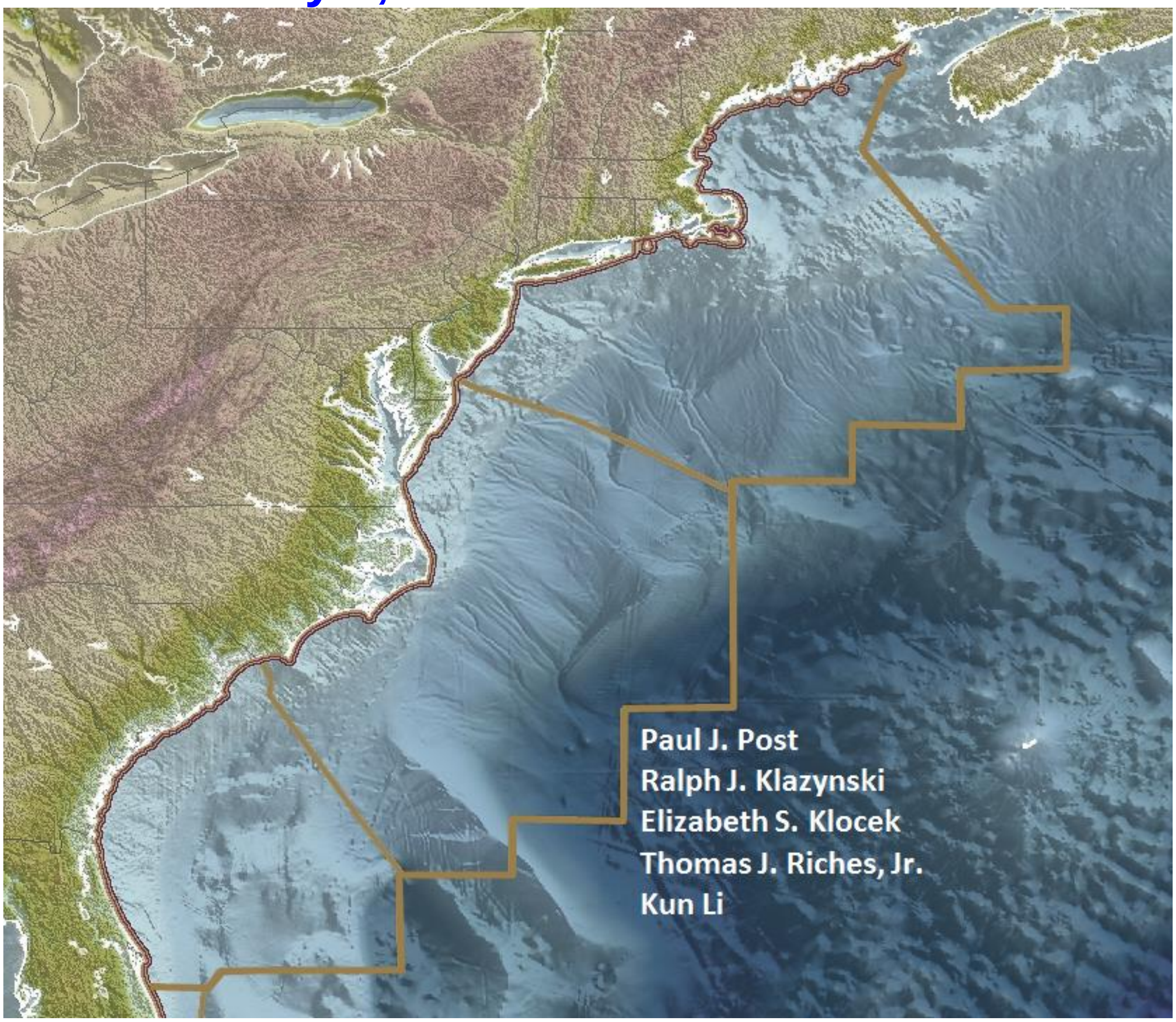
OCS Report
BOEM 2016-071

Inventory of Technically and Economically Recoverable Hydrocarbon Resources of the Atlantic Outer Continental Shelf as of January 1, 2014



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ABBREVIATIONS AND ACRONYMS

2D	two dimensional
3D	three dimensional
Bbbl	billion barrels
bbl	barrels
BBOE	billion barrels of oil equivalent
BCFG	billion cubic feet of gas
BCFGE	billion cubic feet of gas equivalent
BOE	barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management
Fm.	Formation
ft	feet
GoM	Gulf of Mexico
MMbbl	million barrels of oil
MMBOE	million barrels of oil equivalent
MCFG	thousand cubic feet of gas
MMCFG	million cubic feet of gas
MMBNGL	million barrels of natural gas liquids
mD	millidarcies
mi	miles
mi^2	square miles
NFW	new field wildcat
OCS	Outer Continental Shelf
Tcf	trillion cubic feet
TCFG	trillion cubic feet of gas
UERR	undiscovered economically recoverable resources
U.S.	United States
UTRR	undiscovered technically recoverable resources

INTRODUCTION

This report summarizes the results of the 2016 Bureau of Ocean Energy Management (BOEM) inventory of undiscovered, technically recoverable oil and gas resources of the U.S. Atlantic Outer Continental Shelf (OCS) (Figure 1). It complies with and fulfills requirements written in subsection (a), paragraphs (1) through (5) and subsection (b) of Section 357 of the Energy Policy Act of 2005. The area assessed comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction. This resource inventory represents a comprehensive appraisal of data and information considered relevant as of January 2014, which although arbitrary, provides a consistent limiting date for the inclusion of data that populates the distribution of pool/field sizes in the analog database. This inventory incorporates and applies modern exploration concepts, analogs, and key new 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/observations on significant exploration and production activity, but not including volumes, in the international analogs upon which this inventory is based that occurred between January 2014 and the mid-2016. The outcome of these and future activities in these analogs may result in potential additional resource inventory increases.

In the absence of new deep-penetration reflection seismic geophysical datasets in the U.S. Atlantic OCS, available vintage data were enhanced through vectorization and/or reprocessing. All wireline logs were digitized. Biostratigraphic data of all types were of variable quality and diverse vintages. The sequence framework developed by GeoSpec (2003) was used as the primary framework and when integrated with the seismic data provided reasonable consistency throughout the region. Gravity and magnetic data sets have been updated and improved. Originally available and recent geochemical data was assessed, aggregated, and incorporated. All data were integrated to develop a comprehensive petroleum system focused inventory of potential resources.

Since the most recent comprehensive resource inventory (BOEM, 2012), industry activity in international areas considered appropriate analogs for assessment units (AUs) in the U. S. Atlantic OCS has resulted in significantly increased resource volumes for two AUs. In addition, reinterpretation of seismic reflection data using a framework of fully reprocessed data resulted in a change in the areal extent of two other AUs. Consequently, BOEM (2014) issued a fact sheet updating the resource volumes in those four areas, and revised the resource inventory for the entire region.

After issuing that resource inventory and fact sheet (BOEM, 2012 and 2014), additional new field wildcat (NFW) drilling has resulted in discoveries in analogous settings in Northwest Africa (Mauritania and Senegal), West Africa (Côte d'Ivoire), Northeast South America (Guyana and Brazil), and East Africa (Kenya, Tanzania, and Mozambique). Those and earlier discoveries have been delineated and tested in applicable analogous regions. This activity has improved our understanding of discovery size and petroleum systems responsible for those analogs. In addition, to better reflect and incorporate petroleum system methodology, we have evolved the previously assessed plays, designating areas assessed as AUs as defined in Methodology. Consequently, although no new AUs were added and none deleted in this inventory, refinements of the resource estimates evolved primarily due to changes in methodology.

THE ATLANTIC REGION

The U.S. Atlantic Region Planning Areas share many common characteristics; e.g., Regional Setting, Exploration and Discovery Status, Engineering, Technology, Transportation, Petroleum Systems, and Assessment Units.

LOCATION

Located on the eastern margin of the continental U.S., the Atlantic OCS extends approximately 1,150 mi from the Canadian province of Nova Scotia (northeast) to The Bahamas (southwest) (Figure 1). The Atlantic Region is divided into the North, Mid-, and South Atlantic Planning Areas (Figure 2). The Straits of Florida Planning Area, the northernmost part of which is shown in Figure 2, is addressed as part of the Gulf of Mexico (GoM), because GoM AUs extend into that Planning Area. Water depths in the Atlantic OCS range from less than 30 ft to greater than 15,000 ft.

REGIONAL SETTING

The supercontinent Pangea formed by progressive amalgamation of crustal blocks culminating during the late Paleozoic Alleghanian–Variscan orogeny when all existing continents and fragments were assembled into a single entity (Rast, 1988; Rankin, 1994; Hatcher, 2010; and Mueller et al., 2014). The development of the U.S. Atlantic Region began during the Late Triassic breakup of western Pangea. This breakup began approximately 237–208.5 million years ago, and was characterized by region-wide continental rifting (Iturralde-Vinent, 2003; Withjack and Schlische, 2005; Kneller and Johnson, 2011; and Kneller et al, 2012). Subsequently, the North American plate containing the U.S. Atlantic Region and its conjugate margin, the African plate, drifted apart as sea floor spreading opened the current Atlantic Ocean.

As is typical of all Central Atlantic Margins, the geology, petroleum systems, plays, and resultant resource assessment of the region reflect the geometry and transition from the early, complex rift system to the present-day passive margin (Withjack and Schlische, 2005; Sheridan, 1987). A series of four post-rift sedimentary depocenters of Early Jurassic(?)–Holocene age developed linearly along the U.S. part of the margin. From northeast to southwest (Figure 1) these are: the Georges Bank basin, the Baltimore Canyon Trough, the Carolina Trough, and the Blake Plateau basin (including its updip Southeast Georgia Embayment) (Sheridan, 1987). These depocenters and their sedimentary sections vary in size, shape, and thickness (Divins, 2012).

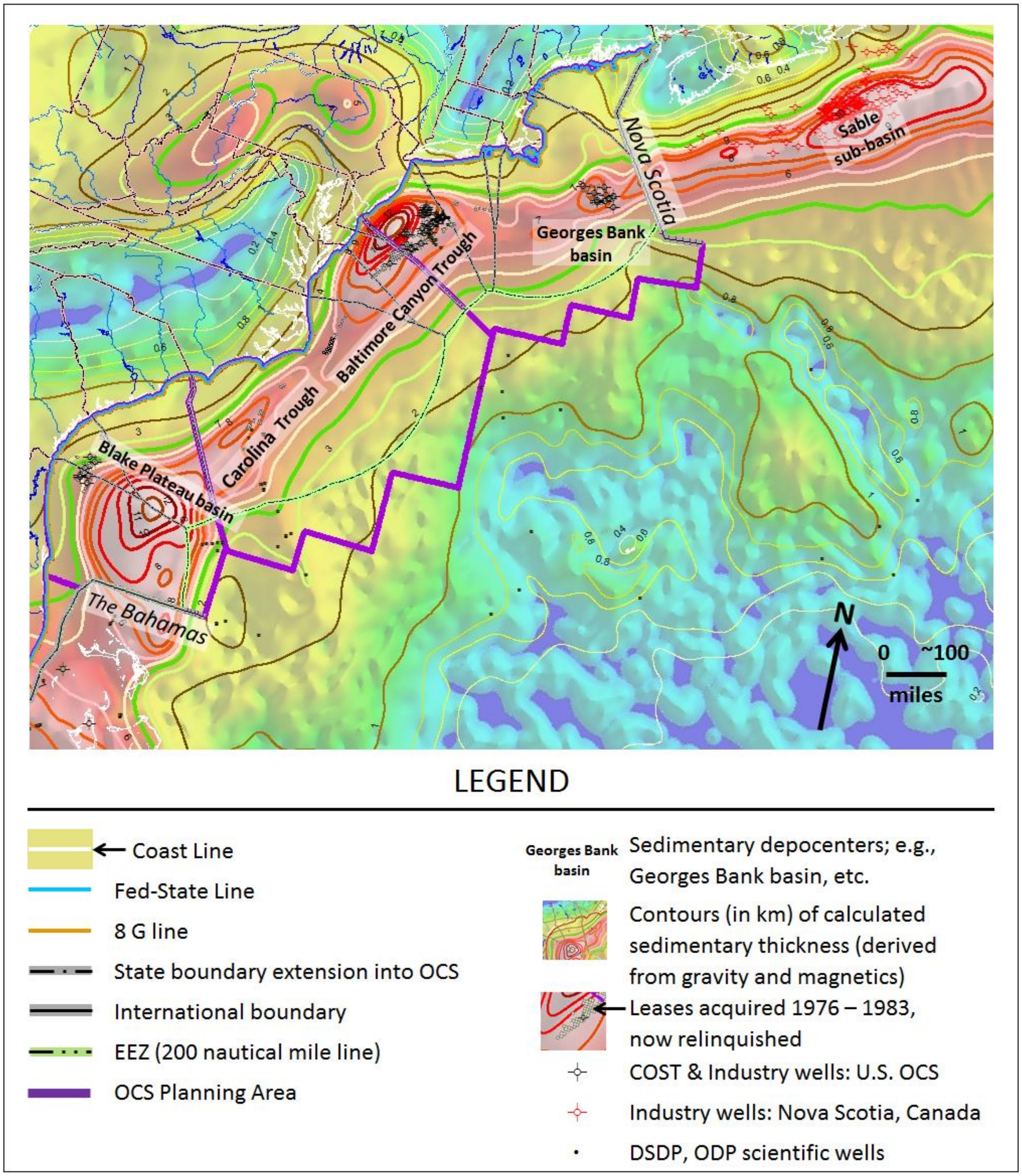

Figure 1. Generalized sedimentary thickness map derived from published data, gravity and magnetic data (Tucholke et al., 1982). This interval represents the calculated thickness from the sea floor to the top of the shallowest, strong magnetic horizon. Where calibrated using well data, the error between this calculated thickness and the measured thickness is <10%.

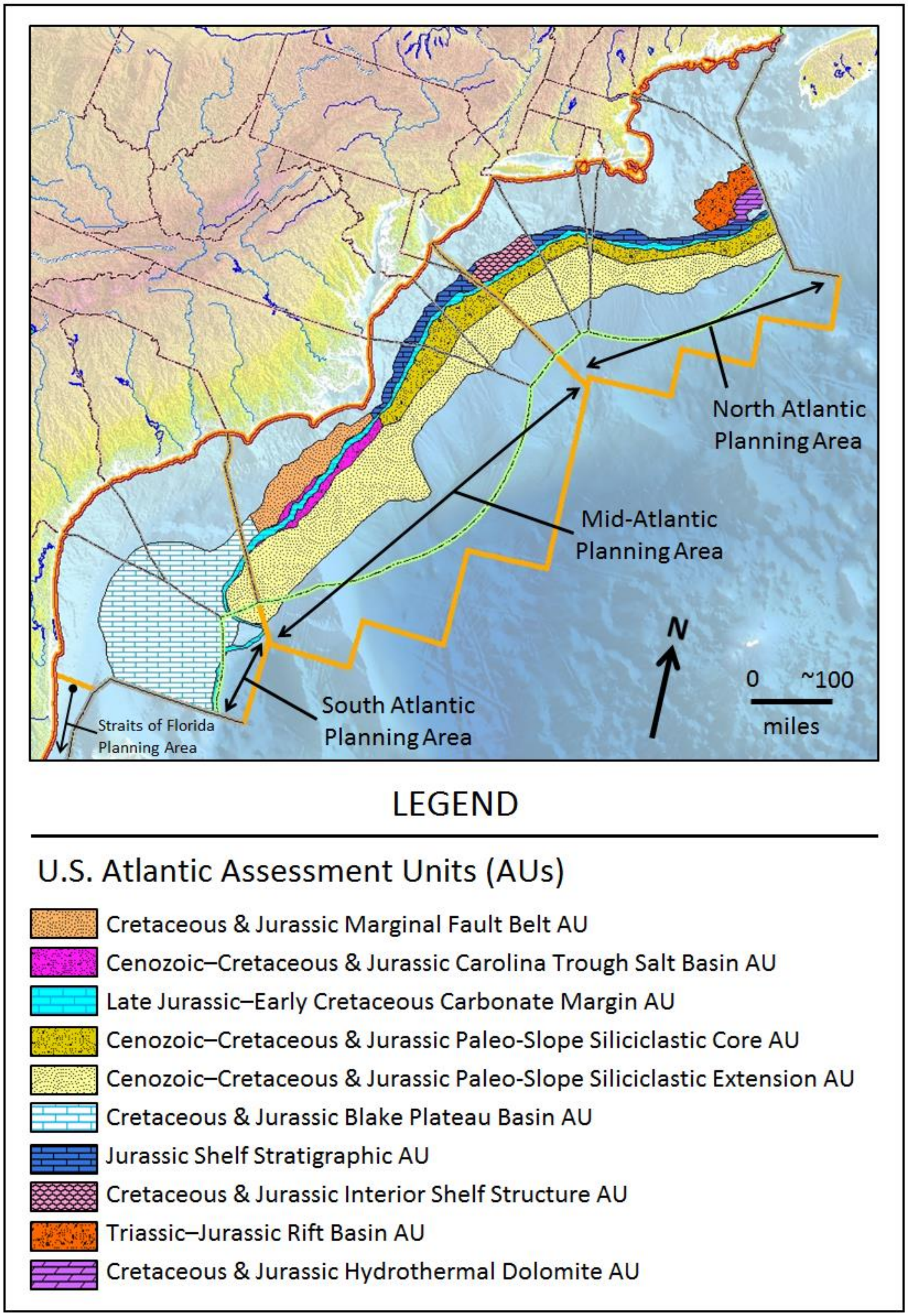

Figure 2. Assessment unit locations, U.S. Atlantic OCS. (Cartographic elements on this figure, although colored differently, are identified on the left side of the Legend of Figure 1).

Stratigraphic Summary of the U.S. Atlantic Region

Figure 3 illustrates the generalized stratigraphy of the U.S. Atlantic region calibrated using ages from the Geologic Time Scale of 2004 (Ogg et al., 2008), integrated with the Haq et al. (1987) eustatic sea level curve. Key seismic horizons interpreted by the BOEM staff are also shown as they are defined by geologic ages and the eustatic curve. Even though drilling in the U.S. Atlantic ended in 1984, it continued offshore Nova Scotia along with the acquisition and processing of modern, deep-penetrating reflection seismic. Here a more modern, consistent, lithostratigraphy and biostratigraphy evolved that is compatible with the state-of-knowledge and supporting data on the U.S. margin. Consequently, the lithostratigraphic nomenclature derived from offshore Nova Scotia (CNSOPB, 2009a & b) is used, referenced, and followed in this report.

Late Triassic–Early Jurassic syn-rift sediments (Figure 3) consist primarily of interbedded fluvial and lacustrine red beds, shales, basalts, and in some syn-rift basins and sag-phases of depocenter development, evaporites may have been deposited. A post-rift or breakup unconformity overlies the syn-rift sequence. Farther eastward, towards the opening Atlantic Ocean, a seaward-dipping reflector (SDR) unconformity overlies the SDR complex represented by the East Coast Magnetic Anomaly (Wyer and Watts, 2006). Although these two unconformities appear synchronous, they differ in age: the unconformity overlying the SDRs being as much as 10 Ma younger than the breakup unconformity (Cramez, 2007). No formation names are used for syn-rift strata because established stratigraphic nomenclature exists (and is different) in each of these rift basins.

A marine transgression above these unconformities resulted in a shallow marine environment (Figure 3) within which updip siliciclastics (Mohican Fm. and equivalents) and downdip limestones, dolomites, and minor evaporites (Iroquois Fm. and equivalents) were deposited (CNSOPB, 2009a & b).

Evaporites (Figure 3) are documented in localized syn-rift (Wade and MacLean, 1990), and probably post-rift, sag-phase settings offshore Nova Scotia, and various post-rift sag-phase settings on the U.S. Central Atlantic; e.g., Amato and Simonis, 1980; McKinney et al. 2005; Elliott and Post, 2012; Post et al., 2012. Reflection seismic and well data along the U.S. and Nova Scotian Atlantic margins indicates that evaporites do not occur in all syn-rift settings, or throughout the lateral extent of the Iroquois Fm., overlying the breakup unconformity, the seaward-dipping reflector unconformity (SDRU), or all SDRs. In the U.S. Atlantic OCS, reprocessed reflection seismic data in the Baltimore Canyon Trough (McKinney et al., 2005) demonstrate that autochthonous evaporites in that depocenter is post-rift, overlying the breakup unconformity. Evaporites overlying SDRs or the overlying SDRU in a setting similar to that described by Jackson et al. (2000) are recognized on seismic data in the Carolina Trough (Dillon et al., 1982), where they form a variety of salt-cored structures.

Sea floor spreading, subsidence of the margin, and sea level rise, resulted in the Atlantic becoming broader and deeper (~3,300 ft) by Middle Jurassic (CNSOPB, 2009b). During this period, a carbonate margin was initiated that persisted until the latest Jurassic–earliest Cretaceous (Figure 3). Its development was affected by contemporaneous Late Jurassic–Early Cretaceous siliciclastic deltaic depocentres that locally restricted carbonate sedimentation (Eliuk and Wach, 2014). Because more drilling has taken place offshore Nova Scotia, the Abenaki Fm. carbonate margin and its updip lagoonal and downdip facies equivalent marls and carbonate mud are better defined. In Nova Scotia, the Abenaki Fm. has four formal members (in ascending order): the Scatarie Limestone Member, the Misaine Shale Member, the Baccaro Limestone Member; and the Artimon Limestone Member (Eliuk, 2004).

Offshore Nova Scotia, the Scatarie is predominantly an oolitic limestone that often shows cyclic deposition. It is typically depicted (Figure 3) as extending from its apparent shoreline to its offshore facies equivalent (Kidston et al., 2005; CNSOPB, 2009a). The oolitic limestones grade into marls and mudstones in deeper water settings. The absence of the overlying Misaine Member (Eliuk, 1978) makes it is difficult to recognize in the proximal setting. The Scatarie is the most areally extensive sequence of the Abenaki Formation (Kidston et al., 2005). Continuing margin subsidence and sea level rise resulted in a marine transgression during which Scatarie carbonates were blanketed by marine shales of the Misaine Member (Kidston et al., 2005; CNSOPB, 2009b). The Misaine interfingers with the updip Mohawk Fm. The Mohawk and Mic Mac formations are interpreted to be primarily updip siliciclastic and lateral equivalents of the other Abenaki Fm. members (Kidston et al., 2005; CNSOPB, 2009a). Where recognized, the Misaine separates the underlying Scatarie from the overlying Baccaro limestone members (Eliuk, 1978). The Baccaro Limestone Member is the thickest and best developed carbonate unit of the Abenaki Formation in Nova Scotia. However, its areal extent is limited to a variable, narrow, 9–15 mi wide belt that follows the Jurassic hinge line and defines the seaward limit of the Abenaki platform margin (Kidston et al., 2005). It is composed of numerous stacked, shoaling-upwards, aggrading and prograding parasequences. Over the width of Baccaro belt, a number of laterally equivalent sedimentary facies were developed: lagoon to inner shelf, oolitic shoal, coral-stromatoporoid reef, and beyond this, reef margin foreslope fans (Kidston et al., 2005). The Artimon Member is the youngest and thinnest member of the Abenaki Fm. Its areal distribution is patchy and limited. Consequently it is not shown in Figure 3. It is composed of argillaceous, cherty limestones representing thrombolytic sponge and stromatoporoid mound deposition with occasional interbedded calcareous shales (Kidston et al., 2005). The associated fossil assemblage infers a reef middle foreslope depositional setting in water depths from 300 to 600 ft, near the limits of the photic zone (Eliuk, 1978). The presence of these sponge-stromatoporoid mounds at the top of the drowned platform margin edge reflects depositional response to a major sea level rise during the earliest Cretaceous (Berriasian).

Offshore Nova Scotia, well and seismic data document an along-strike northeast to southwest change in the geometry of the Abenaki carbonate margin from a progradational, gently dipping ramp-like style with inter-fingering carbonate and clastic facies, to a steeper sigmoidal bank margin, to an eroded margin, and a faulted/eroded margin (Kidston et al., 2005). While not confirmed by wells, reflection seismic data indicates similar changes in the geometry of the Abenaki margin in the U.S. Atlantic OCS.

The Abenaki Fm., and/or its updip equivalents the Mic Mac and Mohawk formations, are recognized in all wells drilled to the Late Jurassic in the U.S. Atlantic OCS. However, the most prospective shelf-edge setting was only targeted by two of the 39 NFW wells in the Atlantic OCS (Kidston et al., 2005). These wells were drilled by Shell et al. in the Baltimore Canyon Trough during 1983 and 1984. They encountered more carbonate-sand-rich beds than the muddier facies containing a higher percentage of reef frame-builder-rich beds typically found by wells drilled offshore Nova Scotia. Although these biofacies differences may reflect a "sampling" bias, there appear to be significant differences between this area and offshore Nova Scotia (Eliuk and Prather 2005). The Artimon and Baccaro members were recognized in the Shell et al., Wilmington Canyon (WI) 587-1 well (Eliuk and Prather (2005). Similar information was not provided on any other wells in the Baltimore Canyon Trough. Regarding the other Shell et al. wells, Eliuk (personal communication, June 1, 2016) stated: "The Misaine and Scatarie age level was never reached and likely such units would be absent since they relate to Laurentian delta shale influx and maybe Callovian glacial drawdown and rapid recovery at the base of the Baccaro that capped the Misaine shale." He further noted that the Artimon is a highly diachronous facies. Just as in offshore Nova Scotia, along strike facies variations and changes in the Abenaki are expected throughout the U.S. Atlantic OCS. The individual members and their sequence stratigraphy have generally not been identified because most of the wells in the region are in the generally non-prospective updip shelf setting. Therefore, projecting facies tracts over any distance is currently problematic.

Spanning the Middle Jurassic–Early Cretaceous, the Verrill Canyon Fm. (Figure 3) is the deep-water facies equivalent of the Mohawk, Abenaki, and Mic Mac Fms., as well as the overlying Missisauga Fm. in both the U.S. and Nova Scotia (Wade and MacLean, 1990). The Verrill Canyon Fm. consists primarily of grey to brown calcareous shale with thin beds of limestone, siltstone, and sandstone. It records deposition in prodelta, outer shelf, and continental slope settings (Wade and MacLean, 1990).

The Missisauga Fm. (Figure 3) consists of a series of thick sand-rich deltaic, strandplain, carbonate shoals and shallow marine shelf units. These facies and the formation dominated sedimentation throughout the Early Cretaceous in both offshore Nova Scotia (CNSOPB, 2009b) and the U.S. Atlantic OCS.

In Nova Scotia, the overlying Logan Canyon Fm. consists (in ascending order) of four members: the Naskapi, Cree, Sable and Marmora. Those not recognized in the U.S. Atlantic OCS are not shown in Figure 3. The basal, widely-recognized, shale-rich Naskapi Member represents a major, early Aptian (mid-Cretaceous) marine transgression that terminates much of the Missisauga Fm. deltaic sedimentation. The sand-rich upper parts of the Logan Canyon are often locally interbedded with shales, silts, and coals. Depositional environments range from coastal plain-lagoonal to outer shelf (CNSOPB, 2009b).

Reflecting the relatively high sea levels of the Late Cretaceous (Figure 3), Dawson Canyon Fm. shales, interbedded limestones, and minor sandstones were deposited in deeper marine environments throughout the U.S. Atlantic OCS. These ultimately overwhelmed and transgressed over the more sand-rich siliciclastic deposition of the upper members of the Logan Canyon Fm. (CNSOPB, 2009b).

Throughout the region, sea level rise continued during the Late Cretaceous (Figure 3). Offshore Nova Scotia marls and chalky mudstones of the Wyandot Fm. were deposited (CNSOPB, 2009b). The Wyandot Fm. has not been recognized in the U.S. Atlantic OCS. Latest Cretaceous and Tertiary marine shelf argillaceous limestones, mudstones, sandstones, and conglomerates of the Banquereau Fm. were deposited during the subsequent overall falling sea level cycle. Depositional environments ranged from shallow shelf to bathyal. Significant sea level falls are recorded in the major unconformities that occur within the formation (CNSOPB, 2009b).

During the Paleocene, Oligocene, and Miocene (Figure 3), fluvial and deep-water currents cut into and eroded these mostly unconsolidated sediments, transporting them into deeper water slope and abyssal environments throughout the entire region (CNSOPB, 2009b).

The BOEM seismic interpretation in the post-rift interval recognizes eight (8) sequence boundaries (SBs). These form the basis of the BOEM interpretation of the geology, stratigraphy, and hydrocarbon prospectivity of the region (Figure 3). The SBs are based on the GeoSpec (2003) interactive interpretation of the deep-penetration, reflection seismic data with wireline well log, lithostratigraphic, palynological, micropaleontological, and nannopaleontological data and sequence stratigraphic concepts throughout the western Central Atlantic in Nova Scotia and the U.S. The interpreted 'base Jurassic SB' (b J SB) is Jurassic in age over most of the region. However, the seismic horizon is diachronous. It marks the boundary of post-rift Mesozoic sediments and underlying pre-Mesozoic units, older Mesozoic syn-rift strata, SDRs, and oceanic crust. Its interpretation is critical, because it controls and constrains the architecture and thickness of the post-rift Mesozoic and Cenozoic age sections where most hydrocarbon prospectivity is interpreted. The SB-based framework was used to delineate the geographic extent of each of the AUs identified and assessed in the U.S. Atlantic OCS.

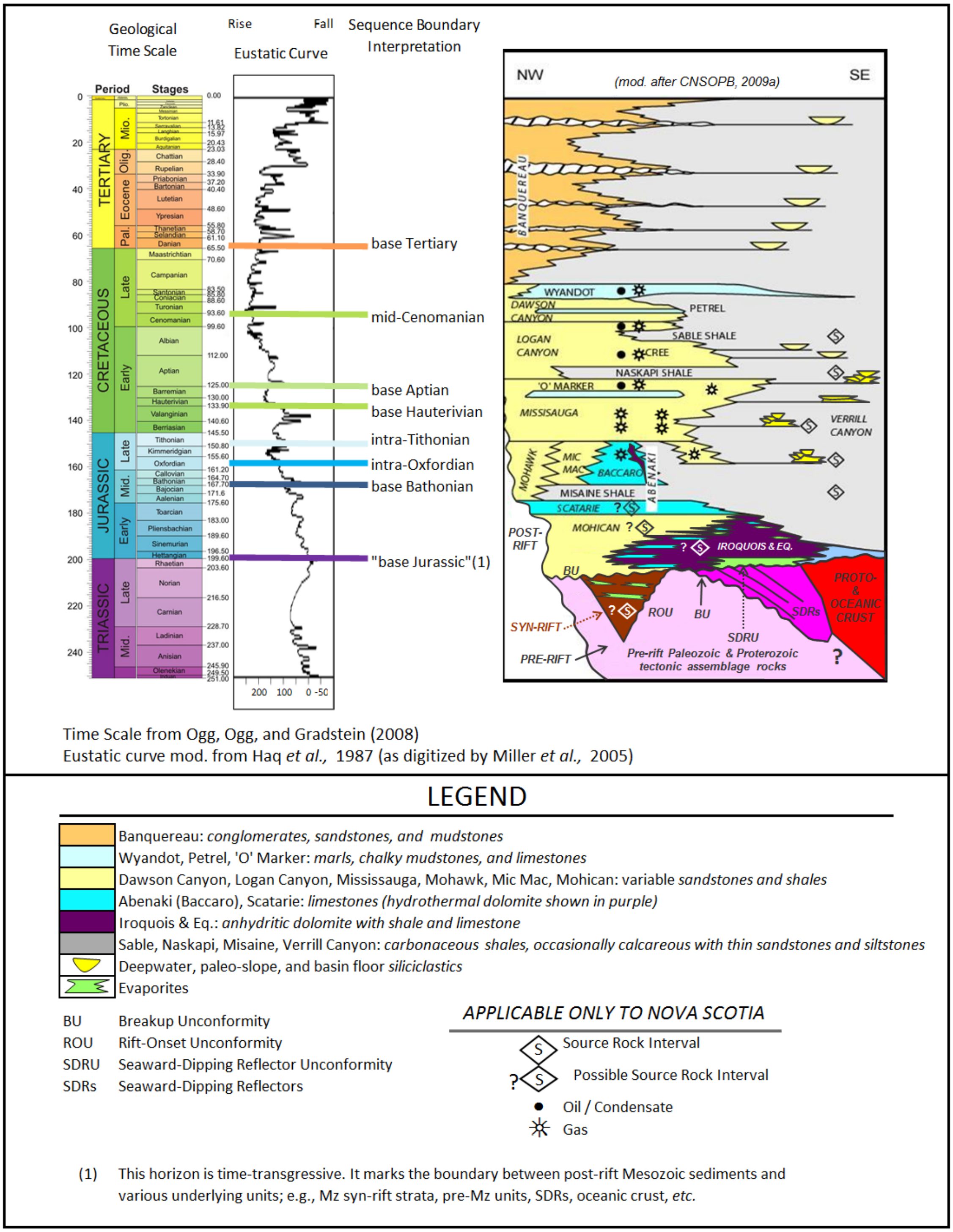

Figure 3. Generalized stratigraphy of the U.S. Atlantic region based on the more heavily explored and drilled northeast-adjacent Nova Scotia offshore. Calibrated using ages from the Geologic Time Scale of 2004 (Ogg et al., 2008), integrated with the Haq et al. (1987) eustatic sea level curve. Key seismic horizons interpreted by BOEM staff represent sequence boundaries initially identified and interpreted by GeoSpec, a CGG company, on GeoSpec's seismic interpretation of the U.S. Atlantic OCS (GeoSpec, 2003).

EXPLORATION AND DISCOVERY STATUS

To date, there has been no commercial hydrocarbon production in the U.S. Atlantic OCS. A single phase of oil and gas exploration was conducted from the late 1960s to the mid-late 1980s. Approximately 239,000 line mi of 2D seismic was acquired, processed, and interpreted between 1966 and 1988. In 1982, an early attempt at a "3D" survey (actually a "pseudo-3D" survey because it consisted of 95 "inlines" on 1,000 ft spacing), was acquired over a four-block area centered on Hudson Canyon (HC) Block 598 area in the Baltimore Canyon Trough (Figure 4).

The BOEM seismic data set in the Atlantic OCS consists of approximately 170,000 line mi of 2D data. To facilitate seismic interpretation and use of well data on workstations, the 2D data and "pseudo-3D" survey described above were digitized, vectorized, and migrated (where necessary). An additional ~12,400 line mi of reprocessed reflection seismic data and approximately 185,000 line mi of depth-converted, time-migrated data in SEG-Y format were licensed from GeoSpec (a CGG Company). Because these data provide better, more accurate imaging, these data comprise the primary data set used in this resource inventory.

In the U.S. Atlantic Region, *excluding the Straits of Florida Planning Area*, nine lease sales were held from 1976–1983 resulting in 410 leases being acquired on 2,334,198 acres. Fifty-one (51) wells were drilled (Figure 4). These consist of: five Continental Offshore Stratigraphic Tests (COST wells) drilled between 1975 and 1979, and 46 industry wells were drilled between 1978 and 1984. Using the classification of Lahee (1944), thirty-nine (39) of these wells were NFW wells; the remaining seven (in the HC 598 area) were outpost/delineation/or extension wells.

The North, Mid-, and South Atlantic Protraction Areas (Figure 2) consist of ~408,584 mi^2. Ignoring the clustering of wells in the various depocenters, this equates to a NFW drilling density of 1 well per ~10,500 mi^2, or 1 well per OCS protraction. Considering only the areas of the currently identified AUs, and assuming all the wells were drilled within them, which they are not, the NFW density would be 1 for every 4,000 mi^2, or 1 NFW for approximately ½ of each OCS protraction.

The HC 598 area (Figure 4), consisting of blocks HC 598, HC 599, HC 642, and HC 643, is located on the shelf in the Baltimore Canyon Trough (BCT) in approximately 450 ft of water. It is the only area where a "discovery" was made during this exploration phase. The trap is a seismically-defined anticlinal structure bounded on its updip side by a listric down-to-the-basin fault with an associated crestal graben. All eight wells drilled on this structure had natural gas shows, most of which were "wet" gas (natural gas containing significant percentages of heavier hydrocarbons; e.g., ethane, propane, often butane, and occasionally pentane). Variable volumes of gas, with differing gas-oil ratio (GOR) values, were successfully drillstem tested in six wells. Additional information summarizing these test results are provided under the ***Cretaceous & Jurassic Interior Shelf Structure AU*** section. Reservoir compartmentalization indicated by detailed cross sections incorporating wireline log correlations, mud log shows, petrophysical calculations using the wireline log data, tests, etc., could not be resolved with the seismic data available at the time, including the "pseudo-3D" survey. The leases were ultimately relinquished, probably due to a combination of issues; i.e., the stratigraphic and structural compartmentalization of the reservoirs that would have necessitated a large number of wells and limited per well recovery, distance from shore (approximately 100 mi), and lack of onshore and offshore infrastructure.

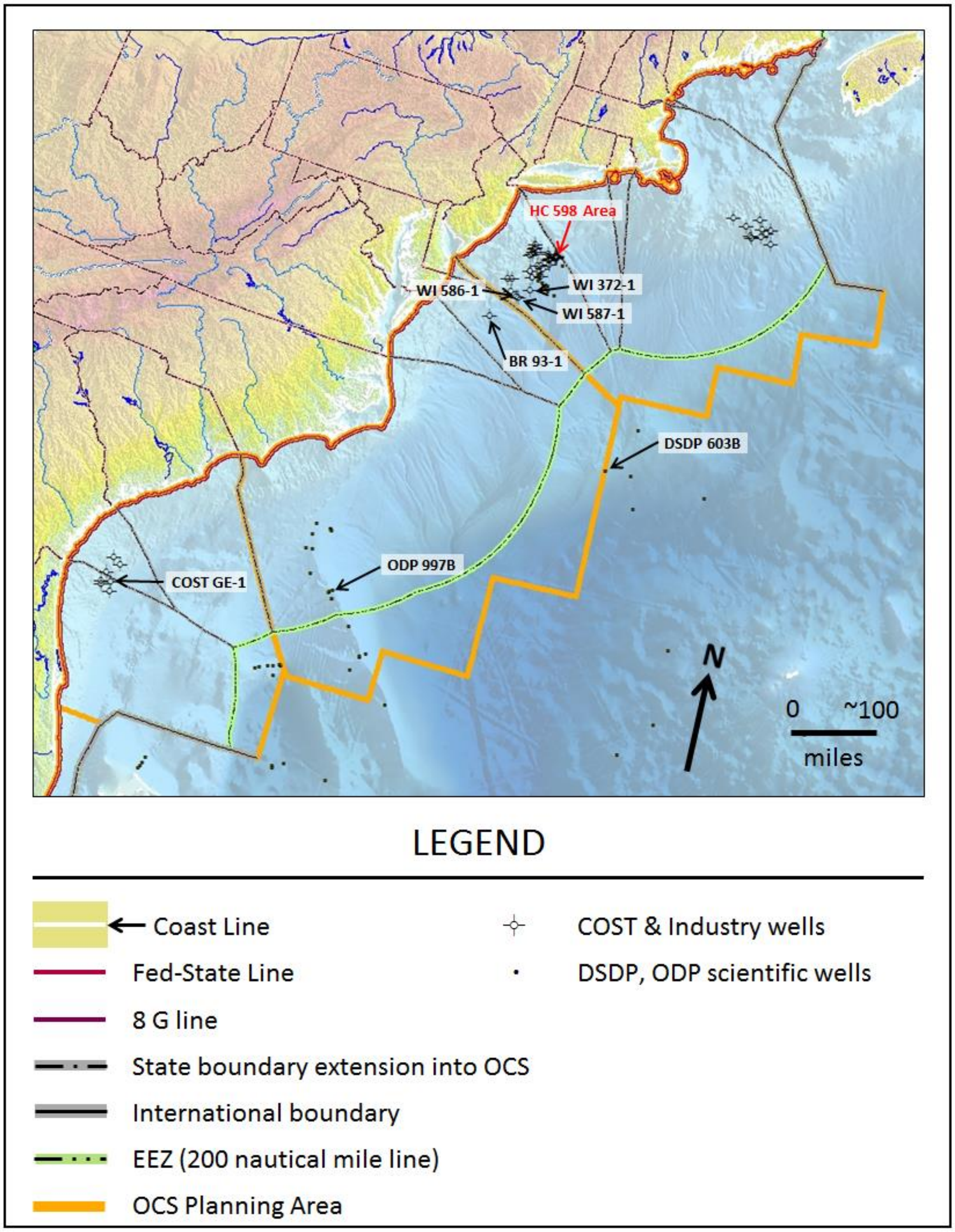

Figure 4. U.S. Atlantic OCS, location of Hudson Canyon 598 area and wells referenced in the text.

Region Level Engineering, Technology, and Transportation

There are no engineering or technology issues that would limit exploration and production in the region, because current drillship capabilities allow drilling in 12,000 ft of water to depths of 40,000 ft. As of mid-2016, the Perdido Spar, moored in approximately 8,000 ft of water, is the deepest production facility in the world. Production from wells in three fields within a 30-mile radius, including currently the deepest water subsea completion in the world (in 9,627 ft of water), is gathered, processed, and exported from the facility. The deepest waters in the world in which floating-production-storage-offloading systems (FPSOs) operate are also in the GoM. The BW *Pioneer* at the Cascade-Chinook field complex in the GoM in approximately 8,500 ft of water represents the deepest currently operating FPSO in the world. In 2016, this was exceeded by the *Turritella* FPSO operated by Shell at their Stones field in 9,500 ft of water (Shell, Stones Project Website, undated; Shell, 2016).

The value of existing infrastructure either for direct use or tie-in cannot be overstated. Instead of building a new 237 mile pipeline system to shore, or using a more costly FPSO, production from the Perdido Spar flows into an oil pipeline approximately 77 mi away and a natural gas pipeline 107 mi away (Shell, Perdido Project Website, undated). It is not possible to build-out existing oil and/or gas pipeline transportation systems and infrastructure into the Atlantic OCS because there is no hydrocarbon production in the onshore coastal regions adjoining the Atlantic OCS Region. Even though oil is processed and offloaded to shuttle or export vessels through the FPSOs, natural gas from the Cascade-Chinook FPSO comes to shore via pipeline, as it will at Stones.

Two options exist for natural gas in the Atlantic OCS and are to an extent dependent on the volume of gas discovered as either associated gas (gas associated with oil production), or nonassociated gas (gas with no, or minimal, liquid content). These would potentially replace shale/resource play gas from the onshore eastern U.S. Appalachian basin in domestic U.S. markets, or be exported as LNG. Incorporation of OCS gas into the U.S. domestic market would be simple, as that market is expanding with supplies from Appalachia. Its use as LNG would be more complex.

The first floating liquefied natural gas (FLNG) facility began operating 14 November 2016. The PFLNG *Satu* is moored over the Kanowit gas field 112 mi offshore Sarawak, Malaysia. Water depth over the field ranges from 230 to 656 ft. PFLNG *Satu* is designed to produce up to 1.2 million tonnes per annum (mtpa) of LNG from Phase 1 of the Kumang Cluster Development, the Kumang, F9, and Kanowit gas fields where more than three trillion cubic ft of gas has been discovered. Feedstock will consist of an estimated 230 MMCFG per day (Harun and Nawawi, 2014) with the project Capex cited at U.S. $ 1.5MM (Cott Oil and Gas, 2016). A total of ten gas fields have been discovered in the area. The other seven fields, in shallower water, will be developed with a second facility, PFLNG 2 (Thomas, 2015). Early 2016 reports indicate that PFLNG 2 will be commissioned at a later date than originally planned.

The cost of liquefaction, transportation, and regasification of natural gas produced from the OCS for U.S. domestic consumption using an FLNG facility appears to make this option uneconomic at typical U.S. prices. These costs were estimated by Messersmith (2012) to be between $2.10 (low) and $3.20 (high) based on liquefaction costs ranging from $1.50 to $2.00/MCFG, transportation costs varying from $0.30 to $0.90/MCFG, and regasification adding an additional estimated $0.30/MCFG. These costs do not include the construction of the FLNG vessel, which although estimated to be cheaper than an onshore plant, will add several billion dollars to the costs, depending on the volume of gas being liquefied per day.

Passage of H.R.2029 (2015) repealed the export of crude oil. However, the Natural Gas Act of 1938 (1938) prohibits the export of natural gas from the U.S. if it poses a threat to national interests. Potentially, depending upon the timeline, if significant volumes of natural gas (multi-TCFG) were discovered and could be produced from the Atlantic OCS, this gas could be a source of LNG for export. As of 18-April-2016, Cove Point, MD had been approved by the FERC for LNG export, with the facility under construction (FERC, 2016). An export facility at Elba Island, GA, has been proposed to the FERC and its application is pending; another, at Jacksonville, FL, has been pre-filed with the FERC (FERC, 2016). In any case, a pipeline to shore would be the most likely transport conduit based on FLNG economics to the U.S. market. If natural gas were the primary product discovered, unless the expansion of onshore liquefaction facilities was not possible, multi-Tcf gas fields (with recoverable reserves in excess of 5 Tcf) would be necessary to support an export-dedicated FLNG.

In any development scenario applied to the Atlantic OCS, new facilities will have a significantly smaller sea-surface footprint than typical of older producing fields. Consequently, depending on the water depths and reserves of potential discoveries in the Atlantic Region, subsea completions connected to facilities like spars, or an FPSO, appear the most likely options for oil development. Natural gas transport to shore via pipeline is the most probable scenario with disposition of the gas decided after its arrival onshore.

Methodology

The BOEM resource inventory methodology continues to evolve. BOEM staff use an enhanced reflection seismic database, new gravity and magnetic data sets and displays, subsurface well data from existing U.S. and Nova Scotian drilling, supplemented with geochemical data and sea surface slicks identified on satellite synthetic aperture radar (SAR) data to constrain the areal extents of the AUs. A global database provides appropriate analogs guidance for potential field sizes and hydrocarbon volumes. Taken holistically, these data facilitate a petroleum system approach to define the AUs.

For the purposes of this Atlantic OCS resource inventory, AUs are informally defined by BOEM staff as a single or composite petroleum system and associated hydrocarbon trap(s). This is a modification of the AU definition used by the USGS which describes AUs as consisting of a mappable volume of rock within a petroleum system that encompasses accumulations (discovered and undiscovered) that share similar geologic traits. Accumulations within an AU constitute a sufficiently homogeneous population such that the chosen methodology of resource assessment is applicable. AUs can be conceptual or proven based on the occurrence or postulation of the petroleum system (Klett et al., 2000b; Klett et al., 2005). Schmoker (2005) notes that a petroleum system consists of all genetically related petroleum generated by a pod or closely related pods of mature source rocks. Therefore, they are more closely associated with the petroleum systems than are plays.

AUs were defined after the development and implementation of petroleum system methodology. Consequently, the comprehensive, intimately interconnected nature of petroleum system elements and processes are an integral part of an AU. The play concept was originally defined earlier and did not consider many of the aspects of a petroleum system. Subsequently, the definition of a play was modified to incorporate petroleum systems; e.g., a play being a group of known and/or hypothesized pools that share common geologic, geographic, and temporal properties, petroleum systems, and prospect attributes. In that definition, petroleum systems seem to be an afterthought. Their inclusion seems related to source rocks, rather than all the elements (source, reservoir, seal, and overburden rocks) and processes (trap formation, generation–expulsion–migration–accumulation, critical moment, and preservation time) that are used to define a petroleum system (Magoon and Dow, 1994).

Petroleum systems and AUs provide an all-inclusive, unifying framework for studying oil and gas accumulations, and are not “plays” per se. AUs can and should be defined such that all accumulations (discovered and undiscovered; i.e., pools/fields, or prospects) represent a reasonably homogenous population that can be assigned common probabilities of occurrence for each petroleum system element and process. The geographic extent of each AU in the U.S. Atlantic OCS was delineated by the existing wells, reflection seismic data, potential field data (where of value), sea surface slicks identified using SAR data, and the interpretation of various data to generally delineate the onset of maturity for hydrocarbon generation from sediments in the U.S. Atlantic OCS (Dickson and Christ, 2011).

Before the 2011 resource inventory of the Atlantic OCS (BOEM, 2012), resource assessments of the region relied on productive analogs primarily from the onshore and offshore Mesozoic basins of the GoM and the Scotian Shelf. The primary selection criterion for these analogs was reservoir age. There were serious issues with these analogs; e.g., GoM analogs consisted primarily of salt-cored structures and associated carbonate or siliciclastic reservoirs; Scotian Shelf analogs cited are typically rollover anticlines associated with down-to-the-basin listric faults that appear to detach into the autochthonous salt layer; e.g., Welsink et al. (1989), etc.

With the exception of the Carolina Trough, depocenters of the U.S. Central Atlantic OCS lack sufficient salt thickness and extent to form similar structures, or features with enough vertical relief and areal extent to develop into targetable hydrocarbon traps (McKinney et al., 2005; Dillon et al., 1982). Reflection seismic data throughout the region show the Sable sub-basin is unique among North American Central Atlantic depocenters, being associated with and related to Sable delta system siliciclastics overlying mobile substrate downdip (outboard) from the carbonate margin in that area (Enachescu and Hogg, 2005). In contrast, most depocenters in the U.S. Atlantic OCS are updip and shoreward from the carbonate margin in areas lacking a mobile substrate of either salt or shale and large delta systems. Therefore, only moderate volumes of accommodation space are created in the settings of the U.S. Atlantic OCS, and there are few robust, areally extensive structures on the shelf.

Consequently, for most of the depocenters and areas of the U.S. Atlantic OCS, different analogs were needed. These would have to be developed, considered, and constrained within the framework of the reflection seismic and well data that were part of the late 1960s–1980s exploration phase in the U.S. Atlantic. These data were subsequently supplemented with new gravity and magnetic data, sea surface slicks identified on satellite SAR data, and depth-converted and time-migrated versions of the vintage seismic data.

As a result, BOEM staff began to investigate other analogs. The conjugate Northwest African Margin was initially explored during the same time period as the U.S. Atlantic Margin. Although there was more success there than on the U.S. margin, results from primarily shallow water, shelf-focused exploration were also generally discouraging. In contrast to the exploration moratoria that were imposed on the U.S. Atlantic OCS in the mid-1980s, companies episodically continued to acquire acreage, deep reflection seismic, and drill wells in the offshore areas of the various countries of Northwest Africa. These efforts always used what were considered at the time as state-of-the-art acquisition and processing technology and practices, interpretation techniques, etc. Exploration also took place on the shallow water shelves in other areas of the African and South American Atlantic margin concurrent with exploration conducted in the U.S. Atlantic OCS. Greater success was encountered in Nigeria, Gabon, Cabinda (Angola), Angola, and Brazil than other parts of the African and South American margins. These are not appropriate analogs for the U.S. Atlantic Margin because of mobile substrates.

While regional plate tectonic restorations focus the analog investigation on conjugate Northwest Africa, publically-available geological and geophysical data document and identify other areas whose geological setting and evolution, although not necessarily the age of the formations, are comparable to the U.S. Atlantic Margin. More detailed geologic and petroleum system analyses and evaluation were conducted in those areas; e.g., the South Viking Graben of the U.K. North Sea, the West African and its conjugate South American Transform Margins, the East African Transform Margin, using primarily literature-based research to characterize their petroleum system elements, processes, and any associated discovered reserves and resources.

Analogs considered appropriate for this U.S. Atlantic resource inventory were ultimately selected based on similar or equivalent tectonic or structural setting, with comparable petroleum system elements; i.e., source, reservoir, seal, etc., environment of deposition, lithology, depth of burial, diagenetic history, porosity and permeability, and trap type being considerations. Although a petroleum system of the same age was desirable, geologic age of reservoir, which was previously the sole criteria, was less important. Analogs provided additional data; e.g., “play” area in square mi (mi^2), NFW density (a proxy for prospect density), discovery/pool/field size, discovered pool/field density, estimates of present-day exploration maturity, an estimate of exploration success rate, etc. Consequently, these analogs and their data provide the foundation for this resource inventory.

Until recently, deepwater offshore Northwest Africa, the West African and South American Transform Margins, and the East African Transform Margin, areas similar to the U.S. Atlantic OCS that also had generally poor success when their shallow water shelves were explored, were underexplored. As technology facilitated drilling in deeper water depths, and exploration concepts for deep water subtle turbidite traps on paleo slopes and basin floors evolved, those prospects were targeted, drilled, found to be successful, and prolific (Grant et al., 2013; Hodgson and Rodgriguez, 2015; Sayers, 2015). Since 2007, giant oil and gas fields with reserves and resources of 500 MMBOE and greater have been discovered. These discoveries have resulted in exploration targeting several areas on the Northwest African Margin that is conjugate to the U.S. Atlantic Margin, the West African and South American Transform Margins (Mello et al., 2013; Hodgson and Rodgriguez, 2015; Sayers, 2015), and the East African Transform Margin (Law, 2011; Pereira-Rego et al., 2013). The number of discoveries and their often much larger volumes have increased the reserves and resources in our analogs from an estimated ~4.5 billion barrels of oil equivalent (BBOE) in 2007 to over 36 BBOE at the January 1, 2014 cutoff date for this resource inventory, an approximately eight-fold increase. Although Grant et al. (2013) and Kolly (2015) used different databases and analogs, and provided information from West and East Africa respectively their work shows similar increases in volumes and larger increases in percentage terms.

“Forensic petroleum system analysis”, a concept developed by David E. Brown of the Canada-Nova Scotia Offshore Petroleum Board, is being used by BOEM staff to identify and constrain the primary causes of failure for the wells and prospects drilled on the U.S. Atlantic Margin (see Well Folios @ http://www.boem.gov/Geological-and-Geophysical-Data-Atlantic/. Identification of higher risk elements and/or processes may allow additional geotechnical work (such as, improved petroleum system modeling, better seismic facies interpretation, the analysis of various seismic attributes, controlled-source electromagnetics, etc.) to potentially reduce element or process risk to a level where it is irreducible without drilling. These evolving concepts are reflected in this resource inventory

The BOEM risks its conceptual AUs on both a petroleum system and prospect level. To avoid potential double risking of a single risk element, the forms and verbiage implemented for petroleum system elements (source, reservoir, seal, and overburden rocks) and processes (trap formation, the generation–expulsion–migration–accumulation of petroleum, and preservation) are at a higher level than prospect risk. The presence and/or occurrence of petroleum system elements and processes could be determined or their probability of occurrence constrained by “regional” geological and geophysical data. For example, establishing a source rock presence, and possibly hydrocarbon generation from that source rock has occurred, could be inferred using sea surface slicks identified on satellite SAR data, thermogenically-derived hydrocarbons in piston cores, seismically-identified gas chimneys, or “direct” hydrocarbon indicators; e.g., flat spots, dim outs, amplitudes (in a simple two component system where the primary variable is reservoir fluid type, etc.).

Prospect risk forms address more specific risk scenarios applicable to the probabilities of success on an individual prospect where petroleum system risk does not exist. Examples of prospect level risks are related to the level of hydrocarbon fill, reservoir, and trap components. A dry NFW, or any exploratory well classified according to Lahee (1944), still has a probability of occurrence in areas where a petroleum system has been confirmed and the petroleum system has no risk.

The significance of risking conceptual AUs as petroleum system probability of occurrence and prospect levels is to acknowledge the multiple risks on both. However, if a petroleum system were to be established in any AU, with or without commercial success, the result would be to eliminate that petroleum system risk in that AU. Risk would then be entirely at the prospect level, as it is in the Cretaceous & Jurassic Interior Shelf Structure AU. It is recognized that there may be some interrelationships between petroleum system elements and processes in some AUs; e.g., the Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin AU, and the Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core AU. Eliminating petroleum system probability risk of occurrence in one AU would not necessarily eliminate that risk in another. The significant point is that eliminating petroleum system risks in an AU would remove that risk. The result would be that inventoried resources in an AU without petroleum system risk would dramatically increase, typically ~300%. Those potentially higher values are not reflected in this resource inventory.

The BOEM (2012) initiated the use of a less subjective risk assignment procedure, which was also employed in this resource inventory. This methodology allowed only three probabilities to be assigned based on "definitely exists (high)" or 1.0; "probably exists (medium)" equivalent to 0.75; and "may or may not exist (low)" = 0.50. If any probability is 0, then the petroleum system cannot exist. There are a total of seven (7) petroleum system elements and processes. BOEM staff observed that in conceptual AUs when four or more of the elements and processes of a petroleum system were assigned probabilities of occurrence of 0.50, those petroleum systems were very unlikely to exist. For example; if five of the seven elements or processes have a probability of occurrence of 0.50 and the other two have probabilities of 1.0, then the probability of occurrence is 3%, if all seven probabilities were 0.50, then the probability of the petroleum system existing would be less than 1%, making its existence statistically unlikely. By limiting the probabilities to the three selected values (1.0, 0.75, and 0.50), probabilities of petroleum systems existing in conceptual AUs had values of either p 0.32 or p 0.56. Prospect risks approximated those observed in the analogs although they were rounded to values of p 0.10, p 0.20, and p 0.30. Table 1 contains the petroleum system probabilities, prospect risks, and total exploration probabilities of success used in this Resource Inventory.

U.S. Atlantic

Assessment Unit	Petroleum System Probability	Prospect Risk	Total Exploration Probability of Success
Cretaceous & Jurassic Marginal Fault Belt	0.56	0.10	0.056
Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin	0.56	0.30	0.168
Late Jurassic–Early Cretaceous Carbonate Margin	0.32	0.20	0.064
Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core	0.32	0.20	0.064
Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension	0.32	0.10	0.032
Cretaceous & Jurassic Blake Plateau Basin	0.56	0.10	0.056
Jurassic Shelf Stratigraphic	0.32	0.10	0.032
Cretaceous & Jurassic Interior Shelf Structure	1.00	0.10	0.100
Triassic–Jurassic Rift Basin	0.32	0.30	0.096
Cretaceous & Jurassic Hydrothermal Dolomite	0.32	0.10	0.032

Table 1. U.S. Atlantic Assessment Units with Risks.

As part of this 2016 Resource Inventory, all petroleum system and prospect level risks were reviewed and modified, if necessary, based on evolution of analogs, an updated satellite SAR identified sea surface slick database, and on-going reassessment and interpretation of the BOEM reflection seismic database.

New model input distributions were generated using the analog data. The assessment methodology makes use of a lognormal distribution assumption to generate the field/pool sizes for each AU. Using these data, the model calculates a lognormal approximation of the data that is used to estimate the field/pool sizes within each AU. This lognormal distribution can be specified by two single value parameters, the mean and the variance. The mean is a statistical measure of central tendency of the field/pool sizes in which the logarithms of the variables are normally distributed. The variance is a measure of the amount of spread in the data. Because the theoretical limit of the lognormal distribution is infinity in both directions, the distribution must be truncated to represent a realistic state of nature. The lognormal distribution is restricted by geologic constraints and interpretations that are applied to each AU to create a reasonable high and low boundary for the field/pool sizes predicted in the modeling process. These limits are applied to ensure that the model accurately represents the individual AU. Consideration was also given to the numbers and sizes of fields/pools that could be expected to exist in the AU as well as the largest size resources that could be reasonably accommodated. This was achieved by using available publications, including company or analyst presentations, to estimate the areal extent of each analog discovery and, where possible, the size of each prospect tested and found to be dry or non-productive. The size of the analog basin or setting hosting these discoveries and wells was also measured using available data and literature.

The hydrocarbon exploration maturity level of each analog was estimated based on the number of NFW wells drilled and the resulting success rate for discoveries. Where possible this was done for the primary petroleum system in the analog area. This was determined by review of geological literature, data and information provided in company reports and presentations, and when possible, information from the country in which the analog was located. If the existing numbers of discoveries and wells did not capture at least one entire exploration cycle (defined by at least the term in years of the average license in the country following the initial discovery), or the pseudo-creaming or discovery history curve for the area (Grant et al., 2013) then the analog was considered to be very immature or maturing. In these cases, the data were considered to be evolving and not reflective of the entire discovery history, and were likely conservative and used as a guide, rather than a limit. These data were then compared to the estimated area of each AU and used to determine a prospect density for each. The reasonableness of the estimated number of prospects and eventual prospect density was then evaluated. Typically, the BOEM values were more conservative than data determined from the analog. Because the analogs had discoveries, with resources, reserves, and often production attributed to them, these were established AUs rather than the predominantly conceptual AUs in the underexplored U.S. Atlantic OCS.

The smallest field/pool size considered for this assessment is 1 MMBOE, the same volume typically used in USGS international assessments (Klett et al., 2000a). All fields/pools smaller were truncated/removed from the distribution. The largest field/pool size in the distribution of inventoried resources in the AU was truncated at the largest field/pool size in the analog distribution. These lower and upper bounding field/pool sizes limit the distribution of the sizes of the fields/pools that are predicted for each AU. In addition, where the state of exploration in an analog was considered immature and evolving, BOEM staff made an effort to reflect this observation. Meisner and Demirmen (1981) established the creaming method in forecasting future oil and gas discoveries in petroleum provinces. Essentially, in a typical discovery history, once commercial discoveries are made, the largest discoveries occur early in the exploration cycle. This reflects economically driven selection of prospect testing in which the areally largest, easiest defined targets are drilled early in an exploration cycle. Because many of the analogs are considered immature and their exploration history is developing, the creaming curves are still very steep, showing no indication of flattening. This indicates that the percentage of very large fields in the ultimate population of discoveries may still be evolving. Consequently, when an analog was considered immature, BOEM staff was conservative, limiting the percentage of very large discoveries to values significantly below their present occurrence.

Assessment Units in Atlantic Planning Areas

Planning Area	North Atlantic
Assessment Unit	Triassic–Jurassic Rift Basin
	Cretaceous & Jurassic Hydrothermal Dolomite
	Cretaceous & Jurassic Interior Shelf Structure
	Jurassic Shelf Stratigraphic
	Late Jurassic–Early Cretaceous Carbonate Margin
	Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core & Extension

Planning Area	Mid-Atlantic
Assessment Unit	Cretaceous & Jurassic Interior Shelf Structure
	Jurassic Shelf Stratigraphic
	Cretaceous & Jurassic Marginal Fault Belt
	Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin
	Cretaceous & Jurassic Blake Plateau Basin
	Late Jurassic–Early Cretaceous Carbonate Margin
	Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core & Extension

Planning Area	South Atlantic
Assessment Unit	Cretaceous & Jurassic Blake Plateau Basin
	Late Jurassic–Early Cretaceous Carbonate Margin
	Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension

DISCUSSIONS OF ASSESSMENT UNITS

Figure 2 shows the areal extent of each AU defined by BOEM in the U.S. Atlantic Region.

Descriptions and discussions of each Assessment Unit organized by progression from the most updip (shoreward) to most downdip (basinward or deepest water) in the Mid-Atlantic Planning Area, as typified in the OCS offshore North Carolina, will be addressed in the following order.

1. Cretaceous & Jurassic Marginal Fault Belt AU
2. Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin AU
3. Late Jurassic–Early Cretaceous Carbonate Margin AU
4. Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core AU
5. Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension AU

The five above AUs contain 88% of the total estimated UTRRs in the region. The Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core & Extension AUs are discussed together.

The remaining five AUs contain an estimated 12% of the UTRRs in the region and are more geographically diverse. Their order of discussion will be:

6. Cretaceous & Jurassic Blake Plateau Basin AU
7. Jurassic Shelf Stratigraphic AU
8. Cretaceous & Jurassic Interior Shelf Structure AU
9. Triassic–Jurassic Rift Basin AU
10. Cretaceous & Jurassic Hydrothermal Dolomite AU

Cretaceous & Jurassic Marginal Fault Belt Assessment Unit

Confined to the Mid-Atlantic Planning Area, the undrilled Cretaceous & Jurassic Marginal Fault Belt conceptual AU occurs in a seismically defined area of ~8,500 mi^2 in the updip region of the undrilled Carolina Trough (Figure 2). Water depths in the AU range from approximately 1,000–4,000 ft. Productive analogs similar to seismically identified features in the AU are located in the updip areas of the onshore GoM Mesozoic basins of East Texas, South Arkansas, and Mississippi-Alabama-Florida; e.g., 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, 2016), Florida (Florida Dept. of Environmental Protection, 2016), 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 GoM 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). In 1982, Dillion et al. 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.

For this resource inventory, 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 laminated lime mudstones of Oxfordian age. Algal- and bacterially-derived organic matter predominates in the source interval with mean total organic carbon (TOC) values ranging from 2–6% (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 satellite SAR data (proprietary CGG NPA report), 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, because of a higher percentage of sandstone-rich intervals, sealing lithologies in this updip paleo shelf area may not be as effective as farther basinward. However, regional marine transgressions in the Cretaceous and Jurassic (Figure 2) indicate the presence of potential sealing intervals. On their poster panels, Coleman et al. (2014) show sealing intervals even farther updip, in Pamlico Sound of North Carolina, based on wireline log character.

Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin Assessment Unit

The conceptual Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin AU is located downdip (basinward) from the Cretaceous & Jurassic Marginal Fault Belt AU (Figure 2). This AU is undrilled, and covers an area of approximately 5,700 mi^2, entirely within the Mid-Atlantic Planning Area. Present-day water depths in this AU range from approximately 8,000 ft to greater than 9,000 ft.

Siliciclastic reservoirs are interpreted to be the primary targets, although carbonates deposited in high-energy environments may also occur. Resources associated with the Late Jurassic–Early Cretaceous Carbonate Margin AU that bisects the area are assessed separately. Although source rocks have yet to be identified in this AU, they can be inferred by sea surface slicks identified using SAR data (A. Williams, Fugro NPA Limited, personal communication, 2010), chemosynthetic communities, methane venting at the sea floor, and reflection seismic data (Paull et al., 1995; Paull et al., 1996; Taylor et al., 2000; Ruppel, 2008). The reservoir element of the petroleum system has not been confirmed by drilling. Therefore, although regional correlations suggest that reservoirs may occur, they remain a risk factor. Vertical salt movement is interpreted to provide cross-stratal migration conduits connecting deeper, mature oil and gas source rocks with younger reservoirs.

Using 2D seismic reflection data and side-scan sonar data, between 25 and 30 salt "diapirs" have been interpreted in the Carolina Trough salt basin (Dillon et al., 1982; Popenoe, 1984; Carpenter and Amato, 1992). The exact number of salt structures interpreted depends on the volume and quality amount of seismic data available to delineate these salt structures and the confidence level of the interpreter.

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. This is a critical point, because it is not known what percentage of these data, if any, was migrated. The data used by those authors are displayed in the time domain except for figure 21 of Dillon et al. (1982), which is noted as being depth-converted. 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 the seismic data also improves its imaging. In the case of the U.S. Atlantic OCS 2D seismic data set, 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. Yilmaz (2001) provides reasons to convert seismic information from time to depth and information on the techniques used.

Unfortunately, because of the steep, near vertical nature of virtually every interpreted salt body, 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 where the reflected energy on the line is actually located, either in or out of the plane of the data, and how far away. Although multiple closely spaced 2D lines can improve the definition of a feature, there are still geometric issues related to migration of the reflectors in the single vertical plane of the data. 3D seismic data provides a more precise (although still not perfect) salt body depiction. However, no 3D data have ever been acquired in this AU. Therefore, the exact location, size, and geometry of these features in this AU are subject to some uncertainty.

The "regional" 2D seismic grid available to the BOEM throughout much of this AU ranges from ~1.25 to ~3.25 mi in a "dip" (approximately NW–SE) direction, and from ~3 to ~7 mi in a "strike" (approximately 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 mi or less. Most of the salt bodies interpreted by BOEM staff for this resource inventory are controlled by two or more 2D seismic lines. Those lines, although 2D, have been depth-converted and time-migrated.

Although subject to considerable error, the 2D seismically identified area of individual salt bodies generally ranges between a few square miles and >15 mi^2 (Popenoe, 1984; Carpenter and Amato, 1992). These size ranges are confirmed by the more recent BOEM interpretations of depth-converted, time-migrated versions of the data. The geometry of these structures is somewhat speculative because of the imaging issues associated with the 2D reflection seismic data.

Several salt bodies have bathymetric expression, either reaching the sea floor or being close enough to it to deform it. Because of possible trap breaching, the crests of these salt bodies are interpreted to be less prospective due to trap integrity than their flanks. Deeper salt bodies, such as those more than 5,000 ft below the sea floor may provide hydrocarbon traps on their crests or their flanks. The largest salt bodies would be preferred targets because of the deep waters in this AU.

Nevertheless, several important questions 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? An AU analog, the Northwest African conjugate margin Mauritania–Senegal–The Gambia–Guinea Bissau–Conakry (MSGBC) basin, contains similar salt-related structures; e.g., diapirs, toe thrusts, detached salt bodies, etc., that are productive and prospective (Maier, 2006). Woodward (2015) published a summary of activity in the analog area in late 2015. Production from analogs is limited in this remote underdeveloped area. As of the January 2014 cutoff date used in this Resource Inventory, most discoveries were either: being delineated; moving toward Final Investment Decision (FID) or Front End Engineering and Design (FEED); being developed; or pending license terms held in abeyance awaiting higher product prices. Resources from these analogs were derived from sources such as industry and company reports and presentations. Using the selection criteria for analogs described in ***Methodology***, those selected for this AU resulted in a range of discovery size from approximately 70–300 MMBOE.

Demonstrating possible issues regarding analogs and resource inventory arbitrary cutoff dates are two potentially significant discoveries in the deepwater area of conjugate southern offshore Mauritania and adjacent Senegal. During April and May 2015, after the cutoff date for analogs used in this assessment had passed, Kosmos Energy (2015a) announced that Tortue-1 had encountered 351 ft of net gas pay at the Tortue West (Ahmeyim) structure. The gas was reservoired in two Late Cretaceous sandstones. The discovery established an outboard Cretaceous petroleum system in Mauritania-Senegal. As of mid-2016, the limited, publically available seismic data fail to resolve whether or not the trapping structure is cored by salt. The reservoirs involve one of a series of Late Cretaceous slope channel reservoir systems within one of the group of combination structural-stratigraphic traps which comprise the Greater Tortue Complex. The discovery and its hosting structure were renamed Ahmeyim/Guembeul because it spans the Mauritania–Senegal international boundary. By March 2016, two highly successful delineation/appraisal wells had been drilled. These wells increased the Pmean (terminology of Kosmos, 2016a) gross resource estimate for the Tortue West structure to 15 TCFG (~2.5 BBOE) by enlarging the areal extent of the Cenomanian and the Albian reservoirs. This resource volume establishes the Ahmeyim/Guembeul discovery as the largest associated or non-associated gas discovery ever made offshore West Africa (Kosmos Energy, 2015a). In addition, a subsequent delineation well increased the Pmean gross resource estimate for the Greater Tortue Complex to over 20 TCFG (Kosmos Energy, 2016a). Resources of that size occur in the field/pool size distribution for the Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core & Extension AUs, but not in the Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin AU. This discovery will have a significant impact, increasing the field/pool size maximum and the mean of the distribution of resource volumes. In November 2015, Kosmos Energy (2015c) announced a significant play-extending discovery, Marsouin, ~37 mi north of Ahmeyim. Pmean resources cited for the Marsouin Channel and Anticline are 2 and 5 TCFG, respectively. In May 2016, Kosmos Energy (2016b) announced another discovery in the trend, Teranga-1, with Pmean resources of 5 TCFG.

Late Jurassic–Early Cretaceous Carbonate Margin Assessment Unit

The Late Jurassic–Early Cretaceous Carbonate Margin AU of the U.S. Atlantic OCS of eastern North America contains a number of shallowing-upwards sequences recording the progradation and aggradation of the Abenaki platform margin during that time. Although deeper, older parts of this carbonate margin complex (Prather, 1991) may be prospective, the youngest, most basinward bank edge, generally represented by the Baccaro Member of the Abenaki Fm, is interpreted to have the highest potential (Kidston et al., 2005; Offshore Energy Research Association, 2011). Seismic and subsurface data offshore Nova Scotia identifies this prospective bank edge as a variable, narrow zone 9–15 mi wide. In the U.S. Atlantic OCS, seismic data and a limited number of wells suggest that the conceptual Late Jurassic–Early Cretaceous Carbonate Margin AU, a continuation of prospective belt offshore Nova Scotia, is also a narrow band, typically averaging less than 10 mi wide. Kidston et al. (2005) documented along-strike changes in the geometry of the Abenaki carbonate margin offshore Nova Scotia. From northeast to southwest, the margin evolved from a progradational, gently dipping ramp-like margin with inter-fingering carbonate and clastic facies, to a steeper sigmoidal bank margin, to an eroded margin, and a faulted/eroded margin (Kidston et al., 2005). Seismic data in the U.S. Atlantic OCS also illustrates changes in margin geometry along strike. Extending from the U.S.–Canadian border through the North, Mid-, and South Atlantic Planning Areas to The Bahamas (Figure 2), this AU covers an area of ~12,000 mi^2 in water depths from ~3,500–6,500 ft.

Deep Panuke, a 1999 natural gas discovery on the shallow water shelf offshore Nova Scotia, is the analog for this AU. The field, delineated with 12 wells, is ~12 mi long and ~1 mi wide. Six of seven development wells were successful. Wells in the reservoir contained 33–330 ft of dry gas pay and had a common gas-water contact. Five wells were tested, with the average test being >50 MMCFG per day. Resources were estimated to range between ~400 BCFG and 1.4 TCFG based on the comprehensive work of EnCana (2006). Dolomitized, fractured reservoirs at Deep Panuke are associated with the Late Jurassic Abenaki Fm (Baccaro Member), that EnCana (2006) informally designated as the Abenaki 4 and 5 carbonate margin (Figure 3) in reefal and reef-adjacent depositional environments (Kidston et al., 2005; Wierzbicki et al., 2006; Eliuk, 2010). Prior to the discovery, Harvey (1993) and Harvey and Macdonald (1990 and 2012) used seismic and well data to model, recognize, and identify porosity in the Abenaki at the future location of Deep Panuke, delineating and de-risking reservoir occurrence.

Conjugate to Nova Scotia, limited exploration for equivalent carbonates has taken place offshore Morocco. A biodegraded heavy (10°–15° API) oil discovery was made in 1969 in porous dolomitic limestone intervals (karstified?) at Cap Juby on the Moroccan margin. Recoverable reserves at Cap Juby have been estimated at 40–70 MMbbl (Kidston et al., 2005). A recent attempt by Cairn Energy PLC et al.

to locate, extend, and define the area of better quality oil in the Middle Jurassic below the Late Jurassic heavy oil was unsuccessful (Cairn Energy PLC, 2014).

Geochemical analyses of condensates in the Deep Panuke field analog (Zumberge, 2010) indicate that their source rock contained a mixture of algal and terrestrial organic matter. Biomarkers are consistent with a paralic-deltaic marine shale source of Jurassic age, similar to the Verrill Canyon Fm., which is the basinward facies equivalent of the Abenaki (Figure 3) that ranges in age from Early Jurassic to Early Cretaceous (Wade and MacLean, 1990). Terpane/sterane thermal maturity ratios indicate Deep Panuke condensates are much more mature than Panuke and other Scotian Shelf condensates and oils, with multiple periods of charging, consistent with possible gas washing (Zumberge, 2010). Diamondoid methyladamantane/methyldiamantane thermal maturity ratios also show Deep Panuke condensate more mature than Panuke oils reservoired in overlying, younger (Early Cretaceous) siliciclastic reservoirs (Zumberge, 2010). Top seals for the reservoir at Deep Panuke are overlying, nonporous limestones of the informal Abenaki 6 and 7 (EnCana, 2006; Weissenberger et al., 2006).

Before the Deep Panuke discovery, NFW drilling for Abenaki carbonate margin traps took place offshore Nova Scotia and in the U.S. Atlantic OCS. Pre-discovery of Deep Panuke, Kidston et al. (2005) classified seven wells as bank edge NFWs and nine other NFWs as having targeted carbonates behind, or siliciclastics in front of, the bank edge. All were dry holes. Shell (operator), Amoco, and Sun Oil Co. drilled three wells (Wilmington Canyon (WI) 586-1, WI 587-1, and WI 372-1) during 1983–1984 in the southern Baltimore Canyon Trough (BCT) in the current North Atlantic Planning Area of the U.S. Atlantic OCS (Figures 4 and 5).

The Shell et al. wells in the BCT targeted various potential carbonate margin trap types in present-day water depths ranging from 5,838 to 6,952 ft. Despite areally large structural/stratigraphic closures with significant vertical relief and porous limestone reservoirs, no significant hydrocarbon shows were encountered in any of the wells (Prather, 1991). All the wells were abandoned as dry holes with minor gas indications recorded by mud logging equipment.

The wells drilled offshore Nova Scotia and by Shell et al. in the BCT were similar enough to apply the same formation terminology and an analogous vertical depositional progression, including a regional Berriasian–Valanginian drowning event. A significant difference was that the wells in the BCT encountered strata richer in carbonate sand. Two of the BCT wells, WI 586-1 and WI 587-1 (Figure 5), were drilled behind the margin edge where reef-flat sands would be more commonly expected (Eliuk and Prather, 2005). Muddier facies with more reef framebuilder-rich beds are encountered on the Nova Scotia margin (Eliuk and Prather, 2005). Most of NFWs in Nova Scotia were located nearer the steep margin between the “double-flexure”, or slightly down-ramp from a distally steepened ramp (Eliuk, 1978; Eliuk and Prather, 2005; Wierzbicki et al 2006).

In this AU, a variety of carbonate lithologies; limestone, dolomitized limestone, or dolostone, the latter probably due to secondary alteration (as is the reservoir at Deep Panuke), could be anticipated to provide reservoirs. Any overlying impermeable carbonates or shales could provide top seals.

Depending on location within this region-spanning AU, any or all of the petroleum system elements (source, reservoir, seal, and potentially overburden sufficient to mature source rocks) may be risks. Harvey (1993) and Harvey and Macdonald (1990 and 2012) demonstrated that risks associated with reservoir occurrence, general thickness, and areal extent could be reduced. Petroleum system processes of generation–expulsion–migration–accumulation (and associated vertical cross-stratal migration conduits likely to be necessary between mature source rocks and shallower, younger, reservoirs) are possible risks.

Fluid Inclusion Technologies, Inc. (FIT), a Schlumberger company, provided insights into the petroleum systems in this AU as part of a fluid inclusion stratigraphic project that incorporated the WI 587-1, WI 372-1, and WI 586-1 wells (Figures 4 and 5). The updip (landward) WI 587-1 (Figures 4 and 5) was interpreted by Eliuk and Prather (2005) to have tested an areally extensive region of near-shelf margin domal or plateau-like features. These were slightly argillaceous, chalk or chalk-like deposits of high porosity but low permeability, with little or no apparent age gap between the chalky limestone and the overlying shale. These "mesas" were interpreted by Eliuk and Prather (2005) as deep-water (not slope) constructional features. A similar sponge reef at the top of the shelf-edge in the Artimon Member of the Abenaki Fm. in Demascota G-32 offshore Nova Scotia is interpreted to have formed in water depths between ~330 and 660 ft (Eliuk, 1978). Although in the area of WI 587-1, Eliuk and Prather (2005) interpret more rapid pelagic and benthic sedimentation.

Fluid Inclusion Technologies, Inc. (2015a) performed a Fluid Inclusion Stratigraphy (FIS) analysis on 251 cuttings samples from 8,560–14,500 ft in the WI 587-1.

- The interval above ~11,400 ft contains relatively low hydrocarbon indications, although methane values are sufficient to indicate anomalous dry gas below 11,020 ft. C1-C4 species increase progressively with depth and may indicate a diffusion or maturation profile within largely tight rock. A thin section from 11,370 ft consists of carbonate and lesser shaly carbonate with no visible liquid petroleum inclusions. Some gas inclusions are tentatively interpreted to be present. Shales in this interval contain minor organic matter.
- The section from 11,400–12,860 ft contains gas and minor liquid-range species to C8 with bulk spectra that resemble dry to wet gas. Highest liquids concentrations are noted in two main zones: 11,450–11,810 ft and 12,150–12,680 ft. Sulfur species of probable thermal origin are identified intermittently through this section, including SO_2, which can indicate porous, water-bearing reservoir rock. Helium tends to covary with gas and suggests a volatile portion of the migrated petroleum phase. Both of these zones are within what has been interpreted to be the Baccaro Member of the Abenaki Fm. (Figure 3) that contains the productive interval from Deep Panuke (Wierzbicki et al., 2006). Five thin sections were prepared from this interval, and all were carbonate dominated. Rare, white-fluorescent oil inclusions are identified at 12,530 ft, suggesting a migration event. Minor live (fluorescent) stain is noted at 12,530 ft and 12,680 ft. Rocks in this interval are organic-lean.
- Below 12,860 ft, the section contained dry gas anomalies with highest values below 14,060 ft. Minor sulfur species of probable thermal origin were identified, suggesting influx of mature gas from deeper in the basin, or deeper in the stratigraphic column. Two thin sections from 13,190 ft and 14,300 ft contained no visible liquid petroleum inclusions. Gas inclusions may occur in the carbonates. Minor drill bit metamorphism was identified at 14,300 ft and may account for some elevated gas responses in this interval.

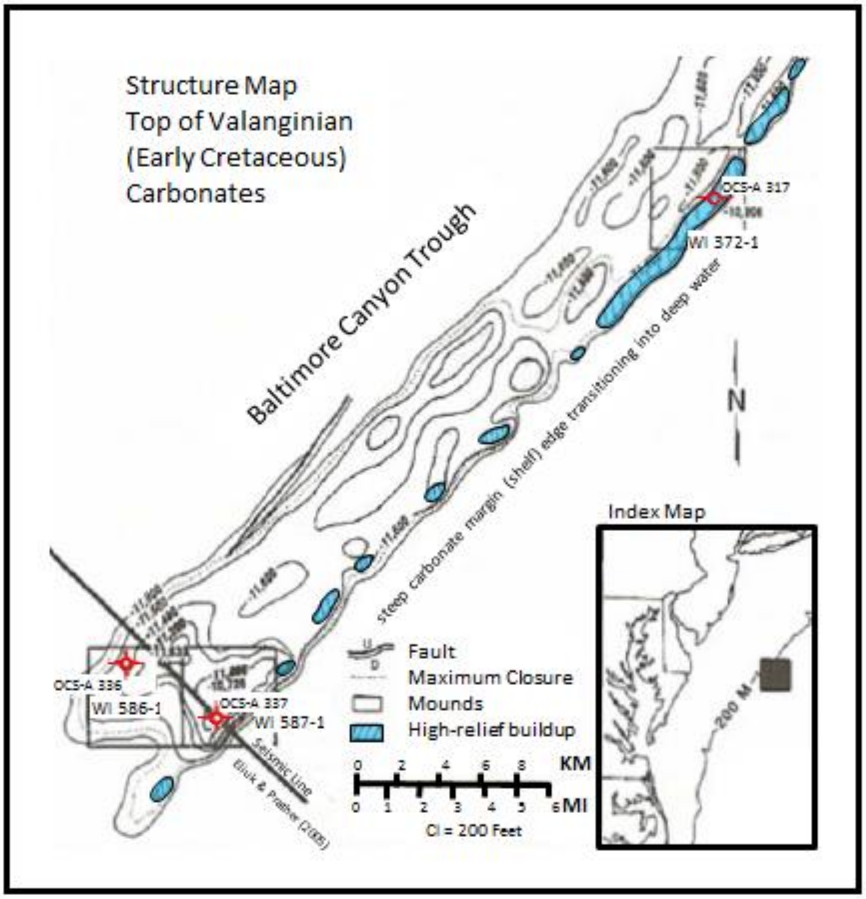

Figure 5. U.S. Atlantic OCS, Baltimore Canyon Trough, structure map top of the Valanginian (Early Cretaceous) carbonates showing location of WI 372-1, WI 587-1, and WI 586-1 wells discussed in text (modified after Eliuk and Prather, 2005).

Farther basinward, on the edge of the Abenaki carbonate margin, the WI 372-1 well (Figures 4 and 5) tested the landward side of a high-relief build-up (Eliuk and Prather, 2005). The age of the shallow-water carbonates in WI 372-1 is younger, Early Berriasian, than similar facies in the more shelfward WI 587-1 (Eliuk and Prather, 2005). Shallow-water carbonate sedimentation continued at the margin in the area of WI 372-1 resulting in a 'pinnacle-like' feature, a *keep-up* carbonate interpreted to represent a relatively rapid rate of carbonate accumulation (Sarg, 1988) after that deposition had ceased in the updip area of WI 587-1 (Eliuk and Prather, 2005).

No significant shows were noted by conventional petrophysical analysis, although the chromatograph on the mud log indicates some minor occurrences of methane, ethane, and propane. Potential source rocks in the well were found to be organic-lean, gas-prone, and thermally immature. The well was abandoned as a dry hole. FIS analysis was performed on a total of 143 cuttings samples from 9,170–11,631 ft in WI 372-1 (Fluid Inclusion Technologies, Inc., 2015b).

- Higher gas responses were found below 10,950 ft, particularly below 11,290 ft, in the Baccaro Member. Helium, which is anomalous, and likely represents a volatile component of a migrated petroleum phase, was also noted. A thin acetic acid anomaly was noted at the top of the interval 10,970–11,000 ft. These anomalies could indicate presence of nearby reservoired oil or gas-condensate.
- Four thin sections were prepared. Rare, yellow-fluorescent, moderate gravity oil inclusions were identified in silty shale at 11,470 ft. Rare, blue-fluorescent, upper-moderate gravity light oil or condensate inclusions were noted in carbonate at 11,580 ft. Minor migration events are implied.
- Additionally, possible non-fluorescent gas inclusions were identified at all depths and could indicate the presence of a separate gas charge in the section. Rock types were dominated by carbonate with lesser silty shale. Shales contained moderate amounts of gas-prone and rare, apparently mature oil-prone kerogen (although independent maturity data suggest the entire penetrated interval is immature). Rare dead stain was noted at 11,330 ft and rare live (fluorescent) stain was identified at 11,580 ft.

These data are encouraging, because Prather (1991) noted that at the WI 372-1 location downlap of the upper Albian sequence boundary (LKI) on the upper Berriasian sequence boundary (LKIII). This implied that the Berriasian shelf-margin carbonates were exposed locally on the sea floor, or possibly the sea surface, for roughly 46 million years before a top seal of sufficient thickness to be resolved seismically was deposited (Prather, 1991).

At Deep Panuke, the top seal for the Abenaki 5 reservoir consists of non-porous, argillaceous carbonates and shales of the overlying Abenaki 6 and 7 cycles (EnCana, 2006; Weissenberger et al., 2006), not overlying younger downlapping shales.

The Shell et al. WI 586-1 (Figures 4 and 5) was drilled landward (~3.25 mi northwest) from the WI 587-1. Its primary objective was a thin carbonate of Early Cretaceous age located over a prograding "clastic wedge" as identified and described by Edson and Carpenter (1986). Eliuk and Prather (2005) describe the feature as a landward "flexure" with ~500 ft of relief, with an area of approximately 70 mi^2 within fault and simple closure (Prather, 1991). The shallow objective was at a depth of ~9,000 ft; ~3,200 ft below the mudline, and it and the overlying and underlying stratigraphic section were therefore immature for thermal hydrocarbon generation. The well encountered the expected late Early Cretaceous margin high-energy facies (Edson and Carpenter, 1986). Although no significant shows were identified during mud logging, the chromatograph recorded traces of methane, ethane, and propane. Conventional cores and petrophysical analysis of wireline well logs also failed to find any significant shows (Nichols, 1986). A conventional core taken in the interval had good porosity, ranging from 10–24% (averaging ~17% over the 22 ft of recovered core). Permeability was fair–poor, ranging from 0.042-12.2 mD, averaging 2.45 mD (Cummings, 1984). No obvious cross-stratal migration conduits between this shallow objective and deeper more thermally mature zones are obvious on seismic. The underlying

Early Cretaceous–Late Jurassic 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). Although no significant shows were encountered in this interval, traces of methane through butane were encountered in the FIS analysis (Fluid Inclusion Technologies, Inc., 2015d, e), suggesting thermogenic gas.

FIS analysis was performed on a total of 382 samples. These consisted of drill cuttings from 7,970–16,000 ft in WI 586-1 (Fluid Inclusion Technologies, Inc., 2015d). Conventional geochemical analysis determined that source rock potential was low, and the stratigraphic section is thermally immature to a depth of ~12,000 ft. Below that depth, palynomorph colors suggest borderline maturity (Miller et al., 1986; Fry, 1986).

- The section above 9,060 ft contained generally low FIS hydrocarbon indications.
- From 9,060–9,880 ft, dry gas spectra with trace wet gas species were found. Sulfur compounds of possible bacterial or thermal origin are identified, including the compound SO_2, which is often associated with porous reservoir rock that is water-bearing. Intermittent benzene anomalies may indicate proximity to gas charge. These could also represent a fragment from a sulfur compound. A thin section from 9,430 ft consists of porous carbonate with no visible liquid petroleum inclusions. Some gas inclusions may be present. Rare dead stain was noted.
- The section from 9,900–11,625 ft contained generally low FIS hydrocarbon responses with weak, intermittent dry gas indications.
- Between 11,650 ft and 14,280 ft, dry gas anomalies with acetic acid were encountered. These could be indicative of nearby oil or condensate. Trace sulfur species of probable thermal origin were identified as well. Strongest methane responses were broadly identified at 11,750–13,560 ft. Two thin sections were prepared from 12,250 ft and 13,440 ft. Both are dominated by carbonate with lesser shale. Neither contains visible liquid petroleum inclusions, but non-fluorescent gas inclusions may be present. Minor dead stain was identified. Shale contained minor organic matter.
- The remainder of the analyzed section (14,300–16,000 ft) contained strong wet gas to gas-condensate responses that initially built with depth to about 14,800 ft, possibly indicating a diffusion profile through tight rock. Five thin sections were prepared from this zone. Rare, white and/or yellow-fluorescent oil inclusions were identified in carbonate at 14,460, 15,480, and 15,780 ft. Blue-fluorescent oil or condensate inclusions were identified in low abundance at 15,780 ft. Migration events are suggested. Non-fluorescent gas inclusions may be present in this interval as well. Some dead stain was recognized, and organic content was low. Some porosity was noted in sandstone at 14,460 ft. Otherwise, the carbonate-dominated section contained relatively low visible porosity.

Microthermometric analysis was performed at 14,460 ft and 15,480 ft by Fluid Inclusion Technologies, Inc. (2015e).

- 14,460 ft:
    - The cuttings sample consisted of carbonate with lesser shale and minor dead hydrocarbon stain. Trace shale contained minor gas-prone and mature oil-prone kerogen. Several, non-fluorescent gas inclusions and rare, white and yellow-fluorescent, unknown-gravity oil inclusions were observed in carbonate cement.
    - Data were collected from aqueous inclusions along quartz dust rims. Homogenization temperatures of these aqueous inclusions are in the range 84–109˚C with the majority of values in the 95–103˚C range, suggesting maximum burial temperature near 109˚C. Current burial temperature is estimated to be about 70˚C. Salinities vary from 0.0–0.7 weight

percent salt, to 1.4–5.6 weight percent salt. This is indicative of fresh water as a minor fluid source, and brackish to evolved marine fluids as major fluid sources.

- 15,480 ft:
  - Samples of drill cuttings consisted of carbonate, lesser shaly carbonate, and sandstone. A moderate amount of dead hydrocarbon stain was noted. Minor gas-prone kerogens were present in the carbonate. The sample contained several, non-fluorescent gas inclusions and rare, white-fluorescent, unknown gravity oil inclusions in carbonate cement.
  - Data were collected from aqueous inclusions near quartz dust rims. Aqueous inclusions homogenize in the range 94–106˚C and have salinities of 0.0–4 weight percent salt. Data suggest that maximum burial temperature may have been at least 106˚C and fluid sources may have consisted of fresh to marine fluids. Current temperature at this depth is estimated at 75˚C.

Preservation of trapped hydrocarbons related to a combination of seal presence, lithification, and integrity represents a significant risk factor in this AU. Modeling of possible hydrocarbon trap charge and structural development must be evaluated on a prospect-by-prospect basis. For example, although preserved, reservoired oils in the carbonate margin are severely biodegraded at the yet-to-be commercialized Cap Juby discovery offshore Morocco. This has been inferred to be related to proximity of the overlying unconformity and present-day shallow reservoir depth (Kidston et al., 2005). An intra-Abenaki top seal, as at Deep Panuke, makes identifying and quantifying seal risk in this AU difficult. BOEM staff has identified possible hydrocarbon indicators on seismic data in parts of this AU. These include flat spots within the shelfward dipping carbonate margin beds, and amplitude anomalies similar to those identified pre-discovery at Deep Panuke by Harvey (1993), and Harvey and Macdonald (1990 and 2012). Where present, these may help better assess prospect risk.

Deep Panuke, the single discovery in Nova Scotia that has been used as the analog (Wierzbicki et al., 2006), is now operated seasonally. The field came on-line in August 2013. In such a fractured, karstified, dolomitized reservoir with high vertical permeability, the possibility of coning water above the known, established water level common to all wells in the field was a very real risk. The operator may have chosen to accept this risk because natural gas prices during the 1st quarter of 2014 averaged $19.10/MCFG and contributed $395 MM to EnCana's operating cash flow (The Globe and Mail, 2014). Deep Panuke is now produced only when natural gas prices are at their winter highs; e.g., the field was brought back on-line in late October 2015 to take advantage of increased pricing caused by compressor outages. Gas sales are handled by nomination 24 hours at a time so production can be increased or decreased depending on the market-to-market need (EnCana, 2015).

Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core & Extension Assessment Units

The Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core AU is interpreted to occur in the North and Mid-Atlantic Planning Areas. The more distal Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension AU is recognized in the North, Mid-, and South Atlantic Planning Areas (Figure 2). Both AUs are conceptual.

The location of the carbonate margin generally progrades basinward and aggrades with time, becoming younger and shallower basinward. Consequently, it is possible that many of the margins have a paleo-slope siliciclastic depositional system downdip (basinward) from it. The "core" AU is closer to its various carbonate margins and the "extension" AU is more distal (Figure 2). The AU locations depicted in Figure 2 are based on the position of the youngest carbonate margin. These are the most basinward AUs of the U.S. Atlantic OCS. Present-day water depths for these AUs range from approximately 4,500–8,000 ft (core) to approximately 8,500–10,500 ft (extension). Coarse-grained lithofacies of siliciclastic turbidites and mass flow deposits on the paleo-slope and basin floor, where present, could constitute reservoir facies. After the publication of the BOEM 2012 assessment (BOEM, 2012), other presentations; e.g., Grant et al. (2013), Erlich and Inniss (2014), and Hodgson and Rodgriguez (2015), were published describing comparable deep and ultra-deepwater plays and AUs. These authors often used similar differentiating characteristics to those used by the BOEM to define its “core” and "extension” as separate AUs.

Reservoirs in the “core” AU area (Figure 2) are siliciclastics deposited on paleo-slope and uppermost paleo-basin floor settings (Figure 3). 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). Traps are both combination structural-stratigraphic and stratigraphic. Identifying and delineating potential reservoir and updip sealing mechanisms in both AUs is often difficult (Grant et al., 2013; Hodgson and Rodgriguez, 2015; and Sayers, 2015). The “core” AU comprises approximately 20,000 mi^2. Several analogs are considered applicable. Most appropriate for the combination structural-stratigraphic rollover traps are the Jurassic-age siliciclastic reservoirs of the South Viking Graben of the UK North Sea (Turner and Allen, 1991; Branter, 2003; Brehm, 2003; Fletcher, 2003a & b; Gambaro and Donagemma, 2003; Hook et al., 2003; Wright, 2003). Other analogs for structural-stratigraphic and stratigraphic traps in the “core” AU include the Cretaceous-age reservoirs of deepwater fields of the Tano basin (offshore Ghana and Côte d’Ivoire) and the Sierra-Leone-Liberian basin (offshore Sierra Leone & Liberia) of the African Transform Margin (Jewell, 2011), and the Woodbine fields of the southern part of the onshore East Texas basin.

Farther basinward, in the “extension” AU (Figure 2), hydrocarbon traps are interpreted to be primarily stratigraphic. In this AU, unconfined basin-floor fans, stacked/amalgamated channels and lobes, and amalgamated sand-rich channels are typical (Grant et al., 2013). This AU is estimated to encompass approximately 59,000 mi^2. Appropriate analogs include fields and discoveries from the South Viking Graben (United Kingdom sector, Fletcher, 2003b), the West African, South American, and East African Transform Margin (Jewell, 2011), and the onshore Texas downdip Woodbine (Bunge, 2011).

Although these AUs have similar petroleum system elements and processes, they differ in important details. These AUs are considered independent rather than dependent because their depositional slope types/profiles favor different reservoir and trapping configurations (Grant et al., 2013; Hodgson and Rodgriguez, 2015), source rock development, organic matter type, and petroleum system processes (trap formation, generation–expulsion–migration–accumulation, critical moment, and preservation time) are interpreted to vary with paleo location, overburden thickness or present burial depth, and heat flow.

The analogs used for these AUs have seen their total reserve/resource volumes grow approximately eight-fold since 2007 (when BOEM staff researched and developed the first version of this analog database) from ~4.5 BBOE to over 36 BBOE. Grant et al. (2013) and Kolly (2015), often focusing on different populations of discoveries on the West and East Africa offshore respectively, report aggregated volume and percentage resource/reserve increases estimated to be from ~1.5 to ~32.75 BBOE, or ~22 fold. As of the January 2014 cutoff date for this Resource Inventory, the field/discovery analogs used in determining field/pool size in these AUs was a mixture of producing fields, some of which have been fully or nearly depleted, and discoveries in various stages of delineation, FID, FEED, or development. Data sources have included production data from the United Kingdom, the Texas Railroad Commission, various country reports of field/discovery size, as well as industry and company reports and presentations. The analogs used by BOEM staff contain reserves/resources ranging from less than 1 MMBOE to +1 BBOE, with more than 50% of those exceeding 200 MMBOE. These values are similar to those cited by Grant et al. (2013) and Kolly (2015).

A significant data point for potential reservoir and source rocks is DSDP 603B (Figure 4) that is located ~250 mi east of Cape Hatteras, North Carolina. At DSDP 603B, variable source rock intervals of Late and Early Cretaceous age have TOC values between 0.57 and 20.4%. Type II / II-III & III kerogen, with Type III predominating, were described (Herbin et al., 1987; Katz, 1987; Stein et al., 1989). Typically, source rocks, unless there are large quantities of sulfur present, are considered immature at vitrinite reflectance (R_o) values of less than 0.6 (Peters and Cassa, 1994). The organic matter in DSDP 603B sediments, in so far as it is not recycled, is immature, increasing only slightly from a vitrinite reflectance (R_o) of ~0.20% in the shallowest Tertiary sample studied to about R_o 0.30–0.35% in the Barremian to Valanginian (Rullkötter et al., 1987). Rock-eval pyrolysis T_{max} values from the well confirm the immature nature of these potential source rocks. The threshold needed for maturity is a pyrolysis T_{max} greater than ~435°C (Peters and Cassa, 1994). Within Tertiary strata, pyrolysis T_{max} values increase from about 38O°C to about 415°C. In Cretaceous age sediments, most are close to 425°C (Rullkötter et al., 1987). The petroleum system process of generation–expulsion–migration–accumulation has not taken place this far basinward because of the lack of sufficient overburden and/or heat flow. Therefore, the downdip (southeastern) boundary for the "extension" AU must occur shoreward (westward) from DSDP 603B.

Dickson and Christ (2011) developed a methodology for approximating a line beyond which the onset of maturity for hydrocarbon generation may occur. Essentially, increasing sediment thickness and regional heat flow data can be used to determine when a sedimentary package would enter the hydrocarbon generating window. They also determined that at a sediment thickness of more than ~13,000 ft, the deepest (approximately 3,300') of those sediments would be mature for oil generation. The location of source rocks within that sediment interval, the organic matter type, and its richness remain unknown. The organic matter type, its kinetics, and level of thermal stress determine the predominant hydrocarbon type(s) generated and their percentages. No inferences regarding the type or volume of oil and/or gas generated-expelled-migrated can be made with any reasonable degree of confidence, because these are unknown throughout wide areas of these AUs.

The exact location of the line best depicting the onset of maturity cannot be determined. However, general credence to a location in the area depicted by Dickson and Christ (2011) is established by ODP 997B (Figure 4). Updip (landward) from the Dickson and Christ (2011) maturity onset line, ODP 997B (Figure 4) was drilled on Blake Ridge, a significant topographic feature in the U.S. Central Atlantic. The ridge is formed by a thick post-Eocene sediment drift (Tucholke et al., 1977) that overlies essentially horizontal, pre-Neogene sediments (Tucholke and Mountain, 1979). Below the bottom simulating reflector (BSR) that marks the interpreted base of the gas hydrate in ODP 997B, Paull et al. (1996) state: "Microscopically visible oil occurred from ~500 to 620 mbsf (meters below sea floor). This observation, coupled with the occurrence of higher molecular weight hydrocarbon gases, suggests some migration of oil and gas." The sediments containing this "oil" are Late Miocene age. Lithologically, it is a diatom-rich interval within a generally homogeneous, dark greenish-gray, nannofossil-bearing clay and claystone (Paull et al., 1996). A mixture of microbial and thermal gases is encountered within and below the hydrate stability zone. The ODP 997B site is thermally immature with a R_o of 0.3% near the total depth. Therefore, the thermally-derived gases must have migrated from older, deeper, more mature source rocks. Based on their carbon isotope ratios, the corresponding source rock would be a marine facies with a maturity within the oil window, R_o ~0.6% to 1.0% (Wehner et al., 2000). Candidate, organic-rich, marine facies have been encountered and described in DSDP 534A and 391C in the Blake Bahama basin, and DSDP 105 and 603B farther north in the offshore area east of North Carolina (Katz and Pheifer, 1982; Herbin et al., 1983; Herbin et al., 1986; Summerhayes and Masran, 1983).

DSDP 603B and the Shell et al. Baltimore Rise (BR) 93-1 well (Figure 4) provide insights into reservoir deposition in these plays. DSDP 603B contains an Early Cretaceous (Valanginian to Barremian age) turbidite unit approximately 980 foot thick, 45% of which is siltstone-sandstone in grain size. The turbiditic sequence is topped by ~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).

BR 93-1, approximately 230 mi to the northeast (Figure 4), targeted a large, faulted structure related to the 'Gemini Fault System' (Poag et al., 1990). The anticipated reservoirs in this trap were interpreted to have been in the updip, shelf-margin delta system that sourced the downdip turbidite fan complex described in DSDP 603B (Sarti and von Rad, 1987). BR 93-1 encountered no charged reservoirs or conventionally identifiable hydrocarbon shows in this interval (Prather, 1991). Water depths during deposition of these strata were estimated to have ranged between 130 and 590 ft, middle to outer shelf depositional environment (Prather, 1991), rather than the lower slope and abyssal environments of DSDP 603B. However, several zones in the Early Cretaceous in BR 93-1 had TOC content exceeding 1%, with Type III (gas-prone) kerogen predominating. The deepest interval in the well approached, or was in, the oil maturity window (Amato [ed], 1987). BR 93-1, the last well drilled and completed during the initial phase of exploration in the U.S. Atlantic OCS, was the only well to target this reservoir objective. A fluid inclusion stratigraphic study completed in late 2015 by FIT provides additional insights related to the BR 93-1 well (Fluid Inclusion Technologies, Inc., 2015c). These include:

- The interval above 9,090 ft (Tertiary–Cenomanian) contained dry gas anomalies throughout with trace sulfur species of probable bacterial origin. CO_2, also of probable bacterial origin, was elevated above 7,890 ft. Rare gas-prone and immature oil-prone kerogens were identified.
- From 9,240–17,050 ft (Early Cretaceous, Albian/Aptian–Berriasian[?]), intermittent dry gas responses were recorded. The highest methane values occurred from approximately 10,100–11,500 ft (Valanginian–Berriasian). Baseline liquids response increased with depth in trace amounts. This is interpreted to probably represent a maturation profile of minor intercalated oil-prone kerogens. Three thin sections were prepared. A thin section from 11,200 ft consisted of carbonate, lesser sandstone, and minor shale. Rare, blue-fluorescent, upper-moderate gravity light oil inclusions occur in the sandstone. Rare, gas-prone kerogen was also noted. Thin sections from 13,350 ft and 15,280 ft consisted of silty shale and lesser sandstone and carbonate with no visible petroleum inclusions. Gas-prone kerogen was commonly identified. Several occurrences of live (fluorescent) stain were noted in the deeper sample.
- Below 17,050 ft (Berriasian?), stronger wet gas spectra, particularly at 17,260–17,450 ft and 17,620–17,670 ft, were noted. Minor sulfur species of possible thermal origin were identified from 17,290–17,420 ft. Helium is also anomalous in this interval, probably indicating a volatile component of the migrated petroleum phase. Four thin sections were prepared. Rare, blue-fluorescent, upper-moderate gravity and yellow-fluorescent, unknown gravity liquid petroleum inclusions were identified in silty shale, sandstone, and carbonate at 17,110 ft, suggesting migration events. No visible liquid petroleum inclusions were noted in the deeper three thin sections from 17,260 ft, 17,420 ft, and 17,630 ft, all of which were dominated by carbonate and silty shale. The shale contained common gas-prone kerogen and minor, mature oil-prone kerogen. Rare, dead stain was identified at 17,260 ft and 17,420 ft. Data suggest probable migration of gas from a more mature source interval.

In both AUs, the petroleum system elements considered of highest risk are the presence of reservoir and source rocks. Reservoir risks (Grant et al., 2013) are related to several points. If the lithology of the provenance rocks eroded to become the potential reservoirs is not quartz-rich, then mudstones rather than sandstones would be the result of erosion and transport into the areas of these AUs. Paleogeography and drainage area are also considerations, because big, sand-rich systems typically require large rivers with long source-to-sink distances, typically 300 mi or more in an Atlantic Margin-style setting (Grant et al., 2013). Too low a sediment volume results in an insufficient amount of coarse-grained facies (potential reservoirs) reaching the depositonal slope and basin floor. The shelf setting and its geometry influence sand transport and sorting because a broad shelf allows reservoir intervals to be cleaned up and concentrated. The geometry of the depositional slope and/or basin-floor also affects reservoir distribution and trapping configurations (Grant et al., 2013). The presence and type of organic matter in potential source rocks are risks. As noted above, ODP and DSDP wells confirm the presence of thin, immature source rocks in basinward ultra-deepwater settings. Sealing lithologies should be abundant in these AUs as fine-grained sediments predominate in both. Overburden in conjunction with heat flow will determine the maturity and timing of generation–expulsion–migration from any source rocks present.

Examples of potential hydrocarbon traps similar to those in analogs have been demonstrated with existing seismic data interpretations by BOEM staff. This seismic data grid ranges from approximately 4 mi (in a dip direction) by 6 mi (in a strike direction) in parts of the North Atlantic Planning Area to approximately 20 mi by 100 mi in much of the Mid- and South Atlantic Planning Areas. This affects the ability to accurately delineate prospect geometries and density along strike in these AUs.

Migrated, mature hydrocarbons in BR 93-1 and ODP 997B provide positive indications of generation–expulsion–migration in the area of those wells in these AUs. Although not in commercial volumes at those locations, this supports the presence and maturity of organically rich source rocks and possibly migration conduits between mature source rocks landward from the ODP and DSDP wells as suggested by Dickson and Christ (2011). Potential reservoirs have been encountered updip (on the paleo-shelf) and downdip in DSDP 603B (Sarti and von Rad, 1987). Timing of generation–expulsion–migration–accumulation from any source rocks and the accumulation and preservation of those hydrocarbons are possible risks depending on the depositional setting and trap/seal/hydrocarbon charge timing. It is important to recognize and acknowledge that based on the analogs, the reward size may exceed several hundred million barrels of oil or trillions of cubic ft of natural gas in an individual trap.

Cretaceous & Jurassic Blake Plateau Basin Assessment Unit

The conceptual Cretaceous & Jurassic Blake Plateau Basin AU encompasses the undrilled Blake Plateau basin (BPB) downdip from the Southeast Georgia Embayment (SEGE), an area of approximately 38,000 mi^2 (Figure 2). This AU area is interpreted to be predominantly in the South Atlantic Planning Area; although, it extends slightly into the Mid-Atlantic Planning Area (Figure 2). Water depths over this AU range between 2,000 and 3,600 ft. A COST well was drilled in the SEGE during 1977. It was followed by six industry NFWs in the SEGE during 1979 and 1980. All of the wells were drilled outside the main depocenter in the BPB, and were plugged and abandoned providing no results considered positive at that time.

Because these seven wells did not drill within the main area of this AU, there is limited relevant petroleum systems data available. In addition, there are a limited number of identifiable potential analog basins for this AU. Two of the best explored analogs are the South Florida basin (SFB) onshore Florida (Pollastro et al., 2001), and the Paris basin (PB) (Perrodon and Zabek, 1990; Sindwell, 1997; Wendebourg and Lamiraux, 2002). Exploration success rates and reserves per discovery are low in both analog basins (Pollastro et al., 2001; Perrodon and Zabek, 1990).

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. Given the nature of the source rocks in the analog basins, and considering a similar depositional setting likely in the BPB, it is believed the BPB has a higher likelihood of oil-prone source rocks than many other areas of the Atlantic OCS. Intraformational evaporites or impermeable carbonates (marls) typically provide local and regional seals in both analog basins (Perrodon and Zabek, 1990). Even though the large, regional, basin-scale structures in both basins have not proven effective hydrocarbon traps, they may have localized reservoir development and focused local hydrocarbon migration with most fields situated preferentially on one of their flanks. 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 (Pollastro et al., 2001; Perrodon and Zabek, 1990).

In an effort to maximize the understanding of the petroleum system of the area, Fluid Inclusion Technologies, Inc. (2015f) performed a Fluid Inclusion Stratigraphy (FIS) analysis on 518 cutting samples from 1,020–13,230 ft in the COST GE-1 (Figure 4), a stratigraphic test drilled in 1977 in the updip SEGE, which is considered non-prospective, and not part of this AU as defined on Figure 2. Drilled in 136 ft of water, the well was the deepest drilled in the SEGE. As a stratigraphic test, the well was intentionally located away from any potential hydrocarbon-bearing structures or traps. After penetrating Tertiary and Cretaceous strata, TD was reached at 13,254 ft in weakly metamorphosed units (Scholle, 1979) radiometrically dated as Devonian (Simonis, 1979). The well is ~40 mi landward of the western margin of the deepest part of the BPB where thicker Mesozoic sediments were deposited (Dillon and Popenoe, 1988).

No significant shows were reported in COST GE-1. Fluid Inclusion Technologies, Inc. (2015f) noted that the water-soluble species benzene, toluene, and phenols were identified in minor concentration in drillstem test (DST) 3 from 7,458–7,608 ft, possibly indicating transport from a distal accumulation. Trace organic gases were also identified in DST 1 at 10,428–10,461 ft. Some source-quality, marine organic matter was identified in the interval between 3,600 and 5,900 ft, although the zone is immature at the wellbore location (Fluid Inclusion Technologies, Inc., 2015f). The interval below about 8,000–9,000 ft may be in the oil window. Drill cuttings in this interval are described as having significant cavings and poor to fair preservation of organic matter (Core Laboratories, Inc., 1977), and are organically lean (Smith, 1978).

- The interval above 2,790 ft (Tertiary) contains weak dry to wet gas species along with sulfur compounds of probable bacterial origin. This could represent a microseep, which would be encouraging for deeper liquids exploration in the vicinity. No thin sections were evaluated in this interval.
- The section from 2,820–4,000 ft (Tertiary–Late Cretaceous) contains low FIS hydrocarbon responses and no significant bacterial species.
- The section from 4,040–7,060 ft (Late to Early Cretaceous) contains intermittent gas and somewhat decoupled liquids indications with the most significant features at 4,590–4,970 ft, 5,770–6,110 ft, and 6,560–7,060 ft. Decoupled gas and liquids could indicate contributions from intercalated kerogen or a two-stage migration history involving oil and gas. Sulfur species are identified at 4,590–4,770 ft. These could be of bacterial or thermal origin. Acetic acid anomalies at 5,770–5,830 ft may be sensing nearby liquid petroleum charge. Thin sections were prepared from five depths. Rare, white-fluorescent, oil inclusions are identified in carbonate cement at 5,850 ft. This sample is dominated by silty to sandy carbonate. Minor organic matter is identified, including immature oil-prone kerogen. No visible liquid petroleum inclusions are identified in other thin sections from 4,770 ft, 6,580 ft, 6,740 ft, or 6,960 ft, although some visible gas inclusions may be present in carbonate. Minor gas-prone organic matter is noted. Rock types are generally dominated by carbonate. Increases in head space gas and organic richness, although not at levels sufficient to expel hydrocarbons from a source rock (an original TOC >2.0%; W. Dow, personal communication 2015), were documented in the well report (Smith, 1978).
- The interval from 7,080–11,090 ft (Early Cretaceous into the top of the Paleozoic) contains intermittent dry gas anomalies with strongest responses from 10,700–11,090 ft. Three thin sections were prepared from this zone. All contained visible liquid petroleum inclusions in low to

moderate abundance within sandstone and silty shale. White and blue-fluorescent subtypes are most common and appear to contain upper–moderate gravity light oils or condensates. Yellow-fluorescent, moderate gravity oil inclusions are less common. Moderate inclusion abundance suggests migration events. Minor dead oil stain is identified. The section is generally organic-lean.

- The remainder of the analyzed section, from 11,120–13,230 ft (Paleozoic), contains low FIS hydrocarbon indications.

Microthermometric analysis was performed at 9,040 ft and 10,860 ft, in Early Cretaceous interval of COST GE-1 by Fluid Inclusion Technologies, Inc. (2015g).

- 9,040 ft:
  - Cuttings sample consists of silty shale, sandstone and carbonate with some porosity. Shale is organic-lean. Minor dead hydrocarbon stain is noted. Several, white and blue-fluorescent, upper-moderate gravity liquid petroleum inclusions are identified in sandstone and silty shale. Rare, yellow-fluorescent subtypes are present as well. Blue-fluorescent oil inclusions with large vapor bubbles produce unreliably high homogenization temperatures (133–240℃), representing the possible variability of heterogeneous entrapment of oil and gas. API gravities are 43–45°. White-fluorescent oil inclusions give measured homogenization temperature (Th) of 50–55°C with a single data point at 80˚C, representing minimum encapsulation temperatures of oil, and API gravities of 43–45°.
  - Aqueous inclusions near quartz dust rims homogenize somewhat bimodally in the ranges 90–100°C and 115–120°C. The former mode has salinities of 13–21 weight percent salt (significantly influenced by evaporites) and the latter gives variable salinities of 3, 6, and 11 weight percent salt (marine-like to evolved basin brines or representing fluid mixing). A few aqueous inclusions from the high Th range display metastable phase behavior during cooling tests. This indicates low salinity fluids. Data suggest that maximum burial temperature may have been as high as 120°C, although independent maturity information for this well, suggest lower maximum temperatures. An alternate maximum is suggested at 102°˚C (R_o equivalent of 0.66%. The highest reliable non-caved R_o measured was approximately 0.6%). Pore fluids are dominated by evaporite-derived brines. Present day temperature is 88°C.
  - Aqueous inclusions hosted by carbonate cement have Th of 79°C, 96°C, and 102°C, representing temperatures during or after carbonate cementation. Salinities during these events were quite high at 21.4–22 weight percent salt (near salt saturated brines). Salinities are significantly higher than DSTs.
- 10,860 ft:
  - Cuttings sample consists of sandstone, shale, and carbonate with some porosity. Shale is organic-lean, and dead hydrocarbon stain is present in minor abundance. Rare, white and blue-fluorescent oil inclusions are observed in sandstone.
  - Aqueous inclusions near quartz dust rims produce Th in the range 110–130°C in general, suggesting that maximum burial temperature may have been near 130°C. Again, other maturity data suggest lower temperatures; thus an alternate maximum of 115°C (R_o 0.78%) may be more reasonable (measured R_o is about 0.75–0.86%). Measurable salinities are 1.7–2 weight percent salt (brackish water) and 3.2–4 weight percent salt (marine-like), representing fluid sources for this depth. Many aqueous inclusions display metastable phase behavior during the freezing tests. As a result, salinities cannot be determined but are inferred to be low. Present-day temperature is 96°C.

FIT data shows a prominent microseep in Tertiary to Late Cretaceous strata in COST GE-1. This may indicate deeper liquid petroleum potential in the BPB. The lack of zones sufficiently organic-rich or mature enough to provide the hydrocarbons for this microseep, suggest that a lateral liquid petroleum charge may have migrated from deeper in the BPB depocenter. The distance to the source of this cannot be accurately determined (Fluid Inclusion Technologies, Inc., 2015f).

Homogenization temperatures of aqueous inclusions in COST GE-1 are higher than present-day burial temperatures (Fluid Inclusion Technologies, Inc., 2015g), implying that the interval had a higher geothermal gradient in the past (based on the proposed burial history curve, which is essentially currently at maximum burial). However, the estimated maturity from fluid inclusions is consistent with measured R_o data in the well. This suggests that the higher heat flow may represent a short term pulse, that was not long enough to affect the other thermal indicators, such as R_o; or that the inclusions are related to fluids from a higher heat flow environment possibly migrated from deeper in the basin.

High measured salinities of aqueous inclusions require direct interaction of pore fluids with evaporites. Lack of penetrated salt or evaporites may suggest that these fluids were derived from deeper in the basin. As hydrocarbons may have used the same "plumbing system", it is possible that this is evidence for a deep basin source of liquids and gas that is proximal to evaporites (Fluid Inclusion Technologies, Inc., 2015g). This would be consistent with the source rock depositional environments similar to those from our SFB and PB analogs within which source rocks are interrelated with anhydrite and minor salt stringers that result in anoxic conditions conducive to organic matter preservation.

Additionally, there is evidence of thermogenic liquids having migrated through the Late and Early Cretaceous section in the COST GE-1. At least two temporally distinct periods of hydrocarbon charge are indicated by the FIT data: a dry, mature, thermogenic gas; and several pulses (probably volumetrically less, although this is speculative) of oil with variable characteristics (dominantly moderate to upper-moderate gravity, gas-undersaturated liquids). Gas undersaturation suggests that the two phases (oil and gas) were temporally distinct and did not occupy the reservoirs concurrently. Measured API gravities are 43–45° (Fluid Inclusion Technologies, Inc., 2015f).

Drilling results from the updip, shallow water SEGE led the BOEM staff not to consider that area as likely for any hydrocarbon resources because the wells failed to find any significant thickness of mature source rocks, or regional top seals. Only the wells closest to the BPB; e.g., the COST GE-1, had indications of migrated hydrocarbons that are inferred to have originated from the deep depocenter. However, the larger, deeper main BPB is undrilled. Expectations, based on the SFB and PB analogs, are low. Drilling ~1,100 NFWs 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; Sindwell, 1997). However, acknowledging our uncertainty about this undrilled basin, we recognize that the BPB could, if successfully explored in the future, have the largest positive assessment adjustment percentage of any AU in the Atlantic OCS.

Jurassic Shelf Stratigraphic Assessment Unit

Updip from the Late Jurassic–Early Cretaceous Carbonate Margin AU, the conceptual Jurassic Shelf Stratigraphic AU covers an area of approximately 10,000 mi² (Figure 2) in approximate current water depths between 200–2,600 ft. As defined, no wells have been drilled in this AU specifically targeting these objectives.

The reservoir element of the petroleum system is anticipated to consist of limestones and/or dolomites, as in the onshore GoM analog fields; e.g., Walker Creek (Arkansas), Oaks (Louisiana), and Little Cedar Creek (Alabama). Although minor faulting may occur, the AU is considered primarily stratigraphic because reservoir facies define and control the hydrocarbon trap. Chimene (1991) provides a detailed discussion on the Walker Creek field (Arkansas), the largest of the analog fields. Throughout the onshore analog area, Oxfordian-age laminated lime mudstones are confirmed as the source for Jurassic shelf reservoirs (Sassen, 1990). The source component in this AU is considered probable, but is unproven as wells drilled along trend often lack hydrocarbon shows. In addition to possible intraformational source rocks (typical of the analogs), deeper carbonate formations are also probable source rocks (Sassen and Post, 2008; Sassen, 2010). Trap seals are interpreted to be non-porous carbonate units, possibly with minor evaporite intervals or thicker evaporite units that overlie or are laterally adjacent to the reservoirs.

Even though the vintage (1966 through 1988) seismic data available to assess this AU were not acquired with a high enough frequency content to identify these stratigraphic traps, some areas of interest in this AU can be identified. Current (2016) state-of-the-art deep penetration reflection seismic acquisition and processing parameters would better image the stratigraphy in these carbonate depositional environments, with a higher likelihood of identifying prospects in this AU. Analog fields appropriate for this AU have produced between 2 and 80 MMbbl prior to their abandonment (Geological Survey of Alabama, State Oil and Gas Board, 2016; Louisiana Department of Natural Resources [SONRIS Lite], 2016; Arkansas Oil and Gas Commission, 2016).

This AU is divided into two areas (Figure 2) separated by the structures of the Cretaceous & Jurassic Interior Shelf Structure AU. It is interpreted to occur in the North and Mid-Atlantic Planning Areas.

Cretaceous & Jurassic Interior Shelf Structure Assessment Unit

The Cretaceous & Jurassic Interior Shelf Structure AU occurs over an area of approximately 3,400 mi² (Figure 2) in the Baltimore Canyon Trough in water depths ranging from 150 to 3,000 ft. This is the only established AU (one in which the petroleum system is confirmed) in the U.S. Atlantic Region. It 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 mature older Jurassic age source rocks and siliciclastic reservoirs of younger Jurassic and Cretaceous age and form structural traps for these hydrocarbons (Prather, 1991; Sassen and Post, 2008; Sassen, 2010).

This AU was targeted by 14 NFWs drilled between 1978 and 1981. This exploration effort resulted in a single gas-condensate discovery in the Hudson Canyon (HC) 598 area (Figure 4), the largest structure on the Gemini Fault System. Following the discovery, seven exploratory/delineation/appraisal wells were drilled in the four-OCS block unit area.

Cased hole DSTs were attempted through perforations (typically after a mud cleanup acid treatment followed by a low volume acid treatment to establish connectivity between the well bore and the formation) on all eight wells with natural gas successfully tested in six. Late Jurassic zones tested at rates as high as 18.9 MMCFG; averaging ~5 MMCFG on variable chokes. Flowing pressures averaged 3,500#. Typical condensate yield was ~4 bbl of average 43° API condensate per MMCFG. Rates were variable, often declining over time. Flow times ranged from 3 to 33 hours, averaging 13 hours. 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 a similar source rock provides the hydrocarbons for all of them. The condensates are enriched in diamondoids and ^{13}C, showing similarities to condensates from laminated lime mudstone source rocks (Sassen and Post, 2008; Sassen, 2010).

An unpublished BOEM analysis of the HC 598 area integrated seismic interpretation, wireline log correlations, mud gas shows encountered while drilling, detailed petrophysical analyses of wireline logs, incorporation of all sidewall and conventional core data, and analysis of all test data. At least 70 reservoir compartments were identified. The DST results indicated that the majority of the tested intervals have very low permeability and/or have limited drainage areas. This implied a lack of continuity and communication between zones indicated productive by petrophysical and core analyses. BOEM staff assigned a resource range for a first-phase development scenario using multi-laterals and fracs for the

HC 598 area of between ~85 and ~254 BCFGE, with a mean of ~160 BCFGE. Commerciality for the HC 598 area is currently considered questionable for a variety of reasons; e.g., reservoir continuity and compartmentalization, flow baffles, production rates, and costs, etc.

Because an accumulation in this AU has been discovered it has no petroleum system risk. Risks exist for individual prospects as demonstrated by other structures drilled and tested without success in similar trapping configuration along the Gemini Fault System. These risks are related to the presence or absence of anti-regional dip associated with the trap-forming faults, how and when those faults function as migration conduits connecting older/deeper/mature source rocks with younger reservoirs, if/when those faults seal or leak the hydrocarbon accumulation, what may be the local nature of the source rocks, the occurrence of permeability in the siliciclastic reservoirs, the presence of traps with minimum rock poroperm volumes, and the presence of effective regional/local top seals.

This AU is recognized in the North Atlantic and the extreme northern part of the Mid-Atlantic Planning Areas.

Triassic–Jurassic Rift Basin Assessment Unit

During early 2013, BOEM staff reinterpreted seismic data in and adjacent to the Georges Bank basin (GBB) of the North Atlantic Planning Area (Figures 1 and 2). As a result, the area of the conceptual Triassic–Jurassic Rift Basin AU was reduced from ~10,000 to ~4,500 mi^2. Water depths over this AU range from ~150 to 800 ft.

At least 30, and possibly as many as another 20, Triassic–Jurassic rift basins are 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 conventional oil and gas or coalbed methane (CBM) accumulations 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).

Post-syn-rift, transpressional/contractional stress affected all onshore (Withjack et al., 2012) and offshore (Post and Coleman, 2015) Late Triassic–Early Jurassic rift basins in the eastern U.S. This stress resulted in basin inversion and concurrent or subsequent erosion of the uppermost (youngest) syn-rift strata. Observed in all onshore and offshore rifts, this represents a common, shared, objective observation and a risk factor that affected all rift basins in the region. Several methodologies estimate the amount of erosion to vary within basins and possibly within individual subbasins and depocenters. Typically, the erosion ranges from ~3,000–10,000 ft, with most onshore basins having closer to 10,000' of late syn-rift material eroded (Pratt et al., 1988; Steckler et al., 1993; Malinconico, 2002; Post and Coleman, 2015). Eliminating this thickness of strata from the late syn-rift would erosionally remove any reservoirs, traps, and hydrocarbons from this part of the section. Hydrocarbon traps not eroded might also be subject to being breached, flushed with fresh water, or having their overlying top seals fractured.

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). These data clearly indicate a sag phase of basin development associated with the Yarmouth basin. This is unique, occurring in no other onshore or offshore Late Triassic–Early Jurassic rift basin of the eastern U.S. (Post and Coleman, 2015). Seismic data quality, especially at depth, is not uniform, because not all data in the area was reprocessed. Consequently, a proxy was developed to locate extent of the underlying Yarmouth Late Triassic–Early Jurassic rift basin. This was a practical solution where the seismic data was reprocessed. In those cases, an overlying sag phase of basin development was always easily recognized as was the underlying Triassic–Jurassic Rift Basin AU. Where the deep seismic data was poor, the deeper rift structure could not be delineated. However, the overlying sag phase of basin development could always be identified and used to locate the underlying rift.

Seismic data, and geohistory modeling based on the interpretation of those data, indicate less inversion/erosion in the Yarmouth basin as documented by the preserved, relatively thick, post-rift sag phase of sedimentation/basin development (Post et al., 2011; Post and Coleman, 2015). Consequently, potential late syn-rift and possibly post-rift, sag phase hydrocarbon traps are preserved in the Yarmouth basin, increasing the probability that significant hydrocarbon prospectivity may exist.

Macgregor (1995) used data from 105 rift basins to characterize rift basins into three broad categories: simple rifts, locally inverted rifts, and regionally inverted rifts. Although the number of rifts in each category was not specified, Macgregor (1995) found that only 62% of the regionally inverted rifts had any conventional oil and/or gas, only 19% of these basins had fields of 250 MMBOE, and none had fields of 2 BBOE. In contrast, 92% of all locally inverted rifts had some oil and gas, and 76% had fields of 250 MMBOE, and 16% had fields with 2 BBOE. Some oil and/or gas was found in 93% of the simple rifts, and 37% of those had 250 MMBOE fields, while 8% had fields of 2 BBOE fields. All onshore and offshore Late Triassic–Early Jurassic rift basins in the U.S. (except the Yarmouth basin) are regionally inverted rifts. Therefore, their lack of conventional discoveries is not unexpected. A literature review based on Macgregor (1995) shows that a preserved sag phase of basin development is characteristic of either a regionally inverted or simple rift. The Yarmouth basin with its preserved sag phase of development is the only example of a locally inverted Late Triassic–Early Jurassic rift in the eastern U.S. (Coleman et al., 2015; Post and Coleman, 2015). For that reason, its hydrocarbon prospectivity might be better than the other onshore and offshore Late Triassic–Early Jurassic rift basins of the Eastern U.S.

However, because the target structures in the Yarmouth basin are undrilled, their prospectivity is speculative. Ductile strata, whose nature is unknown, appear to core the deepest parts of these structures and facilitate their formation. There is no conclusive evidence to determine the nature of this ductile material. However, there is a general geometric similarity between the inversion structures in Yarmouth basin and those in the various rift grabens of the West Natuna basin of Indonesia where the ductile unit is shale (Macgregor, 1995; Maynard et al., 2002; Hakim et al., 2008; Cherdasa et al., 2013; Manur and Jacques, 2014).

Petroleum system elements (source, reservoir, seal, and overburden rock) are found in every major onshore eastern U.S. Late Triassic–Early Jurassic rift basin. It is therefore reasonable to expect that the petroleum system elements will be found in the Yarmouth basin (Post and Coleman, 2015). Sealing mudstone and shale lithologies are likely throughout the syn-rift, sag phase and within the post-rift sedimentary interval. Petroleum system processes (Magoon and Dow, 1994) that acted on and influenced the petroleum system elements (trap formation, generation–expulsion–migration–accumulation, critical moment, and preservation time) are documented in every onshore eastern U.S. Mesozoic rift basin (Coleman et al., 2015). Although not proven by drilling, source rocks and generation–expulsion–migration are inferred because satellite sea-surface slicks are interpreted in the Yarmouth basin area (Post and Coleman, 2015).

Failure to date to locate commercial, conventional oil or gas fields in all of the east coast Mesozoic rift basins implies that a rift basin with slightly different characteristics might be the key to breaking that paradigm. Late syn-rift traps may be preserved, because seismic data identifies a sag phase of development in the Yarmouth basin indicating less inversion and erosion. Geohistory models indicate that if source rocks are present and of typical richness in the Yarmouth, they did not expel all of their hydrocarbons before the post-rift strata were deposited, indicating a second phase of hydrocarbon expulsion and trap charge may occur (Post et al., 2011; Post and Coleman, 2015). In addition, when considered in the context of the global classification scheme for rift basins (Macgregor, 1995), the poor exploration results in the regionally inverted onshore eastern U.S. rift basins are not surprising. The Yarmouth basin is unique among all onshore and offshore eastern U.S. Late Triassic–Early Jurassic rift basins being only locally inverted. A case can be made that it may be the most prospective of all of these basins for conventional hydrocarbon accumulations (Post and Coleman, 2015).

Analogs for the Triassic–Jurassic Rift Basin AU were found in the Vulcan Graben of offshore NW Australia. In this area, complex rift-related structures contain hydrocarbons in Triassic and Jurassic siliciclastic reservoirs with production and/or reserves estimated to range between ~2 and 300 MMBOE per field/discovery (Geoscience Australia, 2008). Productive inversion structures similar to those interpreted in the undrilled Triassic–Jurassic Rift Basin AU are also documented in the West Natuna basin (Maynard et al., 2002; Burton and Wood, 2010). Estimated reserves in this basin range from ~1–2.4 BBOE, with the largest field having ~400 MMBOE (Howes and Tisnawijaya, 1995; Howes, 1997; Manur and Jacques, 2014). These structurally analogous West Natuna basin fields were not used in the field size distribution for this AU because it is believed there are significant differences in reservoir age, depth of burial, and petrophysical characteristics, especially permeability. Data for onshore eastern U.S. Late Triassic–Early Jurassic rift basins in Coleman et al. (2015) and Post and Coleman (2015) average ~13% porosity and ~70 mD of permeability. These values are significantly lower than the average porosity of ~20% and permeability of 500 mD for the locally inverted Late Oligocene–Early Miocene reservoirs of the KH field in the West Natuna basin (Pollock et al., 1984).

CRETACEOUS & JURASSIC HYDROTHERMAL DOLOMITE ASSESSMENT UNIT

The area of the conceptual Cretaceous & Jurassic Hydrothermal Dolomite AU (Figure 2) was also reduced as a result of the 2013 seismic data reinterpretation in the northern part of the GBB in the North Atlantic Planning Area (Figure 1). The AU is now interpreted to occur over a much smaller area of ~1,500 mi^2, in water depths that range from ~100 to 1,100 ft. This AU is associated with the crest and northwest flank of the Yarmouth Arch in the U.S. OCS.

The Yarmouth Arch is a significant structural element of the eastern North American Central Atlantic. Similar to many comparable features, it may have been related to Pangea assemblage and subsequent Pangea breakup (Pe-Piper et al., 2010). Wade (1990) provided the most information on the Yarmouth Arch and its relationship to the Georges Bank and Scotian basins. He described the arch as a buried complex of approximately north-northeast-trending basement elements consisting of several blocks that formed the boundary between the Georges Bank basin and the Shelburne subbasin of the Scotian basin. Seismic data cited by Wade (1990) indicated that the arch was an early-formed, topographically and structurally positive feature that limited communication between the Georges Bank and Scotian basins. Maps in Deptuck et al. (2015) support this interpretation. As noted above, because the nature of the ductile strata that at depth cores the inversion structures in the west-adjacent Yarmouth basin (Post and Coleman, 2015), the presence or volume of salt in that basin is speculative. Allochthonous and autochthonous salt structures are only found east of the Yarmouth Arch, in the Sable sub-basin (Wade, 1990; and Deptuck et al., 2015). Given this understanding and the uncertainty of the nature of the ductile formation in the Yarmouth basin, BOEM currently interpret the Yarmouth Arch to separate salt-poor depocenters on the southwest (the Georges Bank and Yarmouth basins) 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). Later, 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 and through the present-day. It maintained a mild influence on later units based on stratigraphic thicknesses, facies changes, and erosional patterns. Wade (1990) suggested that the large amplitude, linear magnetic anomalies trending south from the vicinity of Yarmouth, Nova Scotia, toward the Yarmouth Arch, suggested a possible structural relationship between the two areas.

Because the AU is undrilled, the petroleum system elements and processes, which may have similarities to some of those found in wells drilled in the GBB, are interpreted and speculative. Although source rocks have not been directly confirmed, satellite-identified, sea-surface slicks occur in this AU. These suggest that source rocks, and generation–expulsion–migration have occurred, or are occurring. Reservoirs in the Cretaceous & Jurassic Hydrothermal Dolomite AU would be formed by hydrothermal dolomitization associated with the upward circulation of deeper, hotter fluids along fault systems resulting in limestone host rock being altered to dolomite, reducing the rock volume and forming sags associated with the trap. Albian-Scipio, the largest oil field in the Michigan basin, and similar fields in the Michigan and Appalachian basin, are considered analogs for this AU with the hydrocarbon seal being typically provided by either 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 MMBbl. Total reserves established in all analog fields appear to be in the 1 BBOE range. 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 (which includes most of the State of Michigan, as well as parts of Illinois, Indiana, Minnesota, Ohio, and Wisconsin) at mean values of 723 MMBO, ~2 TCFG, and ~110 MMBNGL.

RESOURCE INVENTORY RESULTS

UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES

This resource inventory includes data and information available as of January 1, 2014. Estimates of undiscovered recoverable resources for the U.S. Atlantic Region are presented in two categories; UTRR and undiscovered economically recoverable resources (UERR). UTRR values for individual AUs are the 95th and 5th percentiles, and the mean are presented in Table 2. This range of estimates corresponds to a 95-percent probability (a 19 in 20 chance) and a 5-percent probability (a 1 in 20 chance) of there being more than those volumes present, respectively. The 95- and 5-percent probabilities 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 1.150 Bbbl at the P95 percentile to 9.185 Bbbl at the P5 percentile with a mean of 4.593 Bbbl (Table 2). Similarly, estimates of the total gas endowment range from 12.799 to 68.709 Tcf with a mean of 38.169 Tcf. UTRR values for individual AUs are presented in Table 2. The AUs in the Atlantic Region are ranked based on mean-level UTRR in BBOE in Figure 6. The UTRR values by Planning Area and water depth categories, respectively at the 95th, mean, and 5th percentiles are presented in Table 3.

BASIN	Undiscovered Technically Recoverable Resources (UTRR)								
	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
Assessment Unit	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Atlantic OCS	**1.150**	**4.593**	**9.185**	**12.799**	**38.169**	**68.709**	**3.427**	**11.385**	**21.411**
Late Jurassic - Early Cretaceous Atlantic Carbonate Margin	0.000	0.227	0.968	0.000	5.207	22.569	0.000	1.154	4.984
Cretaceous & Jurassic Atlantic Marginal Fault Belt	0.000	0.239	0.752	0.000	5.440	15.306	0.000	1.207	3.476
Cenozoic - Cretaceous & Jurassic Carolina Trough Salt Basin	0.000	0.610	1.722	0.000	7.940	21.308	0.000	2.023	5.514
Jurassic Shelf Stratigraphic	0.000	0.068	0.286	0.000	1.547	6.675	0.000	0.343	1.474
Cretaceous & Jurassic Interior Shelf Structure	0.022	0.057	0.104	0.470	1.294	2.296	0.105	0.288	0.513
Cretaceous & Jurassic Blake Plateau Basin	0.000	0.331	0.874	0.000	0.462	1.212	0.000	0.414	1.090
Triassic - Jurassic Rift Basin	0.000	0.199	0.921	0.000	0.283	1.301	0.000	0.249	1.152
Cretaceous & Jurassic Hydrothermal Dolomite	0.000	0.096	0.517	0.000	0.147	0.895	0.000	0.122	0.676
Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (core)	0.000	1.861	8.113	0.000	10.620	46.626	0.000	3.751	16.409
Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (extension)	0.000	0.904	4.116	0.000	5.229	24.333	0.000	1.835	8.446

Table 2. UTRR by AU.

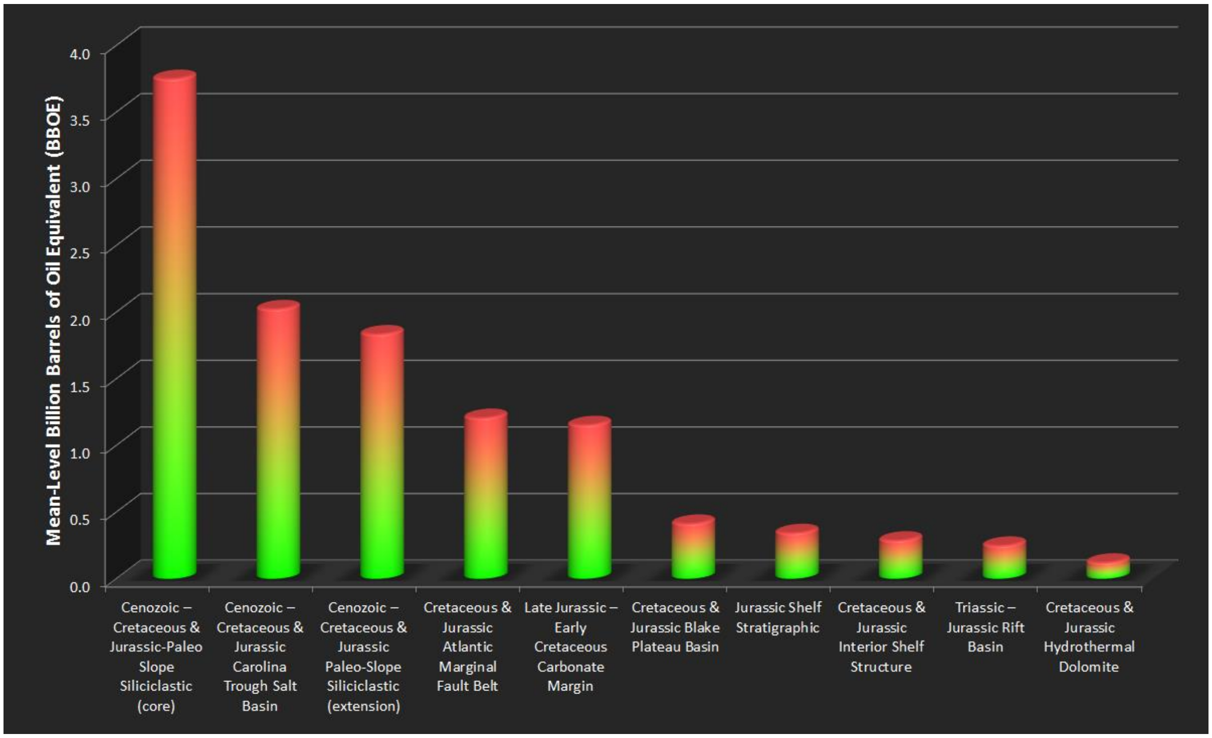

Figure 6. Atlantic Region AUs ranked by mean-level UTRR.

Region / Planning Area / Water Depth	Undiscovered Technically Recoverable Resources (UTRR)								
	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Total Atlantic OCS	**1.150**	**4.593**	**9.185**	**12.799**	**38.169**	**68.709**	**3.427**	**11.385**	**21.411**
0-200	0.046	0.433	1.184	0.879	3.531	5.804	0.202	1.061	2.217
200-800	0.153	0.460	0.795	1.084	6.376	12.986	0.346	1.594	3.105
>800	0.480	3.701	8.080	4.617	28.262	55.551	1.302	8.730	17.964
North Atlantic OCS	**0.061**	**1.771**	**5.114**	**1.075**	**11.761**	**32.741**	**0.252**	**3.864**	**10.940**
0-200	0.024	0.351	1.152	0.480	1.670	2.886	0.110	0.648	1.665
200-800	0.012	0.117	0.278	0.250	2.003	5.237	0.056	0.474	1.209
>800	0.000	1.303	4.634	0.000	8.088	27.046	0.000	2.742	9.446
Mid Atlantic OCS	**0.102**	**2.408**	**5.539**	**2.130**	**24.625**	**50.032**	**0.481**	**6.790**	**14.441**
0-200	0.001	0.082	0.197	0.017	1.862	4.638	0.004	0.413	1.022
200-800	0.004	0.239	0.573	0.018	4.229	9.883	0.007	0.991	2.331
>800	0.015	2.087	5.042	0.031	18.534	41.217	0.021	5.385	12.376
South Atlantic OCS	**0.000**	**0.414**	**0.902**	**0.000**	**1.783**	**4.998**	**0.000**	**0.732**	**1.791**
0-200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
200-800	0.000	0.103	0.273	0.000	0.144	0.378	0.000	0.129	0.340
>800	0.000	0.311	0.650	0.000	1.639	5.034	0.000	0.603	1.546

Table 3. UTRR by planning area and water depth.

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES

In Figure 7, UERR are presented with a gas market value adjustment of 0.3 using three different oil/gas price pairs—$40/bbl and $2.14/Mcf, $100/bbl and $5.34/Mcf, and $160/bbl and $8.54/Mcf. In Figure 8, these values are delineated by Atlantic OCS planning area. Table 4 presents complete economic results under each scenario for oil and gas at the 95th, mean, and 5th percentiles.

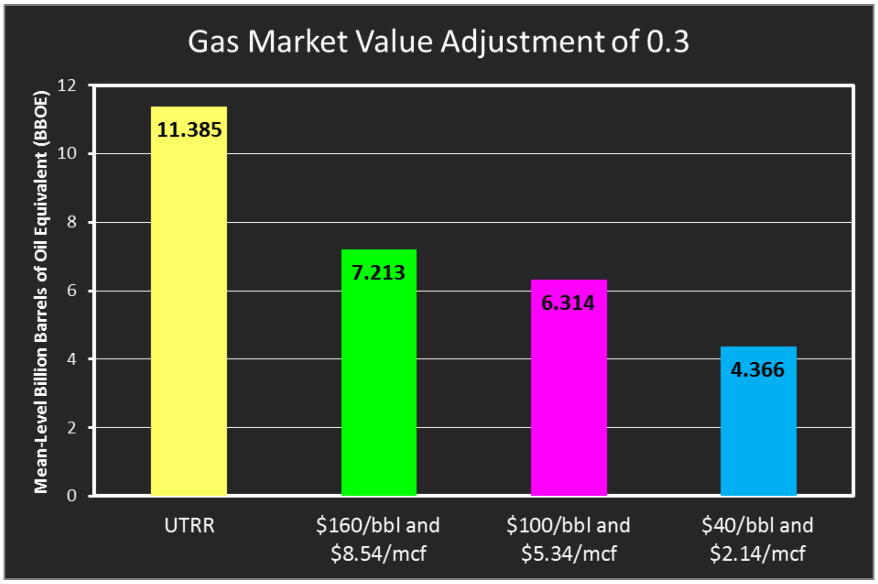

Figure 7. Portions of UTRR that are economic under three price pairs for the Atlantic Region.

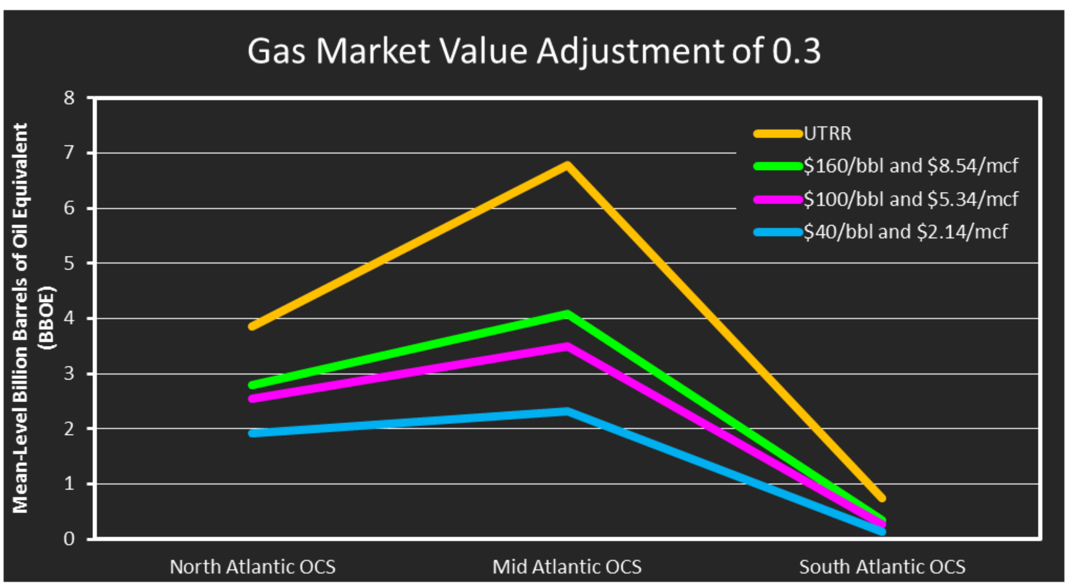

Figure 8. Portions of UTRR that are economic under three price pairs for each planning area.

Region	Undiscovered Economically Recoverable Resources (UERR) Gas Market Value Adjustment of 0.3																										
	$40/bbl and $2.14/MCFG									$100/bbl and $5.34/MCFG									$160/bbl and $8.54/MCFG								
Planning Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)			Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)			Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
Water Depth (m)	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Total Atlantic OCS	**0.715**	**3.466**	**7.287**	**0.834**	**5.061**	**12.140**	**0.863**	**4.366**	**9.448**	**0.894**	**4.002**	**8.228**	**3.093**	**12.997**	**27.851**	**1.444**	**6.314**	**13.184**	**0.955**	**4.149**	**8.475**	**4.437**	**17.217**	**35.159**	**1.745**	**7.213**	**14.731**
0-200	0.031	0.381	1.095	0.048	0.262	0.639	0.039	0.428	1.209	0.043	0.414	1.152	0.174	0.774	1.587	0.073	0.551	1.434	0.044	0.420	1.162	0.255	1.130	2.178	0.090	0.621	1.550
200-800	0.058	0.286	0.515	0.062	0.594	1.189	0.069	0.392	0.727	0.087	0.354	0.627	0.234	1.686	3.367	0.129	0.654	1.226	0.100	0.375	0.661	0.340	2.345	4.729	0.160	0.792	1.503
>800	0.206	2.798	6.541	0.435	4.205	10.196	0.284	3.547	8.355	0.292	3.235	7.347	1.176	10.537	23.568	0.501	5.109	11.541	0.326	3.354	7.541	1.751	13.743	29.826	0.638	5.799	12.848
North Atlantic OCS	**0.041**	**1.481**	**4.318**	**0.026**	**2.448**	**9.911**	**0.046**	**1.917**	**6.082**	**0.056**	**1.645**	**4.732**	**0.132**	**5.049**	**17.892**	**0.079**	**2.543**	**7.916**	**0.059**	**1.684**	**4.840**	**0.228**	**6.236**	**20.838**	**0.099**	**2.793**	**8.548**
0-200	0.016	0.320	1.088	0.013	0.199	0.437	0.018	0.356	1.166	0.022	0.341	1.132	0.068	0.469	1.032	0.034	0.425	1.316	0.023	0.345	1.140	0.109	0.640	1.330	0.043	0.459	1.376
200-800	0.008	0.093	0.231	0.000	0.269	0.849	0.008	0.140	0.382	0.010	0.108	0.261	0.027	0.692	2.102	0.015	0.231	0.635	0.011	0.112	0.266	0.050	0.917	2.752	0.020	0.275	0.756
>800	0.000	1.068	3.934	0.000	1.980	8.271	0.000	1.421	5.406	0.000	1.195	4.300	0.000	3.888	15.521	0.000	1.887	7.061	0.000	1.227	4.398	0.000	4.679	18.133	0.000	2.059	7.624
Mid Atlantic OCS	**0.067**	**1.891**	**4.488**	**0.071**	**2.411**	**6.516**	**0.079**	**2.320**	**5.648**	**0.082**	**2.180**	**5.067**	**0.327**	**7.424**	**17.462**	**0.140**	**3.501**	**8.174**	**0.086**	**2.247**	**5.212**	**0.556**	**10.288**	**23.558**	**0.185**	**4.078**	**9.404**
0-200	0.001	0.061	0.145	0.001	0.063	0.128	0.001	0.072	0.168	0.001	0.072	0.175	0.002	0.305	0.717	0.001	0.127	0.303	0.001	0.075	0.180	0.004	0.490	1.167	0.002	0.162	0.388
200-800	0.001	0.187	0.454	0.000	0.325	0.723	0.001	0.245	0.582	0.002	0.215	0.519	0.002	0.994	2.278	0.002	0.392	0.924	0.002	0.221	0.535	0.004	1.427	3.138	0.003	0.475	1.093
>800	0.002	1.644	4.028	0.000	2.023	6.294	0.002	2.004	5.148	0.005	1.892	4.597	0.002	6.125	15.337	0.005	2.982	7.326	0.007	1.951	4.731	0.003	8.371	19.998	0.007	3.441	8.290
South Atlantic OCS	**0.000**	**0.093**	**0.244**	**0.000**	**0.203**	**0.682**	**0.000**	**0.130**	**0.366**	**0.000**	**0.177**	**0.428**	**0.000**	**0.524**	**1.793**	**0.000**	**0.271**	**0.747**	**0.000**	**0.219**	**0.505**	**0.000**	**0.693**	**2.270**	**0.000**	**0.342**	**0.909**
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	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	0.007	0.022	0.000	0.000	0.000	0.000	0.007	0.022	0.000	0.030	0.084	0.000	0.000	0.000	0.000	0.030	0.084	0.000	0.042	0.119	0.000	0.000	0.000	0.000	0.042	0.119
>800	0.000	0.086	0.228	0.000	0.203	0.729	0.000	0.123	0.358	0.000	0.147	0.346	0.000	0.524	2.019	0.000	0.241	0.705	0.000	0.176	0.405	0.000	0.693	2.610	0.000	0.299	0.869

Table 4. UERR with a gas market value adjustment of 0.3.

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NOTE: Links to all internet references were correct as of the date accessed. Their current accuracy cannot be assured.

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