within the depositional slope influence the different reservoir classes, trapping configurations, source rock development, organic matter type, and petroleum system processes. These characteristics vary as a function of paleo-location, overburden thickness, and heat flow.

Paleoslope Siliciclastic Core (Jurassic–Cenozoic)

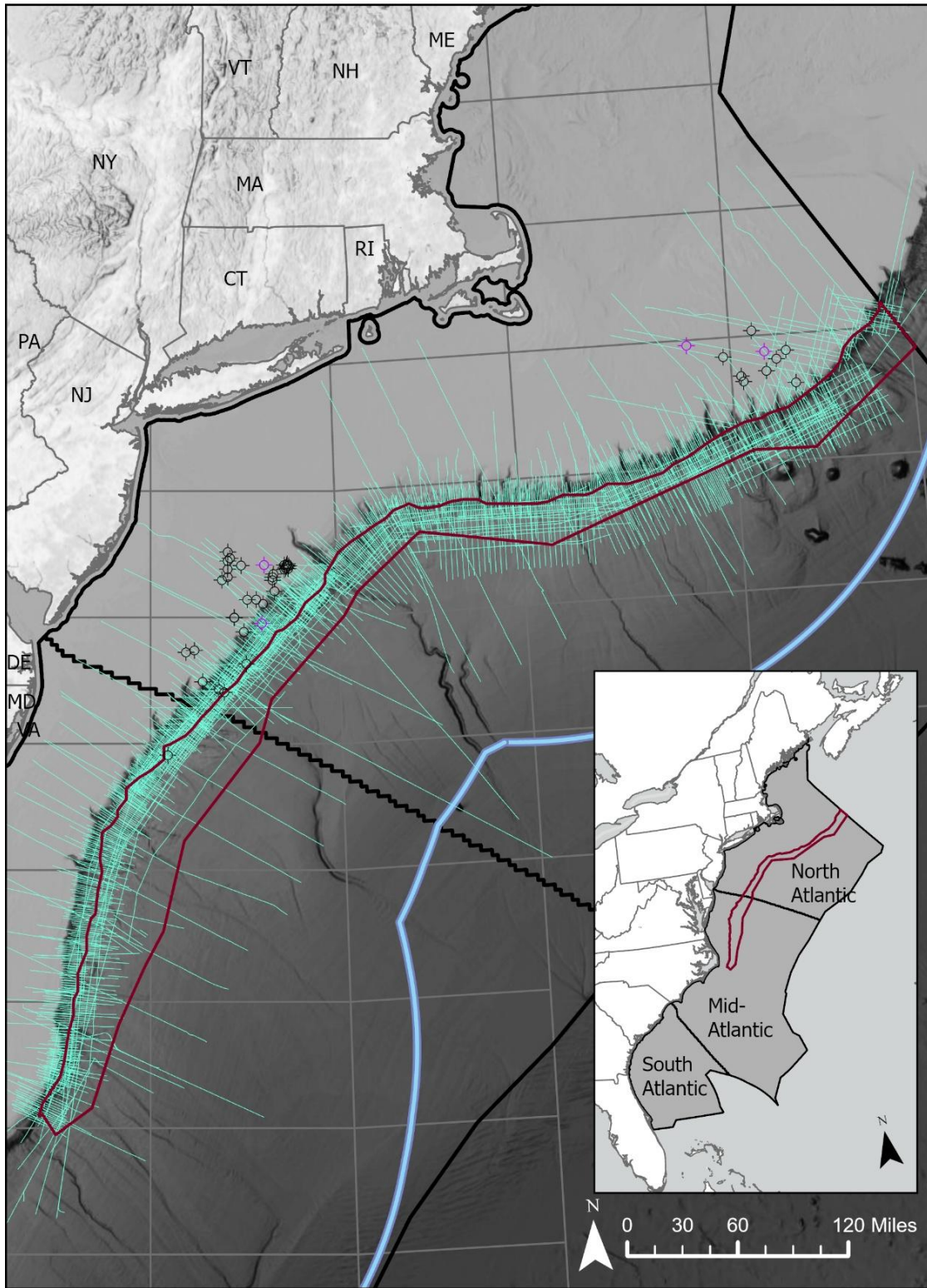


Figure 8. The Paleoslope Siliciclastic Core (Jurassic–Cenozoic) is shown in a dark red outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

Reservoirs in the Core AU ([Figure 8](#)) are siliciclastics deposited on paleo-slope and uppermost paleo-rise settings. These reservoirs potentially represent a range of depositional geometries and types including channel fill, amalgamated channel fill, and relatively small-scale sheet sands and lobes deposited as point bar, levee overbanks and crevasse splays, and slope fans (Grant et al., 2013). Hydrocarbon traps are both stratigraphic and combination structural-stratigraphic. For the more basinward Extension AU, stratigraphic traps are interpreted, including unconfined basin-floor fans, stacked/amalgamated channels and lobes, and amalgamated sand-rich channels (Grant et al., 2013). Coarse-grained lithofacies of siliciclastic turbidites and mass flow deposits are potential reservoir facies for both plays.

Late and Early Cretaceous TOC-rich intervals of Type II/II-III and III kerogens were sampled at DSDP 603B ([Figure 3](#)), a well ~250 miles east of Cape Hatteras, North Carolina. TOC values varied between 0.57 and 20.4% but were immature due to insufficient overburden and/or thermal gradient (Herbin et al., 1987; Katz, 1987; Stein et al., 1989). However, due to the thicker sediment interval updip, a mature source rock closer to shore is likely. The well also sampled a thick (~980 ft) Early Cretaceous (Valanginian to Barremian age) turbidite unit. Grain size was 45% silt-sand with the sequence overlain with ~130 ft of clean, uncemented sands of Barremian–Aptian age (Sarti and von Rad, 1987). Located on the paleo-basin floor, sedimentological and seismic data favor the hypothesis that the turbidite complex consisted of an elongated, channel-levee-interchannel system that developed during the Valanginian–Barremian and extended seaward from the depositional base-of-slope to the lower continental rise (Sarti and von Rad, 1987). Source and reservoir data from 603B helped determine prospectivity and demarcate the Extension AU's eastern boundary.

The deepwater BR 93-1 well ([Figure 3](#)) was drilled to 17,740 ft TD in 5,013 ft of water (Amato, 1987) in the southern BCT and within the Core AU. It targeted a large, faulted structure related to what Poag et al (1990) called the 'Gemini Fault System'. Well objectives were an updip, shelf-margin delta system that is interpreted to have been the source of the turbidite fan complex seen downdip at DSDP 603B (Sarti and von Rad, 1987). While the dry hole didn't encounter charged reservoirs, several Early Cretaceous zones had >1% TOC with Type III (gas-prone) kerogen predominate. The deepest interval in the well was either in or near the oil maturity window (Amato, 1987; Fluid Inclusion Technologies, Inc., 2015e). A 2015 FIS measured BR 93-1 samples from 7,140 ft (undifferentiated Tertiary) through 17,740 ft (?Berriasian). Identified mostly in the deeper sections were wet gas spectra, minor sulfur species of possible thermogenic origin, liquid petroleum inclusions, and hydrocarbon staining (Fluid Inclusion Technologies, Inc., 2015e). These occurrences suggest hydrocarbon generation, expulsion, and migration events near the well's TD.

Microscopically visible oil and thermogenic gas were seen beneath gas hydrates at the ODP 997B well located within the southern area of the Extension AU (Paull et al., 1996). The drilled section encountered only thermally immature organic material so sampled hydrocarbons must have migrated from older, deeper, and more mature source rocks. Based on their carbon isotope

ratios, the corresponding source rock would be attributed to a marine facies within the oil window, $R_o \sim 0.6\%$ to 1.0% (Wehner et al., 2000). Similarly, are the organic-rich, marine facies that were discovered and described in DSDP 534A and DSDP 391C in the Blake Bahama basin, and in DSDP 105 and the aforementioned 603B, both located further north and far from the shelf ([Figure 3](#)) (Katz and Pheifer, 1982; Herbin et al., 1983; Herbin et al., 1986; Summerhayes and Masran, 1983).

Shelf setting and geometry, paleogeography, and drainage area affect reservoir location and quality. Big, sand-rich systems are needed to transport and sort reservoir-sized grains eroded from quartz-rich areas. Broad shelf areas with graded slopes like the northern OCS provide long source-to-sink transport distances leading to greater sediment sorting. Graded slopes are more prone to sediment transport in channels and canyons, with the steeper gradient slopes being more predisposed to sediment by passing the shelf and depositing on the distal basin floor. Stepped and ponded slope geometries trap sediments on their flatly graded sections, preventing transport and deposition on the basin floor (Deptuck, 2011). These are more common on slopes with mobile substrates (Deptuck, 2011) like the CTSB AU and could affect the area of the Extension AU that is downdip of the CTSB.

BOEM-identified analogs for stratigraphic and structural-stratigraphic traps in the Core and Extension AUs include the Woodbine fields (Bunge, 2011) of the southern East Texas basin, the Cretaceous reservoirs of deepwater fields of the Tano and Sierra-Leone-Liberian basins of the African Transform Margin (Jewell, 2011), the passive margin of the Guyana-Suriname basin (Trude et al., 2022), the South Viking Graben of the North Sea (Turner and Allen, 1991; Branter, 2003; Brehm, 2003; Fletcher, 2003a & b; Gambaro and Donagemma, 2003; Hook et al., 2003; Wright, 2003), and the East African Transform Margin (Danforth et al., 2012). The analogs used in determining pool size in these AUs were a mixture of producing fields, some of which have been fully or nearly depleted, and discoveries in various stages of delineation, final investment decision (FID), front-end engineering design (FEED), or development. Data sources have included production and reserves data from a BOEM-licensed Wood Mackenzie database, relevant U.S. state and nation-state agencies, and industry. The analogs used by BOEM staff contain reserves/resources ranging from 1 MMBOE to +1 BBOE, with more than half of those offshore exceeding 200 MMBOE (PetroView, 2020). These analogs have seen their total reserve/resource volumes grow over tenfold since 2007, when BOEM staff researched and developed the first version of this analog database.

Paleoslope Siliciclastic Extension (Jurassic–Cenozoic)

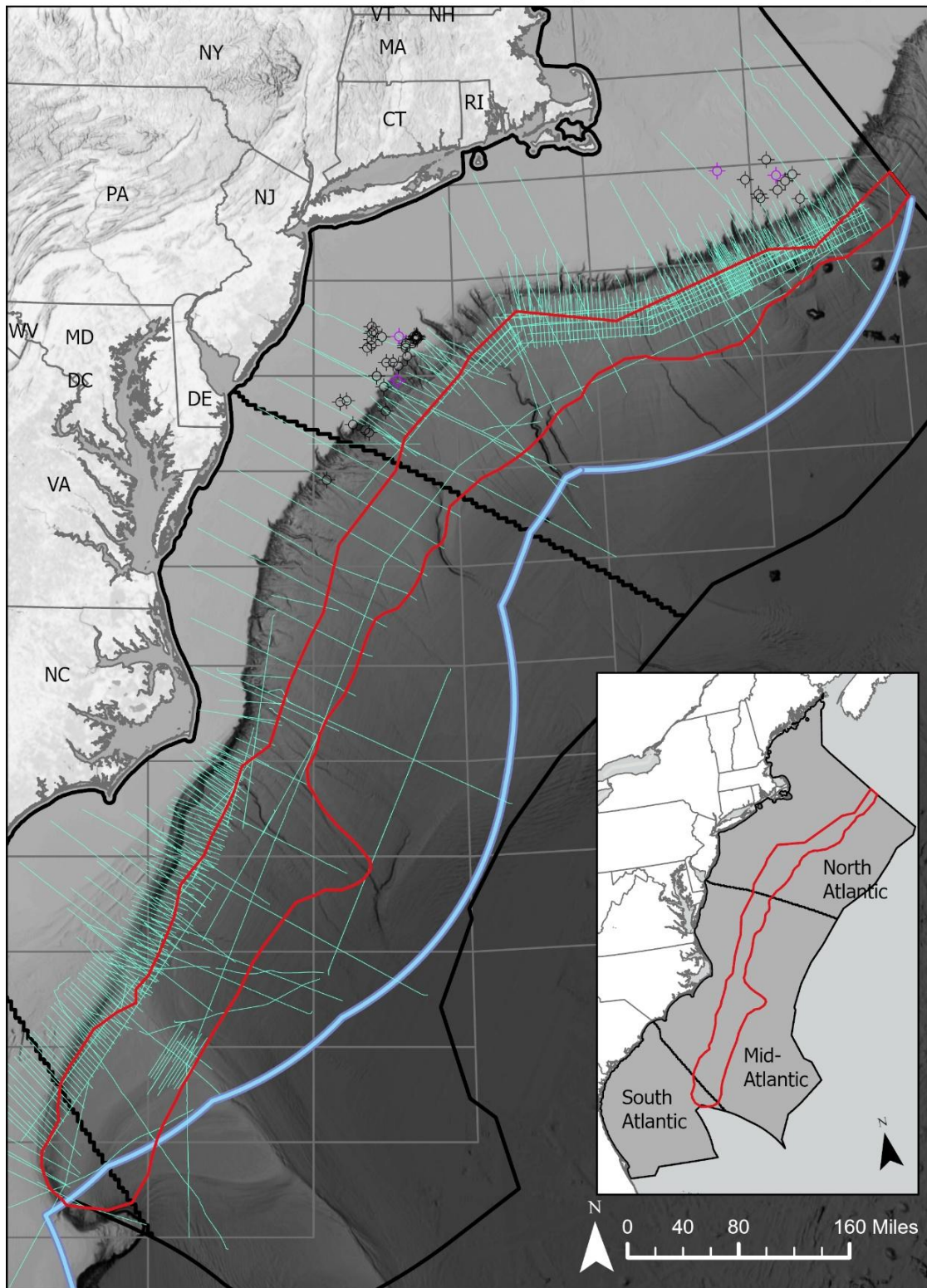


Figure 9. The Paleoslope Siliciclastic Extension (Jurassic–Cenozoic) is shown in a red outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

Reservoir and source rocks are interpreted as the highest risk components for these AUs. Although not in commercial volumes, the migrated, mature hydrocarbons in BR 93-1 and ODP 997B provide positive indications of generation–expulsion–migration in the vicinity of these wells within the Core and Extension plays. Potential reservoirs were encountered updip on the paleo-shelf and downdip in DSDP 603B (Sarti and von Rad, 1987). Examples of potential hydrocarbon traps similar to those in the analogs have been identified by BOEM staff on the coarse 2D seismic grid available. Sealing lithologies are expected to be abundant in these distal AUs as fine-grained sediments predominate in both.

With a mean UTRR of 3.988 BBOE, the Core AU has by far the greatest resource potential in the Atlantic OCS with over 5 times the average UTRR of the other 9 AUs or greater than twice the UTRR of the lower 6 AUs combined ([Table 3](#)). The play has the highest number of mean pools due to a high pool density, large area, ([Table 2](#)) and moderate chance of success (5.9%) ([Table 1](#)). The model’s pool distribution has a high truncation due to the large field sizes seen in the analogs.

The Extension AU has a mean UTRR of 1.640 BBOE ([Table 3](#)) due in part to an acreage nearly 4 times larger than the average Atlantic OCS AU ([Table 2](#)). Its analogs are very similar to those from the Core and therefore include large fields within the pool distribution. Opposing these positive influences is a poor pool density ([Table 2](#)) and low chance of success at 2.8% ([Table 1](#)).

3.5 BLAKE PLATEAU BASIN (JURASSIC–CRETACEOUS) AU

The conceptual, undrilled Blake Plateau Basin AU ([Figure 10](#)) sits within the BPB and downdip from the Southeast Georgia Embayment (SEGE) ([Figure 4](#)). This AU is located predominantly in the South Atlantic Planning Area and has an area of ~37,000 mi². Water depths range between 2,000 ft and 3,600 ft. Located updip in the SEGE was a continental shelf stratigraphic test (COST) well (GE-1) drilled in 1977 that was followed by six industry exploration wells from 1979 to 1980. All wells were dry holes with no thermally mature source rocks sampled and five of the wells having reached metamorphosed Paleozoic basement. These drilling results (Core Laboratories, Inc., 1977; Smith, 1978) on the shallow water shelf led BOEM to conclude this area as unlikely to be prospective. However, greater sedimentary overburden and interpreted hydrocarbon migration from the BPB indicates prospectivity in the deepwater area of the BPB AU.

The analogs used for this play are the nearby South Florida Basin (SFB) (Pollastro et al., 2001) and the geologically similar Paris basin (PB) (Perrodon and Zabek, 1990; Wendebourg and Lamiroux, 2002). In the SFB, carbonate source rocks immediately underlie the carbonate reservoirs (Pollastro et al., 2001). Organic-rich, Early Jurassic black shales are the source rocks for overlying Late Jurassic carbonate and underlying Late Triassic siliciclastic reservoirs in the PB. Intraformational evaporites or impermeable carbonates (marls) typically provide local and regional seals in both analog basins. Characterized by low–moderate relief structures with relatively thin reservoir intervals, these stratigraphic and combination stratigraphic-structural traps are subtle and difficult to image seismically. Exploration success rates and reserves per discovery are low in both analog basins (Pollastro et al., 2001; Perrodon and Zabek, 1990). Drilling

Blake Plateau Basin (Jurassic–Cretaceous)

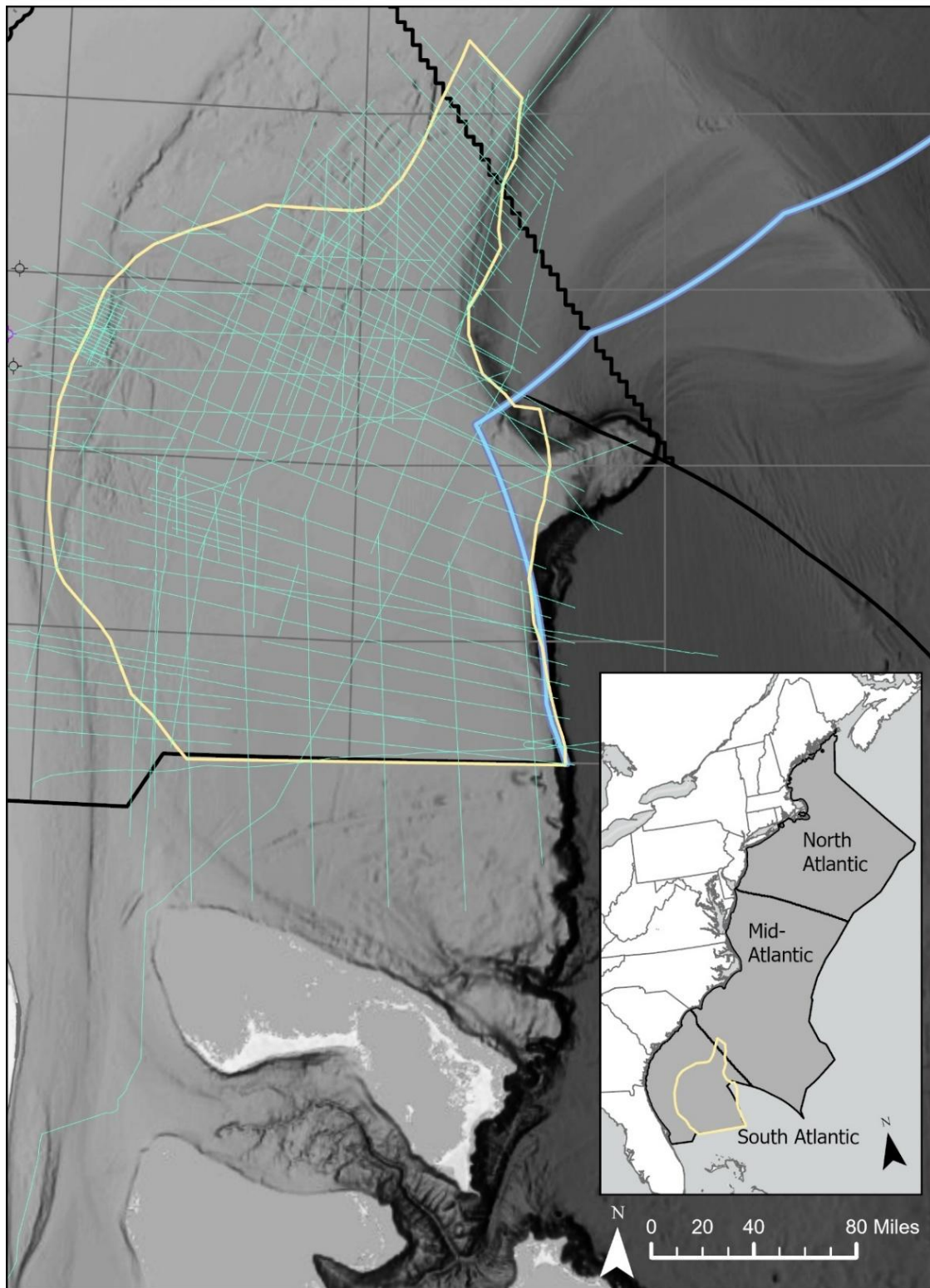


Figure 10. The Blake Plateau Basin (Jurassic–Cretaceous) is shown in a yellow outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

~1,100 exploration wells in the SFB and PB analogs resulted in 32 fields with reserves of >1 MMBOE, 10 fields of >10 MMBOE of reserves, and only 3 fields with >40 MMBOE (Florida Dept. of Environmental Protection, 2016; Wendebourg and Lamiroux, 2002).

FIS analysis on 518 cuttings samples in the COST GE-1 well from 1,020-13,230 ft (Tertiary – Paleozoic basement) revealed evidence for lateral migration of thermally mature hydrocarbon fluids in a prominent microseep in Lower Tertiary and Cretaceous samples (Fluid Inclusion Technologies, Inc., 2015f). This was further supported by microthermometric data and drillstem test (DST) fluids. Hydrocarbon inclusions and staining indicate multiple phases of charge, a dry thermogenic gas charge and multiple instances of oil charge. The aqueous inclusions in COST GE-1 have homogenization temperatures that are higher than present-day burial temperatures (Fluid Inclusion Technologies, Inc., 2015g) and anomalously high salinities caused by direct interaction of pore fluids with nearby evaporites, which were not seen in this well. Migration of fluids from deeper in the basin would explain both observations. Source rocks in the SFB and PB analogs contained anhydrite and minor salt stringers that formed in anoxic conditions that are also favorable to organic matter preservation. FIS from COST GE-1 measured low hydrocarbon indicators in the Paleozoic section from 11,120-13,230 ft. The well reached a TD of 13,254 ft in weakly metamorphosed units (Scholle, 1979) that were radiometrically dated as Devonian (Simonis, 1979). No Jurassic section was seen in the well. For additional information see BOEM's [2016 Atlantic Assessment](#) (BOEM, 2016).

The Blake Plateau Basin AU has the second largest acreage but also the second poorest pool density of the Atlantic plays ([Table 2](#)). Its 4.0% total chance of success is the fourth lowest ([Table 1](#)). Its UTRR is the second lowest with a mean of 192 MMBOE ([Table 3](#)). All but a few of its analogs had fields less than 20 MMBOE leading to a low upper limit for the pool distribution sizes used in the GRASP model.

3.6 SHELF STRATIGRAPHIC (JURASSIC) AU

Updip of the Carbonate Margin AU, the conceptual Shelf Stratigraphic AU ([Figure 11](#)) covers an area of ~7,700 mi² in water depths between ~200–2,600 ft. No wells have been drilled targeting stratigraphic traps within this play's area. The unsuccessful LC 410-1 was the only well within its extent and it was a GBB well targeting a structural closure of interpreted carbonate reservoirs. Trending along much of the North and Mid- Planning Areas, the AU is bisected by the Interior Shelf Structure AU.

Shelf Stratigraphic (Jurassic)

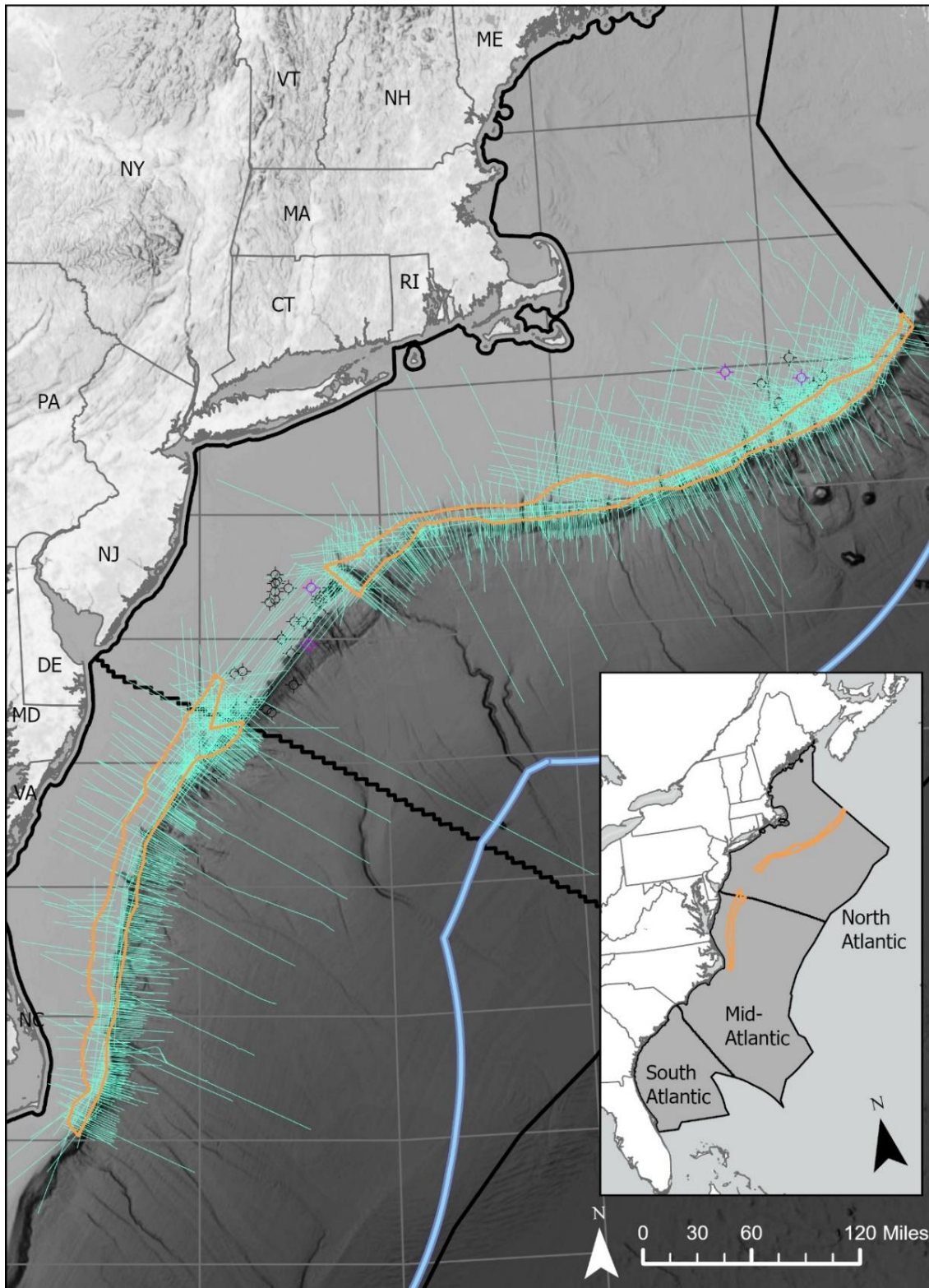


Figure 11. The Shelf Stratigraphic (Jurassic) is shown as two orange outlines. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

Anticipated reservoirs are limestones and/or dolomites similar to the onshore Gulf Coast analog fields, such as Walker Creek (Arkansas), Oaks (Louisiana), and Little Cedar Creek (Alabama). Although minor faulting may occur, the AU is considered primarily stratigraphic with reservoir facies defining and controlling hydrocarbon trapping. The presence of a viable source rock is considered probable but unproven as wells drilled along trend in the contiguous Interior Shelf Structure AU often lacked hydrocarbon shows. Throughout the onshore analog area, Oxfordian age laminated lime mudstones were confirmed as the source for Jurassic age paleo-shelf reservoirs (Sassen, 1990). In addition to possible intraformational source rocks typical of the analogs, deeper carbonate sources are also probable (Sassen and Post, 2008; Sassen, 2010). Trap seals are interpreted to be non-porous carbonate units with additional trapping from minor evaporite intervals or thicker evaporite units that overlie or are laterally adjacent to the reservoirs. Although available seismic data coverage lacks the frequency content to interpret these stratigraphic traps, some areas of interest can be identified on the vintage (1966-1988) data. Modern, deep-penetration seismic acquisition and processing would greatly improve imaging of the stratigraphy within these carbonate depositional environments. 3D seismic surveys would be a further improvement over 2D lines, increasing the odds of identifying prospects and direct hydrocarbon indicators (DHIs) such as amplitude “bright spots”.

The Jurassic Shelf Stratigraphic AU has a mean of 304 MMBOE ([Table 3](#)) due to a low 3.2% (second lowest in the Atlantic OCS) overall chance of success ([Table 1](#)) and a moderate areal size ([Table 2](#)). While the pool density is favorable ([Table 2](#)), the analog pool sizes are modest with most fields producing less than 20 MMBOE.

3.7 INTERIOR SHELF STRUCTURE (CRETACEOUS AND JURASSIC) AU

The proven Interior Shelf Structure AU ([Figure 12](#)) spans ~2,800 mi² within the BCT in water depths ranging from 150 to 3,000 ft. Mapped primarily in the North Atlantic Planning Area, a small portion extends south into the Mid- Planning Area.

The play is confined to an area of generally listric, down-to-the-basin faulting and associated compensating faults of the ‘Gemini Fault System’ (Poag, 1987). These faults provide migration conduits that facilitate the movement of hydrocarbons generated and expelled from interpreted Early–Middle Jurassic source rocks into structurally trapped, siliciclastic reservoirs of younger Jurassic and Cretaceous ages (Prather, 1991). The HC 598 condensates are enriched in diamondoids and ¹³C, showing similarities to condensates from laminated lime mudstone source rocks (Sassen and Post, 2008; Sassen, 2010). The Late Jurassic is interpreted as thermally immature, and a Triassic source is unlikely due to northeastern U.S. Triassic source rocks being depleted in ¹³C hydrocarbons. Satellite collected SAR data provide supporting evidence of a hydrocarbon source with dozens of sea-surface slicks within the play’s geographic extent, including seeps of third rank. Although rank 3 has the lowest confidence of the three rank classes, they remain more likely to represent natural seepage than those categorized as “other” (indeterminate) or “pollution” (known or suspected anthropogenic source).

Moderately explored with 14 exploration wells drilled between 1978 and 1981, this AU has a single gas-condensate discovery in the HC 598 area ([Figure 3](#)). This non-commercial discovery located on the largest structure of the Gemini Fault System was followed with seven appraisal wells within a four-block area. Cased hole DSTs were attempted through perforations on all eight wells with natural gas successfully tested in six. DSTs were typically after a mud cleanup acid treatment followed by a low-volume acid treatment to establish connectivity between the well bore and the formation. Late Jurassic zones tested at rates up to 18.9 million cubic feet of gas (MMCFG), while averaging ~5 MMCFG on variable chokes. Condensate yields average ~4 bbl per MMCFG at ~43° API. Rates were variable, often declining over time. Flow times ranged from 3 to 33 hours with an average of 13. A Late Cretaceous zone was also tested. The initial flow rate was calculated to be over 600 bbl of oil per day of 48° API oil, with the well depleting during testing. Molecular and isotopic properties of condensate samples from tested reservoirs show that the same or similar source rock provides the hydrocarbons for all reservoirs.

An unpublished BOEM analysis of the HC 598 area integrated seismic interpretation, petrophysical analysis and correlations of the wireline logs, mud gas shows, sidewall and conventional core data, and analysis of all test data. At least 70 reservoir compartments were identified. The DST results indicated that most tested intervals have very low permeability and/or have limited drainage areas implying poor continuity and limited communication between hydrocarbon zones. BOEM staff assigned a resource range between ~85 and ~254 billion cubic feet of gas equivalent (BCFGE), with a mean of ~160 BCFGE, for a first-phase development scenario using multi-laterals and fracs. Commerciality for the HC 598 area is currently considered unlikely due to multiple factors including the reservoir compartmentalization that would greatly limit production rates and increase development costs.

The discovery in the HC 598 area established this AU thereby removing the play risk. The remaining prospect risk is therefore equal to the total exploration risk ([Table 1](#)). Dry holes drilled in the other Gemini Fault System structures within similar trapping configurations contributed to a high prospect risk assigned to this AU. Important success factors for this play include the presence of anti-regional dip associated with the trap-forming faults, the timing of fault formation, the timing of hydrocarbon expulsion from deeper source rocks to younger reservoirs above, seal integrity, adequate porosity and permeability in the siliciclastic reservoirs, and sufficient trap volumes.

The Interior Shelf Structure AU ranks 7th in the Atlantic OCS for UTRR at 275 MMBOE ([Table 3](#)) due to its very small acreage ([Table 2](#)). Its pool density ([Table 2](#)) is average along with its analog pool distribution. Due to the favorable results at Hudson Canyon, it has a 10.8% overall chance of success ([Table 1](#)). The second highest of all the plays.

Interior Shelf Structure (Jurassic–Cretaceous)

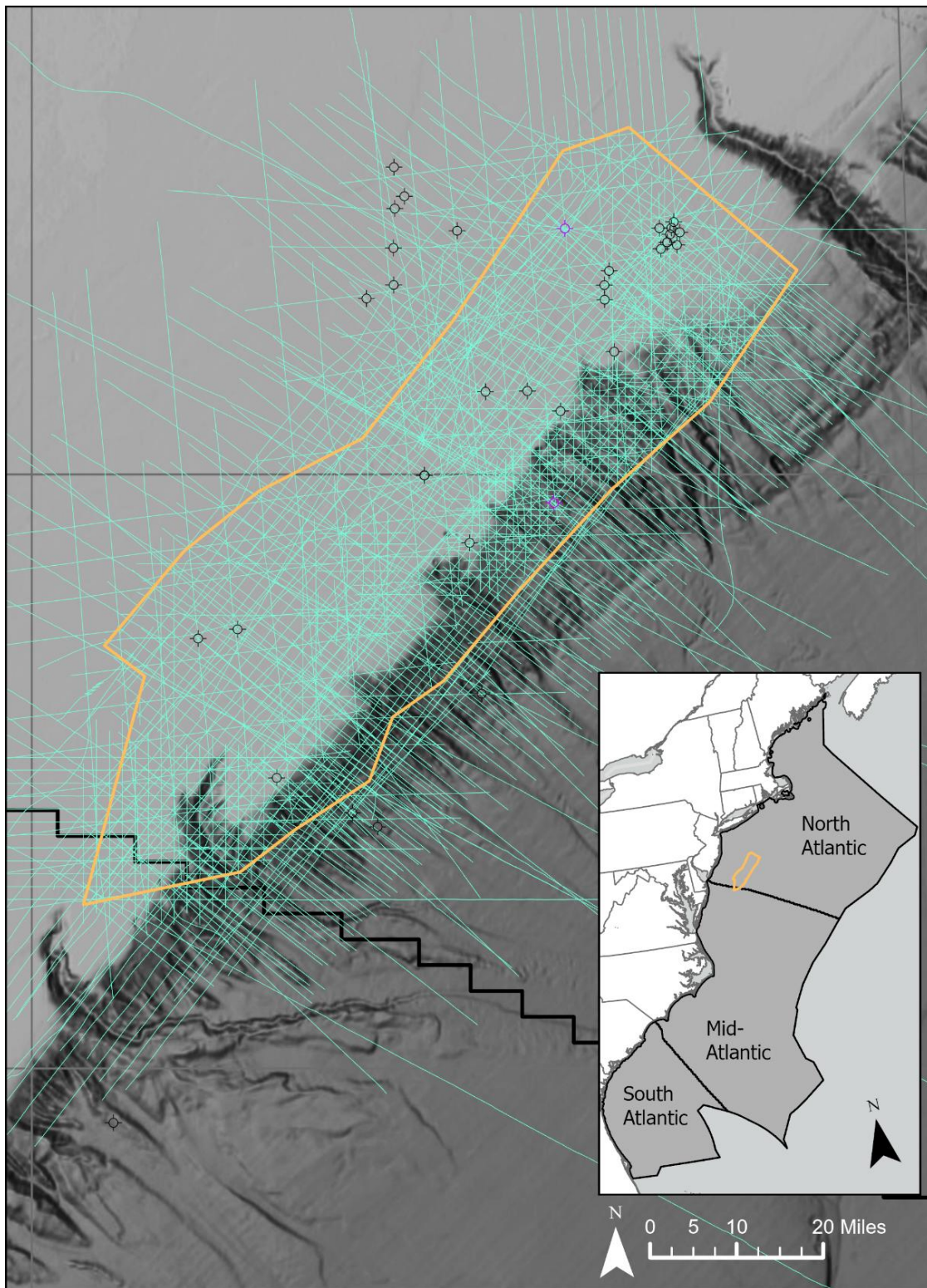


Figure 12. The Interior Shelf Structure (Jurassic–Cretaceous) is shown as a yellow outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

3.8 RIFT BASIN (TRIASSIC–JURASSIC) AU

The conceptual Rift Basin AU ([Figure 13](#)) is ~4,500 mi² within the North Atlantic Planning Area in water depths from ~150 to 800 ft. Truncated to the north-northeast by the U.S.–Canadian boundary, the play sits within the Yarmouth Basin and northern part of the GBB. Downdip is bounded by the Yarmouth Arch and updip by the Long Island Platform ([Figure 1](#)). Its area was last updated in 2016 when it was reduced significantly. Wells drilled in the area were too shallow to test this play, which remains untested.

At least 30, and possibly as many as another 20, Triassic–Jurassic rift basins were documented in the onshore Eastern U.S. Between 1890 and 1998, 80 wells were drilled for oil and gas exploration with some type of reported oil and/or gas show reported in 27 (34%) of the wells. No economic accumulations of conventional oil and gas or coalbed methane have been found (Coleman et al., 2015; Post and Coleman, 2015). At least seven undrilled basins and basin complexes (groups of subbasins), have been identified in the U.S. OCS (Post and Coleman, 2015).

Reprocessed, depth-converted, time-migrated deep-penetration reflection seismic data display rift-related, faulted structures primarily north of the GBB in the Yarmouth Basin (Schlee and Klitgord, 1988; Post and Coleman, 2015). Within the Yarmouth Basin is a late syn-rift to early post-rift sag basin, a broad, gentle depression formed as thermal subsidence outpaced waning rifting forces (Péron-Pinvidic et al., 2013). Whereas this AU's rift features are not always resolvable on available seismic, especially on lines that were not reprocessed, the sag phase strata were. Therefore, this sag basin was a proxy to better delineate the underlying Rift Basin AU. Originally the structure was referred to as the Yarmouth Sag (Schlee and Klitgord, 1981) as sag basins were not seen in the other offshore and onshore rift basins of the eastern U.S. (Coleman et al., 2015; Post and Coleman, 2015).

During drifting, asymmetric spreading rates lead to contractional forces on lithospheric blocks at local and regional scales. This stress resulted in basin inversion along with concurrent and/or subsequent erosion of the uppermost (youngest) syn-rift strata in all onshore (Withjack et al., 2012) and offshore (Post and Coleman, 2015) eastern U.S. rift basins. Work from Macgregor (1995) assessing 105 rift basins found that discovery success had much better odds (92% vs 62%) and located bigger fields for locally inverted vs regionally inverted. The drilled onshore rift basins, which were regionally inverted, had an estimated average of ~10,000 ft of late syn-rift material eroded (Post and Coleman, 2015; Malinconico, 2002; Steckler et al., 1993; Pratt et al., 1988). The Rift Basin AU is interpreted to be a locally inverted rift, based in part on its preserved sag phase strata, with much less uplift and erosion (Coleman et al., 2015; Post and Coleman, 2015). Seal fracturing and reservoir removal are therefore interpreted to be important factors for success in these rift basins. Sediment preservation could be the difference between the previously drilled rifts which had petroleum system elements and processes but no commercial discoveries, and an established play.

Rift Basin (Triassic–Jurassic)

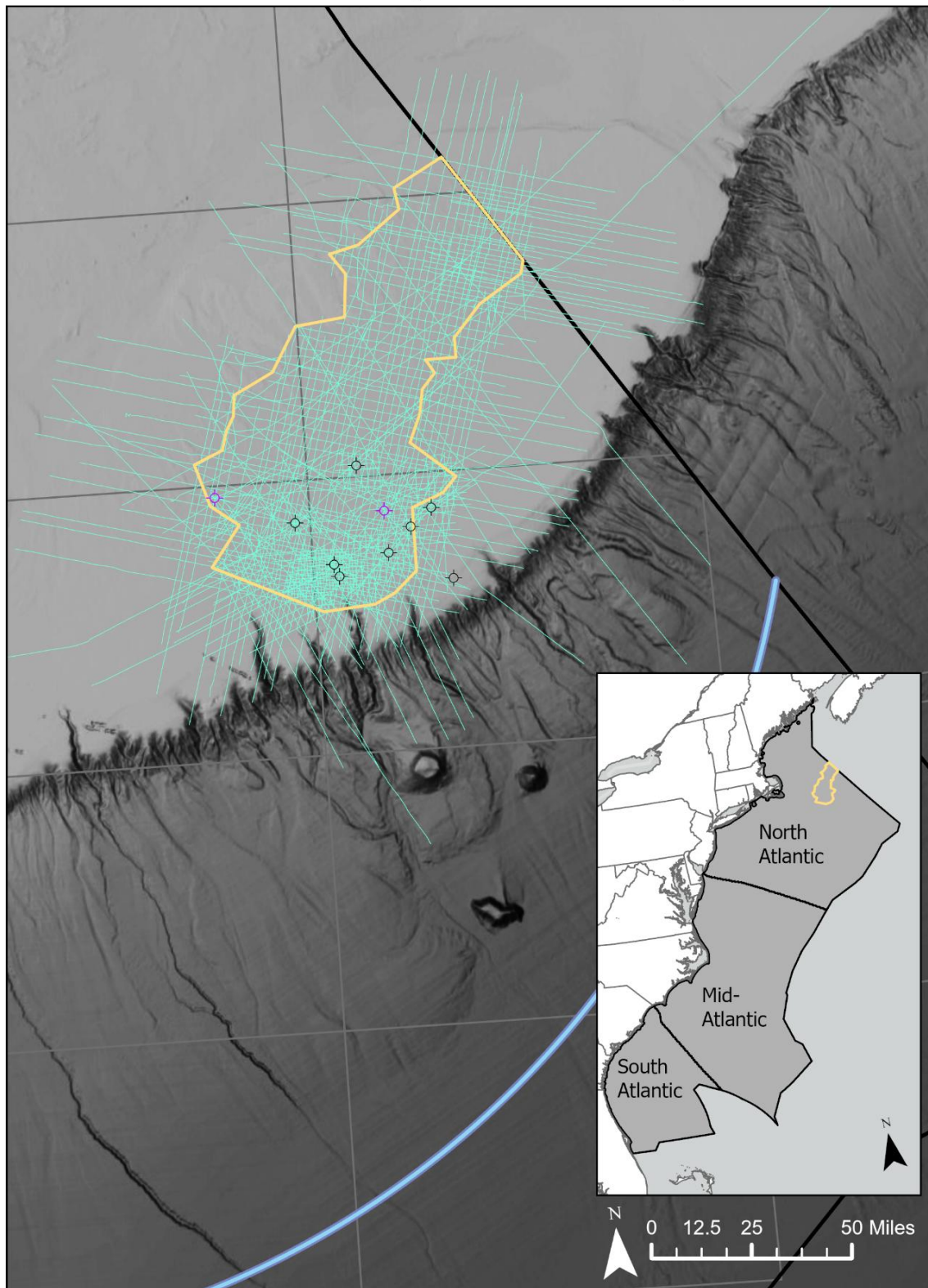


Figure 13. The Rift Basin (Triassic–Jurassic) AU is shown in a light orange outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

One-dimensional geohistory modeling using integrated subsurface well data and seismic interpretation, along with typical richness inputs for expected source types, forecast a phase of hydrocarbon generation and expulsion after sag strata deposition and thus more likely to have been preserved. Source rocks are also inferred from SAR sea-surface slicks seen within the Yarmouth Basin.

The world's giant (>500 MMBOE) fields are frequently, 31% occurrence, found in rifts and their overlying sag basins (Mann et al., 2003). Their narrow, deep architecture with high subsidence and sedimentation rates is partly responsible for their outsized contribution to petroleum resources (Katz, 1995). Rifts with post-rift sag basins and marine-dominant strata, like the Rift Basin AU, are commonly prospective and more prolific than those without. This is due to a high potential for source rocks and seals within the post-rift strata, especially within marine depositional environments (Lambiase and Morely, 1999; Schwarz and Wood, 2016). Based on data from Mann et al. (2003) most rift reservoirs are clastic with fluvial, shoreline, and deltaic facies being dominant (Schwarz and Wood, 2016).

Analogues for the Rift Basin AU include the Vulcan Graben offshore NW Australia, the Viking Graben of the North Sea, and the West Natuna basin, Indonesia. The Vulcan Graben has Triassic and Jurassic siliciclastic reservoirs within complex rift-related structures. Field production and/or reserves range between ~2 and 300 MMBOE per field/discovery (Geoscience Australia, 2008). In the Viking Graben, Early–Middle Jurassic sandstone reservoirs in rift-related, faulted structural traps were charged by pre-rift sources (Gautier, 2005). Analog fields' production ranges had a wide distribution (NSTA, 2020). Combined with the fields from the Vulcan Graben, a broad pool distribution populated the GRASP model for the Rift Basin AU. In West Natuna inversion structures with estimate reserves ranging from ~1–2.4 BBOE, with the largest field having ~400 MMBOE, are structurally analogous to the Rift Basin AU. Underlain by a ductile shale, the inversion structures are similar to the Rift Basin AU structures which are cored by unknown ductile strata (Howes and Tisnawijaya, 1995; Howes, 1997; Manur and Jacques, 2014). However, due to significant differences in reservoir age, depth of burial, and petrophysical characteristics, especially permeability, these fields weren't used in the pool distribution for the GRASP model.

USGS updated their onshore oil and gas assessment in 2025 (Schenk et al., 2025). Onshore rift basins are located within their Atlantic Coastal Plain Province with a UTRR mean of 175.6 BCFG and 7.8 million barrels of natural gas liquids (MMBNGL) and their Piedmont Province with a resource mean of 20.3 BCFG. The amount of UTRRs that were attributed to rift basin play types was not specified. An earlier 2015 assessment on 13 of the onshore Atlantic rift basins estimated a mean undiscovered natural gas resource of 3.86 Tcf and 135 MMBNGL. These were, however, interpreted to exist in continuous or unconventional accumulations (Coleman et al., 2015). This 2026 Atlantic OCS assessment does not assess unconventional resources.

The Rift Basin AU has a mean of 249 MMBOE ([Table 3](#)) due to its smaller acreage and below average pool density ([Table 2](#)). The overall chance of success is good for the Atlantic OCS at 8.5% ([Table 1](#)). Its analogues include large fields leading to a good pool distribution with most pools over

10 MMBOE and many over 100 MMBOE. Modern 3D seismic with attribute analysis and seismic geomorphologic techniques could help identify prospects for this prospective play.

3.9 HYDROTHERMAL DOLOMITE (JURASSIC–CRETACEOUS) AU

Located in the North Atlantic Planning Area, the conceptual Hydrothermal Dolomite AU ([Figure 14](#)) has an area of ~1,700 mi² in water depths ranging from ~100 to 1,100 ft. Its area was last updated in 2016 when it was reduced significantly. Associated with the Yarmouth arch and downdip of the Rift Basin AU, the play is truncated to the northeast by the U.S.–Canadian border ([Figure 1](#)). The Yarmouth Arch is a significant structural element and is likely related to the assembly of Pangea and its subsequent breakup (Pe-Piper et al., 2010). A buried complex of several north-northeast-trending blocks, this topographically and structurally positive feature formed early, limiting communication between the Shelburne subbasin of the Scotian Basin and the GBB (Wade, 1990; Deptuck et al., 2015) ([Figure 1](#)). The arch, a segmented horst block, is likely composed of Early Paleozoic metasedimentary rocks of the Meguma Supergroup with intruded Devonian age granites, whose interpretation is supported by a strong positive magnetic anomaly (CNSOPB, 2015).

As noted earlier in this report, the lithology of the ductile strata coring the inversion structures in the Rift Basin AU is unknown (Post and Coleman, 2015). With no other evidence of potential evaporites, the presence and volume of salt remain speculative. However, east of the Yarmouth Arch, in the Scotian Basin, there are allochthonous and autochthonous salt structures ([Figure 1](#)) (Wade, 1990; and Deptuck et al., 2015). BOEM interprets the Yarmouth Arch as a divide between salt-poor depocenters on the southwest (the GBB and Yarmouth Basin) from salt-rich basins and subbasins offshore Nova Scotia on the northeast. Early(?) Jurassic and early Middle Jurassic strata pinch out on the flanks of the arch (Wade, 1990). During the Early and Middle Jurassic, the arch separated carbonate-rich strata of the GBB from predominantly siliciclastic units of the Scotian Basin (Wade, 1990). The influence of the arch diminishes later in the Jurassic, maintaining a mild influence on younger units seen in stratigraphic thicknesses, facies changes, and erosional patterns.

Because the AU has not been tested, the petroleum system elements and processes are speculative. The petroleum system may have similarities to some of the elements present in the wells drilled in the GBB. Although source rocks have not been directly confirmed, satellite-identified, sea-surface slicks occur in this AU, including a seepage slick third rank (NPA, 2018). This and the other slicks of lower confidence (priority unassigned ranking) suggest that source rocks, and generation–expulsion–migration may have occurred, or may be occurring. Reservoirs in the Hydrothermal Dolomite AU may have formed by hydrothermal dolomitization associated with the upward circulation of deeper, hotter fluids along fault systems. These fluids would have altered the limestone host rock to dolostone (dolomite), thereby reducing the rock volume, enhancing intercrystalline porosity, and forming sags associated with stratigraphic and structural traps. Albion-Scipio, the largest oil field in the Michigan basin, and similar fields in the Michigan

Hydrothermal Dolomite (Jurassic–Cretaceous)

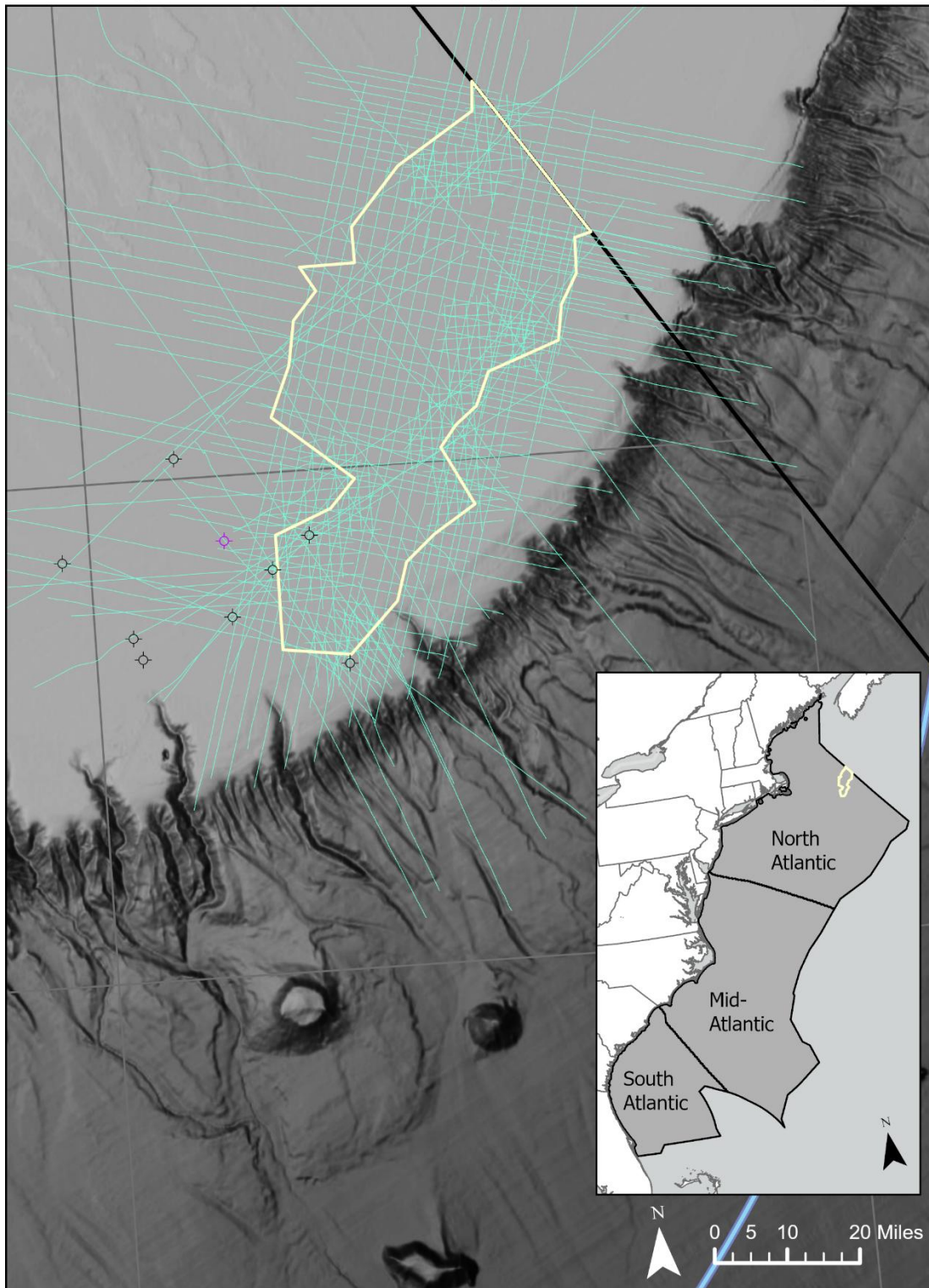


Figure 14. The Hydrothermal Dolomite (Jurassic–Cretaceous) AU is shown in a dark yellow outline. The inset map is a simplified image showing the AU location at a scale of the entire OCS. Other cartographic elements are as labeled in earlier figures.

and Appalachian basins, are considered analogs for this AU. The hydrocarbon seal in these plays is typically limestone that has not been dolomitized or a "tite" caliche zone (Davies and Smith, 2006; and references therein). Reserves for analog fields for this AU range from less than 1 MMBOE to 500 MMBOE. Total reserves established in all analog fields appear to be nearly 1 BBOE. Data sources were developed using extrapolations of annual production data from the New York State Department of Environmental Conservation, the Michigan Department of Environmental Quality, and various historical data sources. Swezey et al. (2015) assessed undiscovered resources in the analog Michigan basin area at mean values of 723 million barrels of oil (MMbbl), ~2 Tcf of gas, and ~110 MMBNGL.

The Hydrothermal Dolomite AU has the lowest UTRR of the Atlantic plays with a mean of 67 MMBOE ([Table 3](#)) due to it having the smallest acreage, poor-average pool density ([Table 2](#)), and a low chance of overall success ([Table 1](#)). The analog field sizes that populated the pool distribution model were moderate but the low number of mean pools ([Table 2](#)) greatly limited play prospectivity.

4.0 UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES

Undiscovered resources are resources postulated, based on geologic knowledge and theory, to exist outside of known fields or accumulations. Estimates of undiscovered recoverable resources for the U.S. Atlantic OCS are presented in two categories: technically recoverable (UTRR) and the economically recoverable (UERR). Technically recoverable resources are those that can be recovered from the subsurface with conventional extraction techniques; that is, technology whose usage is considered common practice. Technically recoverable resources include moderate- to high-gravity crude oil, condensate, and gas, but do not include low-gravity "heavy" oil, oil shale, shale gas, and gas hydrates. Economic viability is not considered for UTRR.

UTRR values for individual AUs are shown in [Table 3](#) with 95th and 5th percentiles, and the mean. The 95th and 5th are considered reasonable minimum and maximum values; the mean is the average or expected value. Estimates of the UTRR for oil on the U.S. Atlantic OCS range from 0.539 Bbbl at the 95th to 11.070 Bbbl at the 5th with a mean of 4.498 billion barrels (Bbbl) ([Table 3](#)). Estimates of the total gas endowment range from 3.403 to 78.302 Tcf with a mean of 34.355 Tcf. The AUs in the Atlantic OCS are ranked by mean UTRR in BBOE in [Figure 15](#). The concentration of resources in select AUs, often in deepwater, becomes apparent in this column graph. The top 2 AUs (Core and CTSB) have nearly two-thirds (59.2%) of the mean BOE.

[Table 4](#) reports UTRR values by planning area and water depth for the 95th and 5th percentiles, and the mean. Resources are concentrated in the Mid- with 61.5% of mean BOE, in part due to its larger size. The Mid- has twice the area of the South and is a fifth larger than the North. This corresponds to 42.1% of the AU acreage in the Mid-, 30.0% in the North, and 27.9% in the South. The South has just 3.9% of mean resources, the North 34.6%. Hydrocarbon ratios are split with oil constituting 42.4% of the Atlantic's mean BOE.

[Figure 16](#) highlights the minor AU acreage located shoreward of the 200 m bathymetry. The 200 m and 800 m isobaths were selected due to economic considerations related to the UERR. Of the shallower water acreage (<200 m), most is within the North and none in the South. Correspondingly, just 8.1% of the total mean BOE is interpreted in <200 m water depth, of which 62.1% are in the North. Nearly 80% of the Atlantic OCS AU acreage and 80.1% of their mean UTRR are in water depths >800 m ([Figure 16](#) and [Table 4](#)). While the entire Atlantic OCS was evaluated for hydrocarbons, areas outside of the AUs were not interpreted as prospective and therefore were not modeled in GRASP.

[Figure 17](#) shows the percentage of mean UTRR within each of the 3 water depth zones from 5 assessment reports. These numbers are for the entire Atlantic OCS and include all 10 AUs and the 3 planning areas. The prominent trend is the increasing percentage of >800 m water depth resources at the expense of the 2 shallower water zones. Technology advances have enabled the exploration and discovery of deepwater and ultra-deepwater resources in the analogs that have influenced the Atlantic play models. The steep change between the 2000 and 2011 assessments corresponds to the new Atlantic AUs that replaced the previous Atlantic plays.

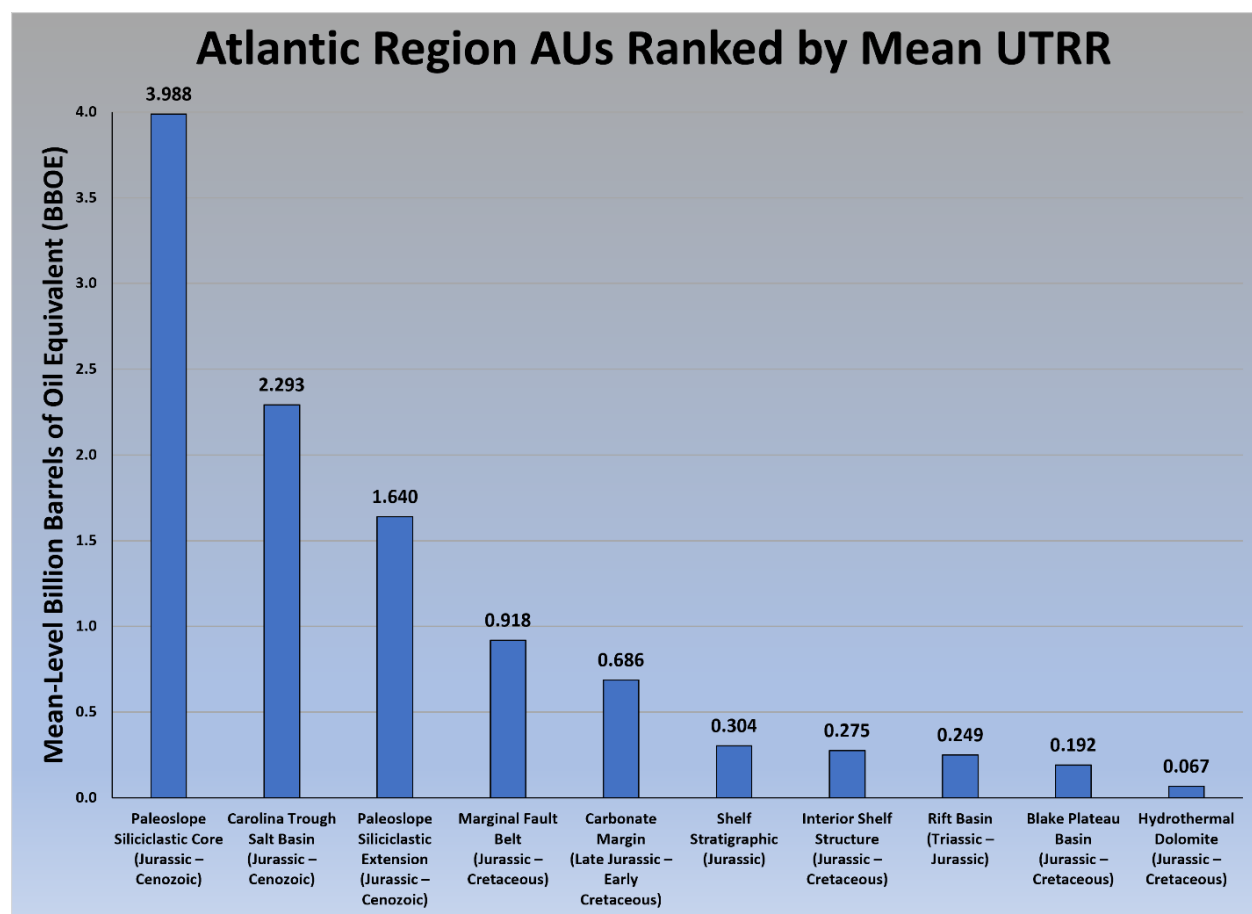


Figure 15. Atlantic OCS AUs ranked by mean UTRR.

Region Planning Area Water Depth (m)	2026 Undiscovered Technically Recoverable Resources								
	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Total Atlantic OCS	0.539	4.498	11.070	3.403	34.355	78.302	1.145	10.611	25.003
0-200	0.034	0.361	0.923	0.577	2.786	5.592	0.137	0.857	1.918
200-800	0.040	0.452	0.976	0.443	4.529	10.285	0.119	1.258	2.806
>800	0.008	3.684	9.877	0.097	27.039	68.719	0.025	8.496	22.105
North Atlantic	0.060	1.647	4.982	0.979	11.407	31.882	0.235	3.676	10.655
0-200	0.027	0.258	0.827	0.410	1.540	3.203	0.100	0.532	1.397
200-800	0.019	0.146	0.312	0.286	1.544	3.448	0.070	0.421	0.926
>800	0.000	1.243	4.292	0.000	8.323	28.418	0.000	2.724	9.349
Mid Atlantic	0.013	2.650	6.141	0.062	21.772	48.348	0.024	6.524	14.744
0-200	0.001	0.104	0.303	0.015	1.246	3.538	0.004	0.326	0.932
200-800	0.001	0.266	0.714	0.012	2.878	7.732	0.003	0.778	2.090
>800	0.002	2.281	5.552	0.017	17.648	41.761	0.005	5.421	12.983
South Atlantic	0.000	0.201	0.651	0.000	1.175	3.009	0.000	0.410	1.187
0-200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
200-800	0.000	0.041	0.189	0.000	0.108	0.497	0.000	0.060	0.278
>800	0.000	0.160	0.471	0.286	1.067	3.448	0.000	0.350	0.978

Table 4. UTRR by planning area and water depth. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

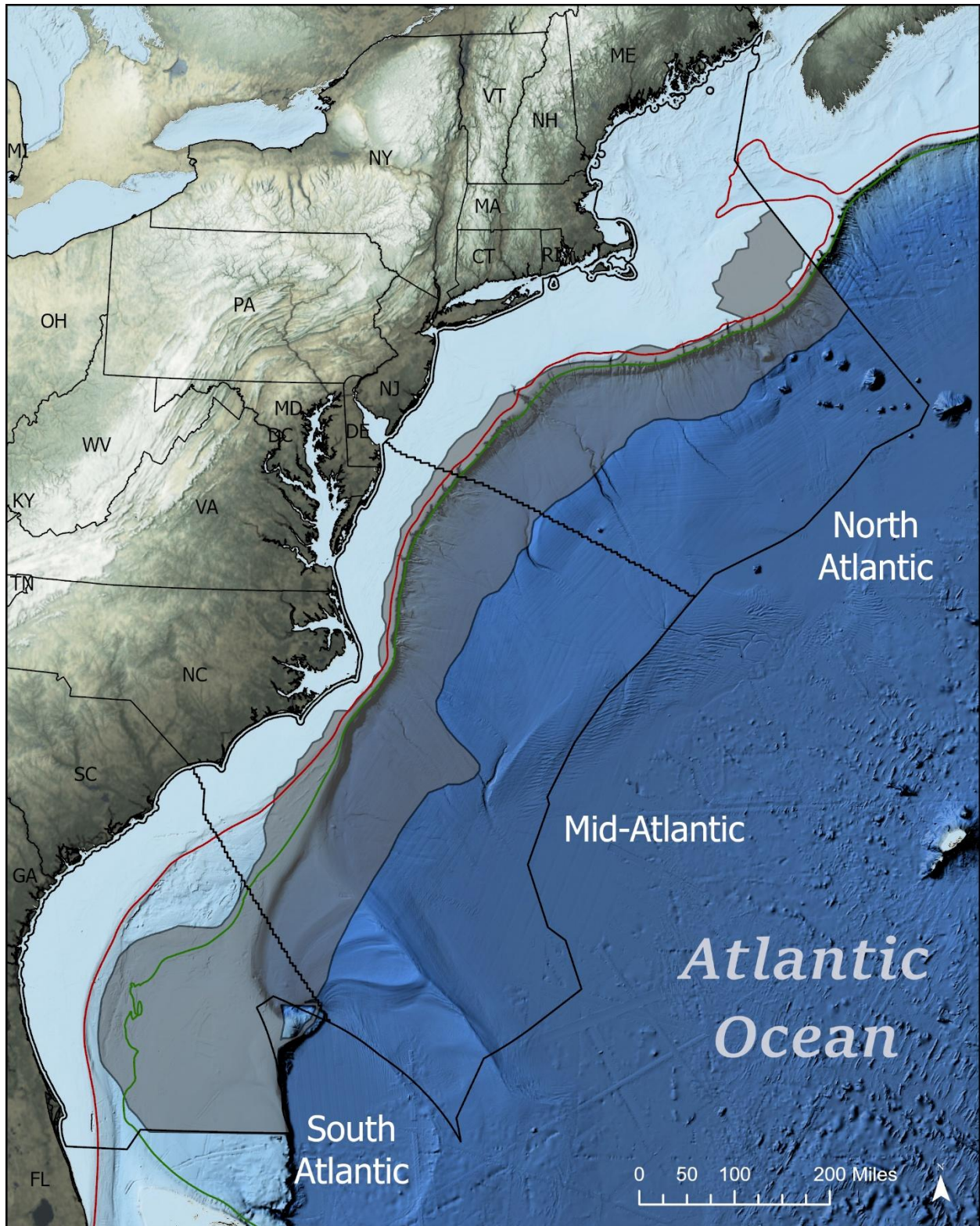


Figure 16. The 200 m (red) and 800 m (green) isobaths for the U.S. Atlantic OCS overlain on the collective assessment area (gray polygon) representing all combined acreage from the 10 AUs. Isobaths were created from GEBCO 2021 gridded bathymetric dataset (GEBCO, 2021). Other cartographic elements are labeled as in previous figures.

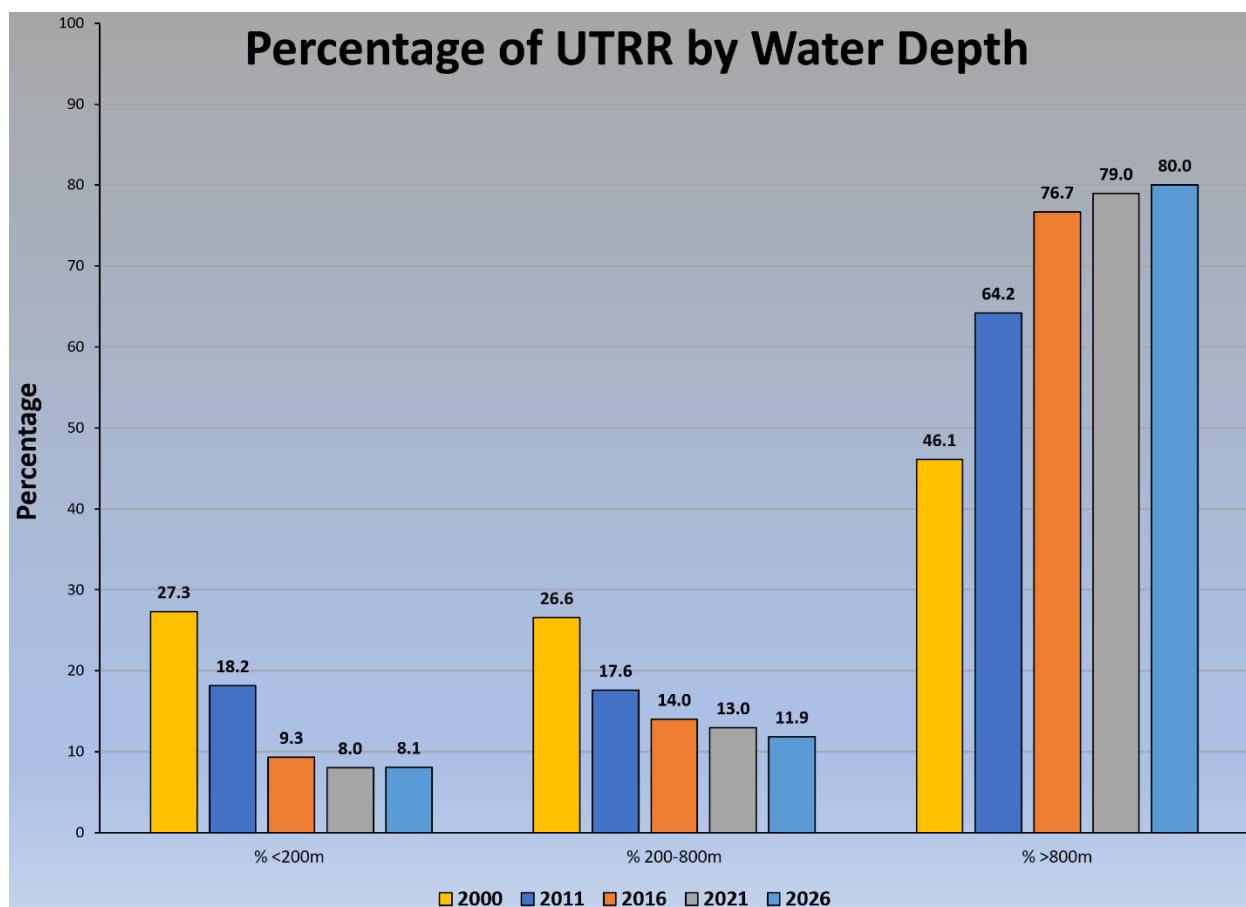


Figure 17. Percentage of UTRR in shallow, deep, and ultra-deepwater for 5 Atlantic assessments. See [Appendix C](#) for additional UTRR data from past assessments.

5.0 UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES

The BOEM GRASP model utilizes various distribution files focused on four main economic and engineering components to estimate UERR. The distributions from these four components are applied to UTRR to develop an estimate of economically recoverable resources. GRASP uses selected engineering parameters and oil and gas price pairs to calculate a net present value of an undiscovered pool. The four main components are:

- Engineering assumptions;
- Costs of exploration and production;
- Scheduling of design, fabrication and installation of infrastructure; and
- Distributions of oil and gas price pairs.

To account for variations in the economic value of gas relative to oil, BOEM applies oil and gas price pairs at different gas market adjustments. For the 2026 assessment, six different British thermal units (BTU)-based gas price adjustments were analyzed. In these adjustments, the oil

price remains the same while the gas price is set at values of 20, 30, 40, 60, 80 and 100 percent of its market value relative to oil. This is updated from the 2021 Assessment, which used five gas price adjustments. Both assessments report a 0.3 gas market adjustment. For the 2026 assessment of UERR, BOEM assessed 50 different oil and gas price pairs across all six gas price adjustments. The oil price was in increments between \$30 and \$210 per barrel. Five (5) representative price pairs at the 0.3 gas market value adjustment are reported in [Figure 18](#).

Major inputs affecting UERR are the UTRR, the size of the pools in the distribution, the water depth, and the distance from shore. The Atlantic is a frontier basin with no oil and gas infrastructure and a vast majority of resources in deep and ultra-deepwater located far from shore. [Figure 18](#) and [Table 5](#) show that a majority of mean UTRR are projected to be uneconomic across the reported prices pairs, with the exception being at \$160/bbl when 54.5% is economic. At the lowest price pair reported (\$30/bbl) in [Figure 18](#), only 13.3% of resources would be economic. Compared to the U.S. GOA where oil and gas infrastructure and facilities are established, 72% of the mean UTRR become economic at the \$160 price pair and 40% at \$40 price pair. (BOEM, 2026b).

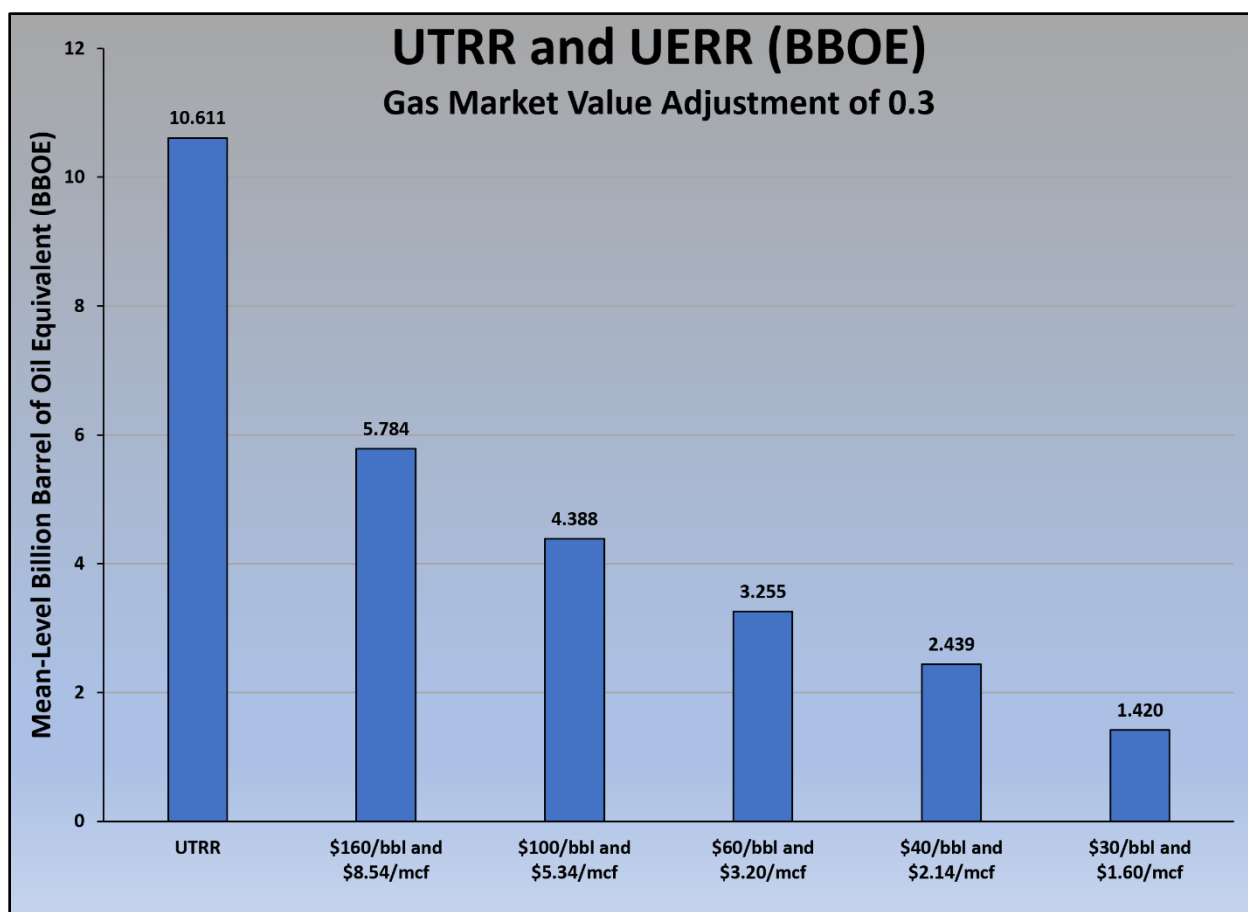


Figure 18. Portions of mean UTRR that are economic under five price pairs for the Atlantic OCS.

[Figure 19](#) highlights the expected resources at both the UTRR and the UERR for 5 price pairs for each planning area. The North Atlantic Planning Area is modeled to have the best economics associated with its resources as 25.7%, 46.7%, and 57.9% of mean BOE are economic at the \$40, \$100, and \$160 price pairs respectively. The South Atlantic Planning Area is the least economic with 5.4%, 14.1%, and 21.0% of mean BOE at these same price pairs. The Mid- is in the middle with 22.6%, 40.0%, and 54.7% of mean BOE at these same price pairs. However, given its much larger mean UTRR, the Mid- generates the largest mean UERR for each price point in BOEM's model ([Figure 19](#) and [Table 5](#)).

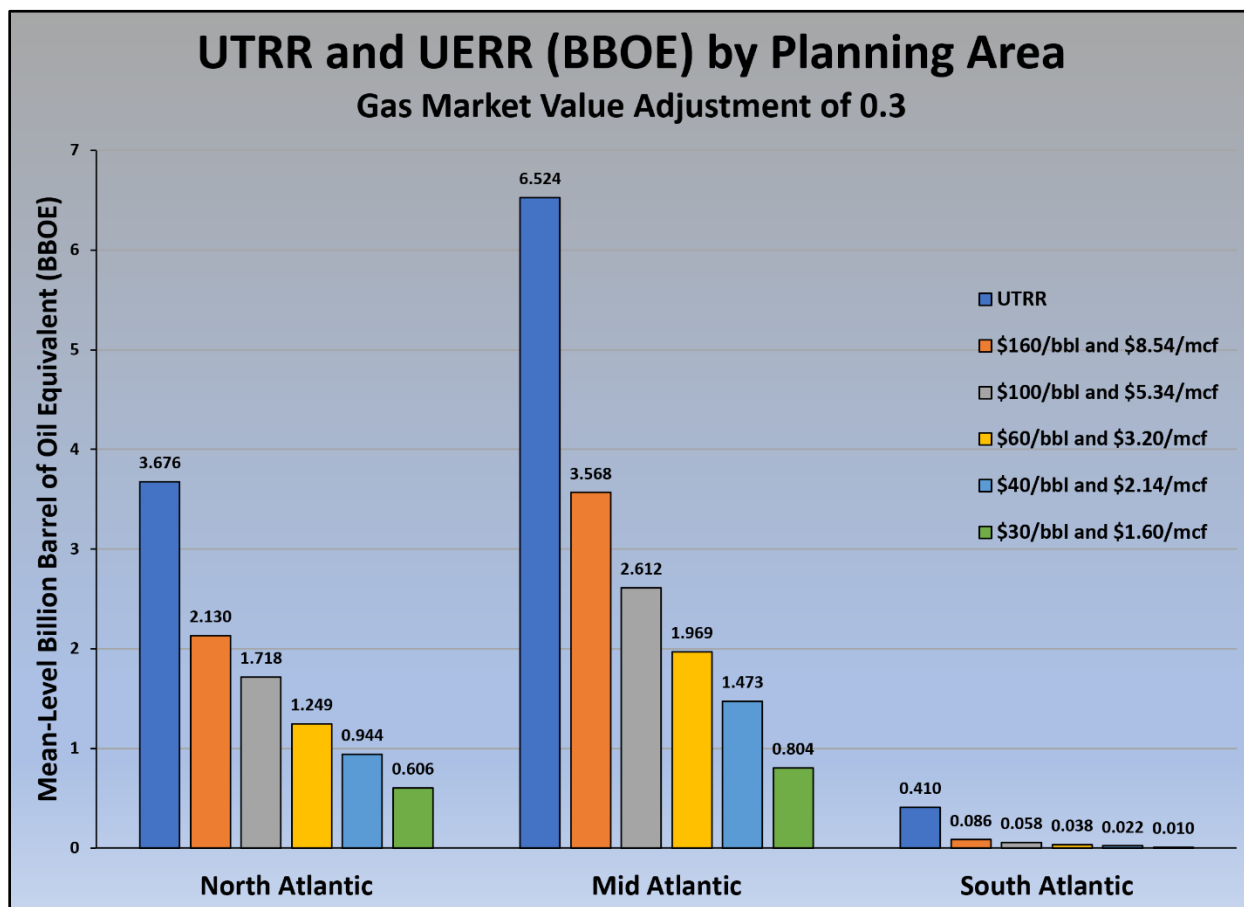


Figure 19. Portions of mean UTRR that are economic under five price pairs for each planning area.

Region	2026 Undiscovered Economically Recoverable Resources (UERR) at the Mean-Level															
	Gas Market Value Adjustment of 0.3															
	Planning Area Water Depth (m)	\$30/bbl and \$1.60/mcf			\$40/bbl and \$2.14/mcf			\$60/bbl and \$3.20/mcf			\$100/bbl and \$5.34/mcf			\$160/bbl and \$8.54/mcf		
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 Atlantic OCS	1.165	1.430	1.420	2.002	2.457	2.439	2.667	3.308	3.255	3.123	7.113	4.388	3.439	13.180	5.784	
0-200	0.043	0.052	0.052	0.116	0.142	0.141	0.192	0.236	0.234	0.238	0.308	0.293	0.258	0.408	0.330	
200-800	0.058	0.072	0.071	0.121	0.149	0.148	0.188	0.233	0.229	0.243	0.463	0.325	0.276	0.781	0.415	
>800	1.064	1.306	1.297	1.765	2.166	2.151	2.287	2.840	2.792	2.642	6.342	3.770	2.905	11.991	5.038	
North Atlantic	0.497	0.610	0.606	0.775	0.950	0.944	1.022	1.273	1.249	1.200	2.912	1.718	1.304	4.645	2.130	
0-200	0.038	0.047	0.047	0.095	0.116	0.115	0.153	0.188	0.187	0.185	0.237	0.227	0.197	0.277	0.247	
200-800	0.021	0.026	0.026	0.035	0.043	0.043	0.058	0.072	0.071	0.080	0.155	0.108	0.092	0.225	0.132	
>800	0.438	0.537	0.533	0.645	0.791	0.786	0.811	1.013	0.991	0.935	2.521	1.383	1.015	4.143	1.752	
Mid Atlantic	0.660	0.810	0.804	1.209	1.484	1.473	1.614	1.997	1.969	1.876	4.138	2.612	2.070	8.417	3.568	
0-200	0.004	0.005	0.005	0.021	0.026	0.026	0.039	0.048	0.047	0.053	0.071	0.066	0.060	0.132	0.084	
200-800	0.037	0.046	0.046	0.086	0.106	0.105	0.129	0.160	0.158	0.161	0.306	0.216	0.179	0.549	0.277	
>800	0.618	0.758	0.753	1.102	1.352	1.343	1.445	1.789	1.764	1.662	3.761	2.331	1.831	7.736	3.207	
South Atlantic	0.008	0.010	0.010	0.018	0.022	0.022	0.031	0.038	0.038	0.047	0.063	0.058	0.065	0.118	0.086	
0-200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
200-800	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.002	0.005	0.007	0.007	
>800	0.008	0.010	0.010	0.018	0.022	0.022	0.031	0.038	0.038	0.045	0.061	0.056	0.059	0.112	0.079	

Table 5. UERR by planning area and water depth. The gas market value adjustment is 0.3. Some total values may not equal the sum of the component values due to independent rounding.

6.0 UNASSESSED RESOURCES

Known gas deposits, hypothesized to be mostly biogenic methane, are abundant within shallow sediments of the Atlantic OCS. BOEM's 2013 assessment estimated a mean of 21.7 Tcf of gas trapped within gas hydrates, a type of clathrate, on the deepwater slope of the Atlantic OCS (Frye et al., 2013). These gas hydrates are an unconventional resource and have been modeled from bottom simulating reflectors (BSRs) interpreted on 2D seismic data ([Figure 20](#)) (Frye et al., 2013; Majumdar et al., 2022; Ruppel et al., 2022). BSRs delineate the base of gas hydrates, which is also the top of pore space-filled free gas (vapor phase) if present. Potentially trillions of additional cubic feet of gas, while unassessed, are thought to be trapped in shallow unconsolidated sediments beneath the hydrate cap. Bright amplitudes terminating at the BSR can be seen on legacy 2D seismic data as well as on the 2018 Mid-Atlantic Resource Imaging Experiment (MATRIX) dataset. Ruppel et al. (2022) interpreted direct gas charging on seismic line PR82-167 ([Figure 20](#)) seen as a bright amplitude below a BSR. More direct evidence for gas hydrates and underlying free gas comes from core and geochemical data at DSDP Leg 76 well site 533 and DSDP Leg 11 well sites 102, 103, and 104 (Kvenvolden and Barnard, 1983), and ODP Leg 164 well sites 995, 995, and 997 (Paull et al., 1996) ([Figure 3](#)). ODP Leg 164 well sites 995 and 997 also had vertical seismic profiles that indicated free gas below the BSR (Holbrook et al., 1996).

Additional BSRs may be undiscovered as seismic coverage is sparse on the deepwater slope, and confident BSR identification relies on uncommon high frequency seismic acquired under specific parameters. Moreover, not all gas hydrates have a BSR (Paull et al., 1996; Majumdar et al., 2022; Ruppel et al., 2022). Majumdar et al. (2022) applied a trained neural net to the MATRIX survey, a 2D seismic dataset of ~1,200-line miles collected with acquisition and processing parameters optimized for identifying BSRs and other seismic indicators of gas ([Figure 20](#)). Results from this model expanded the area of potential gas hydrates (Majumdar et al., 2022).

A 2024 seep inventory update using multibeam echosounder and water column imaging data brought the number of confirmed gas seeps to 1,139 distinct sites ([Figure 20](#)). Located on the shelf and upper slope, this is a minimum as large areas have not been surveyed. A 2014 study identified 570 unique sites and prior to that only 3 seeps were known seaward of the shelf break (Sharke et al., 2014). These studies highlight both their abundance and the effects of data limitations on accurate estimates. The seeps are interpreted to have been long-lived with various forms of slope failure seen in Miocene and possibly older intervals (Ruppel et al., 2024; and references therein). Some individual seeps are interpreted to be >1,000 years based on the thickness and formation rate of the authigenic carbonate present (Sharke et al., 2014). Other evidence of hydrocarbon gas is the large-scale, elongated expulsion features visible on high resolution bathymetry over the continental shelf (Hill et al., 2004).

Abundant gas hydrates and seeps are positive indicators of deeper conventional resources. The enduring underlying geology has maintained a similar onshore river network for much of the Atlantic margin's history that has and continues to transport significant organic content. This

material feeds the methanogenic bacteria even in deepwater environments 200+ miles from shore. Trapped gas under authigenic carbonate caps or within the bathymetric benches as described by Ruppel et al. (2024), could form conventional resources as they become more deeply buried over time. Additionally, organic content deposited during periods of regional or global anoxia, like during oceanic anoxic events (OAEs), could also provide source material for Atlantic petroleum systems. Shallow gas estimates based on the current data would likely increase with additional seismic and well data.

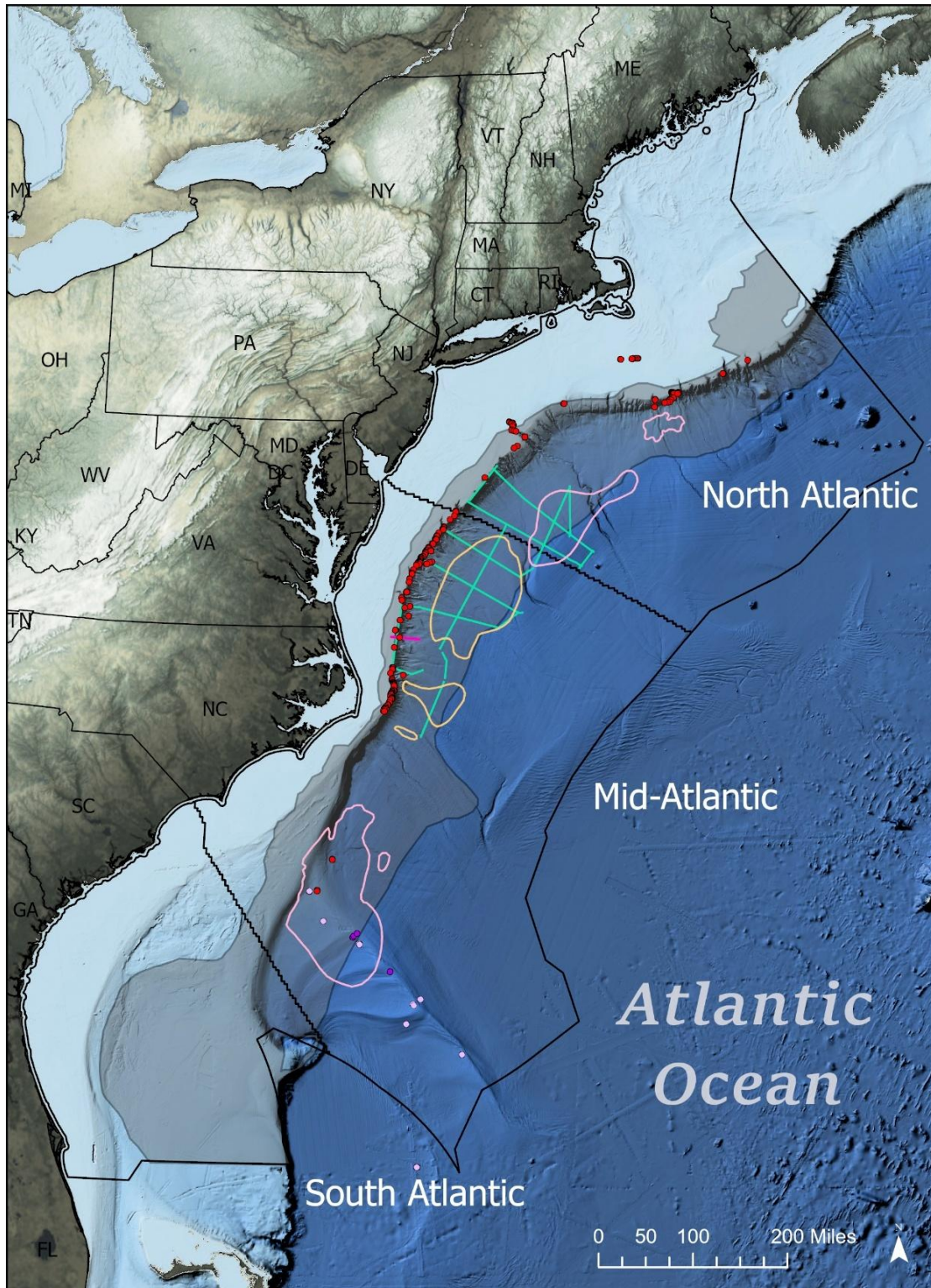


Figure 20. Map of BSRs, gas seeps, and select seismic lines and research wells. Clusters of methane seeps are red circles. Purple circles are DSDP and ODP wells that confirmed gas hydrates. Light purple circles are DSDP and ODP wells that indicated the possible presence of gas hydrates. Pink polygons are the areas where BSRs are interpreted. Yellow polygons are the areas where possible BSRs are interpreted. Green lines are the MATRIX seismic survey. The short, bright pink line is the PR82-167 seismic line. Other cartographic elements are labeled as in previous figures.

7.0 ACKNOWLEDGEMENTS

This report was built largely on the 2016 Atlantic Assessment and the work of the late Paul Post and the 2016 team he helped lead. Their efforts advanced greatly from prior reports. This latest inventory (2026) relied on analog activity updates, minor changes to risking methodology, and a continued pursuit of new datasets for additional improvements. The support and review of this report by BOEM management and reviewers was much appreciated.

Right. Paul Post in Carnival garb.



8.0 GLOSSARY

Assessment unit: All pools sharing a common history of hydrocarbon generation, migration, reservoir development, and entrapment. Used interchangeably with “play” herein.

British thermal unit: Amount of heat required to raise the temperature of one pound (0.454 kg) of liquid water by one degree Fahrenheit at a constant pressure of one atmosphere.

Conventionally recoverable: Hydrocarbons requiring only natural pressure, pumping, or secondary recovery methods, such as gas or water injection to produce.

Field: One or more geologically related reservoirs with producible accumulation(s) of hydrocarbons. Typically refers to a commercial accumulation.

Pool: Accumulation of hydrocarbons, discovered or undiscovered, typically within a single stratigraphic interval.

Play: A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment. Used interchangeably with “assessment unit” herein.

Conceptual or Undiscovered Play: A play hypothesized based on subsurface geophysical data and regional geologic knowledge of the area. These plays have considerable play-level risk as some or all essential play components may be unproven.

Established or Discovered Play: A play in which hydrocarbons have been discovered in at least one well, establishing a working petroleum system. These plays have no play-level risk.

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

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

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

Reservoir: A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes.

Undiscovered resources: Hydrocarbons postulated, based on geologic knowledge and theory, to exist outside of known fields or accumulations.

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 undiscovered technically recoverable resources that is economically recoverable under imposed economic and technologic conditions.

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10.0 APPENDICES

10.1 APPENDIX A. ATLANTIC HISTORICAL TIMELINE

Atlantic Timeline Part I

[illegible]

Atlantic Timeline Part II

[illegible]

Appendix A. Events that influenced current and previous Atlantic resource estimates are included in this timeline. Data collection activities are in green. Administrative events are in blue. The timeline covers the original oil and gas exploration phase along with more recent events. Deep seismic surveys employ lower frequencies to target deeper oil and gas reservoirs compared to seismic surveys designed for imaging shallow geomorphological features and BSRs.

10.2 APPENDIX B. PLAY AND PROSPECT RISK ANALYSIS FORMS

Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	1) Marginal Fault Belt (Jurassic - Cretaceous)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAB			
Date:	April 2025		Assessment:	2026 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	0.4000	0.4000	
a. Presence of a 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	0.4000		
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	0.6000		
2. Reservoir component			2	0.7000	0.5000	0.5000	
a. Presence of reservoir facies							
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.			2a	0.8000	0.7000		
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	0.9000	0.7000	0.7000	
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	0.9000	0.7000		
Overall Play Chance				0.441			
(1 * 2 * 3) Product of All Subjective Play Chance Factors							
Average Conditional Prospect Chance ¹					0.140		
(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors							
¹ Assumes that the Play exists (where all play chance factors = 1.0)							
Exploration Chance			Overall Exploration Chance				
(Product of Overall Play Chance and Average Conditional Prospect Chance)			0.0617				
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:							

Play and Prospect Risk Analysis Form							
Assessment Province:		Atlantic		Assessment Unit Name:		2) Carolina Trough Salt Basin (Jurassic - Cenozoic)	
Assessor(s):		Dominic Smith		Assessment Unit UAI:		AAABANAC	
Date:		April 2025		Assessment:		2026 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	0.6000	0.6000
a. Presence of a 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	0.8000	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	0.8000	0.6000	
2. Reservoir component				2	0.7000	0.6000	0.6000
a. Presence of reservoir facies							
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.				2a	0.8000	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	0.9000	0.8000	0.8000
a. Presence of trap							
Probability of presence of the trap with a minimum rock volume.				3a	0.9000	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	0.9000	0.8000	
Overall Play Chance					0.504		
(1 * 2 * 3) Product of All Subjective Play Chance Factors							
Average Conditional Prospect Chance ¹							0.288
(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors							
¹ Assumes that the Play exists (where all play chance factors = 1.0)							
Exploration Chance				Overall Exploration Chance			
(Product of Overall Play Chance and Average Conditional Prospect Chance)				0.1452			
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:							

Play and Prospect Risk Analysis Form						
Assessment Province:	Atlantic		Assessment Unit Name:	3) Carbonate Margin (Late Jurassic - Early Cretaceous)		
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAA		
Date:	April 2025		Assessment:	2026 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 a 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	0.7000	0.5000	
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	0.7000	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	0.7000	
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	0.8000	0.7000	
Overall Play Chance				0.336		
(1 * 2 * 3) Product of All Subjective Play Chance Factors						
Average Conditional Prospect Chance ¹					0.175	
(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors						
¹ Assumes that the Play exists (where all play chance factors = 1.0)						
Exploration Chance			Overall Exploration Chance			
(Product of Overall Play Chance and Average Conditional Prospect Chance)			0.0588			
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:						

Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	4) Paleoslope Siliciclastic Core (Jurassic - Cenozoic)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAI			
Date:	April 2025		Assessment:	2026 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 a 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		0.5000	
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		0.5000	
3. Trap component			3	0.8000		0.7000	
a. Presence of trap Probability of presence of the trap with a minimum rock volume.			3a	0.8000		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	0.9000		0.8000	
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors				0.336			
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)						0.175	
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)			Overall Exploration Chance 0.0588				
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:							

Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	5) Paleoslope Siliciclastic Extension (Jurassic - Cenozoic)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAJ			
Date:	April 2026		Assessment:	2026 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		0.4000	
a. Presence of a 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		0.4000	
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		0.4000	
2. Reservoir component			2	0.6000		0.4000	
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.			2a	0.6000		0.5000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.			2b	0.6000		0.4000	
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		0.9000	
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors				0.288			
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)						0.096	
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)			Overall Exploration Chance 0.0276				
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:							

Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	6) Blake Plateau Basin (Jurassic - Cretaceous)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAF			
Date:	April 2026		Assessment:	2026 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 a 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	0.6000		0.5000	
2. Reservoir component			2	0.6000		0.4000	
a. Presence of reservoir facies							
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.			2a	0.7000		0.5000	
b. Reservoir quality							
Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.			2b	0.6000		0.4000	
3. Trap component			3	0.8000		0.7000	
a. Presence of trap							
Probability of presence of the trap with a minimum rock volume.			3a	0.8000		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	0.8000		0.7000	
Overall Play Chance				0.288			
(1 * 2 * 3) Product of All Subjective Play Chance Factors							
Average Conditional Prospect Chance ¹						0.140	
(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors							
¹ Assumes that the Play exists (where all play chance factors = 1.0)							
Exploration Chance						Overall Exploration Chance	
(Product of Overall Play Chance and Average Conditional Prospect Chance)						0.0403	
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:							

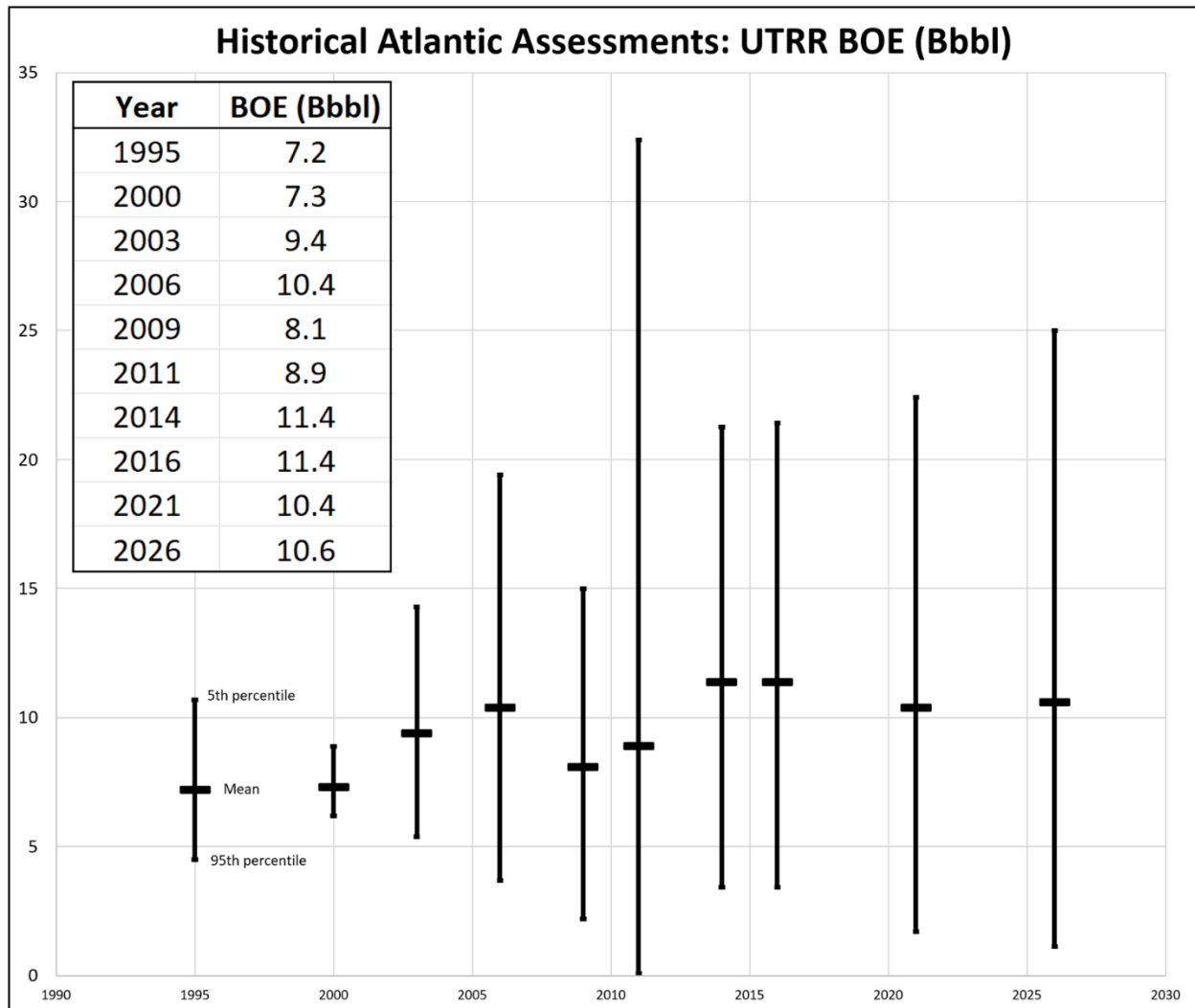
Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	7) Shelf Stratigraphic (Jurassic)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAD			
Date:	April 2025		Assessment:	2026 National Assessment			
Risk Components and Associated Elements			Play Chance 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		0.4000	
a. Presence of a 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		0.4000	
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	0.6000		0.4000	
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	0.6000		0.4000	
3. Trap component			3	0.8000		0.7000	
a. Presence of trap Probability of presence of the trap with a minimum rock volume.			3a	0.8000		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	0.9000		0.8000	
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors				0.288			
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)						0.112	
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)			Overall Exploration Chance 0.0323				
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:							

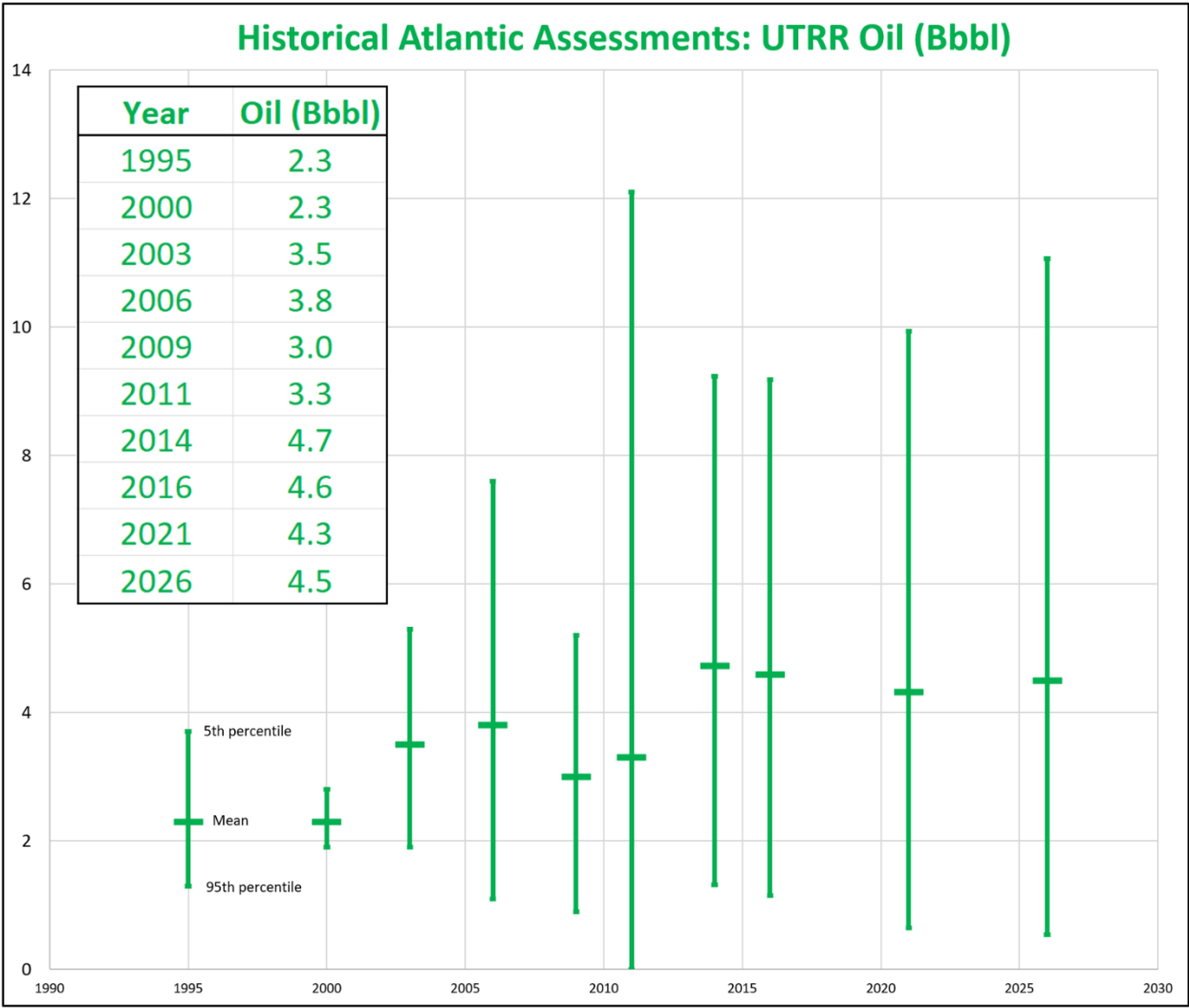
Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	8) Interior Shelf Structure (Jurassic - Cretaceous)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAE			
Date:	April 2025		Assessment:	2026 National Assessment			
Risk Components and Associated 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 a 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		0.8000	
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		0.3000	
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		0.3000	
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		0.6000	
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		0.9000	
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors				1.000			
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)						0.108	
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)			Overall Exploration Chance 0.1080				
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:							

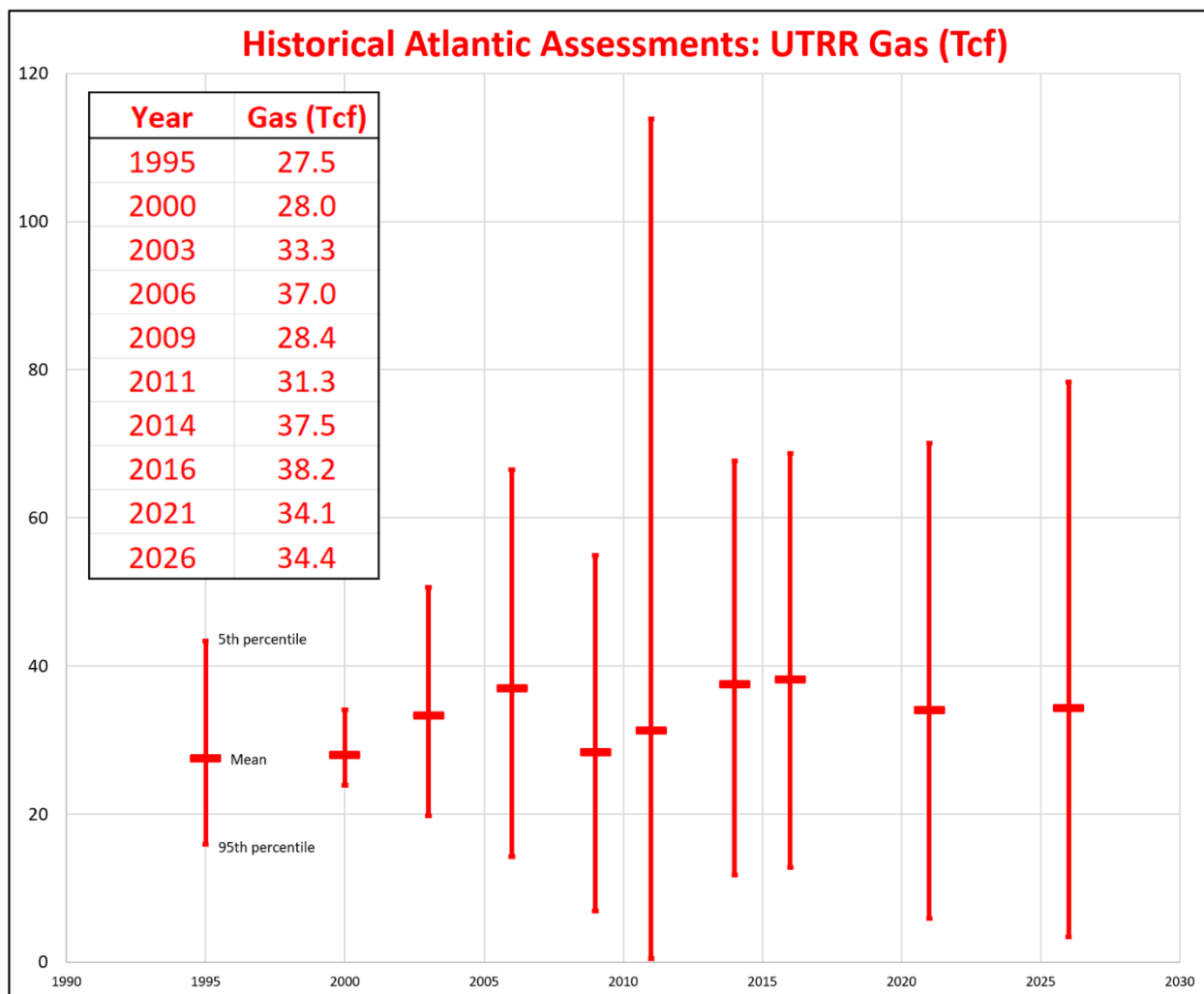
Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	9) Rift Basin (Triassic - Jurassic)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAG			
Date:	April 2025		Assessment:	2026 National Assessment			
Risk Components and Associated Elements			Play 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		0.6000	
a. Presence of a 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	0.6000		0.6000	
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	0.8000		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	0.8000		0.7000	
Overall Play Chance				0.336			
(1 * 2 * 3) Product of All Subjective Play Chance Factors							
Average Conditional Prospect Chance ¹						0.252	
(1 * 2 * 3) Product of All Subjective Conditional Prospect Chance Factors							
¹ Assumes that the Play exists (where all play chance factors = 1.0)							
Exploration Chance					Overall Exploration Chance		
(Product of Overall Play Chance and Average Conditional Prospect Chance)					0.0847		
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:							

Play and Prospect Risk Analysis Form							
Assessment Province:	Atlantic		Assessment Unit Name:	10) Hydrothermal Dolomite (Jurassic - Cretaceous)			
Assessor(s):	Dominic Smith		Assessment Unit UAI:	AAABANAH			
Date:	April 2025		Assessment:	2026 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	0.5000		0.4000	
a. Presence of a 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	0.5000		0.4000	
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		0.5000	
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		0.7000	
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	0.8000		0.7000	
Overall Play Chance (1 * 2 * 3) Product of All Subjective Play Chance Factors				0.240			
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)						0.140	
Exploration Chance (Product of Overall Play Chance and Average Conditional Prospect Chance)			Overall Exploration Chance 0.0336				
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:							

10.3 APPENDIX C. HISTORIC UTRR: REPORTED RESOURCES 1995–2026









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.