CRETACEOUS WELL-LOG AND SEQUENCE

STRATIGRAPHIC CORRELATION OF THE OUTER
CONTINENTAL SHELF AND UPPER SLOPE OFF OF
NEW JERSEY

by

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Distinct, regionally continuous Cretaceous sand bodies are present beneath the outer continental shelf and upper slope off of New Jersey that encompasses much of the basin known as the Baltimore Canyon Trough (BCT). These sand bodies are possible candidates for liquid CO$_2$ sequestration. This thesis aims to delineate and correlate four distinct sand units (Middle Sandstone, Upper Logan Canyon, Lower Logan Canyon Sand units, and Missisauga Unit) and their suitability for CO$_2$ sequestration that requires sufficient depth, porosity, permeability, spatial continuity and presence of cap rock. I have analyzed geophysical logs and biostratigraphic data from 11 wells to identify the lithostratigraphic units of the BCT that are potentially suitable for carbon sequestration and have established three well log transects to demonstrate the spatial continuity of the target sand units.

The correlation of lithostratigraphic units along the dip profiles reveals the stratigraphic patterns of the target sand units. The Middle Sandstone Unit has a
progradational pattern throughout the study area, spanning the Coniacian through Santonian. Weak continuity and presence of hydrocarbon-bearing intervals indicate that this unit is not suitable for sequestration. The Upper Logan Canyon Sand Unit has a progradational pattern, spanning the Albian through Cenomanian. This sand body has a spatial continuity in the northeastern part of the BCT area and includes thick porous sandstone beds sealed with impermeable rocks above, suggesting potential for sequestration. The Lower Logan Canyon Sand Unit follows a retrogradational pattern, spanning the Aptian through Albian. The Lower Logan Canyon Sand Unit promises more continuity towards the south, unlike the upper unit. The Lower Logan Canyon Sand Unit is more favorable as a sequestration target. The Mississauga Unit has a progradational pattern, spanning the Hauterivian through Aptian. This unit is very thick and continuous throughout the study area, including abundant porous sand beds sealed with impermeable beds. However, many gas-bearing intervals are present within this deeply buried unit, and the age control is ambiguous, thus, making it a less favorable to unfavorable sequestration target.
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DEDICATION

To my beloved parents…

Sεvgi∫i ΄ninemε, Sεvgi∫i Βabamα…
# TABLE OF CONTENTS

**ABSTRACT OF THE THESIS** ......................................................................................... ii  
**ACKNOWLEDGEMENTS** .............................................................................................. iv  
**DEDICATION** ............................................................................................................ vi  
**LIST OF FIGURES** .................................................................................................... ix  
**LIST OF TABLES** ....................................................................................................... xi  
**LIST OF APPENDICES** .............................................................................................. xii

1. **Background** .................................................................................................................. 1  
   1.1 Geologic History ........................................................................................................... 1  
   1.2 Offshore Drilling History ............................................................................................ 5  
   1.3 Reason for Recent Interest .......................................................................................... 6  

2. **Methods** ....................................................................................................................... 9  
   2.1 Data Preparation ......................................................................................................... 9  
   2.2 Well Log Interpretation ............................................................................................... 10  
   2.3 Biostratigraphic Interpretation and Time Scale ......................................................... 17  
   2.4 Sequence Stratigraphy ............................................................................................... 18  

3. **Interpretations** ........................................................................................................... 20  
   3.1 Identification of log units on three well log cross-sections ........................................ 20  
      3.1.1 Identification of Log Units for the Middle Sandstone Unit .................................. 21  
      3.1.2 Identification of Log Units for the Upper Logan Canyon Sand Unit ............... 24  
      3.1.3 Identification of Log Units for the Lower Logan Canyon Sand Unit ............. 26  
      3.1.4 Identification of Log Units for the Missisauga Unit ........................................ 29  
   3.2 Age evaluation of log units ......................................................................................... 32  
      3.2.1 Age Evaluation of Log Units Along the Dip Profile 75_7 .................................. 32  
      3.2.2 Age Evaluation of Log Units Along the Dip Profile 78_34 ............................... 38  
      3.2.3 Age Evaluation of Log Units Along the Dip Profile 75_8 ............................... 47  
   3.3 Correlation of log units and Evaluation of Stratigraphic Patterns ........................... 48  
      3.3.1 Correlation of Middle Sandstone Unit ............................................................... 49  
      3.3.2 Correlation of Upper Logan Canyon Sand Unit .............................................. 50  
      3.3.3 Correlation of Lower Logan Canyon Sand Unit .............................................. 52
3.3.4 Correlation of Missisauga Unit ........................................................................... 54
3.3.5 Summary of Ages of Log Units ........................................................................ 55
3.4 Correlation of Onshore and Offshore Sequences .............................................. 56
4. Discussion ................................................................................................................... 62
5. Conclusion ................................................................................................................. 68
6. Future Work .............................................................................................................. 71
REFERENCES ............................................................................................................... 72
LIST OF FIGURES

Figure 1. Schematic cross-section through Baltimore Canyon Trough............... 78
Figure 2. Map illustrating the major Mesozoic rift basins of the eastern North
America................................................................. 79
Figure 3. Map summarizing the seismic survey and drilling history in the U.S.
east coast, between Hudson and Washington Canyons............................ 80
Figure 4. Map showing the locations of the wells drilled for exploration purposes,
and MCS lines crossing or projectable from these wells.............................. 81
Figure 5. Generalized stratigraphic sections of Baltimore Canyon Trough and
Scotian Shelf .................................................................. 82
Figure 6. Schematic illustration of SP deflection behavior for varying drilling
fluid conditions and lithologies.......................................................... 83
Figure 7. Schematic diagram illustrating an idealized borehole environment..... 84
Figure 8. Schematic illustration of Gamma Ray Log responses for varying
lithologies.............................................................................. 85
Figure 9. Hypothetical Neutron-Density Log patterns for various lithologies, in
sandstone porosity units................................................................ 86
Figure 10. Example sections from the Texaco 598-1 well, showing the log
characters for sand, heterolithic and shale intervals.................................... 87
Figure 11a. Geologic time scale 2004 spanning Early Cretaceous, plotted by
using Time Scale Creator 5.0 software.................................................. 88
Figure 11b. Geologic time scale 2004 spanning Late Cretaceous, plotted by using
Time Scale Creator 5.0 software......................................................... 88
Figure 12. Chronostratigraphy of log units and lithologic interpretation for the
Middle Sandstone Unit at the COST B-2 well........................................ 90
Figure 13. Chronostratigraphy of log units and lithologic interpretation for the
Upper Logan Canyon Sand Unit at the COST B-2 well............................ 91
Figure 14. Chronostratigraphy of log units and lithologic interpretation for the
Lower Logan Canyon Sand Unit at the COST B-2 well............................ 92
Figure 15. Chronostratigraphy of log units and lithologic interpretation for the
Mississauga Unit at the COST B-2 well.................................................. 93
Figure 16. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the
paleontology data, and tentative paleoenvironments suggested by the well
completion report for the COST B-2 well.............................................. 94
Figure 17. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the
paleontology data, and tentative paleoenvironments suggested by the well
completion report for the Texaco 598-1 well......................................... 95
Figure 18. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the Exxon 599-1 well................................................................. 96
Figure 19. Chronostratigraphy of log units at the Tenneco 642-3 well obtained from the sparse information available in the well completion report. No information was available on the paleontology and paleoenvironments........... 97
Figure 20. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the Tenneco 642-2 well. ......................................................... 98
Figure 21. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the HOM 855-1 well................................................................. 99
Figure 22. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the Gulf 857-1 well......................................................... 100
Figure 23. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, for the Exxon 902-1 well......................................................... 101
Figure 24. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the COST B-3 well. ......................................................... 102
Figure 25. Chart illustrating the biostratigraphy of the Upper Logan Canyon Sand Unit. ........................................................................................................ 103
Figure 26. Cross section along the Exxon line 75_7, showing the correlation of five wells................................................................. 104
Figure 27. Cross section along the Exxon line 78_34, showing the correlation of four wells. ................................................................. 105
Figure 28. Cross section along the Exxon line 75_8, showing the correlation of five wells................................................................. 106
Figure 29a. Correlation between onshore Sea Girt drillhole and offshore COST B-2 well................................................................. 107
Figure 29b. Correlation between onshore Fort Mott drillhole and offshore COST B-2 well................................................................. 107
Figure 30. Chart showing the age-depth distribution of the target sand units at the examined offshore wells and the two onshore wells penetrating the Cretaceous strata................................................................. 109
LIST OF TABLES

Table 1 Thickness of sand units at the wells along the 75_7 Dip Profile. .......... 110
Table 2 Thickness of sand units at the wells along the 78_34 Dip Profile. ....... 110
Table 3 Thickness of sand units at the wells along the 75_8 Dip Profile. .......... 111
Table 4 Summary table for ages of log units. ........................................... 111
LIST OF APPENDICES

Figure S-1 Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the COST B-2 well.......................................................... 112
Figure S-2 Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Texaco 598-1 well......................................................... 113
Figure S-3 Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Exxon 599-1 well....................................................... 114
Figure S-4 Lithologic interpretation for the Middle Sandstone Unit at the Tenneco 642-3 well............................................................................................................. 115
Figure S-5 Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Tenneco 642-2 well......................................................... 116
Figure S-6 Lithologic interpretation for the Middle Sandstone Unit at the HOM 855-1 well. ...................................................................................................................... 117
Figure S-7 Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Gulf 857-1 well................................................................. 118
Figure S-8 Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Exxon 902-1 well............................................................... 119
Figure S-9 Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the COST B-3 well................................................................. 120
Figure S-10 Lithologic interpretation for the Middle Sandstone Unit at the Exxon 728-1 well. ...................................................................................................................... 121
Figure S-11 Lithologic interpretation for the Middle Sandstone Unit at the Exxon 816-1 well. ...................................................................................................................... 122
Figure S-12 Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the COST B-2 well..................................................... 123
Figure S-13 Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Texaco 598-1 well.................................................. 124
Figure S-14 Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Exxon 599-1 well.................................................. 125
Figure S-15 Lithologic interpretation for the Upper Logan Canyon Sand Unit at the Tenneco 642-3 well.............................................................. 126
Figure S-16 Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Tenneco 642-2 well................................. 127
Figure S-17 Lithologic interpretation for the Upper Logan Canyon Sand Unit at the HOM 855-1 well. .............................................................. 128
Figure S-18 Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Gulf 857-1 well. ................................. 129
Figure S- 39 Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the HOM 855-1 well. ................................................................. 150
Figure S- 40 Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the Gulf 857-1 well. ................................................................. 151
Figure S- 41 Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the Exxon 902-1 well. ................................................................. 152
Figure S- 42 Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the COST B-3 well................................................................. 153
Figure S- 43 Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the Exxon 728-1 well................................................................. 154
Figure S- 44 Lithologic interpretation for the Missisauga Unit at the Exxon 816-1 well................................................................. 155
1. Background

1.1 Geologic History

The outer continental shelf and slope of New Jersey is a typical Atlantic-type passive continental margin that possesses an extremely thick postrift sedimentary fill (>16 km) and encompasses much of the basin known as the Baltimore Canyon Trough (BCT) (Figure 1; Poag, 1985; Grow et al., 1988). The BCT is one of the series of Mesozoic rift basins aligned along the eastern North America (Figure 2), trending NE-SW.

The formation of the BCT started with a Late Triassic to earliest Jurassic extensional rifting, which was followed by the extensional separation of North America and Africa (e.g.; Manspeizer, and Cousminer, 1988; Olsen et al., 1989). The transition from rifting to drifting (i.e., creation of seafloor spreading centers in the Atlantic Ocean) began prior to the Bajocian (~175 Ma), (e.g.; Sheridan, Gradstein et al., 1978; Klitgord et al., 1988), with the likely opening beginning off Georgia by ca. 200 Ma and progressing northward to the U.S. middle Atlantic margin (Withjack et al. 1998). The post-rift unconformity separating the post-rift deposits from the synrift deposits (Withjack et al., 1998) is diachronous (e.g.; ~200 Ma in the southeastern United States; ~185 Ma in the maritime Canada). The rift-drift stage was accompanied by volcanism, metamorphism, and partial melting of the lower crust, quantitative effects of which are still poorly
understood (Grow et al., 1988). With the initiation of seafloor spreading, extension within the basin ended as the spreading center became the main focus of the stress release (Klitgord et al., 1988), and the mid-ocean ridge migrated away from the margin. Subsequently, subsidence began in the basin due to lithospheric cooling and sediment loading.

During the rift-stage of this typical Atlantic type continental margin, tectonic uplift and subsidence were the active processes dominating the basin. As expected in a typical simple tectonic passive margin, the post-rift processes that effect the deposition in the BCT include simple thermal subsidence, sediment loading, lithospheric flexure, compaction, and sea-level changes (Watts and Steckler, 1979; Reynolds et al., 1991; Kominz et al., 1998, 2008; Miller et al., 2005). However some disturbing processes such as small salt diapirism, magmatic intrusion and local non-growth normal faulting with minor displacement took place as well (Poag, 1985).

The structural elements of the BCT are illustrated in a schematic cross-section (Figure 1). The landward edge of the BCT is marked by a hinge zone, where the depth to the top of basement becomes as shallow as 4 km, observed from the multichannel seismic reflection profiles (Figure 1 of Grow et al., 1988). A prominent positive magnetic anomaly known as East Coast Magnetic Anomaly (ECMA) outlines the landward edge of the oceanic crust (Grow et al., 1988). The width of the trough is defined as the distance between the hinge zone and the axis of the ECMA, and varies from 60 km off Virginia to 100 km off New Jersey (Grow et al., 1988). A high-amplitude, circular, positive anomaly in the middle of
the continental shelf, which is approximately 20 km in diameter, and 40 km landward of the ECMA indicates a large mafic intrusion that uplifted the lower Cretaceous and older strata, and is called the Great Stone Dome (Grow et al., 1988). In addition, a shallow diapiric feature was detected near the ECMA along the edge of the BCT (Grow et al., 1988) and is anticipated as a salt structure penetrating into the Cenozoic strata. There is no age information available for the salt off the U.S. Atlantic continental margin and it possibly formed during the rift-drift transition when the rift grabens were invaded by shallow seawaters with restricted circulation and high evaporation rates (Poag, 1978; Grow et al., 1988).

The BCT consists of three major rock strata in general: basement rocks, synrift and postrift sedimentary rocks. The basement of BCT is chiefly composed of granitic and metasedimentary rocks of Paleozoic age, based on the information obtained from the basement penetrating wells drilled on the coastal plain (Poag, 1978; 1985). Syn-rift sedimentary rocks resting on the Paleozoic basement are Upper Triassic (Norian) to Lower Jurassic (Poag, 1985). The oldest of the syn-rift sediments consists of terrigenous, siliciclastic sediments that were deposited as a result of the rapid erosion of the high-standing basement blocks during rifting. The syn-rift rocks of the BCT also include some volcanic layers, indicated by high amplitude, continuous reflections observed in multichannel seismic profiles, and evaporitic strata that were deposited as a result of the restricted water circulation and arid climate during the Early Jurassic (Manspeizer and Cousminer, 1988).
The post-rift sediments of the BCT lie above the post-rift unconformity that separates the angularly discordant pre-rift and syn-rift sediments affected by extensional rifting of the pre-existing continent. The Jurassic section of the post-rift strata consists of thick shallow-water carbonates (8-12 km), overlain by thinner sandstones and shales inferred from the multichannel seismic-reflection profiles and by analogy from adjacent basins (Poag, 1978, 1985; Grow et al., 1988). A carbonate reef complex rimmed the basin, prograding seaward, and is now located beneath the upper continental slope (Figure 1). During the early Cretaceous, the BCT progressively widened due to thermal subsidence and long-term global sea-level rise, leading to burial of the shelf-edge reefal bank that had been building up throughout the Jurassic in the seaward end of the basin (Hauterivian; Poag 1985). Terrigenous sediment accumulation dominated the basin throughout the Cretaceous, resulting in moderately thick siliciclastic deposits, due to large river inputs during the warm Early Cretaceous climatic regime (Poag, 1985). The Paleogene section of the BCT comprises chiefly of carbonates that were deposited during a major marine transgression (Poag 1985, Poag and Valentine, 1988). Regional and global cooling in the earliest Oligocene caused switching to siliciclastic sedimentation with low accumulation rates (Miller et al., 1997). The Neogene sediments are particularly thick due to high sedimentation rates, depositing as large prograding delta lobes (Poag, 1985). The Cretaceous strata of the basin includes thick sand bodies that are the main target of this study, owing to their potential as a reservoir for carbon sequestration.
1.2 Offshore Drilling History

The Baltimore Canyon Trough has been the focus of research for many purposes over the last four decades (Figure 3). Numerous seismic surveys were conducted; numerous wells were drilled on the shelf to rise. The regional studies began with several seismic refraction surveys collected in 1930’s and continued with continuous single channel seismic reflection surveys collected in 1960’s as described in Poag (1985). These studies provided preliminary recognition of stratigraphic units and unconformities in the upper strata of the Baltimore Canyon Trough and attempted to distinguish some of the deeper layers. The U.S. Geological Survey (USGS) began collecting multi-channel seismic reflection profiles across the shelf and slope in 1973, followed by new seismic refraction studies and gravity measurements.

Meanwhile, drilling began in the region. The Atlantic Slope Project (ASP) was a shallow (300 m) drilling attempt in 1967 sponsored by Exxon, Chevron, Gulf and Mobil oil companies that aimed to sample Cenozoic strata at eight core holes at seven sites along the base of the continental slope. USGS conducted the Atlantic Margin Coring Project (AMCOR) in 1976, drilling nine additional shallow wells to sample Cenozoic strata (Hathaway et al., 1979). Later scientific drilling includes Deep Sea Drilling Project (DSDP) Legs 11, 93, 95, Ocean Drilling Program (ODP) Legs 150 and 174A and Integrated Ocean Drilling Program (IODP) Expedition 313 drilled the shelf and slope in the following years.
The Baltimore Canyon Trough became the target for petroleum exploration in the 1970’s. The only deep shelf drilling (aimed to sample Mesozoic strata) was conducted by exploration companies between 1975 and 1983, the first one of which was the Continental Offshore Stratigraphic Test (COST) B-2 well, conducted by a consortium of 31 oil companies. Another stratigraphic test well, COST B-3, was drilled on the continental slope (819 m water depth), sponsored by 11 oil companies. Additionally, 32 exploratory wells were drilled in the Baltimore Canyon Trough by various oil companies (Libby-French 1984; Prather, 1991) (Figure 4).

Additional multichannel seismic reflection surveys conducted in the BCT include regionally focused high resolution profiles collected in 1979 by the German Federal Institute for Geosciences and Natural Resources (BGR) in cooperation with USGS, and reconnaissance-scale profiles collected by the then Exxon Production Research Company in 1975-1977 (Figure 4).

1.3 **Reason for Recent Interest**

The Baltimore Canyon Trough has been the interest for research for several purposes over the last four decades. The Cretaceous sandstone units in the basin were deposited in prograding coastal-plain and transitional marine environments, with regionally extensive top seal units overlying them; these reservoirs and seals are promising for hydrocarbon potential (Libby-French, 1984; Prather, 1991). The stratigraphic evolution of BCT is very similar to that of the Scotian Shelf, owing to the fact that both have gone through similar tectonic and
sedimentary histories (Figure 2; 5). Extensive exploration of the Scotian Shelf has revealed several stratigraphic and structural traps that suggest hydrocarbon potential reservoir for the BCT. Exploration attempts on the outer continental shelf and slope of New Jersey resulted in only non-commercial hydrocarbon shows (Libby-French, 1984).

Thick, porous and permeable sand bodies present beneath the New Jersey outer continental shelf and slope are considered also as a potential for CO\textsubscript{2} sequestration. Initial data gathering to enable such an evaluation is the main purpose of this study. These sand bodies are buried deep enough for the sequestration limit, i.e. deeper than the supercritical storage depth of 800 m (Benson et al., 2005). Furthermore, these sand units are well sealed above by fine-grained deltaic complex dominated by delta-plain shales (Prather, 1991) deposited during the high sea-level period in the Late Cretaceous (Miler et al., 2005). The quiet tectonic regime of the BCT, with little evidence of major faulting or any other structural deformation, confirms the high potential of these sand bodies as sequestration targets. The proximity of the BCT to the power plants in the New York/New Jersey area, which could be the source for the liquid CO\textsubscript{2}, also makes these sand bodies good candidates for sequestration. Evaluation of the continuity of these sand bodies for sequestration potential is the main purpose of this study.

The onshore portion of the New Jersey margin has already been evaluated in terms of sequestration potential. Here, three sand bodies termed the Potomac I, Potomac II, and Potomac III have potential for onshore sequestration based on thick sands confined by Cretaceous-Paleogene clays (Monteverde et al., 2010).
Their offshore equivalents may also be good candidates for CO₂ sequestration. Thus, analysis of the offshore sand bodies will lead to understanding their seaward continuity and spatial distribution.

Correlating well-dated onshore sequences (Sugarman et al., 1995; Miller et al., 2004) to offshore is possible to a limited extent, which would contribute to understanding of Cretaceous sequences across the continental margin. In this study, I attempt to correlate the onshore sequences into the offshore, based on the well logs and age control.
2. Methods

2.1 Data Preparation

This study is based on lithologic, biostratigraphic, and sequence stratigraphic relationships interpreted from well logs and paleontologic data of offshore scientific and industry wells. Data from COST B-2 and COST B-3 has been worked on and extensively published (e.g. Scholle, 1977; 1980; Poag, 1978; 1985; Libby-French, 1984). I reexamined these two wells, used these interpretations as reference sections, and compared them to publicly available datasets of 11 additional wells from the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) that were drilled in the continental shelf and upper slope off of New Jersey (Figure 4) by various oil companies between 1975 and 1983. The well datasets include images of electric logs and miscellaneous documents including paleontology, well completion, daily drilling, sidewall core analysis, conventional core analysis reports, geochemistry results, and velocity surveys. Among these, electric log images and paleontology reports constitute the primary basis of this study.

Sixteen multichannel seismic profiles were acquired by Exxon Production and Research Company in 1977 through 1978 (Figure 4) and provided to Rutgers in 1990 during the planning of DSDP Leg 150 (Greenlee et al., 1992). The seismic profiles were old paper copies. Later in 2011, Exxon donated the electronic SEGY files of these lines to Rutgers. However, difficulty with
navigation data of the SEGY files precluded their usage in this study. My well log cross sections lie on or are projectable to Exxon lines 75-7, 78-34 and 75-8 respectively (Figures 26; 27; 28). Future studies should integrate the well log cross sections with these seismic profiles.

The electronic logs obtained from BOEMRE were all images that required digitization and conversion into the LAS format standard. These images were sent to Brian Slater of the New York State Oil and Gas Division where the digitization process was completed using Neurolog software, which produces LAS files. I imported the LAS files to Petrel, Seismic to Simulation Software, to graphically display the electric logs.

Lithologic interpretation from electric logs was first made on paper, and then transferred into the software. Gamma Ray, Electrical Resistivity, Neutron Porosity, Density Porosity and Spontaneous Potential are the log types that I relied on for the lithological interpretation. Three types of lithologic units were identified for the purpose of this study. These were: confining shale, heterolithic, and blocky sand, as described below.

2.2 Well Log Interpretation

Geophysical well logs are continuous records of measurements made in a borehole to detect physical rock characteristics such as lithology, porosity, pore geometry, and permeability (Asquith and Gibson, 1982). They are very useful tools for oil and gas exploration as well as for the solution of problems in the groundwater, environmental field, and for engineering applications (Griffin,
Logs are used to correlate, identify productive zones, determine depth and thickness of zones, distinguish between oil, gas, and water in a reservoir and assist with structure and isopach mapping (Asquith and Gibson, 1982).

The first geophysical logs were developed and introduced to the oil industry by the Schlumberger brothers in France in 1927, when they manually plotted the deflections of a galvanometer that responded to resistivity of rocks and interstitial fluids (Keys and MacCary, 1971; Keys, 1990). The science of well logging advanced throughout the years, along with the development of three general types of logs; Electrical, Nuclear and Acoustic (Sonic) logs, depending on the sources used to obtain the measurements (Schlumberger, 1989).

Spontaneous Potential, Resistivity, Gamma Ray, and Porosity Logs are the types of logs that I utilized for my lithologic interpretations. Spontaneous potential (SP) logs record the naturally occurring direct current voltage differences between a movable electrode in the well and a fixed electrode located at the surface (Asquith and Gibson, 1982; Schlumberger, 1989). This difference is produced by the interaction between formation water and conductive drilling fluids, which have different salinity values and thus, different resistivity values. The SP log is basically used to identify impermeable zones such as shale, and permeable zones such as sand, to detect boundaries of permeable beds, to determine formation water resistivity, and to determine volume of shale in permeable beds.
Bed thickness, bed resistivity, drilling fluid, invasion, borehole diameter, shale content and the ratio of drilling fluid resistivity to formation water resistivity are the factors that affect SP measurements and should be taken into account when interpreting the lithology. Shales have relatively constant SP response that follows a straight line termed as ‘shale baseline’ (Figure 6). Deflections of the SP curve from the shale baseline (either positive or negative depending on the resistivity values of drilling fluid and formation water) are responses of permeable beds, and the permeable bed boundaries are determined by the inflection points. However, since the SP curve deflection is directly related to the differences in drilling fluid resistivity and formation water resistivity, no deflection will occur when these resistivity values are equal.

Resistivity logs are basically used to identify the type of fluid present within the formation pores (Asquith and Gibson, 1982; Schlumberger, 1989). Most minerals that constitute a rock’s matrix are non-conductive, and the only way for a rock to transmit electricity is via the fluid in the pores. Therefore, it is possible to distinguish the type of the formation fluid by using the resistivity record. Correspondingly, resistivity logs are used to determine hydrocarbon vs. water-bearing zones, to indicate permeable zones, and to determine the resistivity porosity (Asquith and Gibson, 1982; Schlumberger, 1989).

Resistivity recording in a drill hole can be accomplished in two different ways (Asquith and Gibson, 1982; Schlumberger, 1989). In the first method, an induction tool is used which creates an alternating magnetic field through the borehole. The returning signals are proportional to the conductivity of the
formation, which is the reciprocal of resistivity. An electrode log, used for the second method of resistivity measurement, sends an electric current through the borehole. In this way, the resistivity of the formation is measured directly in an electrode log, unlike the indirect measurement of induction tool (Asquith and Gibson, 1982). The type of fluid used for drilling is critical for each of these methods, i.e., for accurate records of resistivity; a non-conductive fresh mud is required for an induction log whereas a salt-based mud with low resistivity is necessary for electrode logs.

The environment of a borehole is divided into three major zones (Figure 7); the flushed zone which is completely invaded by the drilling fluid ($R_{xo}$), the transition zone which is partly invaded by the drilling fluid ($R_i$), and the uninvaded zone ($R_t$) which is completely filled with the formation water, or hydrocarbon, if present. Generally, in the well data used in this study, resistivity values are recorded from each of these zones (i.e. deep ($R_t$), medium ($R_i$), and shallow ($R_{xo}$)), which yield an indication of permeability and type of fluid in the formation pores.

If the formation is water-bearing and impermeable, the three resistivity tools would read the same values, that is, there would be no invasion of drilling fluid into the pores of the formation. On the contrary, in a water-bearing but permeable bed, the three curves would split from each other where the resistivity value is highest in the shallow zone and lowest in deepest zone, in case of fresh drilling mud. However, if the resistivities of the formation water and the drilling fluid are the same, the three tools would read the same values, i.e. would not split
from each other, even though the bed is permeable. If the formation is hydrocarbon-bearing, the three curves would split apart but the deep resistivity would have a higher value than the medium due to high resistivity of hydrocarbons, termed as ‘annulus effect’.

Gamma Ray logs, most commonly used for identification of lithology and stratigraphic correlation, are useful over a very wide range of borehole conditions (Griffin, 1995). They record the naturally existing radioactivity of the formations that comes from the decay of isotopes of potassium, uranium, and thorium (Asquith and Gibson, 1982; Schlumberger, 1989). These radioactive elements, particularly potassium, which is the most abundant, tend to concentrate in fine-grained sediments such as clays and shales. On the other hand, coarse-grained, clean formations generally have little concentration of radioactive elements. Ideally, shales have high radioactive response, i.e. high gamma ray values, where coarse-grained sands are characterized by low values (Figure 8).

However, there are several reasons for considerable variation in the radioactivity of rocks as shown in their gamma ray log character. The presence of potassium feldspars, micas, glauconite, or uranium-rich waters in the sandstone will increase gamma ray values (Asquith and Gibson, 1982; Schlumberger 1989; Griffin, 1995). In addition, coal, limestone, and dolomite are usually less radioactive than shale; however, they can contain deposits of uranium and have higher gamma ray values (Keys, 1990). Therefore, these possibilities should be taken into account when interpreting the lithology from the gamma ray logs.
Porosity logs used for this study include the Combination Neutron-Density Log. In addition to its use for determining porosity, the Combination Neutron-Density Log is useful for determining lithology and gas bearing zones.

Density logs basically measure the electron density of a formation, by emitting gamma rays into a formation (Asquith and Gibson, 1982). The number of electrons in a formation (electron density) is directly related to bulk density, which is a function of matrix density, porosity, and density of the fluid in the pores. A density porosity curve is plotted with the use of this function.

Neutron logs measure the hydrogen ion concentration in a formation by continuously emitting neutrons into the formation (Asquith and Gibson, 1982). Since the hydrogen in a clean (shale-free), porous formation is concentrated in the fluid-filled pores, the hydrogen ion concentration can be related to that formation’s porosity.

Both the Neutron and Density curves are recorded in sandstone porosity units in available well logs. Interpretation of this combination log provides useful information on the lithology, and the material filling the pores (Figure 9). In places where Neutron Porosity values are high and Density Porosity has lower values, the formation is defined as shale. This is because shale has a very high concentration of hydrogen but low density. If the separation between the two curves is lower but the neutron density still has a higher value, then the formation consists of shaly sand, or silt. In a clear and porous sand bed, the curves overlap and measure the same porosity values for neutron and density.
If the pores of the sand body are filled with gas, the density porosity has a very high value where the neutron log records a very low value. This is called the ‘gas effect’; created by gas in the pores, as the neutron log records very low values due to low concentration of hydrogen in gas as compared to oil and water. Density log values are higher than the neutron log values in an oil bearing sand bed, but the separation between the two curves is less than in a gas-bearing interval.

In this study, I aim to identify and understand the spatial distribution of the thick permeable and porous sand beds that are sealed with impermeable units. Accordingly, I assigned three different types of lithology (i.e. confining shale, heterolithic, and sand) to intervals based on certain log characters (Figure 10).

Confining shale is assigned to intervals having high Gamma Ray values (kicks to the right in the curve), constant SP values (following the baseline), with no separation of the deep, medium and shallow resistivity curves, high neutron porosity and low density porosity values (Figure 10).

Sand units are represented by low gamma ray values (kicks to the left; blocky, serrated, or sometimes funnel-shaped log patterns). The SP curve deflects to either positive or negative directions, depending on the resistivity of the fluid filling the pores. Deep, medium and shallow reading resistivity curves split from each other, if the sand body is permeable enough. Otherwise, the curves read the same resistivity value at all depths of invasion into the formation. Neutron and
density log curves move together, reading very close porosity values for a clean porous sand formation.

The heterolithic term is assigned to units that are neither clean porous sands nor impermeable shale, and can be silt, shaly sand or cemented sand. In heterolithic units, the gamma ray curve does not follow a consistent pattern and does not have high values like shales or low values like sands. The three resistivity curves can either be separate or have the same values, and the separation between the two porosity curves is low.

2.3 Biostratigraphic Interpretation and Time Scale

I used the 2004 Geological Time Scale (GTS) of Gradstein et al. (2004) which was plotted using Time Scale Creator (Figures 11a; 11b; Lugowski, Og, Gradstein. https://engineering.purdue.edu/Stratigraphy/tscreator/index/index.php).

Standard zonations of the GTS2004 are used for the biostratigraphic interpretations in this study. The entire Cretaceous is considered in this study, but I particularly focused on sand bodies that are primarily Albian into the Turonian.

Standard zonations given in GTS 2004 were often not recognized in previous studies done in the 1970’s and 1980’s. I used all available data from the paleontology reports that includes planktonic foraminifers, nanofossils and dinocysts. A literature survey was conducted for the taxon ranges that are outside of the standard zonations. References and interpretations of how the ranges and
lowest (LO) and highest (HO) occurrences tie into the modern time scale are provided in the interpretations chapter.

### 2.4 Sequence Stratigraphy

Sequence stratigraphy is the study of stratigraphic sequences in chronostratigraphic and spatial framework, a concept that integrates various disciplines such as lithofacies analysis, biostratigraphy and chronostratigraphy (Catuneanu, 2006). A sequence is defined as the succession of genetically related strata, bounded by unconformities or their correlative conformities (e.g., Mitchum et al., 1977; Vail, 1987; Coe, 2002; Catuneanu, 2006). Sea-level changes, tectonics and paleoclimate act together to produce sequences, and thus, they can be correlated regionally in order to reveal the depositional and sea-level history.

Owing to its quiescent tectonic background, New Jersey passive margin is suitable for applying sequence stratigraphy (Miller et al., 2003). Onshore, Cretaceous sequences have been identified by a regionally integrated corehole array with well logs (Miller et al., 2003, Kulpecz et al., 2008). This allows recognition of sequences in wells without core or rotary samples (e.g. Kulpecz et al., 2008). Such an integration is not available for the outer continental shelf and upper slope off of New Jersey. However, the shallowest updip site examined here, COST B-2, shows remarkably similar log characteristics to the onshore Cretaceous units (Miller et al., 2003, Kulpecz et al., 2008). Therefore, gamma peaks, matching curve patterns, and the biostratigraphic ground truth to test the
datum of correlation provides remarkably good correlation from onshore to COST B-2 well.
3. Interpretations

3.1 Identification of log units on three well log cross-sections

As mentioned earlier, the BCT has experienced very similar tectonic and sedimentary history to that of the Scotian Shelf (Figure 2). Correspondingly, studies of Libby-French (1984) and Poag (1985) point out that the stratigraphic units of the BCT are very similar to the formally established lithostratigraphic framework of the Scotian basin. These studies extended the already established nomenclature for the formations of the Scotian basin by McIver (1972) to the BCT (Figure 5).

According to Libby-French (1984) the Logan Canyon Equivalent in the BCT occurs as two successions of thick sandstone beds, which I subdivide into the Upper Logan Canyon Sand and Lower Logan Canyon Sand Units. Though it is likely that these are distinct depositional sequences, I lack sufficient environmental and age information to establish this for certain. These two units are separated by the Sable Shale Member of the Logan Canyon Formation of Scotian Shelf (Figure 5).

For sequestration purposes, my correlations focus on the Cretaceous sand units within Baltimore Canyon equivalents of the Upper Logan Canyon Formation, Lower Logan Canyon Formation and Missisauga Formation of the
Scotian basin; and on the Middle Sandstone Unit, which has no counterpart in the Scotian basin (Figure 5).

I established three well log transects with 11 wells; some lie on, some are projected (up to 8 km) to the Exxon MCS lines 75-7, 78-34 and 75-8 respectively (Figs 26, 27, 28). The 75-7 dip profile consists of COST B-2, Texaco 598-1, Exxon 599-1, Tenneco 642-3, and Tenneco 642-2 wells. The 78-34 dip profile consists of HOM 855-1, Gulf 857-1, Exxon 902-1, and COST B-3 wells. The 75-8 dip profile consists of COST B-2, Exxon 728-1, Exxon 816-1, Exxon 902-1 and COST B-3 wells.

I identified the lithologies in each well utilizing the electric log interpretation methods described earlier. The target lithologic units were identified in each well, based on the biostratigraphic age control and the lithologic patterns obtained from the well log analysis. All depths mentioned in the following sections are below Kelly Bushing level (BKB) and the elevations of KB are given in Figures 26, 27, 28, and 30.

In this section, I provide illustrations of the four target units from the COST B-2 well (Figures 12 to 15); in the Appendix I show all 44 figures for the four units at 11 sites (Figures S-1 to S-44).

### 3.1.1 Identification of Log Units for the Middle Sandstone Unit

The Middle Sandstone Unit occurs between 6009 and 6380 ft at the COST B-2 well, with 371 ft of potential thickness (Figure 12; S-1). Gamma Ray, Caliper, Resistivity and Porosity logs are available for this well. Individual sand
beds range from 5 to 30 ft in thickness, their porosity values range from moderate to high, and they are very well confined by impermeable beds.

For the Texaco 598-1 well, Gamma Ray, Spontaneous Potential, Porosity and Resistivity logs all confirm the presence of clean porous and permeable sand beds, confined by impermeable units on top. The Middle Sandstone Unit extends from 5909 to 6570 ft, with a thickness of 661 ft (Figure S-2). Individual sand beds are strikingly thick and porous, ranging from 12 to 535 ft in thickness. Overall, the sand beds are highly porous except for a few low porosity intervals.

At the Exxon 599-1 well, only Gamma Ray and Porosity logs are available and the Middle Sandstone Unit extends from 5922 to 6720 ft (Figure S-3), with a thickness of 798 ft. Sandy intervals are sparse when compared to the proximal wells, with porosity values ranging from low to moderate.

At the Tenneco 642-3 well, Gamma Ray and Porosity logs are the only available references, and the Middle Sandstone Unit occurs between 5852 ft and 6282 ft (Figure S-4), with a total thickness of 430 ft. Individual sand beds range from 7 to 23 ft in thickness, and low to high in porosity.

At Tenneco 642-2 well, the Middle Sandstone Unit is 270 ft thick, occurs between 5900 ft and 6170 ft (Figure S-5). Available logs at this well are Gamma Ray and Porosity. Sand beds represented with blocky, sometimes funnel shaped Gamma Ray curves and high to low porosity values range in thickness from 10 to 50 ft. They are fairly well confined by impermeable shales.
The Middle Sandstone Unit occurs from 6350 to 6845 ft at the HOM 855-1 well, with 495 ft of total thickness (Figure S-6). Unfortunately, the only available means of lithologic interpretation at this well are porosity logs. Thus, the lithology at this well is tentative. Correspondingly, sand beds of high to low porosity are present in the Middle Sandstone Unit, sealed with confining shale except for a heterolithic interval. The thickness of sand beds range between 15 and 80 ft.

At the Gulf 857-1 well, the Middle Sandstone Unit was recognized from 6197 to 6462 ft, with 265 ft of thickness (Figure S-7). Gamma Ray and porosity logs are available for this well, and individual sand beds have an average thickness of 34 ft with porosities ranging from high to low, confined well by shales.

At the Exxon 902-1 well, the Middle Sandstone Unit occurs from 6332 to 6635 ft, with 303 ft total thickness (Figure S-8). Available logs for this well are Gamma Ray, Porosity and Spontaneous Potential logs. Thicknesses of individual sand bodies range from 13 to 31 ft, and they seem to be well confined within impermeable shale beds. The porosity values change from high to low.

At the COST B-3 well, Gamma Ray, Spontaneous Potential, Resistivity and Porosity logs are available. The Middle Sandstone Unit occurs from 6685 to 6700 ft at this well, where there is only a 15 ft thick individual sand bed with very low porosity value (Figure S-9).
At the Exxon 728-1 well, Gamma Ray, Spontaneous Potential and Porosity logs makes it possible to infer the lithology. The Middle Sandstone Unit occurs between 6099 and 6441 ft, with a total thickness of 342 ft (Figure S-10). Very clean, porous sand beds are well sealed beneath the impermeable shale units. Individual sand beds vary in thickness, ranging from 10 ft to 101 ft.

At the Exxon 816-1 well, the only means for determining lithology are Gamma Ray and Conductivity (i.e. reciprocal of Resistivity) logs. The middle Sandstone Unit occurs between 6260 and 6621 ft at this well, with 361 ft total thickness (Figure S-11). Individual sand beds are represented with blocky Gamma Ray log character and moderate to high conductivity values. Thickness of sand beds range from 10 ft to 52 ft, and unfortunately there is no information available on their porosity values.

### 3.1.2 Identification of Log Units for the Upper Logan Canyon Sand Unit

The Upper Logan Canyon Sand Unit occurs between 8220 and 8600 ft at the COST B-2 well, with 380 ft of potential thickness (Figure 13; S-12). Blocky sand beds are well confined within impermeable beds, with porosity values ranging from moderate to high. Thickness of sand beds change from 6 to 47 ft.

At the Texaco 598-1 well, the upper Logan Canyon Sand Unit occurs from 7986 through 8454 ft, with 468 ft of total thickness (Figure S-13). Clean and porous sand beds dominate this unit, ranging in thickness from 16 to 73 ft.
At the Exxon 599-1 well the Upper Logan Canyon Sand extends from 7978 ft to 8426 ft, having a total thickness of 448 ft (Figure S-14). The relative proportion of sand beds to shale beds is higher in this basinward located well, where the sand beds are generally thick, reaching up to 115 ft in thickness.

At the Tenneco 642-3 well The Upper Logan Canyon Sand Unit becomes thicker, occurring from 8052 ft to 8728 ft, with a total thickness of 676 ft (Figure S-15). Blocky, highly porous sand beds dominate the formation, where they are confined within impermeable shale beds.

At the Tenneco 642-2 well, the Upper Logan Canyon Sand Unit occurs between 7879 and 8470 ft with 591 ft of total thickness (Figure S-16). Thicknesses of sand beds range from 13 ft to 156 ft, with porosity values ranging from moderate to high.

At the HOM 855-1 well, the Upper Logan Canyon Sand Unit occurs between 8325 and 8774 ft, with 449 ft total thickness (Figure S-17). Sand beds are evenly distributed throughout the unit alternating with confining shale beds, except for a 40 ft thick heterolithic interval. Porosity values change from moderate to high.

At the Gulf 857-1 well, the Upper Logan Canyon Sand Unit occurs between 8250 and 8545 ft, with 295 ft total thickness (Figure S-18). The sand to shale ratio increases in this basinward located well, where the porosity values range from moderate to high.
At the Exxon 902-1 well, the Upper Logan Canyon Sand Unit occurs from 8361 to 8621 ft, with 260 ft total thickness (Figure S-19). The unit consists of two blocky sand beds with thicknesses of 21 and 181 ft. These sand units are well confined by impermeable units, and they have moderate porosity values.

At the COST B-3 well, the Upper Logan Canyon Sand Unit occurs from 8200 to 8642 ft, with 442 ft of total thickness (Figure S-20). The sand beds are distributed throughout the unit, alternating with impermeable shale beds. The porosity values range from low to moderate.

At the Exxon 728-1 well, the Upper Logan Canyon Sand Unit occurs from 8138 to 8438 ft with 300 ft total thickness (Figure S-21). Thick sand beds dominate the unit, with a few confining shale beds. The thickness of individual sand beds range from 45 ft to 71 ft, and they are generally clean and porous, with moderate porosity values.

At the Exxon 816-1 well, the Upper Logan Canyon Sand Unit occurs from 8240 to 8580 ft, with 340 ft of total thickness (Figure S-22). The individual sand beds vary a lot in thickness, (i.e. from 6 ft to 131 ft) and there is no information available concerning their porosity values.

3.1.3 Identification of Log Units for the Lower Logan Canyon Sand Unit

At the COST B-2 well the Lower Logan Canyon Sand Unit extends from 8840 to 9345 ft, with 505 ft of total thickness (Figure 14; S-23). Thick, porous
sand beds alternate with confining shales, except a few heterolithic intervals. Thicknesses of individual sand beds vary between 8 and 102 ft.

At the Texaco 598-1 well, the Lower Logan Canyon Sand Unit occurs from 8518 to 8814 ft, with 296 ft total thickness (Figure S-24). Thick, clean and porous sand beds dominate the unit, with a few alternating shale beds. The topmost sand body is overlain by a heterolithic unit, which would decrease the efficiency of the unit as a reservoir.

At the Exxon 599-1 well, the Lower Logan Canyon Sand Unit occurs from 8490 to 8828 ft, with 338 ft of total thickness (Figure S-25). The thicknesses of individual sand beds vary between 10 and 84 ft, alternating with impermeable beds. Porosity values range between high and low.

At the Tenneco 642-3 well, the Lower Logan Canyon Sand Unit occurs from 8948 to 9388 ft, with 440 ft of total thickness (Figure S-26). Individual sand beds change from 5 ft to 76 ft in thickness, and from high to low in porosity. Sandy intervals seem to be well confined by the shale beds.

At the Tenneco 642-2 well, the Lower Logan Canyon Sand Unit occurs from 8920 to 9330 ft, with 410 ft total thickness (Figure S-27). Thick, porous and clean sand beds dominate the unit, while porosity values range from high to moderate. Thicknesses of individual sand beds range from 15 to 75 ft.

At the HOM 855-1 well, the Lower Logan Canyon Sand Unit extends from 8865 to 9239 ft, with 374 ft total thickness (Figure S-28). The unit consists
totally of sand, except a 24 ft thick heterolithic interval, and a 26 ft thick shale bed. The porosity values range from low to high throughout the unit.

At the Gulf 857-1 well, the Lower Logan Canyon Sand Unit occurs from 8710 to 9079 ft, with 369 ft total thickness (Figure S-29). The sand beds are thicker in the top of the unit, thinning towards the bottom. The sand to shale ratio seem to be more or less equally balanced throughout the unit, and the porosity values range from low to high.

At the Exxon 902-1 well, the Lower Logan Canyon Sand Unit extends from 8760 to 9206 ft, with 446 ft of total thickness (Figure S-30). Individual sand beds are thicker in the deeper parts of the unit, and a thick confining shale bed separates two major horizons of sand beds. Thicknesses of sand beds range between 10 and 38 ft. Porosity values of sand beds range from low to high.

At the COST B-3 well, the Lower Logan Canyon Sand Unit occurs from 8689 to 9113 ft, with 424 ft of total thickness (Figure S-31). Shale dominates the unit and the sand beds are sparsely distributed throughout the unit, ranging in thickness from 5 to 28 ft. The porosity values range from low to high.

At the Exxon 728-1 well, the Lower Logan Canyon Sand Unit occurs from 8507 to 9015 ft, with 508 ft total thickness (Figure S-32). Sand beds of approximately constant thickness are distributed evenly throughout the unit, where they alternate with shales and a few heterolithic intervals. The porosities of sand beds range from low to moderate.
At the Exxon 816-1 well, the Lower Logan Canyon Sand Unit occurs from 8787 to 9092 ft, with 305 ft total thickness (Figure S-33). Sand beds are distributed evenly throughout the unit, confined below thick shale beds. There is no information on the porosity at this well.

3.1.4 Identification of Log Units for the Missisauga Unit

At the COST B-2 well, the Missisauga Unit occurs from 10255 to 11450 ft, with 1195 ft of total thickness (Figure 15; S-34). Individual sand beds are as thick as 98 ft at the top, and they thin towards the bottom of the unit. The porosities of sand beds range from moderate to high, and they are well confined below impermeable intervals.

At the Texaco 598-1 well, the Missisauga Unit occurs from 9064 to 10516 ft, with 1452 ft of total thickness (Figure S-35). Sands with moderate to high porosities dominate this unit, where an individual sand bed is as thick as 161 ft, and as thin as 5 ft. Impermeable shale units confine these sand beds.

At the Exxon 599-1 well, the Missisauga Unit occurs from 9010 to 10610 ft, with 1600 ft total thickness (Figure S-36). This unit consists of alternating sand and shale beds, where an individual sand bed ranges from as much as 163 ft and as low as 7 ft. The porosity values change from moderate to high throughout the unit.

At the Tenneco 642-3 well, the Missisauga Unit occurs from 9471 to 10607 ft, with 1136 ft total thickness (Figure S-37). Some heterolithic intervals are present, but overall this unit consists of alternating shale and sand beds that
range in thickness from 5 to 91 ft. Porosity values of the sand beds change from moderate to very high.

At the Tenneco 642-2 well, the Missisauga Unit occurs from 9410 to 10480 ft, with 1070 ft of total thickness (Figure S-38). Alternation of sand and shales constitutes this unit, with individual sand bodies varying from 10 to 82 ft thick, and their porosities range from moderate to high.

At the HOM 855-1 well, the Missisauga Unit occurs from 10645 to 11947 ft, with 1302 ft of total thickness (Figure S-39). Thickness of sand bodies range from 6 to 133 ft, and they alternate with confining shales. Porosity values range from moderate to high.

At the Gulf 857-1 well, the Missisauga Unit occurs from 10406 to 11392 ft, with 986 ft total thickness (Figure S-40). Individual sand beds are generally thick (i.e. as much as 96 ft), but there are a few thin beds as well (i.e. 6 ft). The porosity values of sand beds that are confined below shales range from moderate to very high (i.e. 56%).

At the Exxon 902-1 well, the Missisauga Unit occurs from 10170 to 11443 ft, with a total thickness of 1273 ft (Figure S-41). Individual sand beds are very thick towards the top of the unit (i.e. as thick as 191 ft) and become thinner towards the bottom of the unit (i.e. as thin as 9 ft). The porosity values of the sand beds range from moderate to high (i.e. 50%).
At the COST B-3 well, the Missisauga Unit occurs from 9873 to 11171 ft, with a total thickness of 1298 ft (Figure S-42). This unit consists of blocky sand beds alternating with shales, and a few heterolithic intervals. The sand beds are thick at the shallow levels (i.e. as thick as 108 ft), thinning towards the bottom of the unit (i.e. as thin as 12 ft). Porosity values of these intervals range between high and low.

At the Exxon 728-1 well The Missisauga Unit occurs from 9618 to 11450 ft, with 1832 ft total thickness (Figure S-43). Sand bodies are distributed randomly throughout the unit, changing in thickness from 9 to 133 ft. They are interbedded with shales and sometimes heterolithic intervals. The porosity values of the sand beds change between low and moderate.

At the Exxon 816-1 well, the Missisauga Unit occurs from 9706 to 10597 ft, with 891 ft total thickness (Figure S-44). The unit consists of interbedded shale and sand, and while sand bodies become thinner towards the bottom, overall there is considerable variation in thickness (i.e. 5 to 236 ft). There is no porosity information for these potential reservoirs.
3.2 Age evaluation of log units

3.2.1 Age Evaluation of Log Units Along the Dip Profile 75_7

3.2.1.1 Age of the Middle Sandstone Unit Along 75_7 Dip Profile

The Middle Sandstone Unit occurs from Coniacian through Santonian at the COST B-2 well, between 6009 and 6380 ft (Figure 16). The top of Santonian is placed at 5736 ft based on the joint occurrence of planktonic foraminifers *Globotruncana coronata* and *Globotruncan carinata* at that level (Smith et al., 1976). Smith et al. (1976) also reported that there are no diagnostic foraminiferal faunas and no calcareous nannofossils that could place the Santonian/Coniacian boundary. Therefore, in this study, the upper limit of Coniacian at COST B-2 is arbitrarily placed at 6063 ft, where a few specimens of the dinocyst *Cyclonephelium distinctum* were identified by Smith et al. (1976). The age, lithologic, and log character of the Middle Sandstone Unit suggests that it is the possible offshore equivalent of the onshore Magothy Formation, which ranges in age from late Turonian to Coniacian (Miller et al., 2003).

At the Texaco 598-1 well, the Middle Sandstone Unit has a Santonian age, and extends from 5909 to 6570 ft (Figure 17). The highest occurrence of the nannofossil *Marthasterites furcatus* places the top of Santonian at 5760 ft in Texaco 598-1 well, and calcareous nannofossil *Lithastrinus grilli* places the top of

At the Exxon 599-1 well, the Middle Sandstone Unit extends from Santonian to lower Campanian, between 5922 and 6720 ft (Figure 18). The top of Santonian at Exxon 599-1 is placed at 6550 ft based on the highest occurrence of the nannofossil *Marthasterites furcatus* (H. Cousminer, W. Steinkraus and Ray Hall, unpublished Exxon OCS-A 0029-1, Block 599-1 Paleontology Report; = top of Zone CC18 with an estimate age of >81.1 Ma).

At the Tenneco 642-3 well, the Middle Sandstone Unit occurs between 5852 ft and 6282 ft (Figure 19). Age information from Tenneco 642-3 is very limited, and there is no information available on the age of the Middle Sandstone Unit in this well. However, the proximity of Tenneco 642-3 well to Exxon 599-1, Texaco 598-1 and Tenneco 642-2 wells makes it possible to estimate the age of the Middle Sandstone Unit as Santonian to possibly Campanian.

At Tenneco 642-2 well, the Middle Sandstone Unit occurs entirely in the Santonian, between 5900 ft and 6170 ft (Figure 20). The top of the Santonian is placed at 5810 ft based on the highest occurrence of *Globotruncan a carinata* and *Globotruncan a concavata*, and the base is placed at 6200 ft based on the highest occurrence of *Globotruncan a sigali, Globotruncan a renzi*, and *Globotruncan a imbricata* (Bielak et al., 1986).

The available biostratigraphy information is consistent with my interpretation of the Middle Sandstone Unit, except at the Exxon 599-1 well. The
Middle Sandstone Unit ranges from Santonian into Campanian at this site, unlike the surrounding updip and downdip located wells. It is possible that the marker for Santonian/Campanian boundary, *Marthasterites furcatus* is premature and that the top of the Middle Sandstone Unit is Santonian. Thus, we suggest that the Middle Sandstone Unit spans the Coniacian through Santonian.

### 3.2.1.2 Age of the Upper Logan Canyon Sand Unit Along 75_7 Dip Profile

The Upper Logan Canyon Sand is primarily Cenomanian at the COST B-3 well based on identification of planktonic foraminiferal Zones UC3 (= *Rotalipora reicheli* zone; ~ mid Cenomanian) and UC2 (= *Rotalipora globotruncanoides* Zone; lower Cenomanian) (Poag, 1980) (Figure 24). A Cenomanian age for the Upper Logan Canyon Sand suggests that it is the offshore equivalent of the onshore Potomac III sequence.

At the COST B-2 well, the upper Logan Canyon Sand occurs from 8220 to 8600 ft and is Albian based on association of the top of the sands with the highest occurrence of both *Favusella washitensis* and *Planomalina buxtorfi* (Figure 16; Figure 25; Smith et al., 1976). The juxtaposition of these two forms suggests a possible early Cenomanian hiatus since *washiensis* ranges into the early Cenomanian (Caron, 1985). Poag (in Scholle, 1980) places the sand below Cenomanian Zones UC2 and UC3 at COST B-2. This would be consistent with correlations of the sands as diachronous between COST B-2 (Albian) and COST
B-3 (Cenomanian) (Smith et al., 1976; plate 2 in Open-File Report 79-1159), though it is possible that the sands were truncated by an unconformity at B-2.

The Upper Logan Canyon Sand at the Texaco 598-1 well occurs from 7986 through 8454 ft, having its upper limit in Albian (Figures 17; 25). At the Exxon 599-1 well the Upper Logan Canyon Sand extends from 7978 ft to 8426 ft, having its upper limit in Cenomanian (Figures 18; 25). At Tenneco 642-3 well the Upper Logan Canyon Sand appears to be mostly Albian, having its upper limit at 8052 ft and lower limit at 8728 ft (Figures 19; 25). At the Tenneco 642-2 well, it occurs from Albian through Cenomanian, between 7879 and 8470 ft (Figures 20; 25).

Texaco 598-1 and Tenneco 642-3 are the two wells in which the Upper Logan Canyon Sands are restricted to the Albian, being inconsistent with the updip and downdip wells. I lack biostratigraphic age information for the Tenneco 642-3 well. On the other hand, the highest occurrence of the planktonic foraminifer Planomalina buxtorfi in Texaco 598-1 places the top of Albian at 7980 feet (Cousminer and Steinkraus, 1978, unpublished Texaco OCS-A-00028 Block 598-1 Paleontology Report). The planktonic foraminifer Planomalina buxtorfi has its highest occurrence in Uppermost Albian (Caron, 1985). However, there are some zonations that put the highest occurrence of this taxon into Cenomanian (Postuma, 1971). Thus, it is possible that this sand unit is Cenomanian in this well.
At the Exxon 599-1 well, the top of the sands (7978 ft) is placed just above the top of Albian, which is placed at 8080 ft based on the highest occurrence of the nannofossils species *Braarudosphaera africana* (Figures 18; 25). However, the paleontology report by H Cousminer, W. Steinkraus and Ray Hall, (unpublished Exxon OCS-A 0029-1, Block 599-1 Paleontology Report) places the boundary at 7900 ft based on the dinoflagellate *Astrocysta cretacea*. This dinoflagellate fossil was renamed as *Palaeoperidinium cretaceum* (Fensome et al., 2009), and has a geological range of Hauterivian-Campanian (Yang et al., 2003). Therefore, *Braarudosphaera africana* is a better biostratigraphic marker, though its highest occurrence is in the middle Cenomanian not at the top of the Albian (De Romero et al., 2003). At Tenneco 642-3, the top of Albian is placed at 8053 ft, based on the very limited age information obtained from the well completion report (Figures 19 and 25).

Along the 75°_7 dip profile (Figure 26), the Upper Logan Canyon Sand occurs from Albian through Cenomanian at the COST B-2, Texaco 598-1, Exxon 599-1, Tenneco 642-3 and Tenneco 642-2 wells, becoming younger in basinward locations. Based on the age range, the Upper Logan Canyon Unit correlates with both the onshore Potomac III (Cenomanian) and Potomac II (Albian) and is diachronous across the shelf.
3.2.1.3  **Age of the Lower Logan Canyon Sand Unit Along 75_7**

**Dip Profile**

The Lower Logan Canyon Sand Unit is the possible offshore equivalent of the onshore Potomac II Unit, with an age of Aptian to Albian at most of the wells along the dip profile 75_7 (Figure 26). Based on my well log interpretation, it occurs from 8840 to 9345 ft at COST B-2, 8518 to 8814 at the Texaco 598-1, 8490 to 8828 ft at the Exxon 599-1, 8948 to 9388 ft at the Tenneco 642-3, and 8920 to 9330 ft at the Tenneco 642-2 well (Figure 30). This unit spans the Aptian to Albian at the COST B-2, Texaco 598-1, and Exxon 599-1 wells. However, at the Tenneco 642-3 and Tenneco 642-2, which are located further downdip, the Lower Logan Canyon Sand Unit is exclusively Aptian. This would imply a retrogradational stacking pattern of these sediments on the outer continental shelf and slope.

At the COST B-2 well, the boundary between Aptian and Albian is placed at 8900 ft based on the deepest occurrence of the dinocyst *Apteia elsenacki* at that level (Figure 16; Smith et al., 1976; Open file Report 76-774). At the Texaco 598-1 well, the dinoflagellates *Cyclonephelium tabulatum* and *Concavissimisporites crassitus* place the top of Aptian at 8710 ft (Figure 17; Cousminer and Steinkraus, 1978, unpublished Texaco OCS-A-00028 Block 598-1 Paleontology Report). At Exxon 599-1 well, identification of nannofossil species *Cyclagelosphaera margereli*, marks the top of Aptian (Figure 18; H Cousminer, W. Steinkraus and Ray Hall, unpublished Exxon OCS-A 0029-1, Block 599-1 Paleontology Report). At the Tenneco 642-3 well, age information is sparse but
sufficient enough to conclude that the Lower Logan Canyon Sand Unit is older than Albian and spans the Aptian at that well (Figure 19). At the Tenneco 642-2 well, the top of Aptian is marked by the highest occurrence of the dinoflagellate *Cyclonephelium tabulatum* at 8810 ft (Figure 20; Bielak et al., 1986).

### 3.2.1.4 Age of the Missisauga Unit Along 75_7 Dip Profile

Along the 75-7 dip profile, the Missisauga Unit spans the Hauterivian-Valanginian to Aptian, being the possible offshore equivalent of the onshore Potomac I/Wastegate Formation (Figures 26 and 30). Interpretation of well logs suggests that the Missisauga Unit occurs from 10255 to 11450 ft at the COST B-2, 9064 to 10516 ft at the Texaco 598-1, 9010 to 10610 ft at the Exxon 599-1, 9471 to 10607 ft at the Tenneco 642-3, and 9410 to 10480 ft at the Tenneco 642-2 well (Figure 30). This sand unit spans the Hauterivian-Valanginian to Barremian at the COST B-2 well, and reaches up to Aptian in the latter basinward located wells. Thus, the available biostratigraphy data is consistent with the interpretation of the Missisauga Unit in this study.

### 3.2.2 Age Evaluation of Log Units Along the Dip Profile 78_34

#### 3.2.2.1 Age of the Middle Sandstone Unit Along 78_34 Dip Profile

Based on my well log interpretations described previously, integration with biochronology for the Middle Sandstone Unit the along dip profile 78_34 is as follows (Figures 27 and 30).
At the HOM 855-1 well, the Middle Sandstone Unit (6350 to 6845 ft) is Santonian through possibly Campanian, where the boundary between Santonian and Campanian is placed at 6480 ft based on the highest occurrence of the planktonic foraminifer *Globotruncana concavata* and *Globotruncana coronata* at that level (Figure 21; unpublished HOM OCS-A 0057, Block 855 No. 1 Well Paleontology Report).

At the Gulf 857-1 well, this sand unit (from 6197 to 6462 ft) is Coniacian through Santonian where the Coniacian/Santonian boundary is placed at 6270 ft based on the identification of *Hedbergella amabilis* at that level (Figure 22; unpublished Gulf OCS-A-0059 Block 857 Well No. 1 Paleontology Report, by ExxonMobil, 1979). The top of the Santonian at Gulf 857-1 is placed at 6150 ft based on the highest occurrence of *Globotruncana concavata* at that level (unpublished Gulf OCS-A-0059 Block 857 Well No. 1 Paleontology Report, by ExxonMobil, 1979).

At Exxon 902-1 well, the Middle Sandstone (from 6332 to 6635 ft) is Santonian through Campanian, where the boundary between Santonian and Campanian is placed at 6422 ft based on the identification of the nannofossil species *Marthasterites furcatus* (Figure 23; W. Steinkraus, H. Cousminer and L. Bielak, 1981, unpublished Exxon OCS-A-0065 Block 902 Well No. 1 Paleontology Report), though this highest occurrence may be premature as discussed below.
The Middle Sandstone Unit is restricted to the Santonian at COST B-3 well (from 6685 to 6700 ft), where it thins in this furthest downdip location (Figure 24). The top of Santonian is placed at 6500 ft based on the highest occurrence of the planktonic foraminifers *Globotruncan concavata*, *Globotruncan carinata*, and *Globotruncan coronata* (Steinkraus, 1979, in open file report 79-1159). The top of Coniacian is placed at 6920 ft based on the highest occurrence of palynomorphs *Schizosporis reticulates* and *Cicatricosiporites perforatus* at 6920 ft (Steinkraus, 1979). On the other hand, Poag (1980) places the top of Coniacian at 7040 ft based on the co-occurrence of the planktonic foraminifers *Marginotruncan marginata* and *Whiteinella archaeocretacea* at that level. Since these taxa also range into the lower Santonian, this call is tentative (Poag, 1980) and I place the top of the Coniacian at about 6920 ft in this study.

Based on the available paleontology data, the Middle Sandstone Unit could be Coniacian to lower Campanian. Along the dip profile 78_34, this sand unit follows a progradational pattern, as it becomes younger. Its top seems to vary on the 75_7 well log transect. It ranges into Campanian only at the Exxon 599-1 well where this unit seems to span Coniacian through Santonian in the rest of the profile. The Campanian marker *Marthasterites furcatus* is possibly depressed/premature at this location since it is known to range well into the Campanian (its highest occurrence is the top of Zone CC18 with an age of 81.1 Ma). On the 75-34 well log transect, a similar situation occurs at the Exxon 902-1 well with *Marthasterites furcatus* and at HOM 855-1 with *Marginotruncan*
concavata which according to Petters (1977) has its highest occurrence in middle Santonian. Thus, the top of the Middle Sandstone at these wells could either be Santonian or Campanian.

The Coniacian age of Middle Sandstone Unit at COST B-2 is based on foraminiferal zonations of Poag (in Scholle, 1980). The only other Coniacian assignment is at Gulf 857-1, where the highest occurrence of Hedbergella amabilis (= H. simplex according to Caron, 1985) places the Coniacian/Santonian boundary at 6270 ft (unpublished Gulf OCS-A-0059 Block 857 Well No. 1 Paleontology Report, by ExxonMobil, 1979) with the sand from 6197 to 6462 ft. This taxon has its highest occurrence in the Santonian according to Petters (1977), whereas Exxon (1979) used it as a marker for the Coniacian and Caron (1985) assigns it to the lower Coniacian. I conclude that the Middle Sandstone Unit is likely Santonian downdip and Campanian updip on the outer continental shelf and upper slope off of New Jersey.

3.2.2.2 Age of the Upper Logan Canyon Sand Unit Along 78_34 Dip Profile

Based on my well log interpretations described previously, integration with biochronology for the Upper Logan Canyon Sand Unit along the dip profile 78_34 is as follows (Figures 27 and 30). The Upper Logan Canyon Unit has an Albian bottom and ranges into Cenomanian at most of the proximal wells and becomes totally Cenomanian downdip.
At the HOM 855-1 well, the Upper Logan Canyon Sand (from 8325 to 8774 ft) is Albian through mid Cenomanian (Figure 21). The top of Cenomanian is placed at 8020 ft based on the highest occurrence of the planktonic foraminifer *Rotaliapora cushmani* (unpublished HOM OCS-A 0057, Block 855 No. 1 Well Paleontology Report). The top of Albian is placed at 8683 ft based on the common occurrence of dinoflagellate *Spinidinium vestitum* at that level. This dinoflagellate is not a very accurate marker but was the only criteria available due to lack of age-diagnostic foraminifers below the Cenomanian (unpublished HOM OCS-A 0057, Block 855 No. 1 Well Paleontology Report).

At the Gulf 857-1 well, the Upper Logan Canyon Sand (from 8250 to 8545 ft) apparently has both its top and bottom in the Albian (Figure 22). The top of Albian at this well is placed at 8220 ft based on the identification of the planktonic foraminifer *Gaudryina dividens* (unpublished Gulf OCS-A-0059 Block 857 Well No. 1 Paleontology Report by Exxon, 1979). This benthic foraminiferal taxon may only range into the early Albian (Bolli et al., 1994) and its reliability, as a marker is suspect. The unpublished report by Exxon (1979) places the top of Cenomanian at 8070 ft, based on the highest occurrence of the planktonic foraminifer *Rotalipora cushmani* at that level.

At the Exxon 902-1 well the Upper Logan Canyon Sand (from 8361 to 8621 ft) is Albian through Cenomanian, and the Albian/Cenomanian boundary is placed at 8402 ft based on the occurrence of nannofossil markers *Nannoconus bucheri* and *N. Elongatus* (Figure 23; W. Steinkraus, H. Cousminer and L. Bielak, 1981, unpublished Exxon OCS-A-0065 Block 902 Well No. 1 Paleontology

At the COST B-3 well, the Upper Logan Canyon Sand unit (from 8200 to 8642 ft) occurs entirely in the Cenomanian (Figure 24). At this well, the top of Cenomanian is placed at 8180 ft based on the highest occurrence of *Rotalipora cushmani* at that level. Other foraminifers including *Rotalipora greenhornensis*, *Rotalipora reicheli* are present in the upper parts of the Cenomanian interval of the COST B-3 well (Steinkraus, 1979, in open file report 79-1159). On the other hand, Poag (in Scholle, 1980) reports the top of the Cenomanian as 8260 ft where the three planktonic foraminifers *Rotalipora cushmani*, *Rotalipora greenhornensis* and *Rotalipora reicheli* occur together, suggesting that the upper Cenomanian rocks are missing. The possibility of a latest Cenomanian hiatus is unlikely when the location of the COST B-3 well is considered. The Cenomanian section is complete in the more updip located wells and it is more likely to be complete in the COST B-3 well, unless there was submarine erosion. Therefore, the top of Cenomanian is placed at 8180 ft in this study (Steinkraus, 1979, in open file report 79-1159). The top of Albian is placed at 8690 ft as defined by the common occurrence of the dinoflagellate species *Spinidinium vestitum* at that level (Steinkraus, 1979, in open file report 79-1159). Poag (in Scholle, 1980) places the top of Albian at 9170 ft based on the appearance of the foraminifer *Favusella cf. scitula*. However, the foraminiferal fauna is very sparse in this
interval and the stratigraphically higher identification of Steinkraus (1979) appears to place the Albian/Cenomanian boundary significantly higher in the section than Poag (in Scholle, 1980).

The Upper Logan Canyon Sand Unit along the well log transect 78_34 follows a prograding pattern, becoming younger in downdip located wells (Figure 27). The only inconsistency occurs at Gulf 857-1 well where the Upper Logan Canyon Sand is exclusively Albian and the top of the Albian is defined by the highest occurrence of the planktonic foraminifer *Gaudryina dividens* (unpublished Gulf OCS-A-0059 Block 857 Well No. 1 Paleontology Report, by Exxon, 1979). This benthic foraminifer has its highest occurrence at mid to late Albian (Williamson, 1987), or early Albian (Bolli et al., 1994). However, the Cenomanian section is extremely thin at the Gulf 857-1 well (150 ft) and it is likely that there is a hiatus. This would explain the appearance of the Upper Logan Canyon Sand Unit only in the Albian. In addition the Cenomanian section is also extremely thin at the Exxon 902-1 well. The co-occurrence of the two Rotaliporid species, *Rotalipora cushmani* and *Rotalipora greenhornensis*, also suggests a mid to late Cenomanian hiatus at the Exxon 902-1 well.

The occurrence of a late Cenomanian hiatus in two downdip wells when the section is complete at the proximal well, HOM 855-1, could be explained by submarine erosion of the younger Cenomanian sediments.
3.2.2.3 Age of the Lower Logan Canyon Sand Unit Along 78_34 Dip Profile

The Lower Logan Canyon Sand Unit extends from 8865 to 9239 ft at the HOM 855-1 well, 8710 to 9079 ft at the Gulf 857-1 well, 8760 to 9206 ft at the Exxon 902-1 well and from 8689 to 9113 ft at the COST B-3 well (Figure 30). It is exclusively Albian along the 78_34 dip profile and thins out towards the basin (Figure 27).

The tops of Albian in each well are already mentioned in the evaluation of Upper Logan Canyon Sand Unit for the 78_34 dip profile. The biostratigraphic data is consistent with my interpretation of log units and reveals no contradiction.

3.2.2.4 Age of the Missisauga Unit Along 78_34 Dip Profile

Based on my well log interpretations described previously, integration with biochronology for the Missisauga Unit along the dip profile 78_34 is as follows (Figures 27 and 30). The placement of the base of the Missisauga Unit is uncertain at the Gulf 875-1 well because my physical correlation does not confirm the biostratigraphic correlation of this sand unit.

At the HOM 855-1 well, the Missisauga Unit (from 10645 to 11947 ft) is Hauterivian through Barremian (Figure 21). The Biostratigraphy Report of this well arbitrarily places the top of Hauterivian at 10800 ft based on the highest occurrence of a dinoflagellate similar to Batioladinium gochti. The top of Valanginian is placed at 12350 ft based on the highest occurrence of the
dinoflagellate *Phoberocysta neocomica* at that level (unpublished HOM OCS-A 0057, Block 855 No. 1 Well Paleontology Report).

At the Gulf 857-1 well, the Missisauga Unit (from 10406 to 11392 ft) occurs entirely in Barremian (Figure 22). Highest occurrences of dinoflagellates *Pseudocreatium pelliferum* and *Muderongia simplex* at 10380 ft place the top of Barremian at that level (unpublished Gulf OCS-A-0059 Block 857 Well No. 1 Paleontology Report, by Exxon, 1979). The top of Hauterivian is placed at 11580 ft based on the highest occurrences of the ostracod species *Everticlammina eccentrica*, *Schuleridea aff pentagonalis* and *Schuleridea aff triangularis* (unpublished Gulf OCS-A-0059 Block 857 Well No. 1 Paleontology Report, by Exxon, 1979).

At the Exxon 902-1 well the Missisauga Unit extends from Hauterivian-Valanginian to Aptian (Figure 23). The Barremian/Aptian boundary is placed at 10462 ft based on the identification of the dinoflagellate species *Muderongia simplex* (W. Steinkraus, H. Cousminer and L. Bielak, 1981, unpublished Exxon OCS-A-0065 Block 902 Well No. 1 Paleontology Report). There is no microfauna or flora identified to be able to restrict the Hauterivian-Valanginian age at the Exxon 902-1 well.

At the COST B-3 well, the Missisauga Unit is Hauterivian-Valanginian through Aptian (Figure 24). Steinkraus (1979) places the Barremian/Aptian boundary at 10070 ft based on the highest occurrences of the dinoflagellates *Muderongia simplex* and *Muderongia staurota*. Foraminiferal assemblages are
sparse near this level (Poag, 1980). The mutual association of the palynomorphs
*Ctenidodinium elongatulum, Broomia jaegari* and *Pseudoceratium pelliferum* at
10610 ft places the top of Hauterivian at COST B-3 well (Steinkraus, 1979). No
diagnostic fauna was available to distinguish the Hauterivian/Valanginian
boundary. However, Poag (in Scholle, 1980) places it at about 10770 ft based on
the abrupt appearance of a rich assemblage of agglutinated benthic foraminifers at
that level.

The range of the Missisauga Unit varies throughout the dip profile 78-34
(Figure 27). This sand unit follows a progradational depositional pattern as it
becomes younger and thicker towards the basin.

The only controversy arises at the Gulf 857-1 well, where the placement
of the base of the Missisauga Unit at the Gulf 857-1 well is uncertain because the
interpretation based on the physical criteria places it at 11392 ft. However, the
individual sand bodies in the section do not follow a certain pattern and make the
base difficult to place. Thus, when the biostratigraphy is also included as a
criterion, the base of this sand unit should be lower in the section, about 12500 ft
where thick and porous sand bodies end.

### 3.2.3 Age Evaluation of Log Units Along the Dip Profile 75_8

For the two Exxon wells 728-1 and 816-1 in the 75_8 dip profile, there is
no publicly available biostratigraphy report (Figure 28). Thus, for these wells, we
based the age determinations on the three relatively well-dated wells COST B-2,
Exxon 902-1 and COST B-3. The proximity of these wells made it possible to physically correlate the lithologic units (Figure 28).

Based on my log interpretation, the Middle Sandstone Unit occurs from 6099 to 6441 ft at the Exxon 728-1 well and from 6260 to 6621 ft at the Exxon 816-1 well (Figure 30). The Upper Logan Canyon Sand Unit occurs from 8138 to 8438 ft at the Exxon 728-1 well and from 8240 to 8580 ft at the Exxon 816-1 well. The Lower Logan Canyon Sand Unit occurs from 8507 to 9015 ft at the Exxon 728-1 well and from 8787 to 9092 ft at the Exxon 816-1 well. The Missisauga Unit occurs from 9618 to 11450 ft at the Exxon 728-1 well and from 9706 to 10597 ft at the Exxon 816-1 well.

3.3 Correlation of log units and Evaluation of Stratigraphic Patterns

Following the identification of lithologies and ages of units, I correlated the target sand units in each of the well log transects (Figures 26, 27, and 28). Three main criteria assisted me in correlating the stratigraphic patterns of the target units: 1- Individual logs to infer whether the sand beds are coarsening or fining upwards; thus, shallowing or deepening upwards, 2- changes in thickness of the individual beds; for example, thickening upwards indicates shallowing upwards, thus, progradation, 3- the overall thickness variations that could be related to location of the depocenters, which is not necessarily related to progradation or retrogradation.
3.3.1 Correlation of Middle Sandstone Unit

The Middle Sandstone Unit in the Baltimore Canyon Trough is defined as a major shaly, glauconitic sandstone within the Dawson Canyon Equivalent, which is primarily composed of calcareous mudstone representing a major marine transgression covering most of the Early Cretaceous delta within the Baltimore Canyon Trough (Libby-French, 1984). This sandstone is absent in the Scotian Shelf, but is laterally continuous enough in the BCT to be assigned as a unit within the Dawson Canyon Equivalent (Libby-French, 1984).

Along the dip profile 75_7 (Figure 26), the total thickness of the Middle Sandstone Unit ranges from 798 ft at the Exxon 599-1 well to 270 ft at the Tenneco 642-2 well (Table 1). Although the total thickness variation does not follow a certain pattern, the decrease in sand to shale ratio downdip in the basin suggests that this unit is thinning out (Figure S-1 through S-5). The Middle Sandstone Unit becomes younger downdip, spanning the Coniacian through Santonian, and indicates a progradational pattern.

Along the dip profile 78_34 (Figure 27), the thickness of the Middle Sandstone Unit ranges from 495 ft at the HOM 855-1 to 15 ft at the COST B-3 well, suggesting that this sand unit is pinching out downdip (Table 2). The age of the unit is restricted to Santonian in the most downdip well, but is Santonian through Campanian updip, suggesting a retrogradational pattern. However, the nannofossil marker used for placing the Santonian/ Campanian boundary at the Exxon 902-1 well is probably premature and the age of the Middle Sandstone
Unit is Coniacian through Santonian along this profile, as discussed in the age evaluation section 3.2.2.1. Thus, the depositional pattern of this unit may be progradational. The unit seems to appear in the Coniacian at the Gulf 857-1 well. However, the fossil used for assigning the Coniacian/Santonian boundary, *Hedbergella amabilis* is probably misinterpreted in the paleontology report, which I discuss in the age evaluation section 3.2.2.1.

Along the dip profile 75_8 (Figure 28), the total thickness of the Middle Sandstone Unit ranges from 371 ft at the COST B-2 well to 15 ft at the COST B-3 well, thinning out downdip (Table 3). There is no age information available for the Exxon wells 728-1 and 816-1 but when the location of these wells are taken into account, together with the age information from the updip and downdip wells, the Middle Sandstone Unit appears to have a progradational pattern along the dip profile 75_8.

### 3.3.2 Correlation of Upper Logan Canyon Sand Unit

The Upper Logan Canyon Sand Unit is described as a prograding deltaic unit composed of both distributary channel and mouth-bar sandstones of a wave-dominated delta based on the examination of drill cuttings and conventional cores (Libby-French, 1984).

Along the dip profile 75-7 (Figure 26) the thickness of the Upper Logan Canyon Sand Unit ranges from 380 ft at the COST B-2 well, to 676 ft at the Tenneco 642-3 well, becoming thicker downdip except at the most downdip located Tenneco 642-2 well (Table 1). However, when the locations of Tenneco
642-2 and 3 are considered, either one could be the distal one depending on the
direction of the source, the thicker one being closer to the depocenter (Figure 4).
The GR log character of all wells through this cross section indicate a thickening
and coarsening upwards pattern of the sandstone beds, as the curve shape changes
from serrated and funnel shaped to blocky, i.e., indicating an increase in the sand
percentage (Figure S-12 through S-16). The Upper Logan Canyon Sand occurs
from Albian through Cenomanian at the COST B-2, Texaco 598-1, Exxon 599-1,
Tenneco 642-3 and Tenneco 642-2 wells, becoming younger downdip. Combined
with the log characters and thickness changes, this suggests a progradational
stacking pattern for this sand body.

Along the dip profile 78_34 (Figure 27), thickness of the Upper Logan
Canyon Sand Unit ranges from 449 ft at the HOM 855-1 well to 260 ft at the
Exxon 902-1 well (Table 2). This unit is thicker in the most downdip located well,
COST B-3. At the two wells, Gulf 857-1 and Exxon 902-1, the thickness of the
unit is lower from both the updip and downdip located wells. This could be due to
the fact that the cross section 78_34 is not linear, and the HOM 855-1 and COST
B-3 wells are probably closer to the paleodepocenter (Figure 4). The GR and SP
curves of the Exxon 902-1 and COST B-3 well, and the GR curve of the Gulf
857-1 well change from serrated and funnel shaped to blocky towards the top of
the unit, indicating a thickening upward succession of sandstone beds (Figure S-
19; S-20). This unit follows a prograding pattern along the 78_34 dip profile,
becoming younger in the down-dip located wells, except at the Gulf 857-1, where
possibly a Cenomanian hiatus is present.
Along the 75_8 dip profile (Figure 28), the total thickness of the Upper Logan Canyon Sand Unit ranges from 260 ft at the updip Exxon 902-1 well to 442 ft at the downdip COST B-3 well (Table 3). This unit follows a progradational depositional pattern, as it becomes thicker and younger downdip. The log curve patterns also confirm the upward thickening pattern of the sand beds (Figure S-12; S-19; S-20; S-21; S-22).

### 3.3.3 Correlation of Lower Logan Canyon Sand Unit

Along the dip profile 75-7 (Figure 26), the thickness of the Lower Logan Canyon Sand Unit ranges from 505 ft at the COST B-2 well to 296 ft at the Texaco 598-1 well (Table 1). Thickness does not follow a consistent pattern, thus, neither decrease nor increase updip to downdip. The log curve patterns (serrated and funnel shaped GR and SP curves at the lower levels) at the COST B-2, Texaco 598-1, and Tenneco 642-2 wells possibly represent coarsening and thickening upward distributary mouth bar deposits of a prograding delta (Figure S-23; S-24; S-27). On the other hand, fining and thinning upward retrogradational pattern is observed in the Exxon 599-1 and Tenneco 642-3 well (Figure S-25; S-26). This sand unit spans the Aptian to Albian at the COST B-2, Texaco 598-1, and Exxon 599-1 wells. However, at the Tenneco 642-3 and Tenneco 642-2, which are located more downdip, the Lower Logan Canyon Sand Unit is exclusively Aptian. This would imply an overall retrogradational stacking pattern of these sediments beneath the modern outer continental shelf and slope.
Along the dip profile 78_34 (Figure 27), the thickness of the Lower Logan Canyon Sand Unit ranges from 369 ft at the Gulf 857-1 well to 446 ft at the Exxon 902-1 well (Table 2). The total thickness variation in this cross section is very slight, suggesting almost uniform thickness throughout the profile. When the age of the unit on each site is considered, it appears to be exclusively Albian, not giving a clue about the stacking pattern. At the Gulf 857-1 well the Gamma Ray curve pattern changes from serrated to funnel and blocky shape, thickening and coarsening upward (Figure S-29). On the other hand, the sand beds thin upward at the Exxon 902-1 and COST B-3 wells. When the sand/shale ratio of the unit is considered on each well site, the sand beds are thinner at the COST B-3 well, whereas it consists almost entirely of sand at the HOM 855-1 well. Thus, it can be concluded that this sand unit thins out downdip, in addition to thinning upward successions, following a retrogradational pattern.

Along the dip profile 75_8 (Figure 28) the thickness of the Lower Logan Canyon Sand Unit ranges from 508 ft at the Exxon 728-1 well to 305 ft at the Exxon 816-1 well (Table 3). The total thickness does not vary much throughout the basin, but the sand to shale ratio decreases downdip suggesting that the unit is shaling out. Age information is lacking for the Exxon wells 618-1 and 728-1. However, when the rest of the profile is evaluated, the unit follows a progradational pattern becoming younger downdip, in contrast with the two other profiles. A possible reason could be that the dip profile 75_8 is not indeed aligned parallel to depositional dip.
3.3.4 Correlation of Missisauga Unit

Abundant thick sandstone beds alternating with shales and silt beds characterize the Missisauga unit, which is typical of delta-front deposits according to Fisher et al. (1969). The blocky and funnel shaped GR and SP curve patterns of some of the thick porous sandstone beds possibly represent channel sandstone deposits of the delta.

Along the dip profile 75-7 (Figure 26), the thickness of the Missisauga Unit ranges from 1600 ft at the Exxon 599-1 well to 1070 ft at the Tenneco 642-2 well (Table 1). Individual sand beds thicken upward at the COST B-2, Texaco 598-1, and Tenneco 642-2 well (Figure x; S-34; S-35; S-38), indicating progradational pattern. On the other hand, there is no certain pattern of either thickening or thinning in the sandstone beds at the Exxon 599-1 and Tenneco 642-3 wells. Overall, it is difficult to speculate on the stratigraphical pattern or source direction of this extremely thick sand unit along the 75_7 dip profile. However the age information suggests progradation, as the unit becomes younger downdip.

Along the dip profile 78-34 (Figure 27) the thickness of the Missisauga Unit ranges from 1302 ft at the HOM 855-1 well to 986 ft at the Gulf 857-1 well (Table 2). There is no significant decrease or increase in total thickness of the Missisauga Unit along this dip profile, except thinning at the Gulf 857-1 well, which is the second proximal site. Individual sand beds at the HOM 855-1 well thin, thus deepen upward at the HOM 855-1 and Gulf 857-1 wells suggesting
retrogradational pattern. Conversely these beds thicken upward at the Exxon 902-1 and COST B-3 wells, indicating progradational pattern. Combined with the age information which becomes younger downdip, the thickening or shallowing upward of the individual sand beds strengthens the possibility of progradation of the Missisauga Unit throughout the dip profile 78_34.

Along the dip profile 75_8 (Figure 28) the thickness of Missisauga ranges from 1832 ft at the Exxon 728-1 well to 891 ft at the Exxon 816-1 well. Thickening upward sandstone beds at all five well sites suggest progradational pattern, combined with the ages younger downdip (Figure S-34; S-43; S-44; S-41; S-42).

3.3.5 Summary of Ages of Log Units

The correlation of log units along the well log transects revealed the ambiguities of the ages. As a summary, age ranges of the log units are as follows (Table 4). The Middle Sandstone Unit ranges from Coniacian to Santonian at most of the wells. There is possibility of this unit to range into Campanian based on the identification of the nannofossil *M. furcatus*. The Upper Logan Canyon Sand Unit spans the Albian through Cenomanian. The Lower Logan Canyon Sand Unit spans the Aptian through Albian. The Missisauga Unit spans the Hauterivian through Aptian.
3.4 Correlation of Onshore and Offshore Sequences

Sequences deposited during the Early Late Cretaceous to Miocene onshore New Jersey have been extensively studied (Miller et al., 2003; 2004; Sugarman et al, 2005; Kominz et al., 2008; Kulpecz et al., 2008; Browning et al., 2008). These sequences reflect the effects of eustatic variations combined with differences in accommodation and sediment supply. Various quantitative and qualitative data were integrated and have been correlated throughout the New Jersey coastal plain and offshore. However, the offshore continuation of these sequences remains a question. In this section, I attempt to correlate between the already identified onshore and the possible offshore sequences in the Cretaceous. I tentatively correlate the COST B-2 well data to the onshore Sea Girt and Fort Mott coreholes (Figure 3; Sugarman et al., 2004; Miller et al., 2006). I utilized the age control and geophysical log data, particularly GR logs, to trace the time equivalent units from onshore to offshore.

Previous works established deltaic deposition as the dominant process influencing the New Jersey sedimentation during the Late Cretaceous, based on intensive studies integrating high resolution well data obtained from 11 onshore coreholes (Browning et al., 2008; Kulpecz et al., 2008). Libby-French (1984) and Poag (1985) suggested deltaic deposition as the dominant process in the Baltimore Canyon Trough throughout the Cretaceous. Thus, despite the large distance between (Figure 3; Sea Girt: 138 km NW of the COST B-2 well; Fort Mott: 241 km W of the COST B-2 well), it is very likely that these two passive
margin settings belong to the same depositional system, and can possibly be correlated to some extent; i.e. as far as the data resolution allows.

Fifteen Late Cretaceous sequences have been recognized so far in the New Jersey coastal plain (Browning et al., 2008; Kulpecz et al., 2008). Kulpecz et al. (2008) established certain geophysical log signatures for these sequences and lithofacies that were first assigned by Miller et al. (2004).

I correlated time equivalent units for the Late Cretaceous within this broad section and tested the consistency of facies changes in a sequence stratigraphic context. I should note that the resolution and quality of the datasets differ extensively from onshore to offshore, i.e., the onshore analysis has been done on continuously cored coreholes, whereas the interpretations on the offshore rely entirely on sidewall core samples and geophysical logs. Facies assignment is difficult at the COST B-2 well with the available data, however the literature can assist to some extent.

The Sea Girt drill site is located 138 km NW of the COST B-2 well (Figure 3); it targeted Upper Cretaceous sequences and recovered 1215.76 ft (370.56 m), with a mean recovery of 77.9% for the 1600 ft (487.68 m) cored (Miller et al., 2006). The oldest sediments recovered belong to the uppermost Potomac Formation (Albian to Lower Cenomanian), correlating with the Potomac III unit, though this unit was undifferentiated in this core. The Sea Girt corehole recovered full sequences from the middle Campanian upper Englishtown Formation, the lower Campanian Merchantville Formation (cryptic sequences
Merchantville I and II), the upper Turonian–Coniacian Magothy Formation, and the Cenomanian–Turonian Bass River Formation (Miller et al., 2006).

A distinct gamma ray kick at 566 ft (172.5 m) at the base of the Navesink Formation marks the base of the Maastrichtian (Figure 29a). A secondary peak above, at 490 ft (149 m), is associated with the Cretaceous–Paleogene transition (Miller et al., 2006). This gamma log signature is recognized at the COST B-2 gamma log signature as well, at 5000 ft (1524 m). It is worth noting the possible absence of the Maastrichtian sediments at the offshore COST B-2 well based on cutting samples (Scholle, 1977), though the gamma log peaks at 5000 and 4970 ft suggest the presence of a thin Maastrichtian section. In contrast, this section is complete in the updip Sea Girt drillhole.

Thick sand bed characterized by blocky gamma ray log character at the COST B-2 well in the uppermost Campanian (Figure 29a) is likely the offshore equivalent of the Mount Laurel Formation, having very similar log signature at the Sea Girt drill hole.

No tentative equivalents were recognized in the COST B-2 well gamma log signature for the other onshore Campanian Wenonah, Marshalltown, and Upper Englishtown formations, and for the Santonian Merchantville and Cheesequake Formations. This is possibly because these sands are thin to lacking at the COST B-2 well as the section fines offshore.

A gamma low at the COST B-2 well between 5684 and 5802 ft is interpreted as a heterolithic unit and associated with the Santonian/Campanian
boundary. This would suggest correlation with the Merchantville II or III sequences. However, these sequences are glauconitic onshore and the blocky, coarsening upward log pattern suggests a shallower water environment at COST B-2. This suggests that the age correlations offshore may be incorrect and the heterolithic unit with low gamma values at 5684-5802 ft may correlate with either the upper Englishtown or lower Englishtown sands.

Magothy Formation at the Sea Girt corehole (565.1-621 ft) is Late Turonian through Santonian and is possibly the onshore equivalent of the offshore Middle Sandstone Unit, also Late Coniacian through Santonian. Onshore, Miller et al. (2006) identified five sequences within the Magothy Formation, consisting of shallow marine to delta plain facies associated with long-term sea level fall (Browning et al., 2008). Kulpecz et al. (2008) were able to distinguish sedimentary facies utilizing gamma log geometries, for example, delta front and fluvial sands of the Magothy sequences I and III (Figure 29a) are characterized by gamma-ray troughs and sometimes serrated patterns, whereas paleosols and swamps are represented by gamma peaks. It is hard/not possible to identify these sequences in the Gamma Log of COST B-2. This is probably because the sequence boundaries developed onshore merge into their correlative conformities offshore. However, the overall serrated pattern of the Gamma Ray log character at the COST B-2 well for the Middle Sandstone unit resembles the log character of the Magothy Sequences at the Sea Girt corehole. The serrated gamma ray log pattern of the Middle Sandstone Unit could be the seaward expression of the rapidly changing lithofacies of the Magothy Formation (including estuarine,
paleosols, distributary mouth bar, inner delta plain, swamp, levee, bay, lagoon and shoreface facies; Kulpecz et al., 2008). Rhodehamel (in Scholle, 1977) reported abundant lignitic and coaly fragments from 6245 ft at the COST B-2 well, indicating a terrestrial influence for the Middle Sandstone Unit. He suggested transitional to inner neritic depositional environment for the Middle Sandstone Unit.

The Fort Mott drill site is located 241 km W of the COST B-2 well (Figure 3 an 29b). It targeted the nonmarine Potomac Formation (Barremian to earliest Cenomanian; Browning et al., 2008) and recovered 638.85 ft (194.7 m), with a mean recovery of 78% for the 820 ft (249.9 m) cored (Sugarman et al., 2004). Browning et al. (2008) tentatively identified three sequences in the Potomac formation (Figure 29b; Potomac I, Potomac II, and Potomac III) based on successions of medium to fine quartz sands overlain by fine-grained units. Sugarman et al. (2004) suggested their depositional environment as anastomosing river environments in an upper delta plain, based on the abundance of fine flood plain deposits and organic rich sediments. They identified a few thick sand units within Potomac sequences that are correlatable throughout the coastal plain, making these units possible targets for CO₂ sequestration. Although the depositional facies suggested for the Potomac Formation is an anastomosing river, the regionally correlatable sand units suggest a delta front component for the Potomac III that was overstepped by the anastomosed river system (Sugarman et al., 2005).
The possible offshore equivalent of the Potomac units could be the Upper Logan Canyon Sand Unit (Albian through Cenomanian), Lower Logan Canyon Sand Unit (Aptian through Albian), and the Missisauga Unit (Hauterivian through Aptian).

The Potomac III Sequence (Albian to early Cenomanian), Potomac II sequence (Albian), and Potomac I Sequence (Barremian through Aptian) are characterized by gamma ray troughs at the lower parts (Figure 29b) that are suggested to represent aquifer sands (Sugarman et al., 2005). The gamma ray log values increase towards the top, representing alternation of silty clays and clayey silts. The possible offshore equivalents, Upper and Lower Logan Canyon Sand Units, and Missisauga Unit have somewhat a different log pattern, sand beds with serrated log character at the bottom, high gamma ray values in the middle and a thick sand bed at the top, characterized by blocky gamma log (Figure 29b). The thickening upward pattern of these units, in contrast to the fining upward fluvial deposits of Potomac III, II and I sequences, could indicate channel sandstone deposits of a prograding delta. The facies change between these two fairly time equivalent sediments is consistent. That is, it is likely that the anastomosing river in the coastal plain turned into a delta downdip.
4. Discussion

For the CO$_2$ sequestration potential of a reservoir, five main criteria should be taken into account. The target unit should be: 1) sufficiently deep (i.e. below the supercritical depth; 800 m; Benson et al., 2005); 2) laterally continuous; 3) sufficiently porous and permeable; 4) sealed with impermeable rocks; and 5) in suitable state in terms of material filling the pores (Benson et al., 2005). Reservoir quality of sandstone targets depends on the porosity and permeability. Since these sand bodies are deeply buried, compaction arising from sediment load will decrease the porosity (Kominz et al., 2011), which should be taken into account when interpreting their potential. Porosity values greater than ~20% are accepted good for a reservoir and those less than ~8% good for a seal (Economides and Ehlig-Economides, 2010).

The Middle Sandstone Unit (ranges from Coniacian to Campanian) is a relatively thin sand unit (varying in total thickness from 798 ft to 15 ft (243 to 4 m), updip to downdip) that was probably deposited as the youngest lobe of the Early Cretaceous delta. This sand unit thins downdip, and pinches out at the most downdip well, COST B-3 (from 6685 to 6700 ft). The unit is thickest at the Exxon 599-1 well, where it becomes as thick as 798 ft (243 m) (from 5922 to 6720 ft; Figure S-3). However, the sand percentage of the unit at this well is low, indicating low potential for sequestration at this site. The most suitable location would be Texaco 598-1 (from 5909 to 6570 ft), where the unit is comprised mostly of sandstone, capped by shales with about 15 ft (4 m) thickness.
According to the Texaco 598-1 completion report, the paleoenvironment of Middle Sandstone Unit is shoreface, which is unlikely when the location of the well is considered (Table 1; Figure S-45). The environment suggested for the Middle Sandstone is middle shelf at the updip COST B-2 well (19.6 km to the W), and outer shelf at the closely located downdip Tenneco 642-2 well (3.3 km to the SE). Shoreface environment between middle shelf and outer shelf is unreasonable. Therefore, we suggest that the environment claimed for the Middle Sandstone Unit at the Texaco 598-1 well is misinterpreted and the thick porous sands within this unit (different from the other closely spaced wells, i.e., Exxon 599-1, Tenneco 642-3 and Tenneco 642-2; Figures S-2 through S-4) are probably local, representing the lobe of a delta, which later switched to another location.

The porosity values of Middle Sandstone at this well are high, and the SP and Resistivity logs indicate high permeability of the sandstones. However, as mentioned above, the Middle Sandstone Unit at the Texaco 598-1 well is possibly a local feature, and continuity of the thick porous sands throughout the basin is questionable. They shale out in the downdip wells, and the sand to shale ratio is lower in the other updip wells. Most importantly, the porosity logs indicate the presence of methane within the Middle Sandstone Unit at the Texaco 598-1 well (Figure S-2). The Density Porosity logs show higher values than the Neutron Logs throughout the sand body, which is typical of gas bearing sands (Figure 8). CO₂ is denser than the gas hydrocarbon (most commonly methane) below the supercritical depth, thus, there is no risk of a chemical reaction occurring between the two. On the other hand, injecting CO₂ into a unit filled with gas hydrocarbon
will lead to pressurizing of the unit, which should be avoided even at very deep sediments. One solution would be to ventilate the reservoir by putting pressure relief wells that will relieve the methane within the rock. However, this would produce undesirable side effects of safety and environmental issues such as the methane release damaging the fauna in that particular area and explosion from methane. Plus the release of a given amount of methane has about 10 times the green house effects of CO$_2$ (Benson et al., 2005). Thus, sequestration of CO$_2$ and release of CH$_4$ would have a negative effect on green house gas emission.

Additionally, it is observed from the well log data that the gas within the middle sandstone does not fill one continuous depth interval, but instead there is stratification of water, gas and a subtle impermeable barrier that is about a few meters thick. The impermeable barriers represented by small amplitude deflections of SP to the shale baseline are very thin but sufficiently thick to cause the stratification of pockets of gas and water. This stratification within the reservoir makes it even more complicated to ventilate the reservoir.

The Upper Logan Canyon Sand Unit generally thickens downdip in all well log profiles, which makes these sand units potential targets for sequestration. At the COST B-2 well, the porosity values of the thickening upward sand beds are not very good except a few intervals (from 8220 to 8600 ft). At the more downdip Texaco 598-1 well, however, the porosity values are high, with blocky GR and SP log characters (from 7986 to 8454 ft; Figure S-13). In addition to the Texaco 598-1, three other closely spaced wells (Exxon 599-1, Tenneco 642-3 and Tenneco 642-2) have similar characteristics of sand beds (Figures S-14 through S-16),
strengthening the potential of this particular area for sequestration. Some of the more downdip wells; Exxon 728-1, Exxon 902-1 and COST B-3 show low porosity values in blocky sandstone beds (Figure S-21; S-19; S-20). On the other hand, sands at the HOM 855-1 and Gulf 857-1 wells range in porosity from moderate to high (Figure S-17; 18). Overall, the Upper Logan Canyon Sand Unit holds advantages as a sequestration target: 1) it is barren of hydrocarbons which eliminates the possible complications; 2) the total thickness variation and stacking patterns indicate that it is spatially continuous throughout the basin, although the reservoir quality decreases in the most downdip wells. If the Upper Logan Canyon Sand Unit is to be determined as the main target, the sequestration should focus on the particular area in the downdip end of the dip profile 75_7 (Figure 26).

The Lower Logan Canyon Sand Unit thickness variation indicates slight differences suggesting uniform thickness throughout the basin. At the COST B-2 well (from 8840 to 9345 ft), porosity values of the blocky sand beds in the Lower Logan Canyon Sand Unit are high, in contrast to the Upper Logan Canyon. In addition, permeabilities in excess of 10000 mD have been reported by Scholle et al, (1980). The downdip wells Texaco 598-1, Exxon 599-1, Tenneco 642-3 and Tenneco 642-2 also possess sufficiently porous and thick sand beds (Figures S-24 through S-27). However, there are a few gas-bearing intervals within this unit at Exxon 599-1 well, which should be taken into consideration while contemplating sequestering CO2. The complications that can arise from a gas-bearing unit are discussed above. The HOM 855-1 and Gulf 857-1 wells contain several high
porosity intervals within the Lower Logan Canyon Sand Unit, but the sand to shale ratio is lower in these downdip wells (Figure S-28; S-29). The sandstone beds at the Exxon 902-1 well lack porosity, in addition to low sand to shale ratio (from 8760 to 9206 ft; Figure S-30). In the Exxon 728-1 well, the porosity values range from low to moderate, decreasing the potential of Lower Logan Canyon Sand Unit as a reservoir at this site. In the most downdip well, COST B-3, the Lower Logan Canyon Sand Unit almost shales out, with sand to shale ratio and the porosity values decreasing (from 8689 to 9113 ft; Figure S-31). Overall, the Lower Logan Canyon Sand Unit can be considered as a good target for sequestration in the vicinity of dip profile 75_7, where it promises spatial continuity of sand deposits of high porosity. Future studies should focus on this transect, if the Lower Logan Canyon Sands are selected for sequestration. The only issue that should be noted is the small interval of gas-bearing sands at the Exxon 599-1 well. The continuity of this interval should be examined to determine whether it is local or not.

The Missisauga Unit in the Baltimore Canyon Trough is the thickest of the potential target units, reaching up to 1832 ft (558 m) at the Exxon 728-1 well (from 9618 to 11450 ft). In the COST B-2 well (from 10255 to 11450 ft), which is the most updip well examined, the Missisauga Unit contains high porosity sand beds interbedded with thick shales. Likewise, this unit at the Texaco 598-1, Exxon 599-1, Tenneco 642-3 and Tenneco 642-2 wells includes high porosity sand beds alternating with impermeable beds (Figures S-35 through S-38). However, the Texaco well contains thick gas-bearing intervals, which is not
desirable for sequestration purposes as discussed above. The HOM 855-1, Gulf 857-1 and Exxon 902-1 wells also include gas in the Mississauga Unit, although thick porous sand beds are present (Figure S-39 through S-41). At another downdip well, Exxon 728-1, the Mississauga Unit contains sand beds with low porosities in addition to low sand to shale ratio (Figure S-43). At the most downdip well, COST B-3, the Mississauga Unit thickens and thick porous sandstone beds are confined by shale beds (Figure S-42). Although the COST B-3 well seems to be good reservoir for sequestration, the great water depth (819 m) and the distance from the coast would raise the cost of sequestration.

To sum up, the most promising target for CO₂ sequestration would be Lower Logan Canyon Sand Unit, in the vicinity of dip profile 75_7. The Upper Logan Canyon Sand Unit can also be considered as a good target in the downdip end of this line. However, the continuity of the potential reservoir is an important factor, and the lower sand unit suggests more continuity as described above.
5. Conclusion

- This thesis aims to evaluate the sequestration potential of the thick Cretaceous sand bodies beneath the outer continental shelf and upper slope off of New Jersey.

I correlated the four target sand units (the Middle Sandstone Unit, the Upper and Lower Logan Canyon Sand Units, and the Missisauga Unit) along three cross-sections, and evaluated their continuities and stratigraphical patterns throughout the NE quarter of the Baltimore Canyon Trough.

- The resolution and quality of the electric log data used in this study is high, making it possible to identify lithologic units down to about 1 meter thick. In the context of this study, I have established three lithologic units for certain log characters: sand, heterolithic, and shale.

- Existing biostratigraphic reports for most of the wells are sufficient to constrain ages of log units. However, uncertainties exist because the biostratigraphy is based on well cutting samples and the resolution is low. Therefore, a reevaluation of the cuttings and sidewall core samples available in the Delaware Geological Survey is needed.

- The Middle Sandstone Unit has a progradational pattern throughout the basin, spanning the Coniacian through Santonian. It appears to range into the Campanian at the two Exxon wells; 599-1 and 902, inconsistent with the updip and downdip wells. Either my interpretation of top of the Middle Sandstone Unit at these wells is mistaken or the highest occurrence of the calcareous nannofossil *M. furcatus* used for placing the Santonian /Campanian boundary at these wells is premature. This unit has thick, porous sand intervals in the downdip area of the dip profile.
75_7 that could be considered as a potential reservoir for sequestration. However, the unit thins out downdip and the thick sand intervals appear as localized features. Moreover, the well log correlation does not suggest continuity for this sand body. In addition, based on the log data, the localized sand body is hydrocarbon-bearing, which would produce complications for sequestration.

- The Upper Logan Canyon Sand Unit has a progradational pattern, spanning the Albian through Cenomanian. This unit has good potential as a sequestration reservoir in the particular area in the downdip end of the dip profile 75_7, where the four closely spaced wells (Texaco 598-1, Exxon 599-1, Tenneco 642-3 and 2) provide control for understanding the spatial distribution of the sand unit. This sand unit thins downdip to the SE in the two other dip profiles, addressing the downdip end of the dip profile 75_7 as the target area.

- The Lower Logan Canyon Sand Unit has a retrogradational pattern, spanning the Aptian through Albian. Like the Upper Logan Canyon, the downdip end of dip profile 75_7 is the area where these sands are thick, porous and continuous. However, unlike the upper unit, the Lower Logan Canyon Sand Unit promises more continuity towards the south. Thus, this unit appears to be the most favorable candidate for sequestration.

- The Missisauga Unit has a progradational pattern, spanning the Hauterivian through Aptian. It is continuous throughout the study area, thickening downdip. However, age constraint is very poor for this unit, due to absence of foraminiferal assemblages. Plus there are many gas bearing intervals in this deeply buried sand unit, making it less favorable as a sequestration target.
My attempt to correlate onshore Cretaceous sequences into the offshore, utilizing age control and geophysical logs, brought about ambiguous results. Although they belong to the same depositional system, the large distance between these two passive margin settings (Sea Girt: 138 km NW of the COST B-2 well; Fort Mott: 241 km W of the COST B-2 well) obscures the continuity of the sequences. However, the synchronicity and the GR log pattern resemblance of the offshore Middle Sandstone Unit (Late Coniacian through Santonian) and the onshore Magothy sequences (Late Turonian through Santonian) suggest their possible equivalency. Likewise, the Potomac I (Albian to early Cenomanian), II (Albian), and III (Barremian through Aptian) are possibly equivalent to the offshore Upper Logan Canyon (Albian through Cenomanian) and Lower Logan Canyon (Aptian through Albian) Sand units, and Missisauga Unit (Hauterivian through Aptian).
6. Future Work

- Integration of the well log cross sections established in this study to the available Multi Channel Seismic lines will make it possible to identify the sequences.
- Correlation of these seismic lines will lead to a better understanding of the spatial distribution of the sand units buried beneath the outer continental shelf and upper slope off of New Jersey.
- Reexamining the well cuttings to generate a more detailed biostratigraphic and lithofacies analysis than has been done previously and reconstructing the paleoenvironments. With a higher resolution age control, integrating the paleoenvironments and sequences will reveal the depositional history of the basin.
REFERENCES


Figure 1. Schematic cross-section through Baltimore Canyon Trough, illustrating the primary structural elements of the basin. Modified after Grow and Sheridan (1988), by Miller et al., (2011).
Figure 2. Map illustrating the major Mesozoic rift basins of the eastern North America, modified from Withjack and Schlische (2005). Inset shows Pangean supercontinent during Late Triassic time and highlights the rift zone between eastern North America and northwestern Africa and Iberia.
Figure 3. Map summarizing the seismic survey and drilling history in the U.S. east coast, between Hudson and Washington Canyons. The oval shapes indicate depth to basement rock. Red lines are track of multichannel seismic lines including USGS regional reconnaissance lines, Exxon, BGR, and Ewing grids. Green and blue circles denote shallow wells drilled onshore and offshore for scientific purposes. Red circles denote deep wells drilled offshore for exploration purposes. White circles are the stratigraphic test wells (COST B-2 and COST B-3) used as reference for this study (Monteverde et al., 2010).
Figure 4. Map showing the locations of the wells drilled for exploration purposes (red circles), and Multi Channel Seismic Lines crossing or projectable from these wells (Red: Exxon lines, Green: BGR lines).
Figure 5. Generalized stratigraphic sections of Baltimore Canyon Trough and Scotian Shelf. Four target sand bodies are highlighted. Modified from Libby-French, 1984.
Figure 6. Schematic illustration of SP deflection behavior for varying drilling fluid conditions and lithologies. Adapted from Asquith and Gibson (1982).
Figure 7. Schematic diagram illustrating an idealized borehole environment. 
$R_m$: Resistivity of the drilling mud, $R_{XO}$: Resistivity of the flushed zone, $R_{MF}$: Resistivity of the mud filtrate, $R_i$: Resistivity of the invaded zone, $R_T$: Resistivity of the uninvaded zone (true resistivity), $R_w$: Resistivity of the formation water, $R_{Mc}$: Resistivity of the mud cake, $R_s$: Resistivity of the adjacent rock, $d$: hole diameter, $h$: bed thickness, $d_i$: diameter of the invaded zone (inner boundary; flushed zone), $d_j$: diameter of the invaded zone (outer boundary; invaded zone). Adapted from Asquith and Gibson (1982).
Figure 8. Schematic illustration of Gamma Ray Log responses for varying lithologies. Modified after Rider (2002).
Figure 9. Hypothetical Neutron-Density Log patterns for various lithologies, in sandstone porosity units.
Figure 10. Example sections from the Texaco 598-1 well, showing the log characters for sand, heterolithic and shale intervals. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure 11a. Geologic time scale 2004 spanning Early Cretaceous, plotted by using Time Scale Creator 5.0 software.
Figure 11b. Geologic time scale 2004 spanning Late Cretaceous, plotted by using Time Scale Creator 5.0 software.
Figure 12. Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal.) Red = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure 13. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal.), Brown = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure 14. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal), Brown = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
**Figure 15.** Chronostratigraphy of log units and lithologic interpretation for the Missisaua Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal.), Brown = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure 16. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the COST B-2 well.
Figure 17. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the Texaco 598-1 well.
Figure 18. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data for the Exxon 599-1 well.
Figure 19. Chronostratigraphy of log units at the Tenneco 642-3 well obtained from the sparse information available in the well completion report. No information was available on the paleontology and paleoenvironments.
Figure 20. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the Tenneco 642-2 well.
Figure 21. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the HOM 855-1 well.
Figure 22. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the Gulf 857-1 well.
Figure 23. Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, for the Exxon 902-1 well.
**Figure 24.** Chronostratigraphy of log units calibrated to GTS 2004 utilizing the paleontology data, and tentative paleoenvironments suggested by the well completion report for the COST B-3 well.
### Standard Chronostratigraphy

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### Geomagnetic Polarity

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### Planktonic Foraminifers

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<td>Tenneco 642-2</td>
<td>Chevron</td>
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<td>Cost B-3</td>
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**Figure 25.** Chart illustrating the biostratigraphy of the Upper Logan Canyon Sand Unit. †: highest occurrence, §: hiatus, brown: shale, yellow: sand.
Figure 26. Cross section along the Exxon line 75_7, showing the correlation of five wells. All depths are in feet below Kelly Bushing (KB) level. KB: COST B-2= 90 ft, Texaco 598-1= 82 ft, Exxon 599-1= 82 ft, Tenneco 642-3= 82 ft, Tenneco 642-2= 88 ft,. Water Depth: COST B-2= 298 ft, Texaco 598-1= 432 ft, Exxon 599-1= 442 ft, Tenneco 642-3= 448 ft, Tenneco 642-2= 445 ft. All columns are at the same depth scale between 5000 and 12000 ft below KB. Yellow lines indicate depth to top of stratigraphic units of the Baltimore Canyon Trough: Middle Sandstone Unit, Upper Logan Canyon Sand Unit, Sable Shale Member, Lower Logan Canyon Sand Unit, Naskapi equivalent, Mississauga Unit and Mic Mac Equivalent. *= nannofossil, **= palynomorph.
Figure 27. Cross section along the Exxon line 78_34, showing the correlation of four wells. All depths are in feet below Kelly Bushing (KB) level. KB: Hom 855-1=100 ft, Gulf 857-1=73 ft, Exxon 902-1=72 ft, COST B-3=42 ft. Water Depth: Hom 855-1=290 ft, Gulf 857-1=349 ft, Exxon 902-1=433 ft, COST B-3=2686 ft. All columns are at the same depth scale between 5000 and 13000 ft below KB. Yellow lines indicate depth to top of stratigraphic units of the Baltimore Canyon Trough: Middle Sandstone Unit, Upper Logan Canyon Sand Unit, Sable Shale Member, Lower Logan Canyon Sand Unit, Naskapi equivalent, Missisauaga Unit and Mic Mac Equivalent. *= nannofossil, **= palynomorph, ***= ostracod.
Figure 28. Cross section along the Exxon line 75_8, showing the correlation of five wells. All depths are in feet below Kelly Bushing (KB) level. KB: COST B-2= 90 ft, Exxon 902-1= 72 ft, Exxon 728-1= 83 ft, Exxon 816-1= 81 ft, COST B-3= 42 ft . Water Depth: COST B-2= 298 ft, Exxon 902-1= 433 ft, Exxon 728-1= 433 ft, Exxon 816-1= 462 ft, COST B-3= 2686 ft. All columns are at the same depth scale between 5000 and 12000 ft below KB. Yellow lines indicate depth to top of stratigraphic units of the Baltimore Canyon Trough: Middle Sandstone Unit, Upper Logan Canyon Sand Unit, Sable Shale Member, Lower Logan Canyon Sand Unit, Naskapi equivalent, Missisauga Unit and Mc Mac Equivalent. *= nannofossil, **= palynomorph.
Figure 29a. Correlation between onshore Sea Girt drillhole and offshore COST B-2 well.
Figure 29b. Correlation between onshore Fort Mott drillhole and offshore COST B-2 well.
Figure 30. Chart showing the age-depth distribution of the target sand units at the examined offshore wells and the two onshore wells penetrating the Cretaceous strata. All depths are in feet below Kelly Bushing (KB) level. KB: COST B-2=90 ft, Texaco 598-1=82 ft, Exxon 599-1=82 ft, Tenneco 642-3=82 ft, Tenneco 642-2=88 ft, Hom 855-1=100 ft, Gulf 857-1=73 ft, Exxon 902-1=72 ft, Exxon 728-1=83 ft, Exxon 816-1=81 ft, COST B-3=42 ft. Water Depth: COST B-2=298 ft, Texaco 598-1=432 ft, Exxon 599-1=442 ft, Tenneco 642-3=448 ft, Tenneco 642-2=445 ft, Hom 855-1=290 ft, Gulf 857-1=349 ft, Exxon 902-1=433 ft, Exxon 728-1=433 ft, Exxon 816-1=462 ft, COST B-3=2686 ft.
### Table 1. Thickness of sand units at the wells along the 75_7 Dip Profile.

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<th>Tenneco 642-3</th>
<th>Tenneco 642-2</th>
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<td>Upper Logan Canyon Sand Unit</td>
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<td>448 ft</td>
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<td>591 ft</td>
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<tr>
<td>Lower Logan Canyon Sand Unit</td>
<td>505 ft</td>
<td>296 ft</td>
<td>338 ft</td>
<td>440 ft</td>
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<tr>
<td>Missisauga Unit</td>
<td>1195 ft</td>
<td>1452 ft</td>
<td>1600 ft</td>
<td>1136 ft</td>
<td>1070 ft</td>
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### Table 2. Thickness of sand units at the wells along the 78_34 Dip Profile.

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<th>Gulf 857-1</th>
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<td>Lower Logan Canyon Sand Unit</td>
<td>374 ft</td>
<td>369 ft</td>
<td>446 ft</td>
<td>424 ft</td>
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<tr>
<td>Missisauga Unit</td>
<td>1302 ft</td>
<td>986 ft</td>
<td>1273 ft</td>
<td>1298 ft</td>
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Table 3. Thickness of sand units at the wells along the 75_8 Dip Profile.

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<th>Exxon 902-1</th>
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<td>361 ft</td>
<td>303 ft</td>
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<tr>
<td>Upper Logan Canyon Sand</td>
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<td>300 ft</td>
<td>340 ft</td>
<td>260 ft</td>
<td>442 ft</td>
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<tr>
<td>Lower Logan Canyon Sand</td>
<td>505 ft</td>
<td>508 ft</td>
<td>305 ft</td>
<td>446 ft</td>
<td>424 ft</td>
</tr>
<tr>
<td>Missisauga Unit</td>
<td>1195 ft</td>
<td>1832 ft</td>
<td>891 ft</td>
<td>1273 ft</td>
<td>1298 ft</td>
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Table 4. Summary of ages of log units.

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<tr>
<td>Upper Logan Canyon Sand</td>
<td>Albian to Cenomanian</td>
</tr>
<tr>
<td>Lower Logan Canyon Sand</td>
<td>Aptian to Albian</td>
</tr>
<tr>
<td>Missisauga Unit</td>
<td>Hauterivian to Aptian</td>
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</table>
Figure S-1. Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal.) Red = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-2. Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Texaco 598-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
**Figure S-3.** Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Exxon 599-1 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-4. Lithologic interpretation for the Middle Sandstone Unit at the Tenneco 642-3 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-5. Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Tenneco 642-2 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-6. Lithologic interpretation for the Middle Sandstone Unit at the HOM 855-1 well. Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
**Figure S-7.** Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Gulf 857-1 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-8. Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the Exxon 902-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
**Figure S-9.** Chronostratigraphy of log units and lithologic interpretation for the Middle Sandstone Unit at the COST B-3 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-10. Lithologic interpretation for the Middle Sandstone Unit at the Exxon 728-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-11. Lithologic interpretation for the Middle Sandstone Unit at the Exxon 816-1 well. Green = Gamma Ray (GR), Black = Deep induction log (CILD)
Figure S-12. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal.), Brown = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI).
Figure S-13. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Texaco 598-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPhi)
Figure S-14. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Exxon 599-1 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-15. Lithologic interpretation for the Upper Logan Canyon Sand Unit at the Tenneco 642-3 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-16. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Tenneco 642-2 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
**Figure S-17.** Lithologic interpretation for the Upper Logan Canyon Sand Unit at the HOM 855-1 well. Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-18. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Gulf 857-1 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-19. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the Exxon 902-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-20. Chronostratigraphy of log units and lithologic interpretation for the Upper Logan Canyon Sand Unit at the COST B-3 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-21. Lithologic interpretation for the Upper Logan Canyon Sand Unit at the Exxon 728-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-22. Lithologic interpretation for the Upper Logan Canyon Sand Unit at the Exxon 816-1 well. Green = Gamma Ray (GR), Black = Deep induction log (CILD)
Figure S-23. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal), Brown = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-24. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the Texaco 598-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-25. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the Exxon 599-1 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-26. Lithologic interpretation for the Lower Logan Canyon Sand Unit at the Tenneco 642-3 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-27. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the Tenneco 642-2 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-28. Lithologic interpretation for the Lower Logan Canyon Sand Unit at the HOM 855-1 well. Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-29. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the Gulf 857-1 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-30. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the Exxon 902-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI).
Figure S-31. Chronostratigraphy of log units and lithologic interpretation for the Lower Logan Canyon Sand Unit at the COST B-3 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-32. Lithologic interpretation for the Lower Logan Canyon Sand Unit at the Exxon 728-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-33. Lithologic interpretation for the Lower Logan Canyon Sand Unit at the Exxon 816-1 well. Green = Gamma Ray (GR), Black = Deep induction log (CILD)
**Figure S-34.** Chronostratigraphy of log units and lithologic interpretation for the Mississauga Unit at the COST B-2 well. Green = Gamma Ray (GR), Black = Caliper (Cal.), Brown = Resistivity (Res), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-35. Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the Texaco 598-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-36. Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the Exxon 599-1 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-37. Chronostratigraphy of log units and lithologic interpretation for the Mississauga Unit at the Tenneco 642-3 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-38. Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the Tenneco 642-2 well. Green = Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-39. Chronostratigraphy of log units and lithologic interpretation for the Missisaua Unit at the HOM 855-1 well. Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-40. Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the Gulf 857-1 well. Green=Gamma Ray (GR), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
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**Figure S-41.** Chronostratigraphy of log units and lithologic interpretation for the Missisaua Unit at the Exxon 902-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
**Figure S-42.** Chronostratigraphy of log units and lithologic interpretation for the Missisauga Unit at the COST B-3 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Solid = Shallow Resistivity (SFL), Dotted = Medium Resistivity (MI), Dashed = Deep Resistivity (DI), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI).
Figure S-43. Chronostratigraphy of log units and lithologic interpretation for the Missisauca Unit at the Exxon 728-1 well. Green = Gamma Ray (GR), Black = Spontaneous Potential (SP), Blue = Neutron Porosity (NPHI), Red = Density Porosity (DPHI)
Figure S-44. Lithologic interpretation for the Missisauga Unit at the Exxon 816-1 well. Green = Gamma Ray (GR), Black = Deep induction log (CILD)