FUGRO CONSULTANTS, INC.

VIRGINIA OFFSHORE OIL AND GAS READINESS STUDY

Prepared for:
COMMONWEALTH OF VIRGINIA
DEPARTMENT OF MINES, MINERALS AND ENERGY

March 2015

World Trade Center
101 West Main Street, Suite 350
Norfolk, Virginia 23510
Tel: (757) 625-3350
Fax: (757) 625-3352

March 26, 2015
Project No. 04.8114.0015

Commonwealth of Virginia
Department of Mines, Minerals and Energy (DMME)
1100 Bank Street, Washington Building, 8th Floor
Richmond, VA 23219-3638

Attention: Mr. Conrad Spangler, Director

Subject: Virginia Offshore Oil and Gas Readiness Study, Final Report

Dear Mr. Spangler:

On behalf of Fugro Consultants, we are pleased to present this final report for the Virginia Offshore Oil and Gas Readiness Study. This report incorporates comments made to the draft individual section by DMME, and other stakeholders, and combines all draft reports into one holistic document. Please let us know if you have any comments or questions regarding any of the information presented in this report. It was a pleasure to work closely with DMME, and we look forward to future projects.

Sincerely,

FUGRO CONSULANTS, INC.

Sean Sullivan
Geologist

Nancy E. Lehr, P.E.
Senior Project Manager

David M. Sackett, P.G.
Vice President, Principal Geologist

Copies Submitted: Digital PDF only

TABLE OF CONTENTS

Page

EXECUTIVE SUMMARY 1

1.0 INTRODUCTION 1-1
- 1.1 Purpose of Study 1-2
- 1.2 Scope of Work 1-2
- 1.3 Authorization 1-3
- 1.4 Report Format 1-3
- 1.5 Key personnel 1-3
- 1.6 Limitations 1-4

2.0 DATA AVAILABILITY AND ASSESSMENT 2-1
- 2.1 Data Type inventory 2-1
- 2.2 Data Sources 2-1
- 2.3 Data Inventory 2-3
  - 2.3.1 GIS Database 2-3

3.0 DATA INVENTORY AND IMPLICATIONS FOR O&G EXPLORATION 3-1
- 3.1 Two-Dimensional Multi-Channel Seismic (MCS) Reflection Data 3-1
  - 3.1.1 Overview 3-1
  - 3.1.2 Analysis of Seismic Data Coverage on the OCS of Virginia and Northern North Carolina 3-1
  - 3.1.3 Field parameters 3-3
  - 3.1.4 Data processing 3-4
  - 3.1.5 Description of Available Datasets 3-5
- 3.2 Wells Drilled in the Mid-Atlantic 3-15
  - 3.2.1 Shallow-penetrating wells 3-15
  - 3.2.2 Oil and Gas Exploration Wells 3-16
- 3.3 Seismic Velocity Surveys 3-17

4.0 DATA GAP ANALYSIS 4-1
- 4.1 Overview of Data Gap Analysis 4-1
  - 4.1.1 Line/Grid Spacing 4-1
  - 4.1.2 Analysis within BOEM Hydrocarbon Play Extents 4-2
- 4.2 Characterization of Existing Seismic Surveys by Acquisition Parameters 4-5
  - 4.2.1 Navigation/Positioning 4-5
  - 4.2.2 Source Type and Energy 4-7
  - 4.2.3 Streamer Configuration (Offset) 4-8
  - 4.2.4 CDP Spacing and Fold 4-9
  - 4.2.5 Source and Receiver Depth 4-11
- 4.3 The Quality of the Seismic Image: Data Processing and the Impact on Data Resolution and the Signal-To-Noise Ratio 4-11
  - 4.3.1 Data Quality as a Function of Seismic Processing Techniques 4-11
  - 4.3.2 Type of Data Available 4-12
  - 4.3.3 Vertical Resolution 4-13

5.0 THE APPLICABILITY OF REPROCESSING LEGACY DATA AND THE POTENTIAL TO ACQUIRE NEW DATA....5-1
5.1 Exploring a Frontier Basin....5-1
5.2 Reprocessing Legacy Seismic Data....5-2
5.2.1 Utilizing Unprocessed Data....5-2
5.2.2 Scanning Paper Sections....5-3
5.2.3 Migrating Stacked Sections....5-3
5.3 Acquisition of New Seismic Data....5-4
5.3.1 Survey Area Rationale....5-4
5.3.2 Survey Design....5-4
5.3.3 Timeframe....5-5
6.0 PROFILE OF U.S. GULF COAST OIL AND GAS SUPPORT TERMINAL INFRASTRUCTURE....6-1
6.1 Overview of Offshore Oil and Gas Exploration and Production Infrastructure Requirements....6-1
6.1.1 Typical Gulf Coast Offshore Oil and Gas Infrastructure....6-1
6.1.2 Offshore Oil and Natural Gas Support Terminals....6-2
6.2 Support Terminal Area Needs....6-4
6.2.1 Support Terminal Area by Lease Area....6-4
6.2.2 Support Terminal Area by Lease Block....6-4
6.2.3 Support Terminal Area by Active Platform....6-5
6.3 Offshore Oil and Gas Support Terminal Typical Infrastructure....6-5
6.3.1 Offshore Support Vessels....6-5
6.3.2 Location, Inland Access and Channel Dimensions....6-6
6.3.3 Wharf and Cargo Loading Area....6-6
6.3.4 Terminal Storage Areas....6-7
6.3.5 Other Infrastructure....6-7
6.4 Summary of Support Terminal Requirements....6-7
7.0 ASSESSMENT OF EXISTING MID-ATLANTIC INFRASTRUCTURE....7-1
7.1 Types and Roles of Infrastructure in O&G Development....7-1
7.1.1 Offshore Oil and Natural Gas Development Phases....7-1
7.1.2 Activity Support....7-1
7.1.3 Supporting Infrastructure....7-3
7.2 Mid-Atlantic Regional Infrastructure....7-5
7.2.1 Service Areas....7-5
7.2.2 Virginia Hampton Roads Port Infrastructure....7-5
7.2.3 Onshore Infrastructure....7-10
7.2.4 Support Services....7-11
7.2.5 Maryland Infrastructure....7-13
7.2.6 North Carolina Infrastructure....7-15
7.2.7 Maryland and North Carolina Site Capability Matrix....7-16
8.0 ASSESSMENT OF ADDITIONAL MID-ATLANTIC INFRASTRUCTURE NEEDS....8-1
8.1 Methodology....8-1

8.2 Development and Infrastructure Timeline 8-1
8.3 Estimate of Mid-Atlantic Active Lease Blocks and Offshore Platforms 8-2
8.3.1 Mid-Atlantic Region and Atlantic OCS Resources 8-2
8.3.2 Projected Mid-Atlantic Offshore Activity 8-3
8.4 Marine Terminal Needs Assessment 8-4
8.4.1 Survey 8-4
8.4.2 Exploration 8-5
8.4.3 Production 8-5
8.5 Current Infrastructure Resources and Infrastructure Gaps 8-6
8.5.1 Marine Terminals 8-6
8.5.2 Heliports 8-7
8.5.3 Oil and Natural Gas Receiving and Distribution 8-7
8.5.4 Ship Repair and Fabrication 8-8
8.5.5 Oil Field Waste Disposal 8-9
8.5.6 Oil Spill Response 8-9

9.0 VIRGINIA'S PLAN TO ADDRESS CONCERNS THAT MAY BE RAISED BY THE MILITARY 9-1
9.1 BACKGROUND AND CONFLICT IDENTIFICATION 9-2
9.1.1 Legislative Background 9-2
9.1.2 Potential Conflicts 9-3
9.2 EXAMPLES OF CONFLICT RESOLUTION 9-10
9.2.1 The Gulf of Mexico 9-10
9.2.2 Texas Wind Group 9-11
9.2.3 Pacific OCS (Southern California) Compatibility 9-11
9.2.4 Pacific OCS (Hawaii) Compatibility 9-12
9.2.5 Virginia Offshore Wind Energy Experience 9-13
9.3 PREPARING FOR COMPATIBILITY IN THE MID-ATLANTIC PLANNING AREA 9-15
9.3.1 Early DoD Coordination is Key 9-16
9.3.2 Form an Intergovernmental O&G Task Force 9-17
9.3.3 Understand the DoD Compatibility Report and OCS Assessment 9-17
9.3.4 Understand the DoD Project Evaluation Coordination Process 9-18
9.3.5 Understand Common Stipulations 9-20
9.3.6 Use Technology to Maximize Space for Development 9-21
9.3.7 Coordination with Other Stakeholders 9-22

10.0 CONCLUSIONS AND RECOMMENDATIONS 10-1
10.1 AdEquacy of Geophysical data 10-1
10.2 Assessment of Ports and Infrastructure 10-2
10.3 Military and DoD Concerns 10-2

11.0 REFERENCES 11-1

TABLES

Page
Table 2.2-1 Sources of Available Data in or Near Virginia Waters 2-3
Table 3.1-1 Seismic Data Surveys Analyzed In This Study 3-2
Table 3.1-2 Aspects of the Exploration Problem that Define Field Parameters 3-3
Table 4.1-1 Seismic Line Spacing for Surveys Acquired in Virginia and Northern North Carolina Waters* 4-4
Table 6.1-1 Active Lease Acres and Operating Platforms 6-2
Table 6.1-2 Available Support Terminal Acreage by Port 6-3
Table 7.2-1 Lambert Point Berthing Schedule 7-8
Table 7.2-2 Terminal Summary Matrix 7-9
Table 7.2-3 Potential Use Summary Matrix for Each of the Virginia Shipyards 7-12
Table 7.2-4 Maryland and North Carolina Port Compatibility Matrix 7-16
Table 8.5-1 Oil Spill Response Agencies, Organizations, and Private Companies within the Mid-Atlantic Region 8-10
Table 9.1-1 Mid-Atlantic Summary 9-5
Table 9.1-2 Summary of Annual Navy and Marine Corps Training Events and Ordnance Expenditure within the Mid-Atlantic Planning Area 9-7
Table 9.1-3 Air Force SUA Utilization in the Mid-Atlantic Planning Area (2001) 9-8
Table 9.1-4 Summary of Navy Test Events and Ordnance Expenditure within the Mid-Atlantic Planning Area 9-10
Table 9.3-1 Designated Mid-Atlantic Warning Areas and Command Headquarters 9-21
Table 9.3-2 Other Non-DoD OCS Stakeholders – NGOs and Regulatory Agencies 9-26

FIGURES

Figure
Extent of Study Area .... Figure 1.1-1

Comparison of Surveys Described in This Report with BOEM's Seismic Database ....Figure 3.1-1
Extent of Geological Play Areas in U.S. Atlantic Region ....Figure 3.1-2
Shallow Penetrating Wells ....Figure 3.1-3
Leased Atlantic OCS Blocks and Industry Well Locations ....Figure 3.1-4
Regional Geologic Features ....Figure 3.1-5
Geologic Interpretation of USGS Seismic-Reflection Profiles 19, 10, and 28 along U.S. Atlantic Margin ....Figure 3.1-6
Interval Velocity, Well Curves and Lithologic Profile Shell 93-1 Well (Offshore Maryland) ....Figure 3.3-1
Checkshot Log and Sonic Log Curve (Shell 93-1), Internal Velocity Profiles from USGS Survey S-1-75, Line 10 ....Figure 3.3-2
Stratigraphic Time Section and Internal Velocity Section for USGS Survey C-1-78, Line 28 ....Figure 3.3-3

Seismic Surveys and Hydrocarbon Plays Analyzed in Study Area ....Figure 4.1-1
Survey Acquisition Parameters ....Figure 4.2-1
Acoustic Source Volume ....Figure 4.2-2

Seismic Cable Length ....Figure 4.2-3
Common Depth Point Fold ....Figure 4.2-4
Depth Section Availability ....Figure 4.3-1
Migrated Section Availability ....Figure 4.3-2
Stacked Section Availability ....Figure 4.3-3
Demultiplexed Data Availability ....Figure 4.3-4

Brute Stack Section of Line 28 (USGS Survey C-1-78) .... Figure 5.2-1 A
Final Stack Section of Line 28 (USGS Survey C-1-78) .... Figure 5.2-1 B
Migrated Section of Line 28 (USGS Survey C-1-78) .... Figure 5.2-1 C
Migrated Sections of Line PR82-130 (Permit E02-82) with
and without Automatic Gain Control (AGC) ....Figure 5.2-2
Potential Future 2-D Seismic Survey Grid ....Figure 5.3-1

Relative Land Areas Dedicated to Offshore Oil and Gas Support Terminals ....Figure 6.1-1
Location of Production Platforms in Relation to Support Terminals ....Figure 6.1-2
Typical 24-Acre Support Terminal ....Figure 6.1-3
Representative 18-Acre Support Terminal ....Figure 6.4-1

Mid-Atlantic Region ....Figure 7-1
Offshore Oil and Natural Gas Development Stages and Needs ....Figure 7.1-1
Offshore Service Heliport ....Figure 7.1-2
Mid-Atlantic Regional Infrastructure ....Figure 7.2-1
Hampton Roads Port Infrastructure ....Figure 7.2-2
Norfolk International Terminal Ro-Ro Berth ....Figure 7.2-3
Portsmouth Marine Terminal ....Figure 7.2-4
Half Moone Cruise Center ....Figure 7.2-5
Newport News Marine Terminal Pier C ....Figure 7.2-6
Cape Charles South Port ....Figure 7.2-7
Lamberts Point Piers N, L and P ....Figure 7.2-8
CSX Piers 14 and 15 ....Figure 7.2-9
Other Hampton Roads Infrastructure ....Figure 7.2-10
Pipelines, Refineries and Terminals ....Figure 7.2-11
Baltimore Harbor ....Figure 7.2-12
Rukert Terminals Primary Port Area ....Figure 7.2-13
AmPorts Terminal ....Figure 7.2-14
Cianbro Corporation Fabrication Yard ....Figure 7.2-15
Sparrows Point Shipyard ....Figure 7.2-16
Sparrows Point Kinder Morgan Site ....Figure 7.2-17
Port of Morehead City Site ....Figure 7.2-18
Port of Wilmington Site ....Figure 7.2-19

Offshore Oil and Gas Development Timeline ....Figure 8.2-1
Mid-Atlantic Geologic Plays ....Figure 8.3-1
UTRR Proportion by Region ....Figure 8.3-2

Offshore Lease Progression ....Figure 8.3-3
Annual and Cumulative Mid-Atlantic Economic Discoveries..........Figure 8.3-4
Survey Vessels in Operation..........Figure 8.4-1
Mid-Atlantic Annual Drilling Projections ....Figure 8.4-2

Proposed Sale 220 (Circa 2008/2009)..........Figure 9.1-1
DoD Assessment of the Mid-Atlantic Planning Area (2010) ....Figure 9.1-2
Existing Civilian/Commercial Submarine Cables in the Mid-Atlantic and South Atlantic Planning Areas..........Figure 9.1-3
Gas Transmission and Hazardous Liquid Pipelines ....Figure 9.2-1
Point Mugu Sea Range..........Figure 9.2-2
Pacific Regional Ocean Uses Atlas Geospatial Layers ....Figure 9.2-3
Virginia Offshore Wind Energy Area ....Figure 9.2-4
Military Use Areas in the Vicinity of the Virginia Wind Energy Area..........Figure 9.2-5
2017-2022 DPP - Mid-Atlantic and South Atlantic Program Area..........Figure 9.3-1
Compatibility and Readiness Sustainment Coordination Process..........Figure 9.3-2
NASA WFF Range Hazard and Relative Use Areas ....Figure 9.3-3

APPENDICES

APPENDIX A RECORDING PARAMETER PLATES

APPENDIX B PROCESSING PARAMETER PLATES

APPENDIX C SUMMARY OF KEY DATA PROCESSING CONSIDERATIONS AND LIMITATIONS

APPENDIX D DESCRIPTION OF PROPOSED METHODOLOGY AND EQUIPMENT FOR POTENTIAL FUTURE 2-D SEISMIC SURVEY

APPENDIX E EXAMPLE LEASE STIPULATIONS

EXECUTIVE SUMMARY

INTRODUCTION

Fugro Consultants Inc. (Fugro) was contracted by the Commonwealth of Virginia Department of Minerals, Mines and Energy (DMME) to prepare the Virginia Offshore Oil and Gas Readiness Study. With the announcement in early 2015 that the Bureau of Ocean Energy Management (BOEM) has included the Mid-Atlantic region for evaluation and inclusion as part of the upcoming 2017-2022 offshore Oil & Gas (O&G) lease program, with possible sales planned for 2021, Virginia embarked on an in-state evaluation of their potential to assume a leadership role in the exploration, development and production of new petroleum resources within the eastern United States of America.

DMME's Request for Proposal called for a three-part evaluation of the readiness of the Commonwealth for the anticipated future offshore O&G industry. The first was to identify and assess the adequacy of legacy geophysical data, collected in the 1970s and 1980s, for characterizing the known geologic plays and their potential for hydrocarbon exploitation. The second was to review existing port infrastructure within the region and compares the present state with equivalent port infrastructure in the Gulf Coast region, and accesses potential gaps in the existing facilities. The third was to review Department of Defense (DoD) concerns on potential conflicts of ocean usage expressed during the previous 2010 cycle of potential lease sales, to identify potential conflicts and means by which to alleviate those conflicts in a manner that would allow O&G exploration and production to proceed, as they have elsewhere in US waters, including the Gulf and West Coasts.

TASK 1

Task 1 consisted of three separate subtasks. In subtask 1A, Fugro studied and described the existing G&G datasets presently available to companies interested in pursuing petroleum exploration in the offshore Mid-Atlantic margin. In agreement with DMME, the study area was narrowed to concentrate on offshore Virginia and northernmost North Carolina. Fugro compiled representative examples of each available dataset and tabulated the types of data originally collected, and current formats of the data. A GIS database was created specifically for this project and extends over a large portion of the U.S. Atlantic Margin. The primary type of data that was inventoried includes:

- 2-D multichannel seismic (MCS) reflection surveys,
- Shallow-penetrating wells and oil and gas exploration wells,
- Seismic velocity information (i.e., checkshot surveys, sonic logs, and velocity analysis from seismic surveys), and
- Published reports and geologic maps.

This industry seismic data, along with data from Atlantic OCS exploratory drilling (e.g., well logs), is publicly available from the BOEM at (www.data.bsee.gov). The United States Geological Survey's (USGS) National Archive of Marine Seismic Surveys (NAMSS) also maintains a large amount of seismic data on their website (walrus.wr.usgs.gov/NAMSS).

In total, detailed information for 19 different seismic surveys were collected in the waters off of Virginia and the northern portion of North Carolina. For each survey, summary sheets including seismic trackline maps and a listing of the field parameters (i.e., equipment used during seismic data acquisition and survey geometry) were presented. Seismic data examples for each survey and the various data processing sequences employed were also presented. For each survey, key components constraining the data were identified and tabulated, including field parameters (line spacing, seismic source, streamer configuration, navigation, etc.), processing techniques and sequence, availability of wells or other boreholes for control, and seismic velocity calculations.

For subtask 1B, Fugro assessed the survey parameters (line spacing, source specifications, streamer configurations, navigation and other factors) of existing seismic data coverage and the ability/inability of these datasets to image potential reservoirs in the various hydrocarbon plays identified by BOEM. This provided both quantitative and qualitative assessments of the data quality and its potential utility for modern day applications. In general, the older data is inferior to modern equivalents due to factors including less accurate navigation positioning which impacts confidence levels of target locations; smaller and weaker seismic sources and shorter streamer lengths with fewer hydrophones which combine to result in shallower penetration and lower resolution of the data; more primitive computational methods that resulted in more simplistic and less precise processing of the dataset; and relatively poor documentation of the field surveys which result in uncertainties in seismic velocity corrections and accurate depth modeling of geologic features of interest. Based on the above criterion, the available data should be used to provide geologic framework for the major plays and perhaps be used for delineation of future lease block sales, but should not be considered adequate for identifying exploration targets or assessing potential and recoverable hydrocarbon quantities.

In subtask 1C, Fugro created a theoretical regional seismic survey grid and schedule required to cover the initial issuing of a tender through final delivery of a report containing the results of interpreting the fully-processed new survey data. The survey would be intended to both provide additional modern survey data to better understand geologic context for the individual geologic plays, and would provide an analog for comparison with legacy datasets to assess their ability to accurately image potential targets. Additionally in subtask 1C, Fugro presented an assessment of the application of modern data processing techniques to the existing data and provided suggestions (based on experience in reprocessing of legacy data) on processing techniques that could be utilized might improve the imaging of the 1970's and 1980's data in a timely and cost-efficient manner.

TASK 2

This task was completed by our sub consultant Moffatt & Nichol, who were tasked with preparing an overview of the infrastructure needed to support future O&G exploration and development in the Mid-Atlantic region. This task was also divided into three separate subtasks. In subtask 2A, Moffatt & Nichol examined the U.S. Gulf Coast to develop a typical profile for O&G infrastructure and qualifying the extent of the existing industry within the Gulf Coast, including the number of active lease blocks and existing platforms. This initial step was obtained by examining eleven major offshore support terminal complexes, including three Louisiana ports: Fourchon, Grand Isle and Cameron. These three complexes, along with eight other terminal sites from Freeport, Texas to Pascagoula, Mississippi were evaluated to develop a relationship between overall port acreage and offshore platforms served.

U.S. Gulf Coast O&G exploration and production was evaluated from the perspective of total lease blocks, total lease area, and active platforms. A database of ArcGIS shape files containing specific production information related to offshore lease blocks is maintained by BOEM. Queries to this database resulted in a general profile of offshore production activities. A set of metrics was developed to relate the lease areas to actual platform development. As initial exploration in the Mid-Atlantic region will be driven by leased area, the relationship between lease areas and platform development will be the more important metric for determining infrastructure in the early stages. Later, as production wells are drilled, the platforms will become the key driver of infrastructure needs.

If U.S. Gulf operations are used as benchmark, this becomes a very conservative approach due to the O&G support of active offshore platforms that also takes place. Currently in the Gulf there are about 18,000 acres of offshore lease area per acre of onshore support terminal. It can be equated to projected lease sales and could provide guidance as to support terminal phasing. In the U.S. Gulf, one acre of onshore support terminal is required for every 3.5 active offshore lease blocks. Based on the U.S. Gulf Coast model, approximately one acre of support terminal is required for every 1.5 active platforms in the region.

Subtask 2B developed a high-level assessment of the existing infrastructure in the Mid-Atlantic region that could be adapted to development of offshore O&G support terminals, ship repair and construction, transportation, emergency services and oil spill response. This assessment was based on current usage and evaluated the potential for implementing changes to include offshore O&G infrastructure within their terminals. A total of fourteen terminals were evaluated from Baltimore southward to Wilmington NC. Seven terminals, both public and private, within the Commonwealth of Virginia were included in the evaluation.

Several other aspects of support requirements were assessed, including the types and sizes of typical vessels utilized in varying support roles for offshore drilling. Channel dimensions, cargo loading/unloading facilities, storage areas, pipeline transport, and heliport facilities required for future O&G development were also addressed during this subtask.

The final subtask combined the findings from subtasks 2A and 2B to develop a description of the anticipated port and waterborne infrastructure necessary in the future to explore and develop O&G along the Mid-Atlantic coast, specifically focusing on Virginia and northernmost North Carolina. This assessment concluded that the existing infrastructure in the area from Baltimore, MD to Wilmington, NC, and including the Hampton Roads area in Virginia, are adequate to support the initial seismic exploration and exploration well phases. Once actual commercial extraction begins, probably no sooner than 2024, there will be a requirement for additional storage and transportation infrastructure including pipelines, but it is anticipated that adequate port facilities will exist to cover an estimated 40 producing fields and 160 offshore platforms. Importantly, concerning emergency oil spill response, there will be a requirement to build this capacity in the region as current support structure is considered inadequate for future offshore O&G production.

TASK 3

Task 3 of this study provided a background and perspective on the concerns of the military regarding O&G structures and activities in the Mid-Atlantic region. Parsons Government Services was subcontracted to perform this phase. The first portion of this task commenced by gathering background and historical information to gain a better understanding of what were the nature and background of the DoD's concerns.

The Norfolk Fleet military assets are the world's largest concentration of ships and aircraft, and the support infrastructure for those assets. The primary mission of the DoD is to ensure they remain in a high state of training and readiness for deployment in case of national emergency. In its Compatibility Report for the previous round of potential lease block sales, the DoD used a comprehensive approach for its analysis of activities on the OCS. Four categories of potential compatibility were developed. Definitions of these four categories include:

- No O&G activity,
- No permanent O&G surface structures,
- Site specific stipulations, and
- Unrestricted.

Parsons lead several meetings and phone calls with DoD personnel to confirm how these individual categories were originally developed and to plan what potential future avenues were available to re-characterize select areas previously considered as restricted to either less restrictive status, or entirely unrestricted. A similar, successful approach had previously been adopted during negotiations with the DoD for the upcoming installation and operation of offshore wind turbines in the area immediately offshore from Hampton Roads.

Although the DoD was identified as a stakeholder with potentially conflicting use of the waters offshore of Virginia, they are by no means the only stakeholder within this region. NASA Goddard Space Flight Center (GSFC) owns and operates NASA WFF (NASA, 2012). The WFF is located in the northeast portion of Accomack County, Virginia on the Delmarva Peninsula (See Figure 9.3-3). The 6,000-acre facility employs nearly 1,700 civil service and contractor employees in addition to military personnel assigned to the U.S. Navy's SCSC at WFF. The U.S. Environmental Protection Agency (USEPA) is the lead federal response agency for oil spills occurring in inland waters, and the U.S. Coast Guard is the lead response agency for spills in coastal waters and deep water ports (United States Environmental Protection Agency, 2011). Marine commercial and recreational fishing are important industries in the Mid-Atlantic Planning Area. The waters off the coast of Virginia constitute one of the busiest areas in the world for maritime traffic (DoN, 2014).

The next step taken as part of the investigation was to explored examples of O&G and DoD conflict resolution in other Outer Continental Shelf (OCS) regions. Two examples are provided for conflict resolution in the Gulf of Mexico where Navy training and testing (e.g., Naval Support Activity Panama City) and Air Force (USAF) training (e.g., Eglin Gulf Test and Training Range) occur in the vicinity of one of the most developed O&G regions of the world. Two additional examples of conflict resolution are presented from the Pacific OCS (one from the Hawaiian Islands and another from Southern California). The goal of this section is to glean success stories from other OCS regions and look at these areas as models for how conflicts might be resolved in the Mid-Atlantic.

The final step set forth several plan elements, both borrowed from successful resolutions in other regions and natural outcomes from DoD meetings or involving technological considerations, for successful future DoD conflict resolution in the Mid-Atlantic OCS planning area. Section 9 of this report provides further details of key suggestions into preparing for compatibility in the Mid-Atlantic planning area.

In summary, the three greatest issues that could impact future O&G exploration in the Mid-Atlantic Region have been assessed separately in the three tasks of this report. While the limitations imposed by the quality of the legacy seismic data, the lack of O&G “ready” infrastructure and the potential conflicts over use of the OCS with the various government agencies all pose significant challenges for inclusion of offshore Virginia acreage the proposed 2017-2022 leasing plan, this report has highlighted possible methods to overcome these obstacles.

The vintage seismic datasets can be reprocessed or used as-is to perform a preliminary analysis of the Atlantic Margin in order to help guide future seismic data acquisition. Existing infrastructure in the Mid-Atlantic Region is not currently adequate for handling O&G development on the same scale as the Gulf Coast, although the existing seaports and terminals are more than capable of handling the early stages of exploration seismic and drilling activities. Once significant quantities of hydrocarbons are found offshore, new facilities including storage and transport structures will need to be built which will result in bringing new jobs to the Commonwealth. Finally, concerns that future O&G exploration will impinge upon the operations of the military and other stakeholders have been successfully addressed and mitigated in other regions of the U.S. Most recently for offshore Virginia, the Wind Energy Industry and DoD came to an agreement on deconflicting ocean usage so that both groups could continue towards a future of shared offshore resources, both powering and defending the nation.

1.0 INTRODUCTION

In January of 2015, the Bureau of Ocean Energy Management (BOEM) released its draft of the 2017-2022 five-year proposed Outer Continental Shelf (OCS) Oil and Gas leasing Program. This program includes the possible leasing of offshore tracts in the Mid-Atlantic and South Atlantic in 2021 as part of lease sale number 260 (BOEM, 2015b). While the existing geological and geophysical (G&G) information suggests that there may be significant oil and gas available in these planning areas, BOEM's assessments of the Undiscovered Technically Recoverable Oil and Gas Resources (UTRR) in the Atlantic OCS are based on data collected primarily in the 1970's and 1980's (BOEM, 2014b and 2015b). Due to the lack of modern seismic data available in the Atlantic OCS, BOEM's assessment of potentially recoverable resources in this planning region lacks the updated geologic characterizations used in assessing other areas of the U.S. OCS (e.g., Gulf of Mexico) where modern seismic datasets are readily available for study. In fact, the removal of Virginia from BOEM's 2012-2017 leasing program, based on the Department of Interior (DoI) published "Summary of Decision in the Proposed Final Outer Continental Shelf Oil and Gas Leasing Program 2012-2017, was in part attributed to a lack of available modern data needed to evaluate resource potential and to assist in the process for preparing lease blocks (BOEM, 2012b).

BOEM's 2014 assessment update for the entire Atlantic OCS estimated the mean UTRR to be 4.72 billion barrels of oil (Bbo) and 37.51 trillion standard cubic feet of gas (Tcfg), an increase of 43% and 20%, respectively compared to BOEM's earlier assessment (BOEM, 2012a). The increased UTRR estimates are not a result of acquiring new data, but rather the result of significant increases in the size and number of oil and gas discoveries in analogous basins, such as those found in West and East Africa. In order to better understand the resource potential in the Atlantic OCS, there is a need to assess the quantity and quality of existing G&G data, as well as the potential need to acquire new data using modern seismic survey equipment and techniques. Presently, several applications to collect new seismic data in the Atlantic OCS have been submitted by various geophysical contractors and are being reviewed by BOEM.

In addition to the limitations imposed by the available seismic data's vintage, the DoI also expressed concern that the existing infrastructure in the region is inadequate to support future oil and gas exploration and development activities (BOEM, 2012b). This includes an inadequate ability to properly respond to emergencies such as offshore accidents or a large-scale oil spill. The DoI has stated that a long-term analysis of infrastructure requirements and planning steps must be completed in advance of preparing for activities associated with oil and gas exploration.

There are also complex issues regarding potentially conflicting uses, especially those issues raised by the Department of Defense (DoD). The DoD raised significant concerns in response to the Draft Proposed Outer Continental Shelf Oil and Gas Leasing Program (MMS, 2008). Regarding the area proposed for a lease sale offshore of Virginia, their concerns were so great that the DoD requested that "no oil and gas activity" be allowed in 72 percent of the area proposed for leasing, and that no permanent facilities be allowed in another five percent of the area. These concerns are addressed in the DoD's "Report on the Compatibility of Department of Defense activities with oil and gas resource development on the Outer Continental Shelf" (DoD, 2010).

1.1 PURPOSE OF STUDY

The Commonwealth of Virginia Department of Mines, Minerals and Energy (DMME) published a Request for Proposal (RFP) which highlighted the DMME's need for an analysis of preexisting geophysical data relevant to offshore oil and gas exploration in the study area (Figure 1.1-1). The study area was defined by Fugro and agreed upon by DMME based on the likelihood of leasing in federal waters greater than 50 miles offshore and by the availability of ports located along the Virginia coast. The RFP requested that part of the study focus on preparing an inventory of available datasets, identifying the key data gaps, and assessing the potential for new data acquisition and interpretation within a timeframe so that that data could be interpreted and utilized for decision making steps in designing the 2017-2022 Five Year Oil and Gas Leasing Program.

Other tasks specified in the RFP include a detailed overview of port infrastructure needed to support future oil and gas (O&G) exploration and development. The RFP specifically requested the need to address the adequacy of existing infrastructure in the Mid-Atlantic region, along with the likelihood that necessary new infrastructure can be put in place in a manner and timeframe adequate to meet the needs of the O&G industry, and the capabilities of other regions along the Mid-Atlantic coast to support exploration and production logistics and materials.

Due to the extensive use of the waters offshore Virginia by all military branches and other DoD stakeholders, a plan to address any concerns that may be raised by the military was an integral part of the RFP. The RFP addressed meeting with DoD personnel to identify potential conflicts and means by which to alleviate those conflicts in a manner that would allow O&G exploration and production to proceed. Conflicts between DoD and O&G development activities that have been successfully resolved in other areas of the U.S. Outer Continental Shelf, such as the Gulf of Mexico and Pacific Ocean, were to be reviewed for possible deconflicting strategies.

1.2 SCOPE OF WORK

For Phase 1 of the Virginia Oil and Gas Readiness project, Fugro divided the task of characterizing the quality and utility of existing data and the ability to acquire and interpret new data prior to the potential 2017-2022 Atlantic lease sale into three separate subtasks. In subtask 1A, Fugro studied and described the existing G&G datasets presently available to companies interested in pursuing petroleum exploration in the offshore Atlantic margin. In agreement with DMME, the study area was narrowed to concentrate on offshore Virginia and the northern portion of North Carolina.

For subtask 1B, Fugro assessed the survey parameters (line spacing, source specifications, streamer configurations, navigation and other factors) of existing seismic data coverage and the ability/inability of these datasets to image potential reservoirs in the various hydrocarbon plays identified by BOEM (BOEM, 2012a). Finally, for subtask 1C, Fugro created a theoretical regional seismic survey grid and schedule required to cover the initial issuing of a tender to the final delivery of a report containing the results of interpreting the fully-processed new survey data. Additionally for subtask 1C, Fugro presented an assessment of the application of modern data processing techniques to the existing data and provided suggestions (based on our experience in reprocessing of legacy seismic data) as to what processing techniques might improve the imaging of the 1970's and 1980's data in a timely and cost-efficient manner.

The second phase of the project was completed by our sub consultant Moffatt & Nichol, who were tasked with preparing an overview of the infrastructure needed to support O&G exploration and development. This task was also divided into three separate subtasks. In subtask 2A, Moffatt & Nichol examined the U.S. Gulf Coast to develop a typical profile for O&G infrastructure and qualifying the extent of the existing industry within the Gulf Coast, including the number of active lease blocks and existing platforms. Subtask 2B developed a high-level assessment of the existing infrastructure in the Mid-Atlantic region that could be adapted to development of offshore O&G support terminals, ship repair and construction, transportation, emergency services and oil spill response. The final subtask combined the findings from subtasks 2A and 2B to develop a description of the anticipated port and waterborne infrastructure necessary in the future to explore and develop O&G along the Mid-Atlantic coast, specifically focusing on Virginia and northernmost North Carolina.

Phase 3 of this study provided a background and perspective on the concerns of the military regarding O&G structures and activities in the Mid-Atlantic region. Parsons Government Services was subcontracted by Fugro to perform this phase. Their first task commenced by gathering background and historical information to gain a better understanding of what were the nature and background of the DoD's concerns. The next step Parsons took as part of their investigation was to explore examples of O&G and DoD conflict resolution in other OCS regions in the U.S. The final step set forth several plan elements, both borrowed from successful resolutions in other regions and natural outcomes from DoD meetings or involving technological considerations, for successful future DoD conflict resolution in the Mid-Atlantic OCS planning area.

1.3 AUTHORIZATION

This study was authorized by Agreement Number: C156016, dated September 22, 2014, between the Commonwealth of Virginia, Department of Mines, Minerals and Energy and Fugro Consultants, Inc. The study was performed in general accordance with DMME's Request for Proposals 15-RFP-DGMR-02 dated July 21, 2014 and our proposal dated August 21, 2014.

1.4 REPORT FORMAT

This report is divided into various sections, each corresponding to a particular subtask following the same order as described in Section 1.2. This report details where accessible G&G data sources were located, how the datasets were acquired and processed and specific limitations of each dataset. Fugro has documented data gaps based on current industry standards for data collection and interpretation as well as discussed the need for future data collection and a likely timeframe required to collect and process the data for use in exploration. The readiness of Virginia to support oil and gas production offshore within our ports and various other support industries necessary for viability, and taking into account military reservations and NASA encroachment issues is also discussed. A digital copy of this report and a copy of the GIS database utilized will be issued to DMME.

1.5 KEY PERSONNEL

Fugro Consultants Inc. held the overall contract with DMME. Fugro Consultants Inc., Vice President David Sackett and Senior Engineer Nancy Lehr provided overall project management, technical expertise, report editing and submission, as well as client contact.

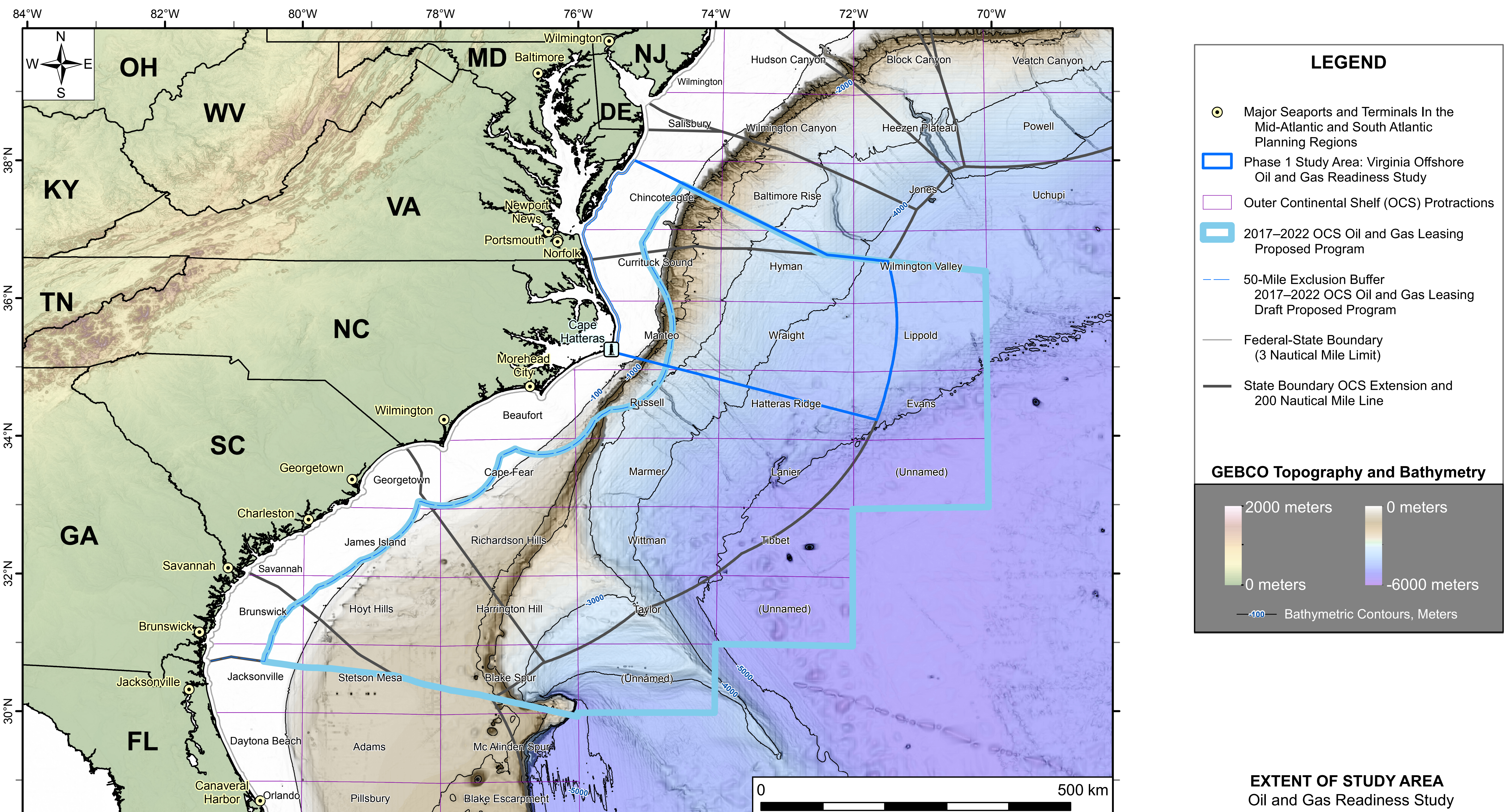
For Task 1, Staff Geologist Sean Sullivan was responsible for locating and acquiring the legacy geophysical data and compiling the project's GIS database with assistance from Associate Geologist Kevin Smith. Mr. Sullivan also played a significant role in preparing and editing the report text. Brian Hottman provided technical expertise and information on future survey specifications and estimated timelines. Dr. Mark Legg, of Legg Geophysical, loaded and reprocessed select seismic lines and provided guidance for potential future reprocessing steps. Sean Sullivan, Brian Hottman and Mark Legg all worked together to complete the data gap analysis portion of Task 1.

For Task 2, Moffatt & Nichol performed the assessment of port infrastructure. For this study, Christopher Matson and David Cortinas provided expertise gained from past port experience, senior management, and prepared draft and final report reviews. Moffat & Nichol were able to acquire background information on both public and private ports that, based on their experience, would have an impact on future development of a Virginia-based oil and gas industry.

For Task 3, Jeffery Butts and Lori Reuther from Parsons Government Services addressed DoD concerns for ocean usage, attended meetings with DoD and military personnel to solicit opinions, and prepared comments on past experience with deconflicting military usage and other stakeholder usage of oil and gas rich lands. This was accomplished by frequent communication with DoD in order to understand their perspectives on ocean usage by the military.

1.6 LIMITATIONS

This Virginia Offshore Oil and Gas Readiness Study has been prepared for the Commonwealth of Virginia, Department of Mines, Minerals and Energy, solely for providing information necessary to be useful for making decision regarding preparing for future oil and gas exploration within and adjacent to the commonwealth. In performing our professional services, we have used that degree of care and skill ordinarily exercised, under similar circumstances, by reputable professional engineers and geologists currently, practicing in this or similar localities. No other warranty, express or implied, is made as to the content of this report. Fugro makes no claim or representation concerning any activity or conditions falling outside its specified purposes to which this report is directed.



EXTENT OF STUDY AREA
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 1.1-1

2.0 DATA AVAILABILITY AND ASSESSMENT

As described in Section 1.2, Fugro followed a phased approach to assess the adequacy of various available datasets, quantify the survey parameters of the various available datasets and the ability/inability of those to image potential reservoirs. As part of this task, Fugro compiled representative examples of each available dataset and tabulated the types of data originally collected, and current formats of the data. A GIS database was created specifically for this project and extends over a large portion of the U.S. Atlantic Margin. Selected in consultation with DMME, the GIS database was also used during other subtasks to document and assess the available data and any data gaps that are present, and to create and layout the theoretical seismic survey.

2.1 DATA TYPE INVENTORY

Fugro researched available geological and geophysical (G&G) data relevant to supporting the assessment and development of oil and gas (O&G) resources in a region covering the OCS of offshore Virginia and northern North Carolina (Figure 1.1-1). DMME requested the study include the northern waters of North Carolina due to their proximity to the ports of Hampton Roads. While the Maryland OCS is also located near Hampton Roads, DMME did not request a detailed analysis of the G&G data in this area based on the government of Maryland's lack of interest in participating in BOEM's 2017-2022 leasing program (BOEM, 2015b). The primary type of data that was inventoried includes:

- 2-D multichannel seismic (MCS) reflection surveys,
- Shallow-penetrating wells and oil and gas exploration wells,
- Seismic velocity information (i.e., checkshot surveys, sonic logs, and velocity analysis from seismic surveys), and
- Published reports and geologic maps.

2.2 DATA SOURCES

Fugro conducted extensive research into numerous publically available databases to identify existing data that may be of significance to future O&G exploration in Virginia and the northern most section of North Carolina (Table 2.2-1). The majority of the 2-D MCS data for this study was collected during Atlantic OCS exploration during the 1970's and 1980's. It is noted that processed seismic data collected for mineral exploration on the U.S. OCS is made available to the public after a 25-year proprietary moratorium period (based on the permit date). The most recent survey to be released from this moratorium period and made available by BOEM was acquired in 1988. This industry seismic data, along with data from Atlantic OCS exploratory drilling (e.g., well logs), is publicly available for purchase online from the Bureau of Ocean Energy Management (BOEM) at (www.data.bsee.gov). The United States Geological Survey's (USGS) National Archive of Marine Seismic Surveys (NAMSS) maintains a large amount of seismic data that is free to download from their website (walrus.wr.usgs.gov/NAMSS). Recently (i.e., in late 2014 or early 2015), many of the seismic datasets previously available exclusively through BOEM's website became available for download on the NAMSS website.

Several regional surveys acquired in the 1970's by various contractors working for the USGS are also available at the NAMSS website. Many of these regional surveys were acquired over large regions of the Eastern U.S. Atlantic Margin and due to their vast extent, only lines within the Virginia and North Carolina OCS were analyzed for this study. NAMSS also stores five large

1975 to 1982 vintage datasets, donated by WesternGeco, that span an area running from offshore Georgia to Georges Bank, Massachusetts. Included in those datasets is a survey that spans the entire continental slope of Virginia with line spacing of approximately 1 mile (0.5-1.6 km) and running perpendicular to the continental margin. While this same dataset is available for purchase from BOEM, the data from the USGS contains stacked sections in SEG-Y format, while the migrated and depth-converted lines are available from BOEM.

Fugro searched several other online seismic data archives, such as the Academic Seismic Portals at both the Lamont-Doherty Earth Observatory (LDEO) (www.marine-geo.org/portals/seismic) and the Institute for Geophysics at The University of Texas at Austin (www.ig.utexas.edu/sdc). These sources supplied only single-channel seismic data collected as part of Ocean Drilling Program/Deep Sea Drilling Project Legs in Virginia waters. Only a few MCS lines that were collected beyond the 200 nautical mile Exclusive Economic Zone (EEZ) are available from these academic websites. At the National Oceanic and Atmospheric Administration's (NOAA) National Geophysical Data Center (NGDC) website (http://www.ngdc.noaa.gov/mgg/mggd.html), archived data is available for some of the previously mentioned 1970's USGS surveys and a nearshore MCS seismic survey, named ECOAST79, within the area of interest. The information from the NGDC provided survey reports for two of the USGS surveys that were not well documented. The NGDC also had scanned paper copies containing relevant acquisition and processing information for several of the USGS surveys.

Through our review of relevant literature, two additional surveys (BGR79 and VAEDGE) were identified in the area of interest. While actual SEG-Y files for the VAEDGE survey were not found, detailed information about this survey was provided through our literature review and examples of the data from publications. A listing of the VAEDGE survey on the website (www.iris.edu) of the Incorporated Research Institutions for Seismology (IRIS), allowed SEG-Y data to be downloaded from this survey, unfortunately the available SEG-Y data was for the land-based seismometers and not the offshore MCS data. Tracklines for the BGR survey were obtained from the USGS Woods Hole Coastal and Marine Science Center (woodshole.er.usgs.gov), which, along with USGS Coastal and Marine Geology Infobank (walrus.wr.usgs.gov/infobank), provides indispensable information on thousands of geological and geophysical surveys dating back to 1901. Finding field parameters and processing information for vintage seismic data can be a lengthy process, and Fugro was not successful in obtaining representative data for all identified surveys. The details of the data search described above are meant to convey a thorough search was conducted for all available MCS data resources.

Table 2.2-1 Sources of Available Data in or Near Virginia Waters

Data Source*	MCS Seismic	Well Info	Seismic Velocity Surveys	Single-Channel and/or High-Resolution Seismic	Multibeam Bathymetry and/or Side Scan Sonar	Gravity and/or Magnetics	Geologic Maps
BOEM/BSEE	X	X	X				X
USGS	X	X	X		X	X	X
IODP/ODP/DSDP		X	X				X
NOAA NGDC	X			X	X	X	
WHOI	X			X			
LDEO				X			
UTIG				X			
DMME							X
DGS							X

*Bureau of Ocean Energy Management (BOEM), Bureau of Safety and Environmental Enforcement (BSEE), United States Geological Survey (USGS), Integrated Ocean Drilling Program (IODP), Ocean Drilling Program (ODP); Deep Sea Drilling Project (DSDP); National Oceanic and Atmospheric Administration (NOAA), National Geophysical Data Center (NGDC), Woods Hole Oceanographic Institution (WHOI), Lamont-Doherty Earth Observatory (LDEO), University of Texas Institute for Geophysics (UTIG), Department of Mines, Minerals and Energy (DMME), Delaware Geological Survey (DGS)

2.3 DATA INVENTORY

The datasets of the various G&G data outlined in Section 2.1 were compiled into a project-based inventory that included a description of the data type, how the data was acquired and processed and the source of the data. Fugro focused on compiling and summarizing key acquisition parameters and processing methods for the MCS data that help assess the data resolution and quality. The data inventory is compiled and presented as part of this document, as well as in a Global Information System (GIS) database.

2.3.1 GIS Database

The GIS database compiled for this project is in an ESRI file geodatabase format that includes tracklines, well locations, OCS blocks, and other relevant information that were reviewed and assessed during this study. The tracklines and wells include basic attribute information (e.g., data type, how it was collected, who collected the data, etc.). Because of the extensive amount of data that was included in each of the different datasets, this GIS database is an efficient mechanism to be able to catalog and visibly represent the datasets.

3.0 DATA INVENTORY AND IMPLICATIONS FOR O&G EXPLORATION

3.1 TWO-DIMENSIONAL MULTI-CHANNEL SEISMIC (MCS) REFLECTION DATA

3.1.1 Overview

The various seismic survey datasets compiled in this section reflect the focused effort of researching known multichannel seismic data (see Section 2) in the waters off of Virginia and the northern portion of North Carolina. In total, detailed information for 19 different seismic surveys were collected, which are listed along with some general information in Table 3.1-1. Many of these surveys/permits extend almost the entire region of the Eastern US Atlantic Margin (Figure 3.1-1), but after narrowing the area of interest for this study, the survey descriptions provided in Section 3.4 focus on the portions of the surveys/permits collected in the waters off of Virginia and the northern portion of North Carolina. For each of the 19 surveys, summary sheets including seismic trackline maps and a listing of the field parameters (i.e., equipment used during seismic data acquisition and survey geometry) are presented in Appendix A. Seismic data examples for each survey and the various data processing schemes are found in Appendix B.

3.1.2 Analysis of Seismic Data Coverage on the OCS of Virginia and Northern North Carolina

Quantifying the density of seismic coverage within the study area is important for determining whether the existing data provides the spatial resolution needed to define hydrocarbon reservoirs and traps as part of future O&G exploration. In areas of complex structure (e.g. near the modern shelf break), dense grids of seismic profiles are required for interpretation while in the distal continental slope, where seismic reflectors are frequently more flat lying and continuous, less data is typically required unless a specific target is under investigation. In order to correlate reflectors along the continental margin it is important to know not only the number of lines available, but also the orientation of the lines. Dip lines, shot along the regional dip of subsurface geological structure and roughly perpendicular to the coast generally contain less contamination by side-swipe from off-line features (as compared to strike-lines), providing effective imaging of the subsurface after application of 2-D migration. Strike lines, shot parallel to the regional structure or roughly parallel to the coast, are necessary to tie the dip lines during interpretation. Three-dimensional effects heavily influence strike lines so that the position of seismic imaging points (common depth points or CDPs) are truly up-dip from the recording ship's trackline. Strike lines are often more useful for velocity analysis because there is more lateral continuity and less dip for important stratigraphic sequences along strike than across strike. Given that the reflections from strike lines contain less dip, apparent velocities come closer to approximating the true velocities which are required for accurate data migration.

Table 3.1-1 Seismic Data Surveys Analyzed In This Study

Permit or Survey	Year	Client or Research Team	Acquisition Company	Number of Seismic Lines Acquired			Approximate Line-Miles Acquired (Line-Km)		
				Entire Survey	Study Area	Virginia OCS	Entire Survey	Study Area	Virginia OCS
S-1-73	1973	USGS	Digicon	3	1	1	589 (949)	213 (343)	161 (258)
S-1-75	1975	USGS	Digicon	7	3	3	2406 (3873)	485 (780)	146 (235)
E14-75	1975	Western Geophysical	Western Geophysical	33	5	0	2697 (4340)	141 (227)	0
E16-76	1976	Offshore Atlantic Group	Digicon	42	33	17	3347 (5386)	2315 (3726)	988 (1590)
S-1-77	1977	USGS	Teledyne	10	1	0	2766 (4451)	114 (183)	0
C-1-78	1978	USGS	GSI	21	3	1	3024 (4866)	299 (481)	99 (160)
E06-79	1979	USGS Conservation Division	Whitehall Corp.	23	5	4	1069 (1721)	244 (393)	165 (265)
BGR79	1979	Bundesanstalt für Geowissenschaften und Rohstoffe	Prakla-Seismos	21	4	4	2959 (4763)	270 (434)	224 (360)
E01-80	1980	South Atlantic Group	Geosource	159	57	0	4117 (6625)	1159 (1866)	0
E02-80	1980	South Atlantic Group	Digicon	106	39	0	3665 (5899)	807 (1299)	0
E01-81	1981	Exxon	Geosource	107	9	7	4464 (7184)	256 (412)	190 (306)
E07-81	1981	Chevron	Digicon	12	12	0	294 (473)	294 (473)	0
E02-82	1982	Mid-South Atlantic Group	Geosource	274	113	63	8597 (13835)	3170 (5101)	1444 (2324)
E04-82	1982	Shell	Shell (Assumed)	40	13	5	2009 (3233)	534 (859)	150 (242)
E11-82	1982	ARCO	ARCO	92	46	45	2395 (3855)	1250 (2011)	1163 (1872)
E05-83	1983	Amoco	Norpac	23	12	2	598 (962)	232 (374)	48 (77)
E05-86	1986	Spectrum Resources & Texaco	Teledyne	3	1	1	129 (207)	38 (62)	38 (62)
E03-88	1988	Texaco	GECO	29	17	17	731 (1176)	467 (751)	436 (701)
VAEDGE	1990	USGS & various academic institutions	GECO	4	4	3	344 (554)	344 (554)	193 (311)
TOTAL:				**1009**	**378**	**173**	**46200 (74352)**	**12633 (20329)**	**5445 (8763)**

3.1.3 Field parameters

The design of any seismic survey is determined by the objective of the investigation. Defining a seismic survey's field parameters in preparation for data collection is constrained both by limitations of the equipment available and the conditions at the exploration site (Table 3.1-2). In exploration seismology, the depth and appropriate resolution needed to image potential hydrocarbon-bearing strata are often the most important factors that help define the survey design. For example, the maximum offset, which is the greatest distance from the seismic source (e.g., an air gun array), to the farthest receiver (e.g., hydrophone) should be set so that it is approximately equal to the depth of the deepest zone of interest (Sheriff and Geldart, 1999). In order to adequately assess the viability of the existing MCS data available in offshore Virginia waters, it was important to carefully document all of the key field parameters of each seismic survey (Appendix A).

Table 3.1-2 Aspects of the Exploration Problem that Define Field Parameters

Seismic Parameters to be Defined	Depth of Interest	Reflection Quality	Required Resolution	Steepest Dip	Type of Feature	Noise Problems	Access Problems	Special Processing
Far-Trace Offsets	X							
Near-Trace Offset	X						X	
Group Interval			X	X				
Source Size	X		X			X		
Charge Depth		X	X			X		
Multiplicity (CDP Fold)		X	X			X	X	X
Sample Rate	X		X					X
Low-Cut Filter	X		X					X
Geophone Frequency	X		X			X		X
Record Length	X							X
Geophone Array Size			X			X		X
Spread Type						X	X	
Line Length	X				X		X	X
Line Direction					X		X	X
Line Spacing			X		X		X	X

*From Sheriff and Geldart, 1999

3.1.4 Data processing

The types of seismic data available for each of the 19 surveys are categorized as unprocessed, demultiplexed (one abbreviated as DEMUX) data or processed seismic sections which can be further divided into 1) stacked sections, 2) migrated sections and 3) migrated depth-converted sections. When multiple types of processed seismic data (i.e., stacked, migrated and/or migrated depth-converted sections) are available for an individual survey described in this report, examples of each seismic data type, with the associated processing steps, have been documented in Appendix B. In order to understand the differences in the four main seismic data categories, the following two paragraphs provide a brief introduction to seismic reflection data processing.

Demultiplexing of seismic data volumes is often categorized as a pre-processing step and involves sorting the original field records into a trace sequential format needed for further data processing. The three main phases of seismic data processing are deconvolution, stacking and migration (Yilmaz, 1987). Each of these processing methods helps improve the data's resolution in order to provide a more accurate image of the subsurface. Deconvolution is performed to improve temporal resolution by compressing the source wavelet contained in the seismic data and attenuating reverberations and short-period multiples. Stacking involves taking all of the traces in a common midpoint (CMP), also known as a common depth point (CDP), grouping and summing them together to form a single trace. Stacking therefore reduces the seismic data volume (originally composed of many traces equal to the CDP fold of the data) to single, zero-offset traces that have an increased signal-to-noise (S/N) ratio. Migration is a form of spatial deconvolution (most-commonly performed on the zero-offset stacked section) that increases spatial resolution by moving dipping layers to their correct location via projecting reflectors updip, shortening their length and making their slopes steeper while also collapsing diffractions that are produced due to surface discontinuities (Yilmaz, 1987).

After the seismic data are processed to best image the interval(s) of interest, subsurface mapping of seismic reflections and discontinuities (representing layers and faults) in two-way travel time (TWTT) can commence in order to produce time-structure maps and isochron (thickness measured in TWTT) maps along with identifying fault distribution and orientation. While the results of mapping geologic features in seismic time-volumes help identify possible locations for exploratory drilling, the need will always arise prior to drilling to convert the seismic data from measurements in time into measurements of the distance below a datum such as sea level. Depth-conversion is necessary so that the economic viability of a prospect can be assessed by calculating the drilling depth (measured in feet or meters below a common datum such as mean sea level) and volume of a potential hydrocarbon reservoir. Migrated depth-converted seismic data also has the advantage of depicting the subsurface more accurately than time-migrated data. Depth-converted seismic attempts to remove the influence of anomalously high or low velocity/density interlayers displayed in the seismic section.

The three previous paragraphs are meant to provide an introduction into seismic data processing in order to better understand the information analyzed and presented in subsequent sections of this report. Certain topics mentioned briefly in this section (e.g., deconvolution) are described in greater detail in Appendix C, although for a comprehensive review of seismic data processing, the reader is referred to Yilmaz (1987). Appendix C instead focuses on specific processing techniques applicable to the reprocessing of the 1970's and 1980's data and describes important acquisition parameters (e.g., sampling rate and group interval) that influence the quality of the legacy data. Additionally, modern data processing techniques (e.g., Surface-Reflected Multiple Elimination) that were not utilized when processing the legacy data are briefly described to indicate how these methods can provide superior imaging of the subsurface.

3.1.5 Description of Available Datasets

3.1.5.1 Seismic data collected for offshore O&G exploration

In 1960, the first federal Geological and Geophysical (G&G) permit was issued by the DoI for seismic surveying in the Mid-Atlantic. The permit was awarded to Kerr-McGee Oil Industries, Inc., an energy company based out of Oklahoma, to collect seismic data in an area on the Continental Shelf off New Jersey, Delaware, Maryland, and Virginia Beach (Richards, 1961). Between 1960 and 1968, 45 G&G permits were issued in the Atlantic OCS region. During this time, the DoI did not distinguish whether the data collected was of a geological or geophysical nature. From 1969 to 1990, the federal government issued 183 geophysical permits in the Atlantic Outer Continental Shelf (OCS) region. Originally the issuing of permits was conducted by the U.S. Geological Survey (USGS), Conservation Division until 1982 when the Minerals Management Service (MMS) was formed (Dellagiarino et al., 2002). Presently, BOEM and the Bureau of Safety and Environmental Enforcement (BSEE) are responsible for the activities once performed by the now disbanded MMS.

According to the "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Atlantic Outer Continental Shelf" report (BOEM, 2012a), approximately 240,000 line-miles of 2-D data were collected in the Mid-Atlantic region from 1968 to 1992. In 1976, new regulations required that all processed geophysical information be released to the public after a 25-year proprietary moratorium period based on the permit date, so the first processed seismic datasets were released in 2001. Raw geophysical data purchased by MMS/BOEM is held from the public for 50 years (based on the permit date), hence the first legacy survey data is scheduled to become available in approximately 2026. It is estimated that between 1968 and the early 1990's, industry acquired approximately 500,000 line-miles of CDP seismic data each year on the entire U.S. OCS while MMS selected and acquired only 10% of this data for the Resource Evaluation Program. MMS limited the amount of data they acquired/purchased due to: 1) the cost of reimbursing permit holders for processing and delivering the data, 2) the lack of personnel at MMS to manage and interpret the data, and 3) data redundancy due to data being collected in similar areas by different companies. In contrast to the entire U.S. OCS, MMS acquired a much larger portion of the available G&G data for the Atlantic Region as compared to the Gulf of Mexico Region. The 2-D seismic data available to BOEM for resource evaluation on the Atlantic OCS covers approximately 170,000 line-miles (BOEM, 2012a).

Of the data available from the BOEM/BSEE online data center (www.data.bsee.gov), Fugro acquired seismic data from 13 separate permits of 1975 to 1988 vintage that surveyed in and around Virginia and northern North Carolina waters for this study (Table 3.1-1). When comparing the 2-D seismic data coverage from MMS, most, but not all, of the data acquired by MMS in Virginia and northern North Carolina waters was part of these 13 permits (Figure 3.1-1 and Appendix A). Possible reasons that not every seismic line was acquired for this report include: 1) the data was acquired after 1988 (the vintage of the data available in the latest BOEM data release), 2) the data was acquired before 1975 and has not been released to the public (no seismic surveys are available from BOEM/BSEE prior to 1975), 3) the data has been lost or is missing from the data releases, or, 4) the data is high-resolution seismic reflection data that is not part of the data releases.

Descriptions of each seismic survey includes a reference to individual BOEM hydrocarbon plays (BOEM, 2012a) that overlaps the seismic survey's acquisition area (Figure 3.1-2), the industry and shallow-penetrating wells that were used for geologic correlation (Figures 3.1-3 and 3.1-4) and the tracts that were leased as part of the nine lease sales between 1976 and 1983 (Figure 3.1-4). There are five post-rift sediment depocenters of Early Jurassic to recent age in the Eastern U.S. Atlantic Margin: trending from NE to SW, they include Georges Bank basin, the Baltimore Canyon Trough, the Carolina Trough, the Southeast Georgia Embayment and the Blake Plateau basin (Figure 3.1-5). These basins and other geologic trends were used by MMS/BOEM to separate the prospective hydrocarbon plays in the Atlantic into ten unique plays, four of which occur within the study area (e.g., BOEM, 2012a). These four plays are the Jurassic Shelf Stratigraphic Play in water depths ranging from approximately 200 to 2600 feet, the Late Jurassic-Early Cretaceous Carbonate Margin Play which extends from the U.S./Canadian border to the Bahamas as a narrow band in water depth ranging from approximately 3500 to 6500 feet and both the Core and Extension Plays of the Cenozoic to Cretaceous and Jurassic Paleo-Slope Siliciclastic sediment packages found in the deepest waters of the study area.

Western Geophysical - Permit E14-75 (Plates A-1 and B-1)

In 1975, 33 seismic lines were acquired by Western Geophysical extending along the inner shelf from Long Bay, South Carolina northward to offshore Cape Hatteras, North Carolina. The majority of these lines lie landward of the 50-mile "no lease" coastal environmental buffer (BOEM, 2014b). Portions of 5 of these lines lie within the southernmost limits of the study area. The seismic lines were collected with a 6 to 12 mile (10 to 20 km) grid-like spacing of 25 dip lines and 8 strike lines. The strike lines have limited lengths in the survey's most landward limits in Long Bay, Onslow Bay and Raleigh Bay due to the seaward projection of Cape Fear, Cape Lookout and Cape Hatteras. Therefore, the strike line coverage varies from 3 to 7 lines throughout the entire survey. Seismic lines were collected near three shallow-penetrating wells of the Atlantic Slope Project (ASP 4) and the USGS Atlantic Margin Coring project (AMCOR 6005 and 6006) located along the Carolina Platform (Figure 3.1-3). Portions of 19 lines of this survey cross into the Cretaceous and Jurassic Marginal Fault Belt Hydrocarbon Play (BOEM, 2012a) south of the study area. Within the study area, three of the four hydrocarbon plays (i.e. all but the Cenozoic-Cretaceous and Jurassic Paleo-Slope Siliciclastic Extension Play) are imaged by the northernmost lines of the survey.

While all other surveys described in this report made use of air guns, the E14-75 survey created an acoustic source through a sleeve exploder device called an Aquapulse System. For the Aquapulse system, a propane-oxygen mixture is exploded in a closed chamber surrounded by a rubber sleeve that releases the gases to the air post-explosion to reduce oscillations. The processing techniques applied, and the order in which they were applied, are not well documented and information comes from a single scanned data label of Line WE-1, which is located outside of the study area in Long Bay, SC. Stacked sections in SEG-Y format are available for all lines from BOEM and the USGS, where the survey is known as W-5-75.

Offshore Atlantic Group (OAG)/Digicon - Permit E16-76 (Plates A-2, B-2A and B-2B)

The seismic data acquired for permit E16-76 by Digicon consist of a grid of 42 lines acquired along the continental shelf and slope extending north from offshore Cape Hatteras, North Carolina into southern New Jersey waters. The seismic grid is composed of 35 dip lines with 2 to 9 mile (4-15 km) spacing between lines and seven strike lines approximately 6 to 15 miles (10-25 km) apart. Both stacked and migrated seismic time sections in SEG-Y format are available for all lines collected in Virginia waters. Geophysical permit E16-76 was issued in 1976, the same year as Lease Sale #40, the first Atlantic OCS lease sale which offered tracts in the North Atlantic.

USGS (MMS)/Whitehall - Permit E06-79 (Plates A-3, B-3)

Multichannel CDP data collected for the USGS Conservation Division (later to become the MMS), as part of permit E06-79, images the nearshore subsurface in an area running from central Florida to southern New Jersey. A wealth of information concerning this survey is found on a series of images scanned from microfilm and available for download at NOAA's NGDC, where the survey is known as ECOAST79. The information available in the scanned images consists of two operator's reports (one covering the data collected near Charleston, the second covering the rest of the survey), velocity scans and severely degraded images of the various lines using a single-channel for display. The reports contained in the microfilm files provide detailed information concerning the surveying equipment such as the navigation system, the air gun array design, the streamer used, and the recording system, which is lacking for all but one other survey (i.e., USGS Survey S-1-77) described in this report. For the Charleston leg of the survey, handwritten notes from USGS's Ken Bayer present his thoughts on novel aspects of their automatic cable depth control equipment and the unique air gun array design while also explaining the downside of using Whitehall Corporation over the larger contractors such as Digicon and GSI. The seismic data for this survey were acquired after contacting BOEM when it was noticed that a seismic permit data label for line V-104 was included on one of their DVD sets. All lines in the study area exist only as scanned copies and only D-100 and D-102, outside of the study area exist as SEG-Y files.

South Atlantic Group/Geosource - Permit E01-80 (Plates A-4, B-4A and B-4B)

Two seismic surveys were collected in 1980 for the "South Atlantic Group" that covered almost identical areas and often with lines overlapping one another. Geosource collected seismic data as part of permit E01-80 and Digicon acquired data as part of permit E02-80 (described in the following section). It is unknown why the two surveys were collected with such similar areal distribution and funded by possibly the same group of industry members. The area surveyed by both Geosource and Digicon for these permits extends from the Southeast Georgia Embayment to the Manteo Protraction (Figure 1.1-1) east of the Outer Banks of North Carolina.

For Permit E01-80, in the Currituck Sound Protraction (Figure 1.1-1) 16 dip lines have line spacing varying from 1 to 2 miles (2 to 3 km) and the 6 strike lines in this protraction are spaced 1.3 to 3 miles (2.5 to 5 km) apart. In the Manteo Protraction, 23 dip lines were collected at a 1.5 to 3 mile (2.5 to 5 km) spacing and the 7 strike lines of the survey have line spacing varying from 2 to 2.5 miles (3 to 4 km). Almost every block that was leased between 1981 and 1983 in North Carolina was imaged by this survey. East of the Outer Banks of North Carolina and within the study area of this report, seismic lines acquired for permit E01-80 predominantly image the Late Jurassic to Early Cretaceous Carbonate Margin Play (BOEM, 2012a) in water depths ranging from approximately 150 feet (50 meters) to 6500 feet (2000 meters). Both stacked and migrated sections are available for the seismic lines collected as part of this survey.

South Atlantic Group/Digicon - Permit E02-80 (Plates A-5, B-5A, B-5B, and B-5C)

As mentioned in the previous survey description, the data collected by Digicon for permit E02-80 covers a geographic extent very similar to the data acquired by Geosource for permit E01-80 and additionally both surveys have very similar line spacing. If the data acquired for these two survey will be interpreted to aid future O&G exploration, the availability of depth sections for permit E02-80 will be valuable as no depth sections are available for the data acquired for permit E01-80. In the Currituck Sound Protraction (Figure 1.1-1) located in northern North Carolina and southern Virginia waters, 8 dip lines with spacing varying from 1 to 3 miles (2 to 5 km) and 2 strike lines spaced approximately 4 miles (7 km) apart were collected as part of this permit. Just south of this area within the Manteo Protraction (Figure 1.1-1), 22 dip lines were collected at a 1 to 3 mile (2 to 5 km) spacing and 2 strike lines tie these dip lines spaced between 6 to 12 miles (10 to 20 km) apart.

Exxon/Geosource - Permit E01-81 (Plates A-6, B-6A and B-6B)

Data collected for Exxon Exploration by Geosource Inc., as part of Permit E01-81, extends across a large portion of the Eastern U.S. Atlantic Margin with five broadly spaced lines running either N-S or E-W seaward of southern Georgia, and a denser distribution of data located in an area extending from Virginia's OCS to Georges Bank Basin. The seven lines collected in Virginia waters intersect the locations of the three Atlantic Slope Project wells (Figure 3.1-3) and continue northward into Maryland waters, where the lines intersect tracts both previously leased in 1979 (lease sale 49) and tracts leased as part of lease sales 59 (1981), RS-2 (1982) and 76 (1983). Lines collected in waters extending from Virginia to just south of Georges Bank generally straddle the shelf break in close proximity to the Late Jurassic-Early Cretaceous Carbonate Margin Play identified by BOEM (2012a).

Chevron/Digicon - Permit E07-81 (Plates A-7, B-7A and B-7B)

The 12 lines collected in the North Carolina OCS in water depths of approximately 147 to 8200 ft. (45 to 2500 m) for permit E07-81, image the area that is known as the Manteo Prospect or Manteo Exploration Unit (Figure 3.1-4C). These lines were collected near the shallow-penetrating ASP 7 and 8 core locations (Figure 3.1-3). The 11 dip lines of the survey are spaced approximately 1.5 to 3 miles (2 to 5 km) from one another and extend from BOEM's Jurassic Shelf Stratigraphic Hydrocarbon Play into the Cenozoic-Cretaceous and Jurassic Paleo-Slope Siliciclastic Core Play. A single strike line ties the dip lines along the trend of the Late Jurassic-Early Cretaceous Carbonate Margin Play.

The acquisition parameters used for this survey are comparable to other surveys in the early 1980's, utilizing the DFS V recording system to record 96 channels and a 2 mi (3.3 km) long cable. Unfortunately, the source volume is not provided in the scanned data labels, but it is likely that it is around 2220 cubic inches, which was used during the E02-80 survey acquired by Digicon 8 months prior to this survey, and utilized the same number of guns and source pressure. Migrated sections using the process of downward continuation (likely Kirchhoff migration) are available as scanned paper copies and in SEG-Y format. Depth migrated sections are available for all lines except Lines 1, 3 and 7 and part A of Line 12.

Mid-South Atlantic Group/Geosource - Permit E02-82 (Plates A-8, B-8A, B-8B and B-8C)

Geosource collected approximately 274 seismic lines along the middle and northern Atlantic as part of the geophysical permit E02-82. This large survey covers the offshore New York shelf/slope region just north of the Baltimore Canyon Trough, and a nearly continuous region from offshore southern North Carolina to southern Maryland waters. The southern region is made up of four sub-regions based on the seismic grid spacing which, moving south to north, includes: 1) a relatively course seismic grid within the Carolina Trough, 2) a grid with more closely-spaced lines due east of Cape Hatteras with a few tie lines running north to 3) a small grid of lines due east of the Albemarle Sound and finally, 4) a tightly-spaced data grid extending from northern North Carolina across the entire Virginia OCS and into Maryland waters. Northwest to southeast oriented seismic lines collected in the Virginia OCS are spaced approximately 1 mile (1.5 km) apart and four tie lines run perpendicular to dip lines. No seismic lines for this entire survey were collected near existing exploration wells, while many lines cross offshore tracts that were leased after the surveys' completion (i.e., lease sales 76 and 78 which took place in 1983). The lines collected in Virginia waters span three out of the four hydrocarbon plays defined by BOEM, excluding only the far offshore Cenozoic to Jurassic Paleo-Slope Siliciclastic Extension Play (for details see Section 4.1.2 and Figure 3.1-2). Seismic data available for this survey includes SEG-Y files of stacked sections, migrated sections and depth-converted sections. The migrated and depth-converted sections were purchased from BOEM, while the stacked sections were downloaded from the USGS NAMSS website, where the survey is listed as WesternGeco Middle Atlantic (W-4-82-NA). Geosource, the geophysical contractor for this survey, was acquired and merged with several companies before it became part of WesternGeco in 2000.

Shell - Permit E04-82 (Plates A-9, B-9A and B-9B)

For permit E04-82, limited recording and processing information is known, but the SEG-P1 navigation files indicate that the client was Shell. The 40 lines collected as part of this survey run north of the Southeast Georgia Embayment to Georges Bank Basin, offshore Massachusetts. Migrated sections and depth-converted sections are available for the five NW-SE oriented lines collected in the Virginia OCS which are spaced approximately 6 to 18 miles (10 to 30 km) apart. Like permit E02-82, no lines were collected near existing exploration wells for the entire survey and the coverage in offshore Virginia extends across the three BOEM hydrocarbon plays closest to shore, excluding the Cenozoic to Jurassic Paleo-Slope Siliciclastic Extension Play (Figure 3.1-2). While the seismic acquisition group and data processor are unknown for this survey due to cryptic information listed on the scanned section data labels, it is assumed that Shell likely collected and processed the data as other surveys (not described in this report) with similar coded processing steps all have Shell listed as the client in the associated SEG-P1 navigation files.

ARCO - Permit E11-82 (Plates A-10 and B-10)

In 1982, ARCO Exploration surveyed three Mesozoic Rift Basins as part of Permit E11-82. Near Georges Bank, the Atlantis Basin was surveyed using a relatively tightly-spaced seismic grid with 30 lines as close as 2.5 km apart covering an area of 2800 km^2 and several lines, more sparsely-spaced, imaged the more northerly Franklin Basin. In Virginia waters, another grid of 44 lines with approximately 1.55 mile (2.5 km) spacing were collected in the Norfolk Basin and an additional four regional dip lines acquired along the inner shelf from the Maryland side of the Delmarva Peninsula to the Virginia/North Carolina border.

Amoco/Norpac - Permit E05-83 (Plates A-11, B-11A and B-11B)

Permit E05-83 consists of 23 sparsely spaced lines collected by Norpac for Amoco in North Carolina, Virginia and Maryland waters in 1983. The lines collected overlap many of the 26 blocks leased during the August 5, 1982 Reoffering Sale (RS-2), therefore, the sparse spacing of the lines reflects the areas of prime interest for O&G exploration at that time. Thirteen lines (Lines 147-152, 198, 201-204, 223 & 225) were collected in the Baltimore Canyon Trough, with Lines 225 and 198 collected in Virginia waters. Additionally, five lines were collected east of the Outer Banks shoreline (Lines 266, 267, 268, 285 & 286) and six lines were collected in the Carolina Trough region of North Carolina (Lines 298, 301 & 327-330). The seismic data available from BOEM/BSEE consists of migrated sections and/or depth-converted seismic sections for each line mentioned above. Unfortunately, much of this information (especially the depth-converted data) exists only as scanned documents and not as digital SEG-Y files. Specifically, only 6 out of 21 depth sections are provided in SEG-Y format and 18 out of 25 migrated sections are available in SEG-Y format. For the 2 lines collected in Virginia waters (Lines 198 and 225), seismic data is available only as scanned documents. Depth-converted sections are available for both lines with a migrated section available only for Line 198. Also of note for permit E05-83, is the absence of any navigation information (or SEG-Y data) for Line 268, so the exact position of this scanned line is uncertain.

Spectrum and Texaco/Teledyne - Permit E05-86 (Plates A-12 and B12)

Permit E05-86 consists of only three seismic lines: 1) Line 5-YRE extending southeast from the mouth of Chesapeake Bay to the inner continental shelf of Virginia over the southern half of the buried Norfolk Basin, 2) Line OSC-2 running east of Myrtle Beach, SC and 3) Line OSC-3 collected offshore of Charleston, SC. All three lines have both scanned seismic stacked sections and stacked SEG-Y files. The words “Rift Basins-Water” are handwritten on the scanned paper copy of Line 5-YRE, and the other two lines collected for this permit have “Offshore South Carolina Triassic” written along the top section of the scanned documents. It is likely that these nearshore seismic lines were collected to understand the extent of offshore Mesozoic Rift Basins along the East Coast of the United States that became the focus of onshore drilling in the late 1980’s (Aldinolfi, 1990). The data for this permit was acquired by Teledyne Exploration for Spectrum Resources (Line 5-YRE) and Texaco (Lines OSC-2 and OSC-3). Texaco’s interest in the southern Atlantic Mesozoic Basins resulted in the drilling of six core holes in Caroline, Essex and Westmoreland Counties, Virginia in 1986 and the completion of the Texaco/Wilkins-1 well in the Taylorsville Basin in August of 1989. Texaco also completed a stratigraphic test in the Florence rift basin of South Carolina in 1987 (Adinolfi, 1990).

Texaco/GECO - Permit E03-88 (Plates A-13 and B-13)

Permit E03-88 consists of data covering four areas: 1) The Currituck Embayment—with seismic lines labeled 88-16, 2) the Norfolk Basin with seismic lines labeled 88-17, 3) the Long Island Basin with seismic lines labeled 88-18 and 4) the Block Canyon Area with seismic lines labeled 88-19. The data available for the most southern region, the Currituck Embayment area, consists of migrated seismic sections of eight lines (Lines B,C & H-M) running E-W along the southern Virginia Shelf and one tie-line (Line A) running N-S from North Carolina into Virginia waters. There are 20 total SEG-Y files (due to individual lines often being broken up into three separate SEG-Y files) for the Currituck Embayment area and one SEG-P1 navigation file. It should be noted that parts 1 and 2 of line H, the most-northerly E-W running line are not included in the navigation file and most likely extend Line H to the east approximately 6 miles (10 km) based on the number of shotpoints and the trace spacing. The trace interval in the SEG-Y text header is listed as 82 feet (25 m) for 17 of the 20 seismic sections and 41 feet (12.5 m) for the lines 88-16-C-W, 88-16-H-1 and 88-16-H-2. Upon closer inspection, it appears that 41 feet (12.5 m) is a typo based on the shotpoint numbering, CDP numbering, and the navigation file, and the trace interval is actually 82 feet (25 m).

The seismic data available for the Norfolk Basin consists of eight filtered and stacked seismic lines, with 7 lines (A-G) running E-W and 1 tie-line (Line H) running N-S. There are 12 total SEG-Y files (Lines D-F are broken into two SEG-Y files) and one SEG-P1 navigation file that also contains the navigation information for the Long Island Basin and the Block Canyon Area. Like the Currituck Embayment Area, the trace spacing is 82 feet (25 m) contrary to being listed as 41 feet (12.5 m) in several of the SEG-Y text headers. There are 8 lines with stacked sections in SEG-Y format for the Long Island Basin and 4 lines with stacked sections in SEG-Y format for the Block Canyon Area.

3.1.5.2 Seismic data acquired by, or in cooperation with, USGS

Authorized by Congress in the 1970's to evaluate the resources of the Eastern U.S. Atlantic Margin, the USGS Branch of Atlantic-Gulf of Mexico Geology began collecting long regional MCS lines off the East Coast in 1973 to understand the geologic framework of the OCS and address the viability of O&G exploration (Doyle, 1982). Seven different surveys collected by various contracted seismic acquisition groups worked with the USGS to collect a total of 41 lines along the Eastern U.S. Atlantic Margin. The first survey, S-1-73, consisted of three lines running perpendicular to the shoreline and spaced approximately 125 to 310 miles (200 to 500 km) apart. By the end of the seventh survey, C-1-78, the line spacing had been reduced to approximately 25 miles (40 km) between adjacent dip lines and approximately 100 miles (165 km) along strike.

In 1979, the Bundesanstalt für Geowissenschaften und Rohstoffe (BGR), a cooperative project between USGS and Carl Hinz of Germany's Federal Institute for Geosciences and Natural Resources, resulted in the collection of various types of geophysical data along the OCS including 21 MCS reflection profiles, magnetic and gravity profiles, and information derived from sonobuoys. The seismic lines collected in this survey are long, regional lines that were meant to compliment the regional data collected by the USGS in the 1970's. With the addition of these lines, the spacing of regional lines from government-funded seismic projects along the Middle and North Atlantic OCS was improved to 6 to 16 mile (10 to 25 km) spacing between adjacent lines (Schlee and Hinz, 1987).

Unlike the data purchased from BOEM, which was held proprietarily for 25 years as explained in Section 2.2, the USGS and BGR lines have been the basis for numerous studies that helped document the geologic history of the Eastern U.S. Atlantic Margin. From 1994 to 1996, researchers at USGS (Klitgord and Schneider, 1994; Klitgord et al., 1994; Hutchinson et al., 1995; and Hutchinson et al., 1996) created a series of reports forming the “Geophysical Database of the East Coast of the United States” which relied almost entirely on the USGS surveys collected in the 1970’s.

Four of the seven surveys (S-1-73, S-1-75, S-1-77 and C-1-78) collected by the USGS in the 1970’s are located in Virginia and northern North Carolina waters. SEG-Y files are available for these datasets from the USGS’s National Archive of Marine Seismic Surveys (NAMSS). Of all the surveys described in this report, unprocessed DEMUX files are only obtainable for these 1970’s seismic lines. Stacked sections of most of the lines are also available and documentation of each survey is provided on the USGS Woods Hole Coastal and Marine Science Center including links to relevant publications, navigation files and observer logs. Details of the BGR survey and the four USGS surveys, with specific emphasis on the lines collected in Virginia waters are described below.

USGS/Digicon Survey S-1-73 (Plates A-14, B14A and B14B)

In May of 1973, Digicon Geophysical Corporation was contracted to collect the first MCS reflection survey on the Atlantic OCS for the USGS. Just one month prior, on April 18th, President Nixon had informed Congress of his plans with the Secretary of the Interior to triple the amount of acreage leased on the OCS for O&G exploration by 1979. This USGS survey marked the beginning of a focused research effort by the USGS to determine the underlying stratigraphic structure of the Atlantic shelf, slope and continental rise in order to assess potential offshore resources. Three MCS lines were collected during this survey, one across Georges Banks and two across the Baltimore Canyon Trough east of New Jersey and Virginia. Line 3 remains the longest MCS line collected along the Virginia OCS, extending from the Eastern Shore of Virginia to the abyssal plain near the boundary of the U.S. EEZ. In addition to providing almost complete coverage across the OCS, line 3 provided a correlation between onshore and offshore stratigraphy as it was collected east of the onshore E.G. Taylor #1-G well, located 80 km north of Eyreville in Accomack County, Virginia (Schlee et al., 1976).

The data was collected aboard the M/V *Gulf Seal* using a linear streamer and processed by Digicon to produce 12-fold coverage along the shelf, slope and upper rise and 6-fold coverage in deeper waters (Schlee et al., 1976). Raw DEMUX SEG-Y files and stacked sections are available for download from the USGS NAMSS website where stacked sections of line 3 are available in its entirety (i.e., line 3 and 3A) as scanned images converted into SEG-Y format, while line 3A is available as it was originally retrieved from the master tape. Details of the migration of SEG-Y data from the “Gulf Seal” master tape indicate that there were numerous problems with the data transfer of line 3 which resulted in the loss of data. This is perhaps the reason why only scanned sections are available for the entire line.

USGS/Digicon Survey S-1-75 (Plates A-15 and B-15)

During 1975, the USGS again contracted Digicon Geophysical Corporation to collect seismic data along the Eastern U.S. Atlantic Margin. This 1975 survey provided 36-fold coverage using a non-linear streamer with the nearest 24 groups spaced 100 meters apart, groups 25 and 24 spaced approximately 250 feet (75 m) apart and the farthest 24 groups spaced 50 meters apart. The lines collected as part of this survey consist of five dip lines, which infilled data coverage gaps collected during previous surveys, and two lines running parallel to the continental margin extending from offshore Cape Hatteras, North Carolina into Canadian waters. Three of the seven lines image the subsurface in Virginia waters, the two strike lines (lines 12 and 13) and line 11. Lines 12 and 13 are broken into sections due to their length with sections B and C of line 12 and section B of line 13 collected along the Virginia OCS. Although line 11 provides the most detailed information regarding offshore Virginia stratigraphy, line 10 (also part of S-1-75) was collected near Shell's exploratory Baltimore Rise well (Shell 93-1) and provides the nearest correlation between offshore drilling and the various USGS seismic surveys (Figures 3.1-3 and 3.1-4).

For the lines collected in the Virginia OCS, unprocessed DEMUX SEG-Y data is available for all lines while only lines 12B, 12C and 13B are available as SEG-Y stacked sections. It is unknown why no stacked section is available for line 11, as it is shown in publications by both Peterson et al., (1979) and Bayer and Milici (1987). Line 13B is broken into two parts (13B1 and 13B2) and stacked sections of Line 13B2 is available as an unfiltered and a high-cut filtered stacked section. Wise and Oliver (1987 and 1989) reprocessed lines 12 and 13 as these lines span such a large portion of the Atlantic OCS and are crucial to tying mapped horizons between dip lines. They found that there had been some deterioration of the original field tapes during the demultiplex process. Additionally, Wise and Oliver (1987 and 1989) noted that 1) the lines required editing to remove noisy traces due to bad hydrophones or corruption in the recording system, 2) a shallow mute during original processing allowed noise from refraction and direct arrivals to contaminate the stacked sections, and 3) when reprocessing the data with deconvolution applied before stacking (which was ignored in the original processing) multiples and ringing were attenuated in the final stacked profiles. It is uncertain whether the data available for download is the original processed data or the reprocessed data.

USGS/Teledyne Survey S-1-77 (Plates A-16 and B-16)

Teledyne Exploration acquired 10 seismic lines for the USGS in 1977 aboard the M/V *Coral Seal*. These long, regional lines were collected to image the Long Island Platform (Line 16, a dip line), the Baltimore Canyon Trough (Lines 14 and 15, both strike lines collected in New Jersey waters), the Carolina Platform (Lines 17 and TD6, both dip lines) and the region extending from the Florida Platform to the Blake Plateau Basin (Lines TD-3, 4 and 5, all dip lines). Additionally, two long strike lines were collected as tie-lines between Lines TD-3 to TD-6 in shallow water (TD-1) and in the deep water (TD-2). Only one line was collected in the study area and it consists of two parts (Line 17 and Line 17A). Line 17 was acquired near the shoreline with 160 feet (50 m) shotpoint intervals to produce 48 fold data while Line 17A was acquired with shotpoint intervals of 320 feet (100m) to produce 24-fold data in deep water. The S-1-77 survey is the first of the surveys cataloged for this report (chronologically speaking) to use the DFS IV recording system to produce 48 fold and utilized an acoustic source with a volume of over 2000 cubic inches.

The survey dip lines provide a regional understanding of all identified BOEM hydrocarbon plays extending from the shelf to slope within each area sampled. Some of the seismic lines for this survey ties the existing industry wells drilled before data acquisition. Line 14 intersects the COST B-2 well in the Baltimore Canyon Trough and Line TD5 intersects the COST GE-1 well in the South Georgia Embayment in addition to intersecting the shallow-penetrating ASP 3 well (Figure 3.1-3). Also, Line TD1 intersects the shallow-penetrating ASP 5 and AMCOR 6006 wells. The intersection of future DSDP and ODP wells collected during Legs 44, 164, 174 and 177 with Lines TD-3, TD-5, 14 and 15 indicate that they were likely used in the planning of these academic drilling programs. The processing sequence described in Plate B-16 are for Lines 14, 17, TD-6 and part of TD-2 using the Phoenix “I” computer, while the rest of the lines were processed by Teledyne. For specific details about the Teledyne processing sequence refer to Gilbert and Dillon (1981). Demultiplexed, raw data and stacked sections in SEG-Y format are available for download from the USGS. Scanned stacked sections, observer logs and a final “Seismic Data Acquisition” report are available for download from NOAA’s NGDC website.

USGS/GSI Survey C-1-78 (Plates A-17 and B-17)

Geophysical Services Inc. (GSI) was contracted by the USGS to collect and process the 21 seismic lines making up survey C-1-78. A non-linear streamer with the same group interval spacing as described in survey S-1-75 was used to produce 48-fold data for this survey. Line 28 was the only line collected in Virginia waters and is available in SEG-Y format as both unprocessed DEMUX data and as a stacked section. Line 10 from survey S-1-75 and lines 19 and 28 (collected as part of this survey) are interpreted in Figure 3.1-6, detailing the contrasting geologic stratigraphy and structure along the northern Atlantic OCS. Lines collected as part of this survey provide a substantial amount of information used for the Northern Atlantic Margin portion of the “Geophysical Database of the East Coast of the United States” (Klitgord et al., 1994; Klitgord and Schneider, 1994).

BGR/Prakla-Seismos 1979 Survey (Plates A-18, B-18A and B18B)

Four strike lines from the BGR 1979 survey span the Virginia OCS in water depths ranging from approximately 650 to 8200 feet (200 to 2500 m). These lines are spaced approximately 7 to 15 miles (12-25 kilometers) from one another and, as was mentioned before, improve the data coverage of the previously acquired USGS seismic surveys. While searching to locate this data, it was discovered that, while not advertised on their website, BOEM had a contractor scan paper copies to vectorize and convert all available lines of the BGR 1979 survey to SEG-Y format. At Fugro’s request, BOEM provided this data with SEG-Y and paper copies of stacked and migrated sections of the four lines acquired in the study area.

3.1.5.3 Seismic data acquired as part of academic research programs

The majority of academic data collected in the Mid-Atlantic, and in particular, within Virginia waters, is primarily 2-D single-channel seismic data and/or various types of high-resolution seismic data (e.g., sparkers, boomers, pingers and echo sounders) with higher source frequencies that allow for a detailed view of the shallow subsurface, but offer little information about the deep subsurface where oil and gas reservoirs are typically located. One cooperative project (supported by grant ES8721194 from the National Science Foundation and Texaco Oil Company) between USGS and various academic institutions, including Woods Hole Oceanographic Institution, the University of Wyoming and the University of Georgia, known as the Virginia 1990 EDGE Experiment (VAEDGE), aimed to image the deep crustal structure extending from the U.S. mainland to offshore waters along the coast of Virginia (Plate A-19).

The goal of the VAEDGE project was to understand the origin of a series of magnetic anomalies, such as the East Coast Magnetic Anomaly (ECMA), that extend across a large portion of the U.S. Atlantic Margin (Carr, 1993). Often regional free-air gravity and/or magnetic anomaly maps are utilized by geophysicists to understand deep structural trends, that while very rarely the target of oil exploration, help delineate the major underlying features responsible for controlling basin formation and subsequent deformation. Four MCS profiles were collected along the Virginia margin with recording lengths up to 16 seconds (c.f., maximum recording lengths of 14 seconds for 1970's and 1980's industry data obtained from BOEM/BSEE) along regional transects overlying 10 ocean bottom seismometers (OBS) with additional recording of the seismic data using 11 portable land-based IRIS seismic instruments (Plate B-19). To quickly summarize the results as they pertain to oil exploration, the VAEDGE survey was able to better define the geometry of the Norfolk basin, help define the extent of the thick igneous crust that led to the ECMA, and provide a migrated depth seismic section extending to a depth of approximately 40 kilometers (Sheridan et al., 1993; Holbrook et al., 1994). A survey very similar to this study was concluded in October of 2014 south of the VAEDGE program (Van Avendonk et al., 2012) collecting seismic data offshore North Carolina with additional land seismometers located in northern North Carolina and Virginia.

3.2 WELLS DRILLED IN THE MID-ATLANTIC

3.2.1 Shallow-penetrating wells

The first wells completed along the US Atlantic OCS were part of the Atlantic Slope Project (ASP). Thirteen wells were drilled in 1967 by a consortium of oil industry members including Exxon, Chevron, Gulf and Mobil aboard the R/V *Caldrill I* (Figure 3.1-3). The Norfolk Canyon offshore Virginia was drilled twice during this program, at sites 10 and 22, in water depths of 2,020 and 4,130 ft. (616 and 1259 m), respectively (Weed et al., 1974). The ASP site 22 core penetrated 751 ft. (229 m) into the subsurface encountering a 531 ft. (162-m) Pleistocene section, above a thin Oligocene section, and a 50 feet (15 m) thick Eocene section (Poag, 1979). Approximately 2.1 miles (3.5 km) away, ASP site 10 penetrated 820 feet (250 m) of the subsurface and recovered a 544 foot (166 m) thick middle to outer-shelf Pliocene clay above middle Miocene sands and clays of fluvial-marine origin (Poag, 1979). ASP site 23 recovered data over a 1000 foot (305 m) interval in Washington Canyon, in a water depth of 4872 feet (1485 m), encountering thick Pleistocene sequences of gray to dark gray, gassy, silty and sandy clays (Weed et al., 1974; Poag, 1978).

In 1976, the USGS conducted its Atlantic Margin Coring Project (AMCOR) to determine the general stratigraphy at various sites along the shelf and slope of the East Coast of the United States (Figure 3.1-3). Three wells were drilled in the Mid-Atlantic (AMCOR 6006, 6007 and 6008) with AMCOR 6007 being the most relevant for this study. AMCOR 6007 was drilled in 278 ft. (85 m) of water on the Virginia Shelf to a total depth of 1020 feet (311 m) below the mudline. At AMCOR 6007, a Pleistocene and Pliocene section was encountered before reaching an entirely deltaic Miocene section (Poag, 1979).

Academic drilling, as part of the Deep Sea Drilling Project (DSDP) and the later Ocean Drilling Program (ODP), drilled numerous wells on the New Jersey Shelf and in southern North Carolina waters along the Carolina Trough, the Blake Plateau and Blake Ridge (Figure 3.1-3). Due east of Virginia, in water depths greater than 15,000 ft. (4000 m), two DSDP wells penetrated a sedimentary section 2,076 feet (633 m) thick at site 105 of Leg 11 and 5,120 ft. (1576 m) thick at site 603 of Leg 93. Seismic sections imaged a bright reflector believed to be oceanic basement not much deeper than the total depth of these two wells (Poag, 1987). Site 105 reached the Upper Jurassic Cat Gap Formation, composed of calcareous claystones and limestone (Hollister et al., 1972; Poag, 1987).

3.2.2 Oil and Gas Exploration Wells

Drilling for O&G along the Atlantic Margin of the United States resulted in the completion of 51 exploration wells between the years of 1976 and 1984. Two wells (Shell 587-1 drilled in 6,400 ft. (1,965 m) of water and Shell 372-1 drilled in 6,860 ft. (2,120 m) of water) drilled in the U.S. Atlantic Margin during this period utilized current state-of-the-art drilling technologies breaking existing world records for deep-water drilling (Figure 3.1-3A). Three main geographic areas were drilled including: 1) thirty four wells drilled near Wilmington and Hudson Canyons in the Baltimore Canyon Trough primarily in New Jersey waters, 2) ten wells drilled in Georges Bank offshore Massachusetts and 3) seven wells drilled in the Southeast Georgia Embayment.

Only one well was drilled in the Mid-Atlantic, the Shell Baltimore Rise 93-1 (OCS-A-0370-1) well, completed in November 1984 in approximately 5,000 ft. (1,529 m) water depth to a total depth of 17,740 ft. (5,407 m) True Vertical Depth (TVD). The Shell 93-1 well is approximately 35 miles (57 km) from Virginia waters, being the closest industry well to the study area. Shell Oil Company leased Block 93 during OCS Lease Sale 59 in December, 1981 and after plugging and abandoning the well as a dry hole, Shell discontinued their Atlantic deep water drilling program (Amato, 1987). The lease for Block 93 was relinquished on January 31, 1986.

The Shell 93-1 well was drilled into a faulted anticline in hopes of encountering hydrocarbon reservoirs within the Lower Cretaceous and Upper Jurassic sandstones at a depth of approximately 10,000 ft. (3,048 m). The Lower Cretaceous interval was encountered at 9,150 ft. (2,789 m) and was composed of a channel fill sequence 2,700 ft. (823 m) thick (Amato, 1987). The Upper Jurassic was encountered at 17,280 ft. (5,267 m) and was composed of nearshore and non-marine strata. The porosities for targeted intervals were lower than expected and the potential hydrocarbon intervals were thin and silty. There were seven total hydrocarbon shows in the well, although none were deemed to be commercially relevant. A study of the source rock maturity indicated that the kerogen in the Lower Cretaceous and Upper Jurassic strata was gas-prone kerogen of terrestrial origin and the onset of source rock maturity was near the bottom of the well (Amato, 1987). This well was unique in that it was the only well drilled in the Cenozoic-Cretaceous and Jurassic Paleo-Slope Siliciclastic Play defined by BOEM in their most recent assessment (BOEM, 2014b) of undiscovered technically recoverable O&G resources of the Atlantic OCS (Figure 3.2-1).

North of the Baltimore Rise area, drilling in Georges Bank, offshore Massachusetts, targeted the Triassic-Jurassic Rift Basin Play (Figures 3.1-2 and 3.1-3A). In the Baltimore Canyon Trough, the first wells drilled from 1978 to 1981 targeted a number of structures within the Cretaceous and Jurassic interior shelf (Figure 3.1-4B) such as the Stone Dome (also known as

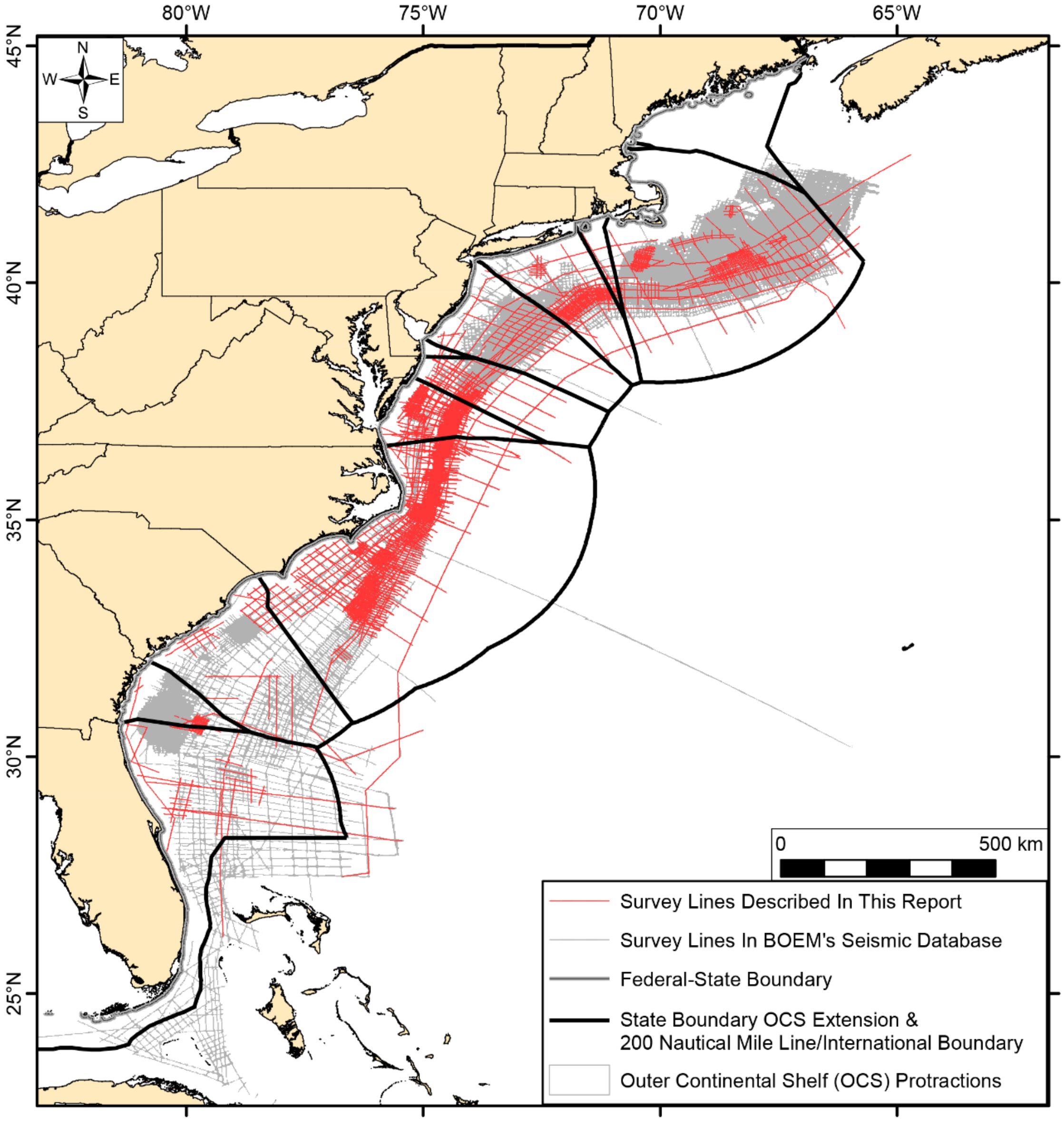
Schlee Dome), the Wilmington Dome, the Avalon Structure and the Northeast Slope Structure (Doyle, 1982). Spudded in 1983 and 1984, three dry holes were drilled by Shell into the Late Jurassic-Early Cretaceous Margin of the Baltimore Canyon Trough in New Jersey waters. No wells were drilled in Virginia waters and only block 566 (leased in 1983 during Sale 76 and presently referred to as block 6636 after the approval of protraction NJ 18-8 Chincoteague in May of 2006) was leased within the OCS State boundary extension of Virginia during the period of O&G exploration in the 1970's and 1980's (Figure 3.1-4).

3.3 SEISMIC VELOCITY SURVEYS

Information for converting seismic two-way travel time to depth comes from three main sources: 1) sonic logs, 2) checkshot surveys and 3) seismic data velocity analysis. Industry well Shell 93-1 is the sole source for velocity measurements as a function of depth in Mid-Atlantic waters. Sonic log data available for purchase from BOEM for well Shell 93-1 includes a digital Log Information Standard (LIS) file that contains a standard sonic log and a long-spaced sonic log that were collected over two log runs on September 6, 1984 (depth interval of 9,660 to 13,633 feet TVD relative to the kelly bushing) and November 1, 1984 (depth interval of 13,628 to 17,730 feet TVD relative to the kelly bushing). Additionally, analog information (i.e., paper copies) from a dual induction spherically focused log sonic tool collected during a logging run in August 2, 1984 over an interval of 7,504 to 9,705 feet (2,287 to 2,958 meters) TVD relative to the kelly bushing are available for purchase from BOEM. An edited version of the sonic log at this well is shown in Figure 3.3-1. The quality of the sonic data available in the LIS data file is of questionable quality containing a spiky character, which often indicates cycle skipping. It is noted by R. Nichols in his "Formation Evaluation" section of the well report (Amato, 1987) that cycle skipping appears in numerous intervals in the long-spaced sonic tool and that readings from the sonic log have high readings that would indicate higher porosities than those determined from well cuttings. Nichols suggests that the higher readings are possibly due to an enlarged borehole that resulted from clean out trips, washing/reaming and cleaning/conditioning activities. Unfortunately a caliper log which displays the borehole diameter in inches is available only for the 9,660 to 13,633 feet (2,944 to 4,155 meters) TVD logging run, making attempts to correct for borehole conditions limited. Fugro attempted to correct the sonic log for problematic readings by using Microsoft Excel and following the methods presented in Burch (2002). This preliminary analysis resulted in a pseudo-sonic log with considerably less spikes and generally lower readings throughout the well. In order to perform a better data analysis, it would be best to perform log editing using a petrophysical software package so that the log can be partitioned into zones determined by the borehole size and compared to other logs.

Schlumberger conducted a check shot survey using a proprietary well seismic tool (WST). This downhole tool is used to calibrate sonic log depths with seismic times (Amato, 1987). Velocity data from the WST was collected during three separate runs from 5,017 to 9,600 feet (1,529 to 2,926 meters), 9,600 to 13,500 feet (2,926 to 4,115 meters) and 13,500 to 17,000 feet (4,115 to 5,182 meters). The interval velocities from this tool are shown in Figure 3.3-1. Klitgord and Schneider (1994) used the velocity data from the WST collected at the Shell 93-1 well to convert seismic line 10 of survey S-1-75 from seismic two-way travel time (TWTT) to depth and show a generally good agreement with interval velocities determined from stacking velocities (Figure 3.3-2).

For line 28 of survey C-1-78 (Plate A-4 and Plate B-4), located in Virginia waters, Klitgord and Schneider (1994) relied almost exclusively on velocities derived from seismic data to convert TWTT to depth (Figure 3.3-3). A detailed description of the methods used to convert the numerous seismic lines collected by the USGS in the 1970's from time to depth for the "Geophysical Database of the East Coast of the United States Northern Atlantic Margin" can be found in Klitgord and Schneider (1994).

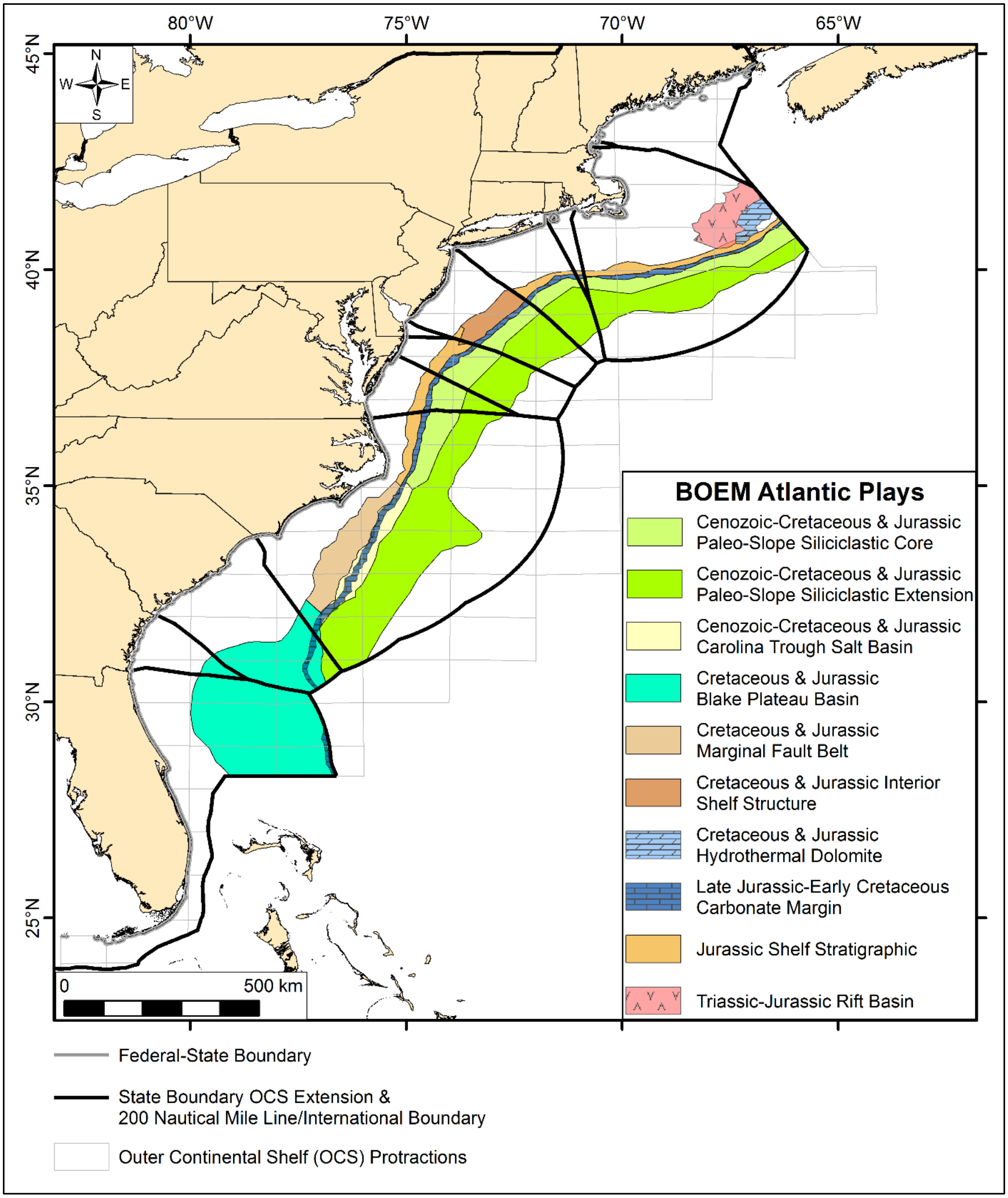


Gray lines from Dellagiarino et al. (2002)

COMPARISON OF SURVEYS DESCRIBED IN THIS REPORT WITH BOEM'S SEISMIC DATABASE

Oil and Gas Readiness Study

Offshore Virginia



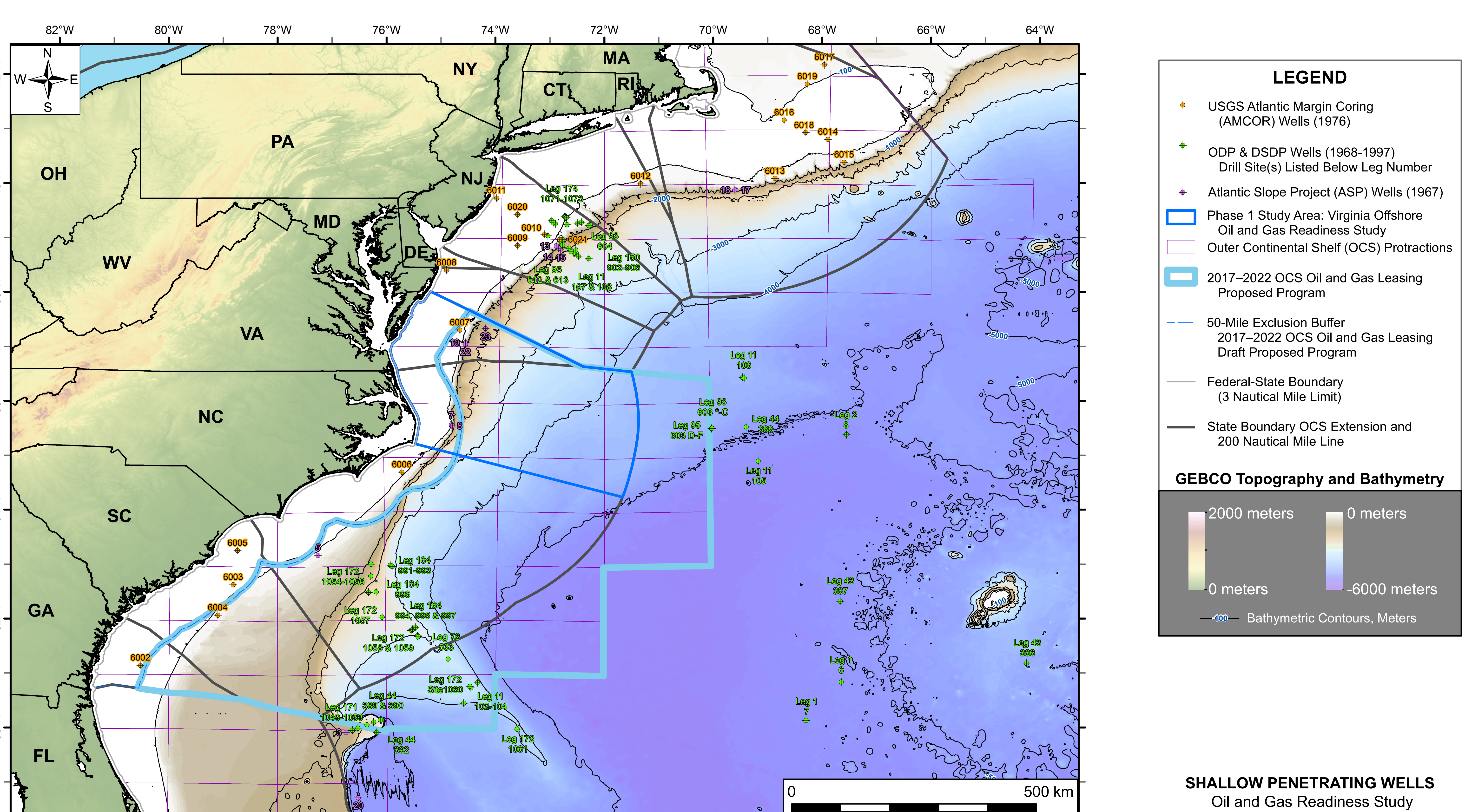
Geological plays are discussed in detail in BOEM (2012a)

Play area polygons were downloaded from BOEM's website in 2014 and are an updated version of the polygons presented in BOEM (2012a)

EXTENT OF GEOLOGICAL PLAY AREAS IN U.S. ATLANTIC REGION

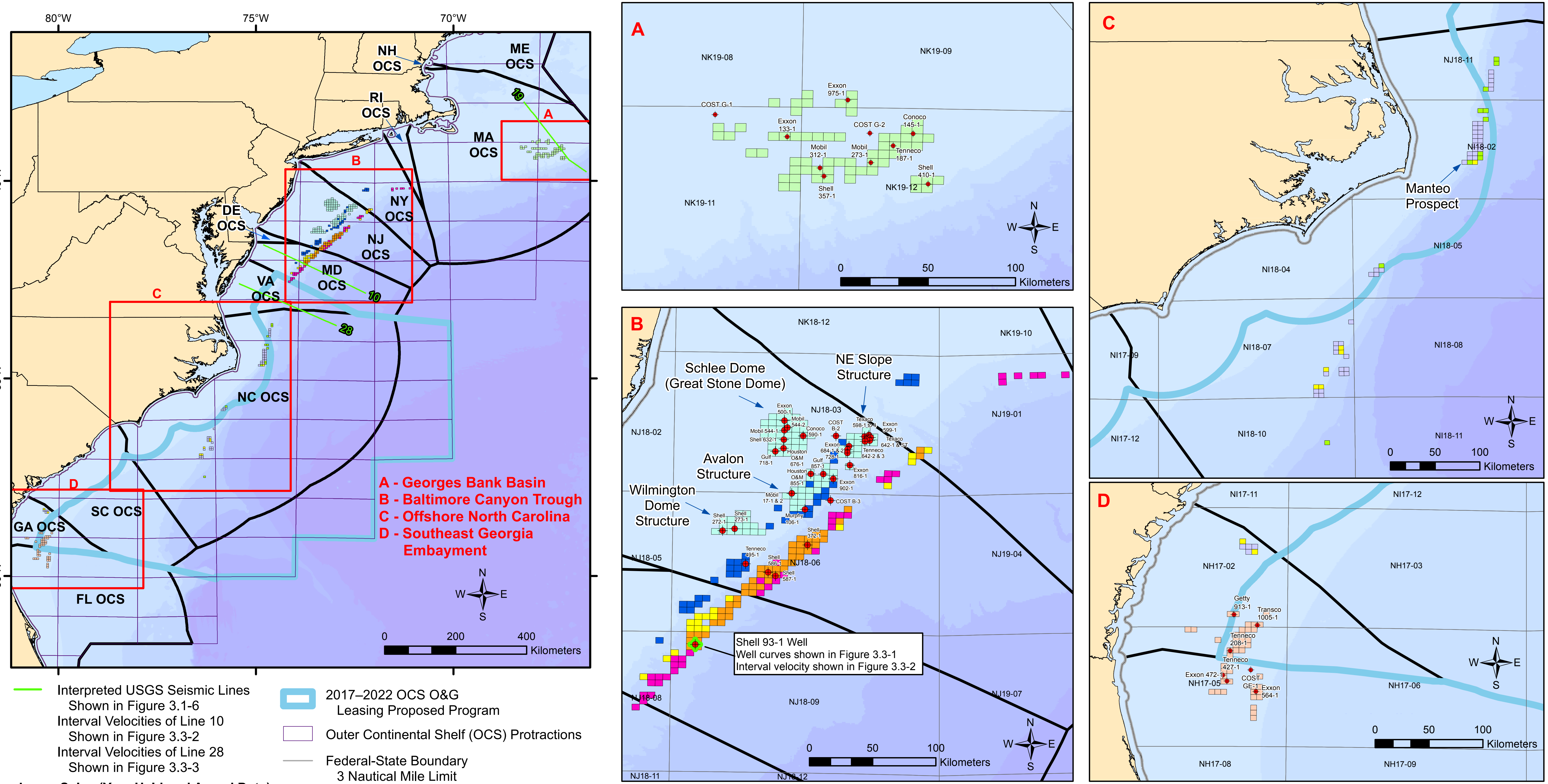
Oil and Gas Readiness Study

Offshore Virginia



SHALLOW PENETRATING WELLS
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 3.1-3



Interpreted USGS Seismic Lines
Shown in Figure 3.1-6
Interval Velocities of Line 10
Shown in Figure 3.3-2
Interval Velocities of Line 28
Shown in Figure 3.3-3

Lease Sales (Year Held and Award Date)

- 40 (1976)
- 43 (1978)
- 42 (1979)
- 49 (1979)
- 56 (1981)
- 59 (1981)
- RS-2 (1982)
- 76 (1983)
- 78 (1983)

2017–2022 OCS O&G Leasing Proposed Program

Outer Continental Shelf (OCS) Protractions

Federal-State Boundary 3 Nautical Mile Limit

State Boundary OCS Extension and 200 Nautical Mile/International Boundary

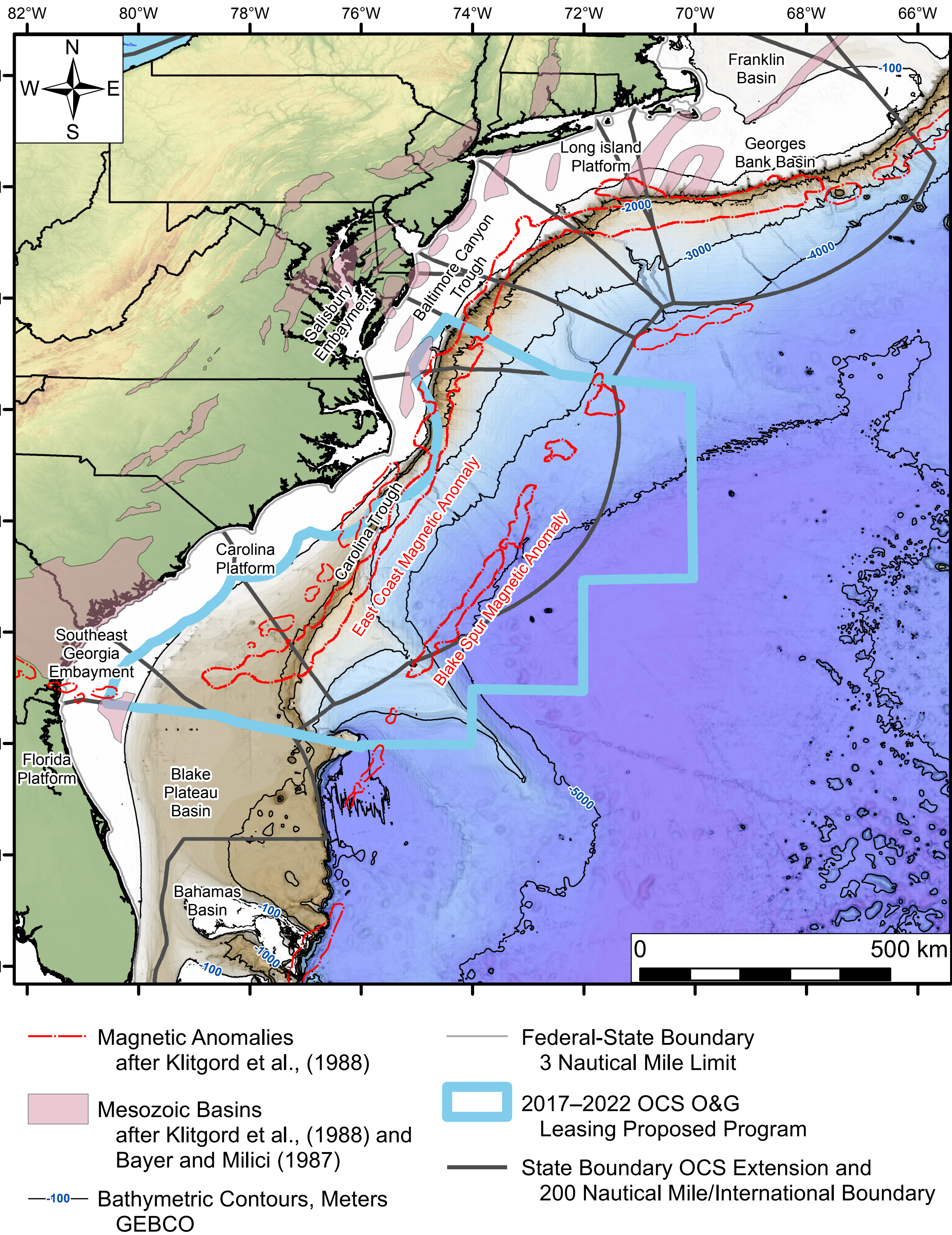
Offshore Atlantic Industry Wells (Drilled 1976 to 1984)

N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-3-1-4_Leased_OCS_Tracts.mxd, 3/13/2015, sullivans

LEASED ATLANTIC OCS BLOCKS AND INDUSTRY WELL LOCATIONS

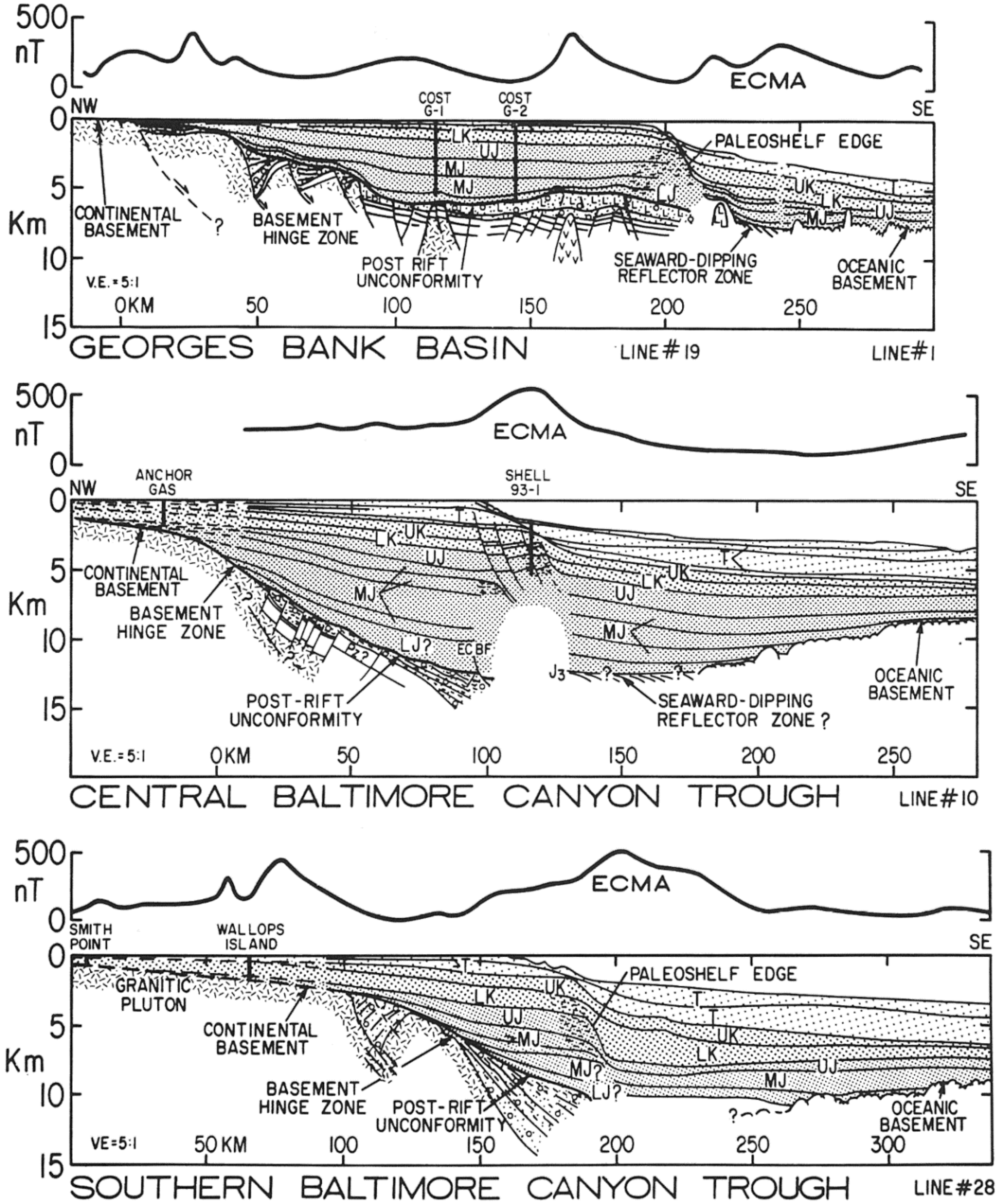
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 3.1-4



REGIONAL GEOLOGIC FEATURES
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 3.1-5



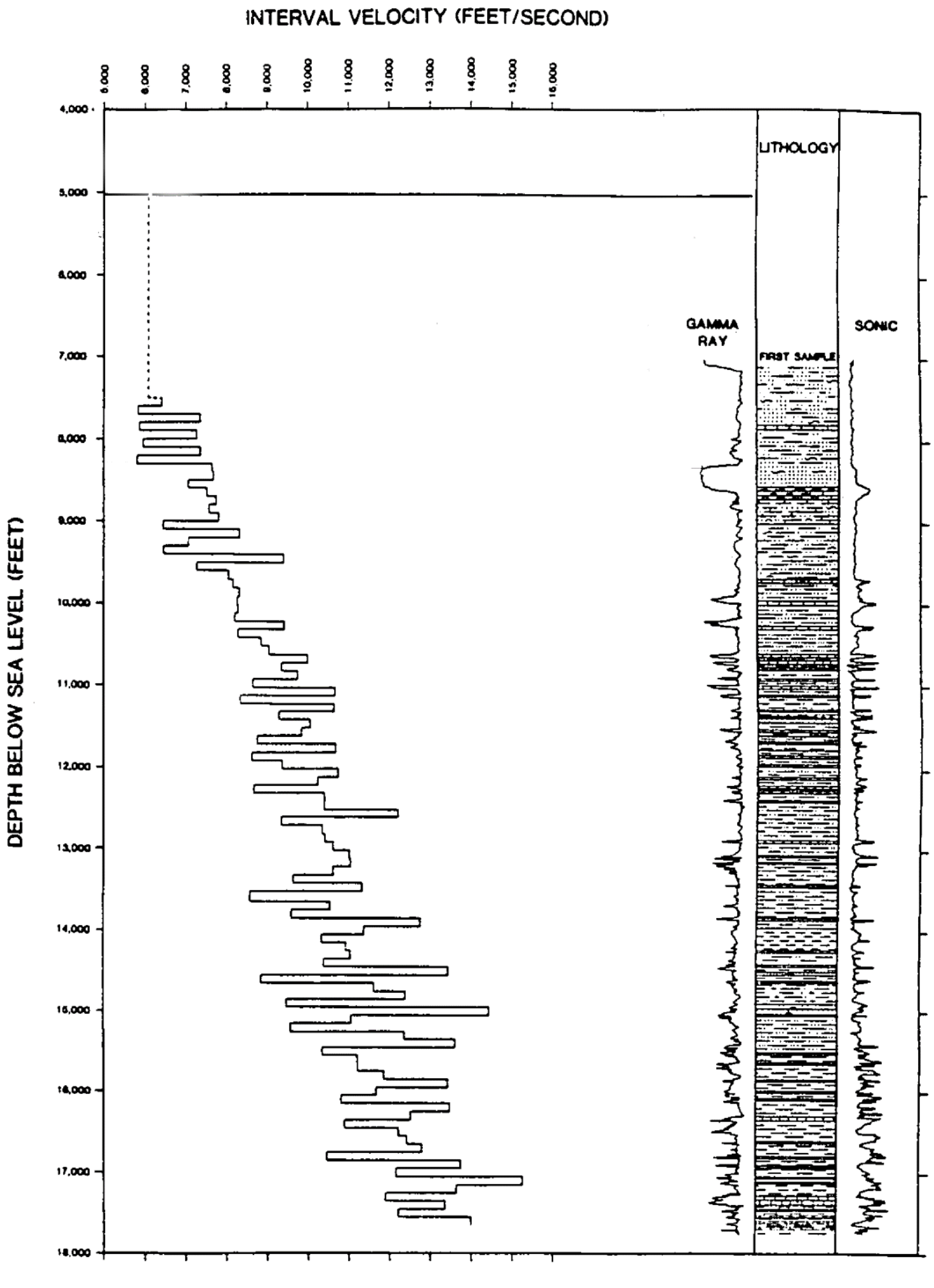
	LEGEND
Note: While USGS lines 19, 10 and 28 were the primary data source used to construct the cross sections above, interpretation of the subsurface was extended farther landward and/or seaward than each individual seismic line. For the Georges Bank Basin cross section, line 1 was used in conjunction with line 19 to lengthen the interpreted cross section to the southeast, well past the modern shelf break. From Klitgord et al. (1988) USGS lines shown on Figure 3.1-4	Tertiary (T) Upper Cretaceous (UK) Lower Cretaceous (LK) Upper Jurassic (UJ) Middle Jurassic (MJ) East Coast Magnetic Anomaly (ECMA)

GEOLOGIC INTERPRETATION OF USGS SEISMIC-REFLECTION PROFILES 19, 10, AND 28 ALONG U.S. ATLANTIC MARGIN

Oil and Gas Readiness Study

Offshore Virginia

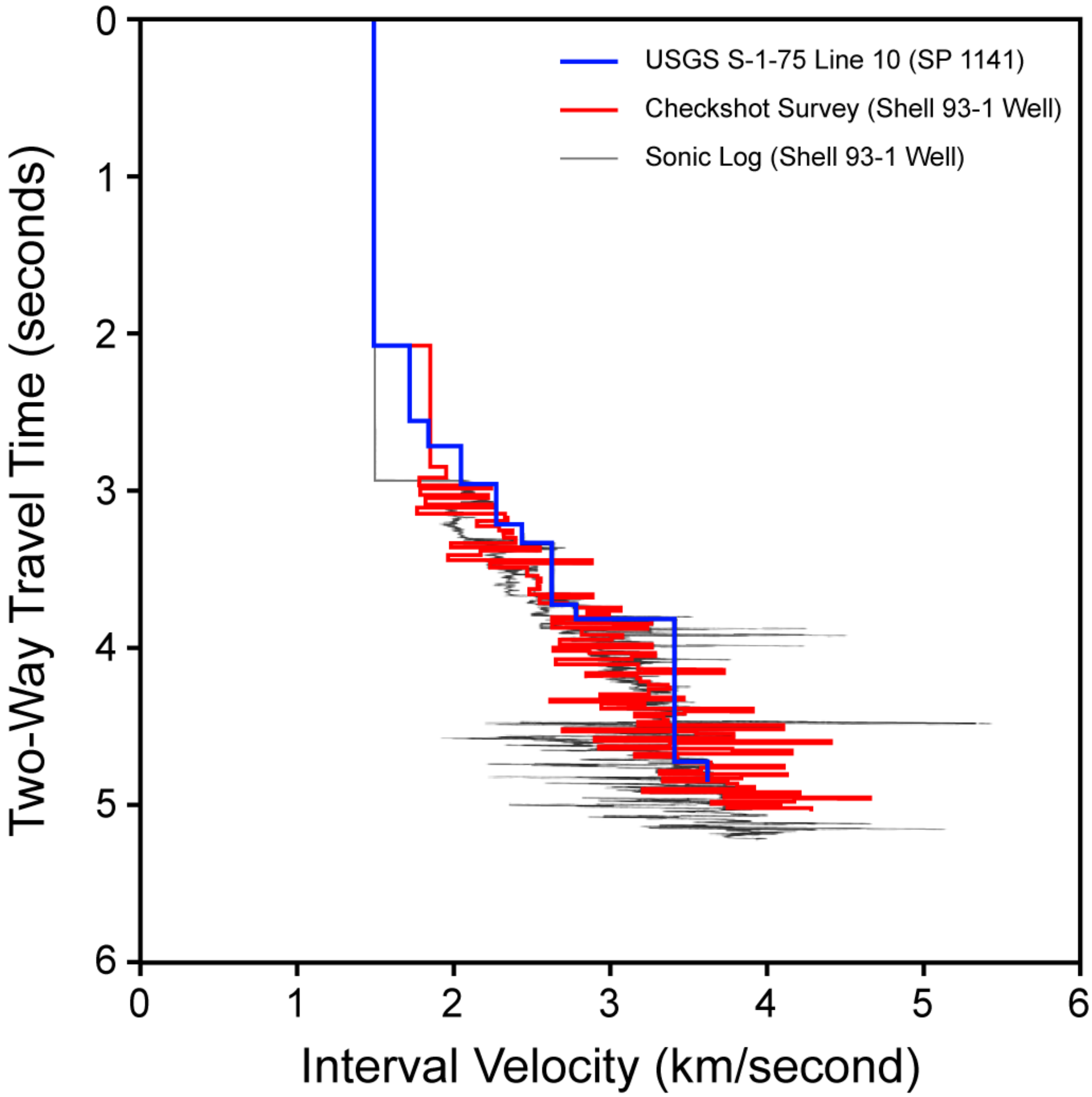
FIGURE 3.1-6



Note: The sonic curve shown above is an edited version of the digital sonic curve available from BOEM/BSEE's Data Center.

INTERVAL VELOCITY, WELL CURVES AND LITHOLOGIC PROFILE, SHELL 93-1 WELL (OFFSHORE MARYLAND)

Oil and Gas Readiness Study
Offshore Virginia



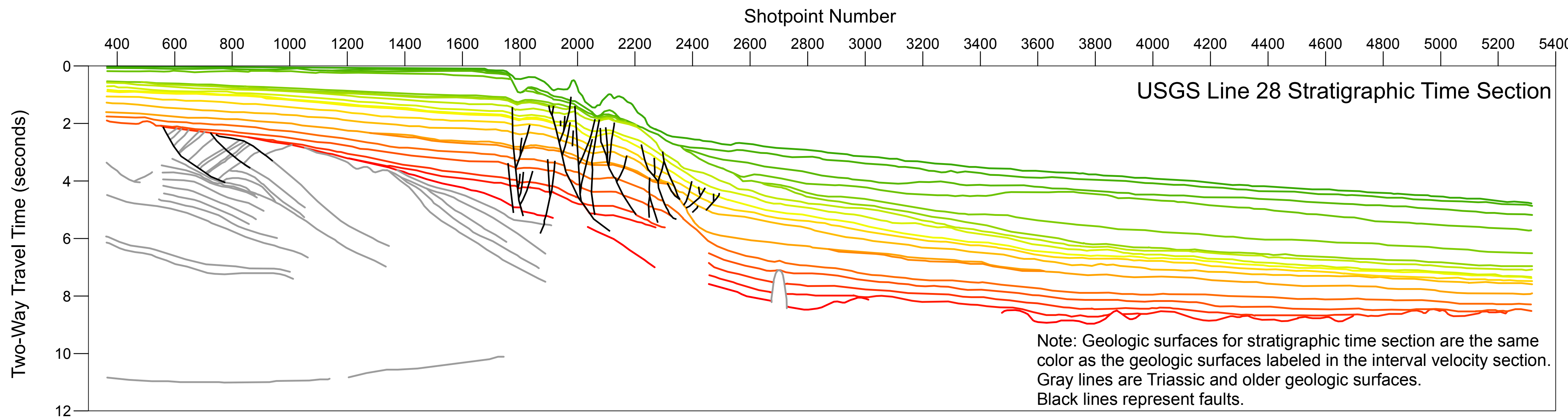
Modified after Klitgord and Schneider (1994)

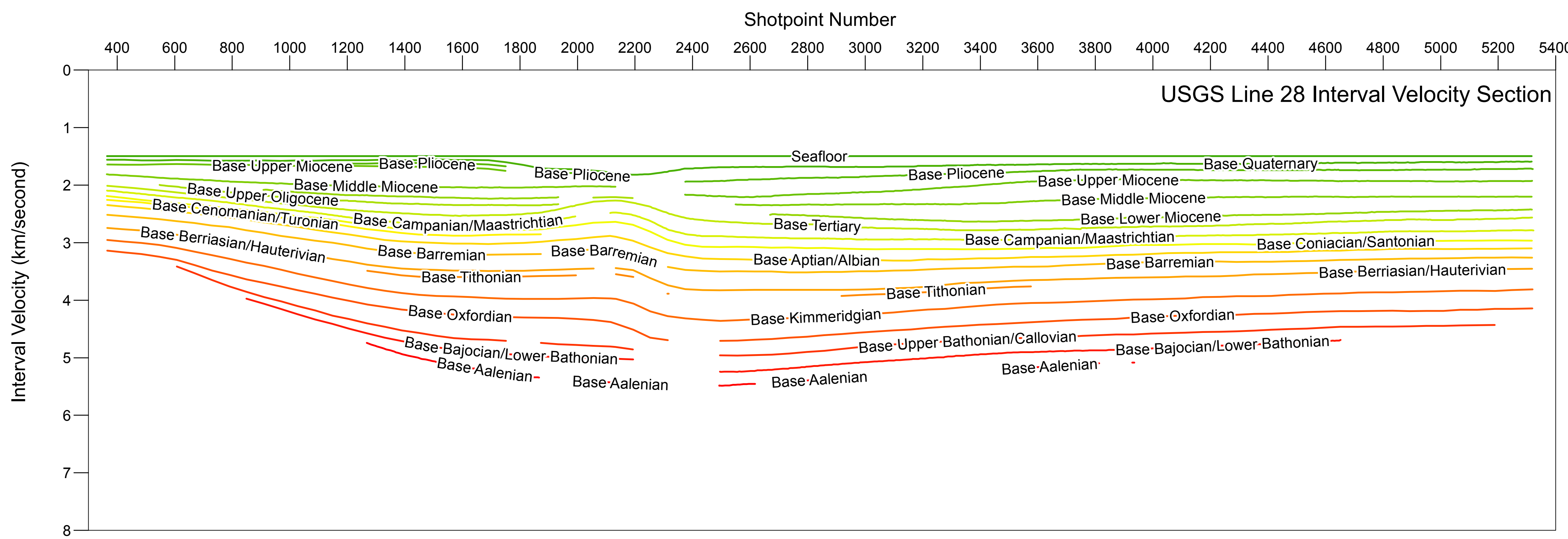
USGS Survey S-1-75, Line 10 shown on Figure 3.1-4 Index
Shell 93-1 well shown on Figure 3.1-4B

CHECKSHOT LOG AND SONIC LOG CURVE (SHELL 93-1), INTERVAL VELOCITIES FROM USGS SURVEY S-1-75, LINE 10

Oil and Gas Readiness Study

Offshore Virginia





Modified after Klitgord et al. (1994)

Location of USGS Line 28 shown on Figure 3.1-4

STRATIGRAPHIC TIME SECTION AND INTERVAL VELOCITY SECTION, USGS Survey C-1-78, Line 28
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 3.3-3

4.0 DATA GAP ANALYSIS

4.1 OVERVIEW OF DATA GAP ANALYSIS

Following the documentation of all existing and publicly available legacy MCS seismic datasets in Virginia and northern North Carolina waters, it was necessary to determine the usefulness of these data in future O&G exploration programs on the OCS. The large amount of seismic data available in the study area came as surprise to all members of the Fugro team and our colleague Dr. Mark Legg of Legg Geophysical. After numerous discussions on how to perform the data gap analysis portion of this study the Fugro/Legg Geophysical team decided to concentrate on three criteria that would best quantify the applicability and limitations of the legacy data for use in modern exploration.

The first criterion assessed was whether the existing data provided adequate coverage over the potential future OCS leasing areas. First, the line spacing between both dip lines (generally running perpendicular to the shoreline) and strike lines (tie lines, running parallel to the shoreline) for all surveys with a grid-like design were calculated. Using these calculations, each survey was then categorized as 1) regional if the typical line spacing was greater than 8 nautical miles (15 kilometers), 2) semi-regional if the typical line spacing was between 3 and 8 nautical miles (5 to 15 kilometers) or 3) exploration-scale if typical line spacing was less than 3 nautical miles (5 kilometers). Next, the density of seismic data coverage within the Mesozoic Norfolk basin (mapped by Bayer and Milici, 1987) on the inner continental shelf of Virginia and also within the four individual BOEM hydrocarbon plays found in the study area (BOEM, 2012a) were determined.

The ability/inability of the existing data to meet the imaging standards of a modern exploration program were analyzed as part of the second and third criteria. For the second criterion, deficiencies in seismic imaging as a result of each survey's field parameters (i.e., the equipment used during acquisition and the survey's geometry/design) were compared to modern standards. Finally, for the third criterion the availability of both unprocessed data, for potential reprocessing, and processed data types were analyzed along with measuring the vertical resolution of each seismic dataset as a function of the frequency content at depths where potential hydrocarbon reservoirs would likely be encountered.

4.1.1 Line/Grid Spacing

When exploring for O&G in a frontier basin, it is common for modern industry of today to first collect regionally-spaced 2-D seismic lines in order to initially analyze the basin's hydrocarbon potential. If interpretation of the regional (or semi-regional) seismic data indicates a favorable condition for hydrocarbon accumulation and extraction, seismic data will next be collected at the exploration scale with a much tighter line spacing, or as a continuous 3-D dataset. As indicated in Table 4.1-1, seismic acquisition during O&G exploration in the 1970's and 1980's followed a similar pattern. In order to assess the ability of industry to make use of the previously collected seismic data as part of an O&G exploration program, each survey's scope is classified as regional, semi-regional and exploration-scale based on the documented scientific objective and line spacing.

In 1973, the USGS began acquiring long, regional seismic lines to set up the regional framework of the Atlantic Margin by allowing onshore-offshore well correlation and providing insight into the large-scale structural and stratigraphic framework (see Section 3.1.5.2 for details). By 1978, the USGS had collected enough infill lines during multiple seismic programs to produce a regional grid of data extending from offshore Florida to Canada's Exclusive Economic Zone (EEZ). In 1979, the BGR 79 survey was acquired in cooperation with the USGS to further improve the existing offshore data density.

As mentioned in Dellagiarino et al., (2002), seismic exploration in the offshore Atlantic began in 1960. Since BOEM does not release data collected prior to 1975, it is difficult to know the nature and extent of the seismic data collected from 1960 to 1975 in the study area, however, it is safe to assume that this pre-1975 dataset would typically be inferior quality to the late 1970's to 1980's data. In 1975 and 1976, prior to the first Atlantic lease sale (Lease Sale 40), two seismic datasets with a semi-regional line spacing were collected by Western Geophysical in North and South Carolina (collected with plans to sell the data to interested O&G companies) and by Digicon with financing from the "Offshore Atlantic Group" in Virginia and Maryland. After the completion of the USGS/BGR surveys and these two semi-regional industry datasets, the acquisition of new seismic data for O&G exploration took on a more focused approach, commonly collecting lines in select areas based on the upcoming leasing schedule. It should be noted that the three permits (E01-81, E04-82 and E11-82) categorized as regional-scale in scope have an exploration-scale scope in areas away from the northern NC and VA study area. For permits E01-81 and E04-82, scanned seismic sections indicate there are numerous intersecting lines that were collected for these permits but are currently unavailable. Additionally, paper copies of lines for certain surveys (including permit E01-81) lack navigation files needed to project the data in their actual locations.

Classifying the line spacing for each survey helps to evaluate how a geologic reconnaissance interpretation study may best be approached. Typically, a first step in this interpretation would be to import the regionally-spaced USGS/BGR datasets into a seismic project on a workstation and incorporate horizons (in TWTT and in depth), faults and interval velocities from the existing USGS publications (i.e., Klitgord et al., 1994; Klitgord and Schneider, 1994) to set up an initial framework. Next, it would be important to interpret lines at semi-regional level by incorporating the semi-regional datasets along with a subset of the exploration size surveys. The final interpretation step would be to focus on identifying and mapping key horizons and faults over all lines that cover the area of interest. Likely, this would be done by first interpreting a single exploration scale survey with the best available coverage (such as E02-82 located along the shelf-slope transition) and then extending that interpretation over lines from other surveys extending across the targeted interval.

4.1.2 Analysis within BOEM Hydrocarbon Play Extents

Four potential hydrocarbon plays have been identified in the study area by BOEM (2012a and 2014b) and assessed for undiscovered potential hydrocarbon resources (Figure 4.1-1). Additionally, the Norfolk basin, located on Virginia's inner continental shelf, was the target of two seismic surveys in the 1980's and is of particular interest for future exploration due to its comparison with similar basins with exploration potential found both on and off shore along much of the East Coast. Since these four plays and the Norfolk basin are the most likely targets of future exploration efforts, and because they divide the offshore area into logical subareas, seismic data coverage within the polygons that define each play/basin have been studied as part of this data gap analysis.

The Norfolk basin was the focus of two seismic surveys, the 1982 survey collected by ARCO (Permit E11-82) and a portion of the 1988 survey collected by GECO for Texaco (Permit E03-88). Coverage within this basin is considered adequate, based on typical coverage for the timeframe, for initial exploration given that 44 lines were collected for permit E11-82 at a spacing of 2.2 by 2.7 nautical miles (4.0 by 5.0 kilometers) and the permit E03-88 further increased the data coverage in this basin. Of the four plays defined by BOEM, only the Late Jurassic-Early Cretaceous Carbonate Margin is covered nearly in its entirety by lines with tight spacing. In Virginia, 79 lines totaling 485 nautical miles (898 kilometers) were collected in the 390 square mile (1,010 square kilometer) area of this play.

Both the Jurassic Shelf Stratigraphic Play and the Cenozoic-Cretaceous and Jurassic Paleo-Slope Siliciclastic Core Play have only portions of their defining polygons covered by adequately spaced lines. In Virginia, 93 lines totaling approximately 717 nautical miles (1,328 kilometers) were collected in the Jurassic Shelf Stratigraphic Play, most collected in the area farthest from the shore near the Late Jurassic-Early Cretaceous Carbonate Margin. Seismic data coverage in the Cenozoic-Cretaceous and Jurassic Paleo-Slope Siliciclastic Core Play includes 78 lines totaling approximately 1,100 nautical miles (2,040 kilometers) in the Virginia OCS, with adequate exploration coverage existing only near the Late Jurassic-Early Cretaceous Carbonate Margin at the shallowest, most westward area of the play.

The Cenozoic-Cretaceous and Jurassic Paleo-Slope Siliciclastic Extension Play is the farthest offshore play located in the greatest water depths with seismic coverage over this area inadequate for even a semi-regional study. Only 16 seismic lines extend into this region of northern North Carolina and Virginia. For 7 of these lines, their overlap into this play is less than 4 nautical miles (7 kilometers). In the Virginia OCS only two lines (Line 3 of USGS survey S-1-73 and line 13 of USGS survey S-1-75) image this region. Therefore, no exploration is anticipated to begin in this area until further data is acquired.

Table 4.1-1 Seismic Line Spacing for Surveys Acquired in Virginia and Northern North Carolina Waters*

Permit or Survey	Specific OCS Area Tabulated[1]	Survey Scope[2]	Seismic Data Type Available	Number of Dip Lines	Typical Spacing Between Dip Lines	Number of Strike Lines	Typical Spacing Between Strike Lines
All four 1973-1978 USGS surveys in study area	Lines extending into VA and Northern NC waters	Regional	Demux & Stacked	6	22-27 nmi (40-50 km)	2	92 nmi (170 km)
E14-75	Cape Hatteras, NC to Northern SC	Semi-Regional	Stacked	25	5-11 nmi (10-20 km)	Variable, 3 to 7	5-11 nmi (10-20 km)
E16-76	Cape Hatteras, NC to MD	Semi-Regional	Stacked & Migrated	35	2-8 nmi (4-15 km)	6	5-14 nmi (10-25 km)
BGR 79	Lines extending into VA waters	Regional	Stacked & Migrated	0	NA	4	7-14 nmi (12-25 km)
E01-80	Currituck Sound Protraction	Exploration	Stacked & Migrated	16	1-2 nmi (2-3 km)	6	1-3 nmi (2-5 km)
	Manteo Protraction	Exploration	Stacked & Migrated	23	1-3 nmi (2-5 km)	7	1.5-2 nmi (3-4 km)
E02-80	Currituck Sound Protraction	Exploration	Stacked, Migrated & Depth	8	1-3 nmi (2-5 km)	2	4 nmi (7 km)
	Manteo Protraction	Exploration	Stack, Migrated & Depth	22	1-3 nmi (2-5 km)	2	5-11 nmi (10-20 km)
E01-81	Northern NC and VA	Regional	Stacked & Migrated	7	14 nmi (26 km)	2	10 nmi (18 km)
E07-81	Manteo Protraction	Exploration	Migrated & Depth	11	1.5-3 nmi (2.5-5 km)	1	NA
E02-82	Northern NC to Southern MD	Exploration	Stack, Migrated, Depth	104	1 nmi (1.5 km)	4	7 nmi (13 km)
E04-82	Northern NC and VA	Regional	Migrated & Depth	9	5-16 nmi (9-30 km)	0	NA
E11-82	Norfolk Basin, VA	Exploration	Migrated	33	1.5 nmi (2.5 km)	11	2 nmi (3 km)
	Northern NC to Southern MD	Regional	Migrated	5	14-34 nmi (25-63 km)	3	4-15 nmi (7-27 km)
E05-83	Northern NC slope	Exploration	Migrated & Depth	6	1-3 nmi (2-5 km)	0	NA
E03-88	Currituck Sound Protraction	Exploration	Migrated	8	3 nmi (5 km)	1	NA
	Norfolk Basin, VA	Exploration	Stacked	7	3 nmi (5 km)	1	NA

*Line spacing for surveys E06-79, E05-86 & VAEDGE 1990 were not calculated because tracklines are generally unevenly spaced and of a regional nature within the VA and northern NC OCS.

[1]Many of the surveys cover numerous areas of the Atlantic margin and since line spacing often changes within different regions of the same survey, we have calculated line spacing mainly within the study area in areas of consistent spacing between lines.

[2]Regional scale: Average line spacing greater than 8 nmi. Semi-regional scale: Average line spacing between 3 and 8 nmi. Exploration scale: Average line spacing less than 3 nmi.

4.2 CHARACTERIZATION OF EXISTING SEISMIC SURVEYS BY ACQUISITION PARAMETERS

With the rapid advances in technology during the last quarter of the 20th century, the field equipment used and vintage seismic survey's design are, perhaps, the most important details to consider when determining if data is of suitable quality to aid a modern exploration program. For example, it would be very difficult to interpret volumetrics of a reservoir 65 feet (20 meters) thick at 12 seconds Two-Way Travel Time (TWTT) with data that was acquired using a 1.2 mile (2 kilometers) long streamer and a small energy source, due to the lack of resolution and depth penetration. Using the field parameters listed on individual survey sheets in Appendix A (also compiled for comparison in Figure 4.2-1), each seismic survey has been characterized to focus on the details concerning 1) the navigation/positioning system used, 2) the seismic source (number of air guns and volume produced), 3) the source-receiver offset (the maximum offset, being a function of the streamer's length), 4) the depth of the source and receiver, and 5) the various other parameters (such as the hydrophone spacing, number of channels recorded and shotpoint interval) that effect the processed seismic section's fold and CDP spacing.

4.2.1 Navigation/Positioning

While maximizing the depth of penetration and improving the ability to resolve the details of the subsurface are often considered the most important aspects of seismic imaging, without the knowledge of the precise location where the data was acquired, the data is far less useful for properly performing CDP processing or interpretation. Many details concerning navigation for the legacy surveys are lacking for 13 of the 19 seismic surveys, containing only rudimentary information from lack of available field reports, except the USGS/Teledyne S-1-77 and the USGS (MMS)/Whitehall E06-79 surveys. In the 1970's and 1980's, marine seismic surveys often relied on integrating radio navigation systems, satellite navigation systems, Doppler-sonar 'dead-reckoning' and gyrocompasses to provide positioning of the vessel, the seismic source and the streamer in the marine environment. Radio navigation systems such as Loran-C and ARGO relied on receiving radio signals transmitted from one or more land-based stations with the accuracy of the system being a function of the frequency of the transmitted signal, the distance traveled and the correct measurement of the survey angles. For example, the Loran-C system operated at low frequencies on the order of 100 kHz which allowed a range of 1000 kilometers and 500 meter accuracy, while the Argo system utilized a medium-frequency of 2 MHz which provided more accurate positioning but with a limited range of 100 kilometers or less.

Transit satellite positioning, provided by the U.S. Navy, on the other hand used a small number (4 to 6) of low altitude (1075 km) satellites with polar orbits to determine the ship's location. Each satellite transmitted its location every two minutes using 150 and 400 MHz frequencies which are Doppler-shifted when received on the moving vessel, due to the relative motion of the satellite with respect to the ship (Sheriff and Geldart, 1999). The number of satellites, the length of time to orbit the Earth and the time the satellites were within the sight of the vessel allowed for satellite fixes (with accuracy of +/- 50 meters) to be determined approximately every 60 to 90 minutes if the ship's velocity was accurately known. One disadvantage of using transit satellite positioning is that it only provides accurate positioning at the time of the satellite fixes and therefore other systems had to be integrated with the SatNav system in order to provide continuous positioning during the long intervals between transitions when satellite positioning was not available (Sheriff and Geldart, 1999).

Both the USGS/Teledyne S-1-77 survey and the USGS (MMS)/Whitehall E06-79 survey made use of multiple marine positioning systems. The fully integrated navigation system, as based on survey notes, used aboard the M/V Coral Seal for the S-1-77 survey consisted of a Magnavox MX 702hp receiver, a Hewlett-Packard 2100A computer, an Edo Model 435E Doppler Sonar, a Sperry Mark 227 Gyrocompass, a Micrologic ML-200 Loran-C receiver and a Houston Omnigraphic track plotter. The Magnavox Navigation System was used to obtain satellite fixes utilizing U.S. Navy Transit satellites. Between these fixes, the gyrocompass provided the ship's heading and both the Doppler-Sonar and Loran-C were used to determine the ship's velocity. The Edo Model 435E Doppler Sonar provided accurate velocities in water depths of less than 300 meters, but in deep water the scatter of the sonar beams and heterogeneity in the water column dominated so that the Doppler Shift gave a measure of the velocity with respect to the water rather than to the ocean floor. Therefore, the Loran-C system became the primary sensor of the ship's velocity in water depths greater than 300 meters. Cable drift for the S-1-77 survey was monitored by a radar reflector and was typically held to 15 degrees, except in the Gulf Stream (possibly due to rough seas making it difficult to distinguish the tail buoy reflection from water-wave backscatter).

The USGS (MMS)/Whitehall E06-79 survey used a similar integrated system to the S-1-77 survey, incorporating a Magnavox Model MX-702A satellite receiver, a Magnavox MX-601 S Doppler Sonar system, an Arma Brown MD-X-201 gyrocompass and a Loran-C integrated system. The USGS (MMS)/Whitehall E06-79 survey made use of water break detectors to measure the channel wave, which determined the streamer's distance from the acoustic source. The USGS/Digicon S-1-75 survey used Satellite Navigation and Loran-C for positioning, and a combination of satellite navigation and sonar for cable positioning (Wise and Oliver, 1989). Both the South Atlantic Group E01-80 and Exxon E01-81 surveys, acquired by Geosource, made use of Argo radio navigation and the E01-80 used Loran-C for auxiliary surveying. During the 1990 VAEDGE seismic survey, the STARFIX navigation system aboard the M/V GECO SEARCHER was used to determine 'true' positions and had no Loran system on board (Purdy and Holbrook, 1990).

The first use of a GPS receiver for marine navigation did not occur until the mid-1980s, and it was not until 1993 that a full constellation (i.e., 24 satellite) Global Positioning System (GPS) providing 24-hour coverage in North American waters became available to the seismic industry. While it is possible that developing GPS systems were used for the 1986 and 1988 seismic surveys (permits E05-86 and E03-88) described in this report, there is no documentation of the navigation systems employed. Only the VAEDGE/GECO 1990 survey is known to have utilized the first privately developed satellite positioning system, the STARFIX system of John E. Chance & Associates (now a Fugro company), which in 1990 provided continuous coverage along the Atlantic coastline, precision to about 5 meters and positional accuracy comparable to that obtained using the GPS systems available in 1990. The STARFIX system employed two onshore tracking stations to transmit GPS correction signals to multiple geostationary communications satellites, which, in turn would respond by sending signals back to vessel receivers. The measured phase differences provided pseudo-ranges which were relayed to users through communication links on the satellites.

Today's seismic surveys utilize GPS, Differential Global Positioning System (DGPS), Inertial Navigation Systems (INS), etc. to provide sub-meter accuracy for the seismic vessel and the towed streamer(s) and air gun array(s). Accurate positioning is a prerequisite for processing 3D seismic data.

4.2.2 Source Type and Energy

The seismic source is often considered the most important factor to consider in seismic surveying, due to the fact that the frequency content of the source controls the resolution of the seismic image. Additionally, the seismic source controls the depth of penetration. It is critical to produce a powerful acoustic signal where enough energy is retained to be recorded by near-surface hydrophones after the seismic wave has traveled to, and reflected back from, a layer with a thick sedimentary overburden. Of the various types of seismic sources that have been utilized in the history of marine surveying, only air guns and the Aquapulse system were utilized in the legacy surveys described in this report. The Aquapulse system, utilized only for the Western Geophysical E14-75 permit and rarely used in modern seismic surveying, is a sleeve exploder and was designed to avoid the bubble effect which is described in the next paragraph. This system used the explosion of a propane-oxygen mixture in a closed flexible chamber (with the waste gases venting to the atmosphere) to create the acoustic source (Sheriff and Geldart, 1999).

Air guns are the most commonly used energy source in both legacy and modern marine O&G exploration that, depending on the chamber volume used, can produce a wide range of signals with variable energy and frequency output. High-pressure air is discharged from the chamber into the water and reverberations are produced as the air bubble expands and contracts. Each oscillation produces a new pulse that obscures the primary pulse. To remove the unwanted bubble pulse oscillations, an array of air guns (i.e., groups of air guns with different chamber volumes) are frequently used to cancel out the different frequencies of bubble-pulse oscillations. This is done through destructive interference to create a more impulsive initial source pulse with a broad-band or "white" spectrum. Arrays also provide directivity in the source to avoid generating significant horizontal-propagation of coherent noise (e.g., direct wave energy and backscatter). Geophysical contractors frequently design unique air gun array configurations to improve the source's signature (impulse), the directivity of the source, and the ability to image the deep subsurface. Tuned air gun arrays were expanded into areal or wide source arrays that better focus the acoustic energy downward and reduce the potential for side-swipe and backscatter. The use of areal source and receiver arrays were a prelude to full-scale 3D seismic data acquisition which was enabled by the major technology advances of the 1980s.

Each legacy seismic survey's source volume (measured in cubic inches) has been divided into four categories: 1) less than 2200 cubic inches, 2) between 2200 and 5000 cubic inches, 3) greater than 5000 cubic inches and 4) unknown volume or Aquapulse system (Figure 4.2-2). In general, there was an increase in the source volume utilized for the legacy seismic surveys with time. All surveys with volumes of less than 2200 cubic inches were collected in the 1970's, with the exception of the three lines collected by Teledyne Exploration in 1986 for Spectrum/Texaco under permit E05-86, which utilize the smallest source volume of all surveys described in this report (see the survey description in Section 3.1.5 for more details). Surveys collected between 1980 and 1982 used larger source volumes, between 2220 and 3060 cubic inches, although the ARCO E11-82 survey used a source volume of 5600 cubic inches. Only the three surveys utilized sources with volumes greater than 5000 cubic inches (Permit E11-82, Permit E03-88 and the VAEDGE 1990 survey). These would be comparable to typical modern marine surveys conducted today, but whether air gun array designs and configurations are outdated compared to modern surveys is not determinable given the lack of detailed design of these legacy air guns.

In order to perform a more detailed analysis of the acoustic source generated for each survey, it would be necessary to know proprietary details of the array design, far-field signatures peak to trough amplitude, primary to bubble ratio (P/B), and the frequency spectrum. Digicon surveys S-1-73 and E16-76 provide the cubic volume of each gun in the array, as does the Teledyne S-1-77 survey, but other than the detailed information found in the USGS/Whitehall E06-79 survey, and described in the following paragraph, no other information is available. For Exxon's E01-81 survey the pulse-to-bubble ratio was provided as "PB=93", but a 93% P/B is unlikely, and further, this information is listed with the streamer information and not with the specifications of the air gun array.

The details provided in the Field Operations Report for the E06-79 survey (available from NOAA's NGDC) include specifications of a 21-air gun array (SEISARRAY) with a total gross volume of 2183 cubic inches. The array was designed to optimize the maximum output while maintaining the best P/B. For the SEISARRAY, a tuned array was created utilizing 3 sub-arrays each with 7 air guns of different volumes. The 21 guns were towed in two parallel strings so that the array was spread over an area roughly 65 feet by 75 to 100 feet providing an enhancement of vertical signal and cancellation of horizontal waves. The measured far-field waveform had a measured peak-to-peak pressure of 56 bar-meters with a suppression ratio of 8.5 for P/B. This information has been provided, not only to offer an example of what information is needed for a true evaluation of the acoustic source, but also to provide one example of an air gun array utilized in the late 1970's.

4.2.3 Streamer Configuration (Offset)

The horizontal distance from the energy source center (or center of the source array) to the center of the recording hydrophone group is termed offset. Seismic wave energy reflected from the seafloor and subsurface geological features are recorded at times equal to the distance from the energy source to the seafloor and back again, divided by the average seismic velocity (two-way travel time). The reflection time varies with distance from the energy source to the hydrophone group due to the length of the raypath being slightly different for each adjacent group. When reflections are assumed to be at normal-incidence and perpendicular to the reflecting interface and the differential travel time, this is called the normal moveout (NMO). The NMO provides a measure of the seismic velocity to the reflecting interface, which is needed to determine the depth of the reflection point. In the CDP method of seismic data processing, NMO is one of the most important parameters used to enhance the signal, attenuate noise, and provide velocity information for time-to-depth conversion of the processed seismic profile. The far trace offset (each group records a seismic trace) must be large enough to provide good velocity control (measurable NMO) for the reflecting horizons at the target depths.

During the 1970's and 1980's, the limiting factor in imaging deep targets was often a function of the length of the streamer, which influences the far offset. A rule-of-thumb for seismic acquisition is that the maximum offset should be about the same value as the depth to the target reflection interface (horizon). Modern streamers are typically six to twelve kilometers long whereas the streamers used in the 1970's and 1980's were generally around three kilometers long (Figure 4.2-3). Therefore, targets more than three to four kilometers below the sea surface would not have been adequately imaged using the shorter streamers used during vintage surveys.

The near trace offset must be close enough to the source array to obtain good recordings of the seafloor and shallow geology beneath the shotpoint, but far enough away to avoid severe source-generated noise – the direct wave of acoustic energy that travels horizontally along the streamer. Coherent noise, noise that is repetitious and may be enhanced in the data stacking process, is usually source-generated and more severe in shallow water due to acoustic energy trapped (waveguide effect) between the seafloor and the near-perfect reflection interface between the water and air at the surface. For exploration seismology, where hydrocarbon plays are relatively deep beneath the seafloor, the near trace offset is usually greater than the water depth in shallow water. Adjusting seismic traces to correct for the NMO before CDP stacking, causes shallow seafloor and subsurface reflections to be stretched in time – these reflections are usually muted (zeroed) because the exploration geophysicist/geologist usually does not analyze the near surface stratigraphy. However, other effects from the trapped coherent noise in shallow water can cause issues that must be addressed in the seismic data processing to avoid obscuring the deeper geological information.

4.2.4 CDP Spacing and Fold

The three significant parameters to consider for reprocessing vintage data are shotpoint spacing, the group interval and number of channels, which determine the spacing of subsurface image points (CDPs) and fold (Figure 4.2-4) used for the CDP stacking process.

4.2.4.1 Shotpoint Spacing

Acquisition of marine seismic reflection data can be expensive considering costs to mobilize and maintain the ship, equipment, and crew needed for operation. However, continuous seismic reflection profiling, where many long seismic profiles can be acquired relatively quickly and efficiently, provides a more cost-effective technique compared to land acquisition. In addition, with both source and receiver arrays embedded within the subsurface (water), marine seismic reflection data tends to provide superior subsurface images compared to land based data for lower overall costs. The time spent at sea is a critical factor in estimating costs along with the number of shotpoints produced. Fewer shot records require less media storage and reduces processing costs, while sacrificing subsurface image quality. Shot spacing is designed to be consistent with the receiver spacing to provide relatively uniform subsurface sampling according to the principles of the common-depth-point (CDP), or common-mid-point (CMP) method.

Due to relatively high cost and recording limitations, shot spacings were typically 328 feet (100 meters) or 164 feet (50 meters) in the 1970s and 1980s. Shot spacing was also limited by the ship's speed and desired record length for continuous reflection profiling. At a typical speed of 4 knots which was required to maintain steerage and streamer stability, a ship travels 82 feet (25 meters) in only 12 seconds. For all surveys described in this report with recording lengths greater than 12 seconds, the shot spacings were 50 meters or more. The time required in digitizing and recording the data to tape also limited the record length by several seconds depending on the specifics of the acquisition system used. Additionally, air guns needed sufficient time for recharging the high-pressure air in the chamber. In modern seismic surveying, digital streamer technology, increased channel capacity, and increased recording capabilities can achieve higher resolution images utilizing shorter shotpoint intervals or spacing.

4.2.4.2 Group Interval

A streamer consists of a flexible hose filled with hydrophones, flotation, and other electrical components. A group of individual hydrophones are wired together to record the acoustic wave energy along sections of the streamer at specific intervals, known as the group interval. This array of hydrophones acts as a spatial filter for the acoustic waves, so that vertical wave energy is enhanced by constructive interference and horizontal energy is attenuated by destructive interference. The temporal frequency spectrum is affected by this array and the bandwidth of frequencies “passed” depends on the number of hydrophones in the group, distance between hydrophones, and the speed of sound in water. Some source-generated coherent noise is attenuated by the hydrophone array, while the reflected seismic energy is enhanced by the summation of the multiple hydrophone recordings. However, the hydrophone array may also attenuate important reflected signal energy coming from angles away (off line) from the vertical. As technology improved, exploration seismologists realized that shorter groups in large numbers provided better flexibility in improving the subsurface image through data processing including pre-stack migration and more precise design of arrays to attenuate coherent noise.

Typical group intervals for 1970s to mid-1980s streamers were most frequently “linear” with uniform spacing of 338 feet (100 meters) and later, 164 feet (50 meters). Hybrid setups that included the first streamer sections with the longer interval and shorter groups at the end, were used to provide closer trace spacing at far offsets where the moveout of reflected (and refracted) seismic energy was most vulnerable to spatial aliasing (see Appendix C). With the development of digital streamer technology, shorter group intervals became standard. It is important to note that most streamers are designed with sections and group spacing measured in binary metric increments of 12.5 meters (41 feet) such as 25, 37.5, 50 and 100 meters (82, 123, 164 and 338 feet). Shorter group intervals provide shorter CDP spacing and higher fold for higher resolution data processing and an increase in the signal-to-noise ratio (Figure 4.2-4).

4.2.4.3 Number of Channels

The cost for data acquisition and processing is always a critical factor in the survey design, especially during economic recessions like the downturn in the oil industry that occurred during the mid-1980’s. Coincidentally, most of the available seismic data collected in the Virginia and northern North Carolina OCS were acquired in the 1970’s and 1980’s when major advances in technology enabled significant improvement in seismic imaging. Perhaps the most significant advance was due to the exponential increase of computational capability provided by digital microprocessor evolution. Texas Instruments (TI) developed the first integrated circuit-based Digital Field System (DFS) in 1966. TI’s various recording systems, the Western Geophysical DDS-COBA and Geosource’s MDS systems dominated the seismic industry for over a decade (Figure 4.2-1). TI’s DFS III was the first binary gain ranging system and its successor, the DFS IV, was the first system to use Instantaneous Floating Point (IFP) gain control for more accurate recordings. The DFS V, developed in 1975 (the same year that GSI/TI processed the first 3-D seismic survey), incorporated CMOS (Complementary Metal-Oxide-Semiconductor) technology and was utilized in at least seven of the seismic surveys described in this report. With each advance in recording system technology, the accuracy of data recording improved along with an increase in the amount of data that could be recorded. Typically, 24 or 48 channels (hydrophone groups) were used for vintage data of the 1970s to mid-1980s while 96-channel streamers became available in the mid-1980s (Figure 4.2-1).

Advances in recording technology enabled the development of digital hydrophone streamers and 24-bit recording technology resulting in a movement from single streamers, with less than 100-channel recording, to multiple streamers, with hundreds to thousands of recording channels, and the development of cost-effective 3-D seismic data acquisition. Furthermore, digital hydrophone streamers reduced electrical noise in the recording system by moving the digitization into the streamer and removing the analog wiring that was subject to several types of electromagnetic interference. The recording systems used in the legacy seismic surveys performed the analog-to-digital (A/D) conversion for an analog streamer. Modern day digital streamers have the A/D conversion built into the streamer.

4.2.5 Source and Receiver Depth

The reflection of the acoustic source impulse from the water surface interacts with the down-going source waveform to produce a “ghost” notch in the frequency spectrum from destructive interference. The frequency (and harmonics) associated with this notch are directly related to the depth of both the source and streamer receiver arrays. These arrays are typically towed at 15-50 feet (5-15 meters) below the water surface to reduce noise from ocean waves (breaking white-caps and sea state). The hydrophone streamer is maintained at a relatively constant depth by using “birds” – streamlined devices with fins that can be independently adjusted to raise or lower the streamer section as needed. The depth for source and receiver arrays is selected based on the target depth of penetration. Deeper tow depths result in a lower frequency ghost notch and narrower bandwidth, but are suitable for deep targets. Final imaging requires at least two octaves of bandwidth to provide a well-shaped seismic waveform (wavelet). The tow depths must be balanced with other acquisition parameters to provide the desired frequency bandwidth. Deeper tow depths allow the receivers to be below the orbital particle motion produced by ocean surface gravity waves, which diminish exponentially with depth for typical swell and sea conditions. New methods of using a “slant” cable, with varying depth along the length of the streamer, helps increase the bandwidth by creating “ghost” notches over a wider range evening out the spectrum.

4.3 THE QUALITY OF THE SEISMIC IMAGE: DATA PROCESSING AND THE IMPACT ON DATA RESOLUTION AND THE SIGNAL-TO-NOISE RATIO

4.3.1 Data Quality as a Function of Seismic Processing Techniques

Years of seismic data processing experience are not always required to analyze the seismic sections of the surveys found in Appendix B and find the obvious deficiencies in the various datasets. Multiples, diffractions, incoherent noise, reflections originating from out of plane, poor signal penetration, and low data resolution are only a few of the more common phenomena that are noticeable on seismic sections which limit the ability to properly analyze the subsurface. A seismic interpreter can attempt to improve the ability to interpret the data by changing the displayed color, applying amplitude gains and filters to remove unwanted “noise” for hours only to realize that the seismic image they were hoping for is simply not there.

Typically, an optimal strategy needs to be developed for selection of data and procedures to reprocess legacy seismic data. In general, more advanced acquisition and processing techniques were utilized in the more recently acquired seismic surveys and modern methods of processing, may not provide much improvement over the original seismic images. In many of the datasets reviewed, only the stacked seismic data are available in digital format, so a simple reprocessing effort of post-stack migration may be sufficient to provide subsurface images of suitable quality for confident interpretation of the subsurface geology and identification of potential shallow exploration targets. Older data may be limited in the number of recording channels and density of shot coverage, but still can be of high quality and may benefit from advanced procedures and technology available for reprocessing.

In order to analyze how well the subsurface is imaged, or qualitatively assess the signal-to-noise ratio, the frequency content of the available seismic data has been determined to identify the ability to vertically resolve a reservoir at a specific depth. The type(s) of data available for each seismic line has also been determined so future efforts to reprocess or interpret the data will be streamlined. In Appendix C, several additional relevant aspects of data processing are presented.

4.3.2 Type of Data Available

The types of legacy data available (i.e., unprocessed data, stacked sections, migrated sections and/or depth sections) within the OCS study area influences whether expeditious quality interpretation can be completed within a prospecting leasing area or if reinterpretation will be delayed while the data goes through additional processing steps to make it suitable for analysis. One job of the petroleum geoscientist is to provide the reservoir engineer with the likely size and depth of a potential exploration target in order to determine whether the target could be of interest, economically speaking. In order to do this, the seismic interpreter would either interpret and map stratigraphic horizons using depth sections, or utilize migrated sections that would eventually be converted to depth using a velocity model. Stacked sections would be of limited value since faults would not be projected in their true location and diffraction patterns would make interpreting horizons difficult.

Depth sections are available for approximately 45% of the seismic lines within the study area for five of the surveys analyzed in this report (Figure 4.3-1). Approximately 15% of the depth sections are available only as scanned paper copies, including line 801 of the VAEDGE survey, line 18066 of permit E04-82, 8 lines from permit E05-83 and 22 lines of permit E02-80. If the lines with only scanned depth sections were converted to SEG-Y format, the area covering the transition from the shelf to slope would be, for the most part, adequately covered and ready for interpretation. However, most of the data located nearest to shoreline, such as permit E11-82 which covers the Norfolk basin, lack depth sections. None of the USGS lines include depth sections, therefore, accurate mapping in depth would not be possible in the far offshore OCS. The data located landward of where the depth sections are tightly spaced is unlikely to be of use for future leasing due to the activities of the military, commercial vessel navigation routes and environmental issues as indicated by the 50 mile coastal buffer defined by BOEM (BOEM, 2015b). In order to convert the USGS lines to depth, it would simply require digitizing the interval velocities of Klitgord et al. (1994) and applying the resulting velocity model to the lines of interest, allowing the far offshore to be mapped in depth. Although the USGS lines would be converted to depth sections, the method employed by Klitgord et al. (1994), which relies mainly on the Dix equation and converting stacking velocities to interval velocities, has limitations providing only good approximations to the true interval velocities where there is relatively uniform, flat-lying stratigraphy. Additionally, one of the many limitations in using the depth sections to map the subsurface would come from horizon mis-ties that result from differences in the velocity models used for depth conversion and between methods employed in the conversion process (i.e., applying a velocity model to stacked sections, simple stretching migrated sections, or by depth-migration).

Migrated sections and stacked sections are available for approximately 90% and 75%, respectively, for all lines covering the OCS study area (Figure 4.3-2 and 4.3-3, respectfully). The only surveys lacking migrated sections are those collected by the USGS and five lines within the study area by Western Geophysical in 1975 (Permit E14-75). Additionally, the portion of data from permit E03-88 collected in the Norfolk basin is not available as migrated sections. The 2017-2022 leasing program is likely to exclude the Norfolk basin, the area covered by permit E14-75, due to the 50-mile coastal buffer limit, so these will likely only be of value in setting up a regional framework for the area (BOEM, 2015b).

The only datasets available in unprocessed, demultiplexed (DEMUX) formats are the eight lines collected by the USGS from 1973 to 1978 (Figure 4.3-4). Only these lines are available to the public for full reprocessing and therefore a detailed analysis of reprocessing line 28 of USGS survey C-1-78 is presented in the “Reprocessing of Legacy Data” section of this report (Section 5.2). Additionally, in Section 5.2 we discuss the possible benefits of migrating the available stacked sections and other possible routes to improve the quality of the seismic data.

4.3.3 Vertical Resolution

4.3.3.1 Method to Determine Vertical Resolution of Vintage Seismic Data

As part of the data gap phase of this study, it was necessary to define a consistent and reproducible methodology to analyze the vertical resolution of the various seismic datasets collected offshore Virginia and in northern North Carolina waters. The imaging of hydrocarbon reservoirs using seismic data is a function of the underlying geology, the survey’s field parameters (e.g. the seismic source, survey geometry, and the method used in analog-digital conversion) and the processing steps applied to the data. One way to define the adequacy of a seismic dataset’s ability to define individual hydrocarbon-bearing units is to determine the minimum thickness vertically resolvable by the seismic data, known as the tuning thickness. When a reservoir is below the tuning thickness, the top and base of the reservoir cannot be resolved using the seismic data and, therefore, the thickness of the reservoir remains unknown and no reservoir volumetric analysis can be calculated to figure out the economic feasibility of the prospect. The tuning thickness is a function of the frequency content (f) of the seismic dataset and the compressional velocity (Vp) of the interval of interest, often defined as equaling a quarter of the wavelength (where wavelength, $\lambda = Vp/f$). Determining the frequency content of the seismic dataset is typically accomplished by producing a frequency spectrum over the desired interval of interest. The p-wave velocity, measured by the methods outlined in Section 3.3, is then divided by the dominant frequency (or range of frequencies) to determine the wavelength (λ) which is then in turn divided by four to give the tuning thickness.

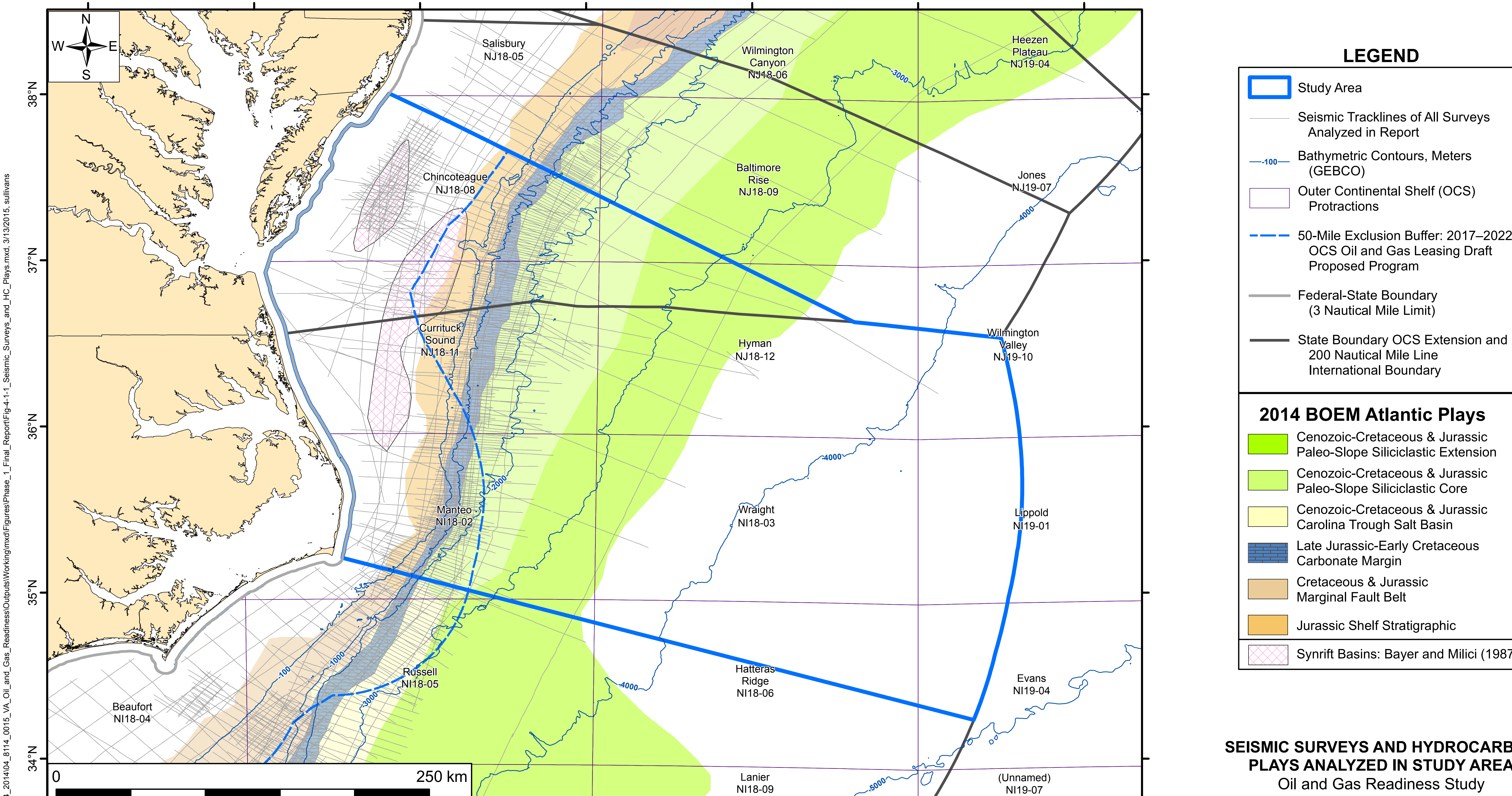
While the frequency of the seismic data can be easily calculated using the available SEG-Y data, a much lengthier analysis is required to determine the zone of potential hydrocarbon-bearing strata and its associated interval velocity. Given the nature of this project, which is not to interpret the seismic data but rather determine the ability to use it for future O&G assessments, the existing hydrocarbon plays defined by BOEM (2014b) and the geophysical analysis of Klitgord and Schneider (1994) and Klitgord et al., (1994) were used to determine the two-way travel time, interval velocities, and calculated depth of potential hydrocarbon-bearing units. The methodology used to incorporate the results of the three publications mentioned above with the SEG-Y data analyzed in this study follows the steps described below.

1) An ArcGIS polygon shape file of the most recent Atlantic hydrocarbon plays was downloaded from BOEM's website and geospatially projected into the proper coordinate system for analysis (i.e., WGS 1984, UTM Zone 18N).
2) The top and base of the four geo-chronologically-defined hydrocarbon plays that exist in the study area (Figure 4.1-1) were then correlated to the corresponding geologic surfaces (and their associated seismic reflectors) defined by Klitgord and Schneider (1994) and Klitgord et al., (1994).
3) Four structure maps (i.e., subsurface elevation maps relative to sea level) created by Klitgord et al., (1994) and corresponding to the top or base of the four BOEM plays were spatially projected using ArcGIS and the depths of the target intervals within the individual plays were determined.
4) For each play we selected a representative USGS seismic line used by Klitgord et al., (1994) that crossed the play's boundaries and was close to other seismic lines from the various seismic surveys analyzed in this study.
5) Using the representative USGS line, we then determined approximate shotpoint locations where the line crossed the geologic play in order to define the extent of the play on the time sections and the corresponding interval velocities from Klitgord et al., (1994). This provided us with the two-way travel time of the top and base surfaces and the range of velocities throughout the interval.
6) We then selected nearby lines from the other surveys analyzed in this report which were near the USGS line and determined the shotpoint and/or CDP locations corresponding to where the various lines crossed the play's boundary.
7) Next, we opened the SEG-Y files of the seismic lines that were within the play and determined the range of frequencies over a one second time-interval within the play and covering at least 100 traces.
8) Using the frequency content of the individual lines, we next determined the tuning thickness using the interval velocities from Klitgord et al. (1994) in order to characterize resolution limits with each seismic dataset.

4.3.3.2 Frequency analysis results

As a preliminary word of caution, it should be mentioned that it is often unknown whether the SEG-Y files of the seismic lines analyzed came directly from the original processed digital files or whether paper copies of the seismic data were scanned, digitized and exported in SEG-Y format. When inquiring whether BOEM had access to seismic data from the 1979 BGR survey, a BOEM representative mentioned the data had been converted from paper copies to SEG-Y format and migrated by an outside contractor. This conversion is noticeable in the SEG-Y files, as horizontal amplitude changes streak across the entire section in equally spaced intervals which correspond to the time lines of the paper copies. Other possible seismic surveys with lines that contain similar digitization artifacts are S-1-73, E01-80, E07-81, E04-82 and E05-83. It is important to understand this conversion method can potentially negatively influence the analysis of the data's frequency content. While digitization companies presently advertise that the dynamic range of the data is maintained (and the effect of time lines can be removed) when vectorizing the traces, there is potential for the digitization process to influence the frequency content of the data if the right methodology is not carefully employed throughout the process.

The dominant frequency of all seismic lines analyzed ranges from 8 to 24 Hertz within geological plays in the Virginia OCS. Typically, if an interval velocity of 4 km/second was applied to calculate the vertical resolution using the minimum and maximum frequencies mentioned above, the corresponding tuning thickness would be 56 to 102 meters. While the range of dominant frequencies may not seem overly variable, the ability to determine whether a reservoir is 196 or 328 feet (60 or 100 m) thick will impact the economic risk of exploration considerably. Generally, the dominant frequency content of the various seismic surveys decreases with age. For example, the dominant frequency of the Jurassic Shelf Stratigraphic Play interval for permit E16-76, line MA-026A acquired in 1976 is 12 Hertz (with a corresponding tuning thickness of 308 feet (94 meters)) and the dominant frequency of the same interval for a 1988 survey (E03-88, line 88-16-J-1) is 20 Hertz (with a corresponding tuning thickness of 183 feet (56 meters)). The higher frequency content improves the ability to define the geometry of thinner reservoirs.



N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-4-1-1_Seismic_Surveys_and_HC_Plays.mxd, 3/13/2015, sullivans

SEISMIC SURVEYS AND HYDROCARBON PLAYS ANALYZED IN STUDY AREA
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 4.1-1

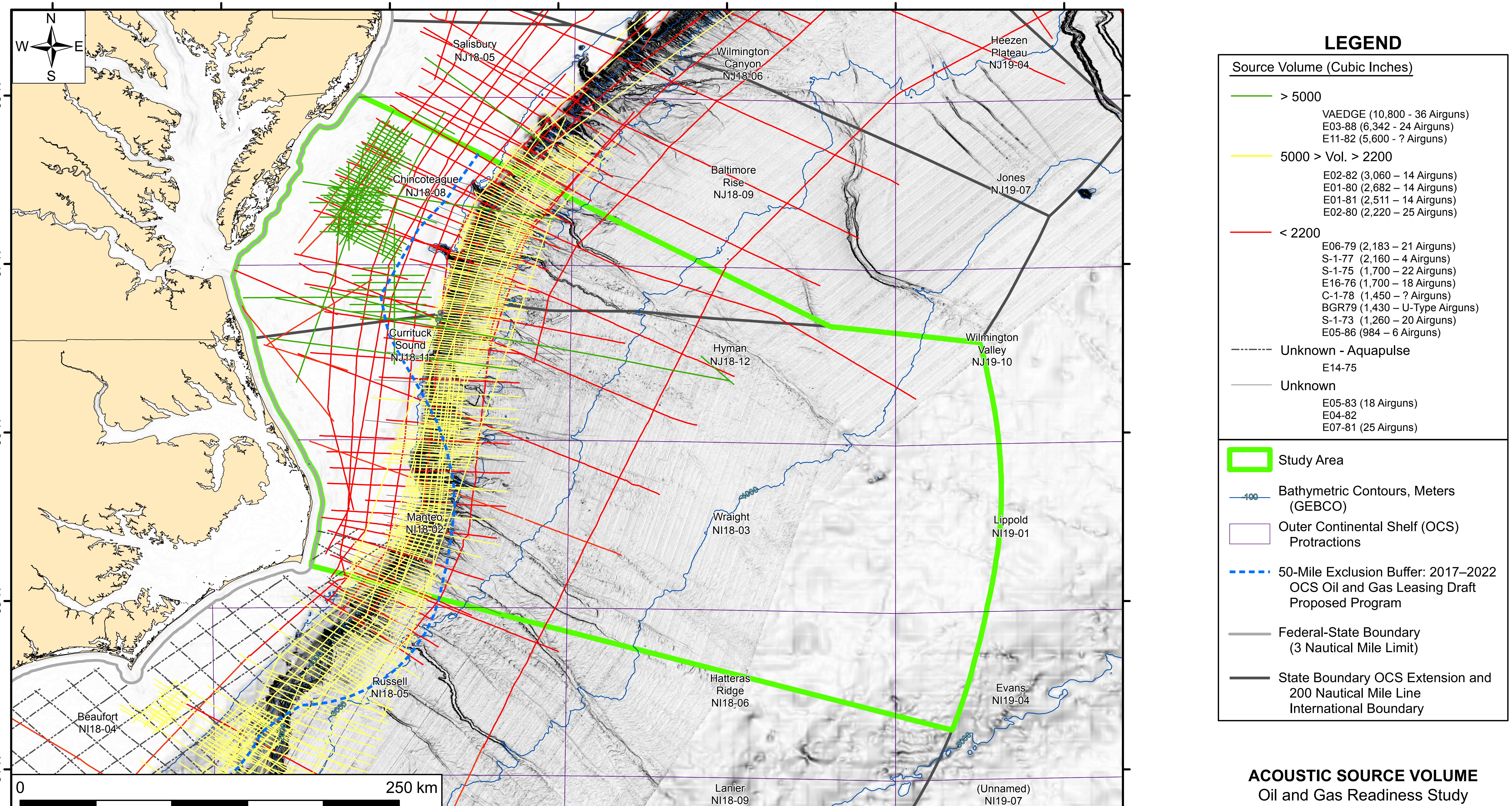
Survey	Client	Contractor	Date	Shotpoint Interval	Acoustic Source			Group Interval	Number of Channels	CDP Fold	CDP Interval	Cable Length	Offset		Sample Rate (Milliseconds)	Record Length (Seconds)		Recording System
					Number of Guns	Volume (Cubic Inches)	Pressure (PSI)						Minimum	Maximum		No Delay	With Maximum Delay	
S-1-73	USGS	Digicon	1973	338 ft (100 m)	20	1260	1800 to 2000	338 ft (100 m)	24	6, 12 or 24	164 ft (50 m)	7635 ft (2327m)	1112 ft (339m)	8747 ft (2666m)	4	10	11	DFS III
S-1-75	USGS	Digicon	1975	338 ft (100 m)	Unknown	1700	1700	164/328 ft (50/100 m)	48	12 to 48	82 to 164 ft (25 to 50 m)	11483 ft (3500m)	1142 ft (348m)	12625 ft (3848m)	2	10	14	DFS III
E14-75	Western Geophysical	Western Geophysical	1975	220 ft (67 m)	Aquapulse			220 ft (67 m)	48	24	110 ft (33.5 m)	10340 ft (3152 m)	1024 ft (312 m)	11364 ft (3464 m)	4	5 or 7		DDS-888 COBA I
E16-76	Offshore Atlantic Group	Digicon	1976	338 ft (100 m)	18	1700	Unknown	164/328 ft (50/100 m)	48	36	164 ft (50 m)	11710 ft (3569m)	1108 ft (338m)	12818 ft (3907m)	4 (From processed SEG-Y file)	8	10	DFS III
S-1-77	USGS	Teledyne	1977	164 or 328 ft (50 or 100 m)	4	2160	2000	164/328 ft (50/100 m)	48	24 or 48	164 ft (50 m)	8858 ft (2700m)	984 ft (300m)	9843 ft (3000m)	2	12		DFS IV
C-1-78	USGS	GSI	1978	164 ft (50 m)	Unknown	1450	2000	164/328 ft (50/100 m)	48	48	164 ft (50 m)	11821 ft (3603m)	1099 ft (335m)	12920 ft (3938m)	4	12		DFS IV
E06-79	USGS	Whitehall	1979	164 ft (50 m)	21	2183	1800 to 2000	164 ft (50 m)	64	16	82 ft (25 m)	10335 ft (3150m)	617 ft (188m)	10951 ft (3338m)	4	5		MDS-10
BGR79	BGR	Prakla-Seismos	1979	164 ft (50 m)	"U-Type" Airgun Tuned Array	1430	1430	164 ft (50 m)	48	24	82 ft (25 m)	10991 ft (3350m)	984 ft (300m)	11975 ft (3650m)	4	10	13	DFS V
E01-80	South Atlantic Group	Geosource	1980	246 ft (75 m) 2 POPS/SP	14	2682	1850	246 ft (75 m)	48	48	123 ft (37.5 m)	11562 ft (3524m)	730 ft (223m)	12292 ft (3747m)	2	8		MDS-10
E02-80	South Atlantic Group	Digicon	1980	328 ft (100 m) 2 POPS/SP	25	2220	1700 to 1800	82/164 ft (25/50 m)	96	36	164 ft (50 m)	11683 ft (3561m)	800 ft (244m)	12485 ft (3805m)	2	7	9	DFS V
E01-81	Exxon	Geosource	1981	73.8 ft (22.5 m)	14	2511	Unknown	Assumed: 49.2/147.6 ft (15/45 m)	75	40 to 75	73.8 ft (22.5 m)	9646 ft (2940m)	711 ft (217m)	10357 ft (3157m)	4 (From processed SEG-Y file)	8	9	DFS V
E07-81	Chevron	Digicon	1981	328 ft (100 m) 2 POPS/SP	25	Unknown	1800	82/164 ft (25/50 m)	96	36	82 ft (25 m)	10843 ft (3305m)	886 ft (270m)	11729 ft (3575m)	2	8		DFS V
E02-82	Mid-South Atlantic Group	Geosource	1982	123 ft (37.5 m)	14	3060	1800 to 2000	123 ft (37.5 m)	96	48	123 ft (37.5 m)	11686 ft (3562m)	738 ft (225m)	12423 ft (3787m)	2	8	9	DFS V
E04-82	Shell	Shell	1982	100 ft (30.5 m)	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	100 ft (30.5 m)	Unknown	Unknown	Unknown	4 (From processed SEG-Y file)	7	9	Unknown
E11-82	ARCO	ARCO	1982	41 ft (12.5 m)	Unknown	5600	Unknown	Assumed: 82 or 164 ft (25 or 50 m)	Assumed: 60 or 120	144 to 240	82 ft (25 m)	9799 ft (2987m)	1079 ft (329m)	10878 ft (3316m)	2	7		Unknown
E05-83	Amoco	Norpac	1983	82 ft (25 m)	18	Unknown	2000	82 ft (25 m)	120	60	41 ft (12.5 m)	9758 ft (2974m)	820 ft (250m)	10578 ft (3224m)	2	9		DFS V
E05-86	Spectrum and Texaco	Teledyne	1986	82 ft (25 m)	6	984	2000	41 ft (12.5 m)	96	48	41 ft (12.5 m)	3895 ft (1187m)	410 ft (125m)	4305 ft (1312m)	2	6		DFS IV
E03-88	Texaco	GECO	1988	82 ft (25 m)	24	6324	Unknown	82 ft (25 m)	240	70 to 95	82 ft (25 m)	19603 ft (5975m)	922 ft (281m)	20525 ft (6256m)	2	8		DSS/DFS V
VAEDGE	USGS	GECO	1990	164 ft (50 m)	36	10800	2000	82 ft (25 m)	240	60	41 ft (12.5 m)	19685 ft 6000 m	Unknown	Unknown	2	16		Unknown

SURVEY ACQUISITION PARAMETERS

Oil and Gas Readiness Study

Offshore Virginia

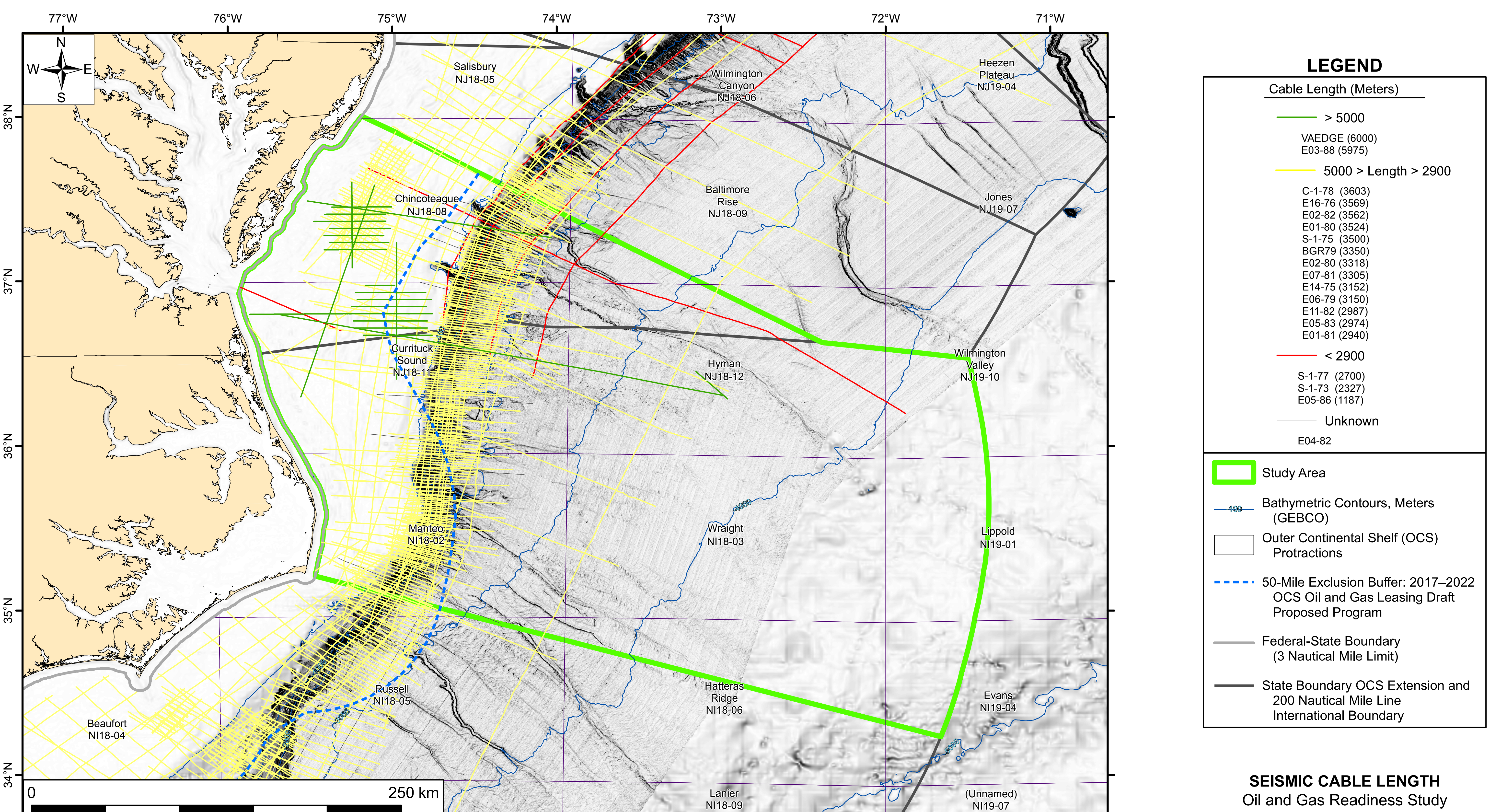
FIGURE 4.2-1



ACOUSTIC SOURCE VOLUME
Oil and Gas Readiness Study
Offshore Virginia

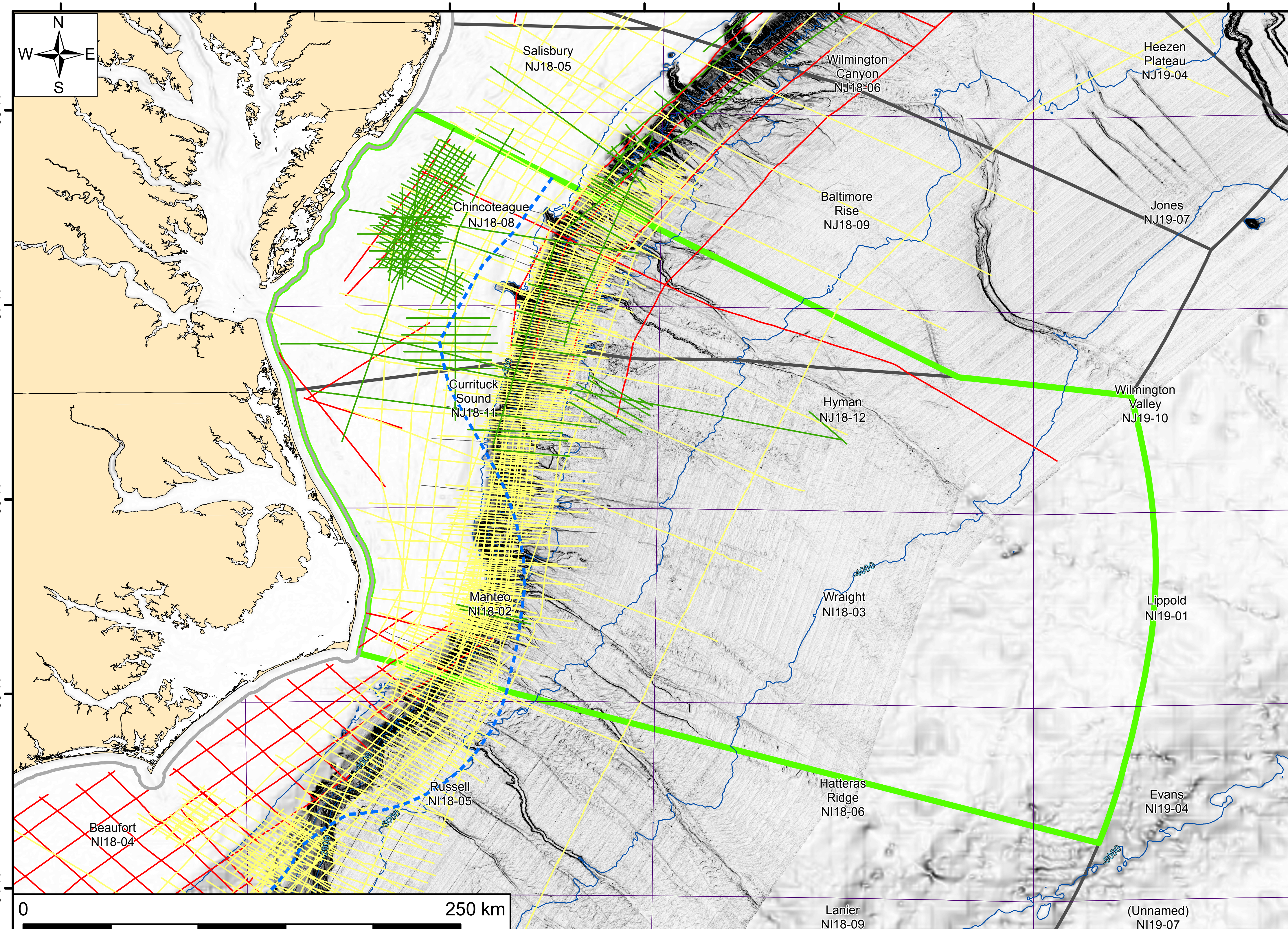
FIGURE 4.2-2

N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-4-2-2_Acoustic_Source_Volume.mxd, 3/13/2015, sullivans



SEISMIC CABLE LENGTH
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 4.2-3



LEGEND

Common Depth Point (CDP) Fold

> 50

E11-82 (144 - 240)
E03-88 (70 - 95)
E01-81 (40 - 75)
VAEDGE (60)
E05-83 (60)

50 > Fold > 25

E05-86 (48)
E02-82 (48)
C-1-78 (48)
E01-80 (48)
E07-81 (36)
E02-80 (36)
E16-76 (36)
S-1-75 (36)
E14-75 (36)
S-1-77 (24 or 48)

< 25

BGR79 (24)
E06-79 (16)
S-1-73 (6, 12 or 24)

Unknown

E04-82

Study Area

Bathymetric Contours, Meters (GEBCO)

Outer Continental Shelf (OCS) Protractions

50-Mile Exclusion Buffer: 2017–2022 OCS Oil and Gas Leasing Draft Proposed Program

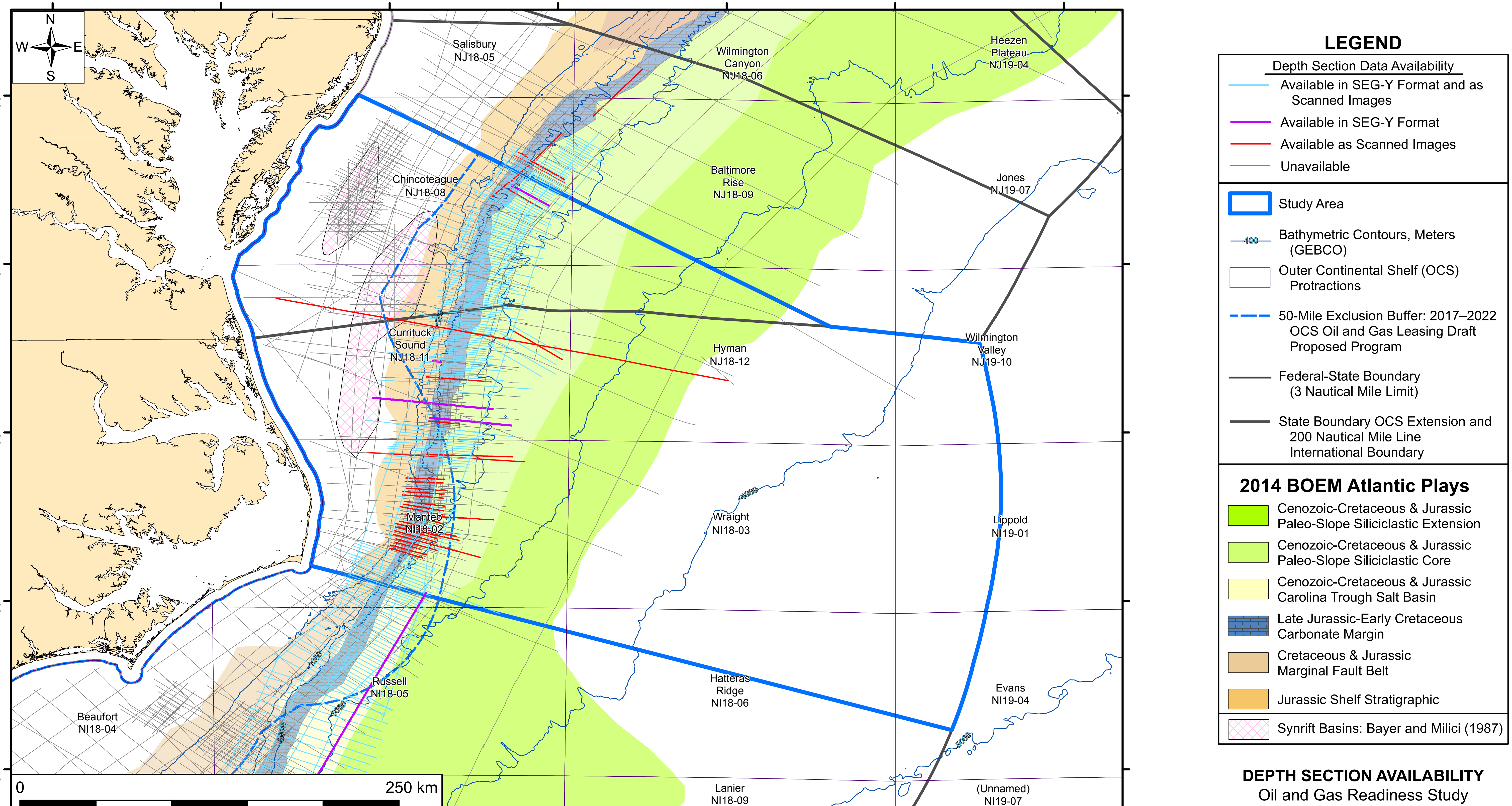
Federal-State Boundary (3 Nautical Mile Limit)

State Boundary OCS Extension and 200 Nautical Mile Line International Boundary

COMMON DEPTH POINT FOLD
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 4.2-4

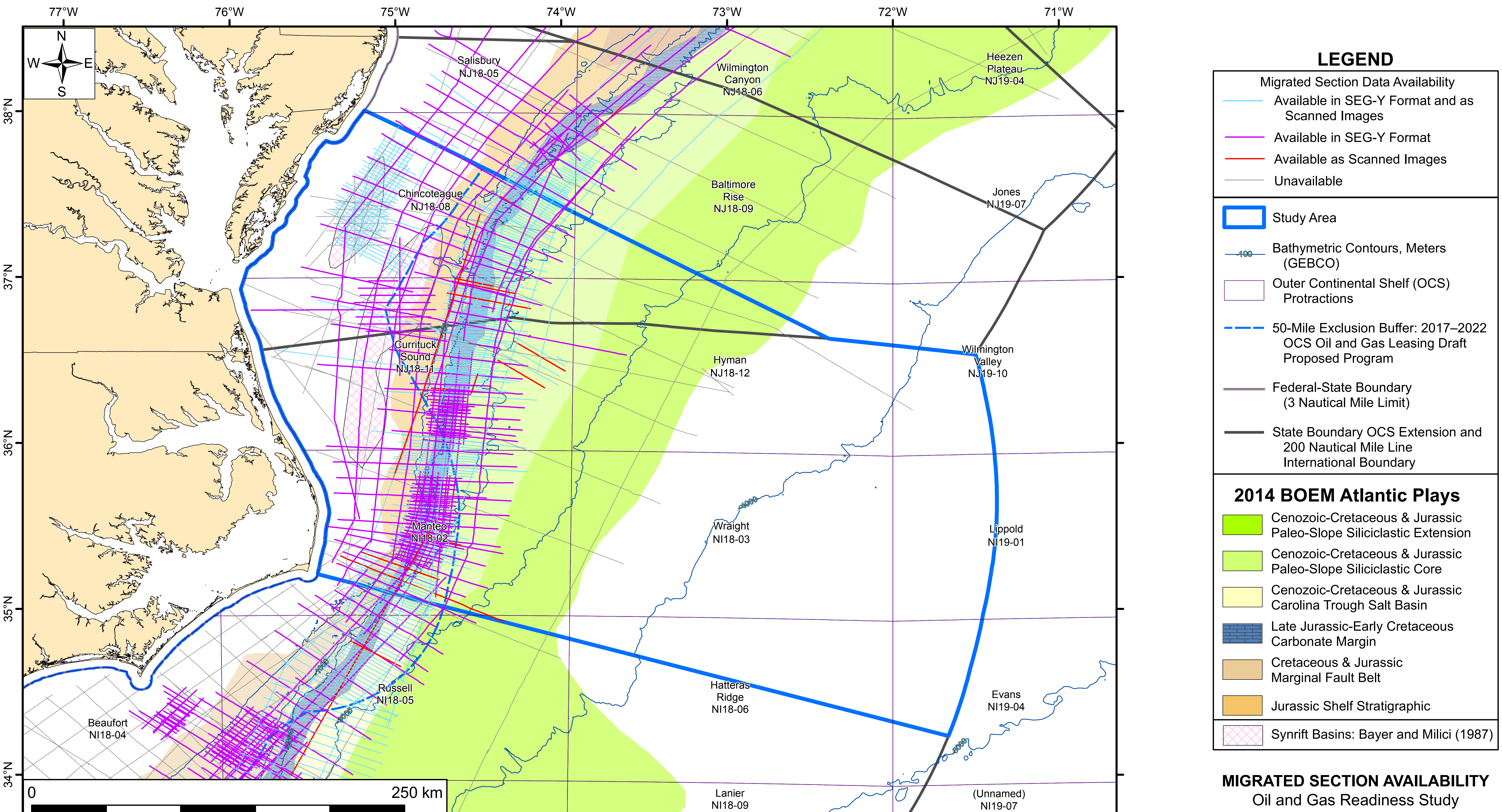
N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-4-2-4_CDP_Fold.mxd, 3/13/2015, sullivans



DEPTH SECTION AVAILABILITY
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 4.3-1

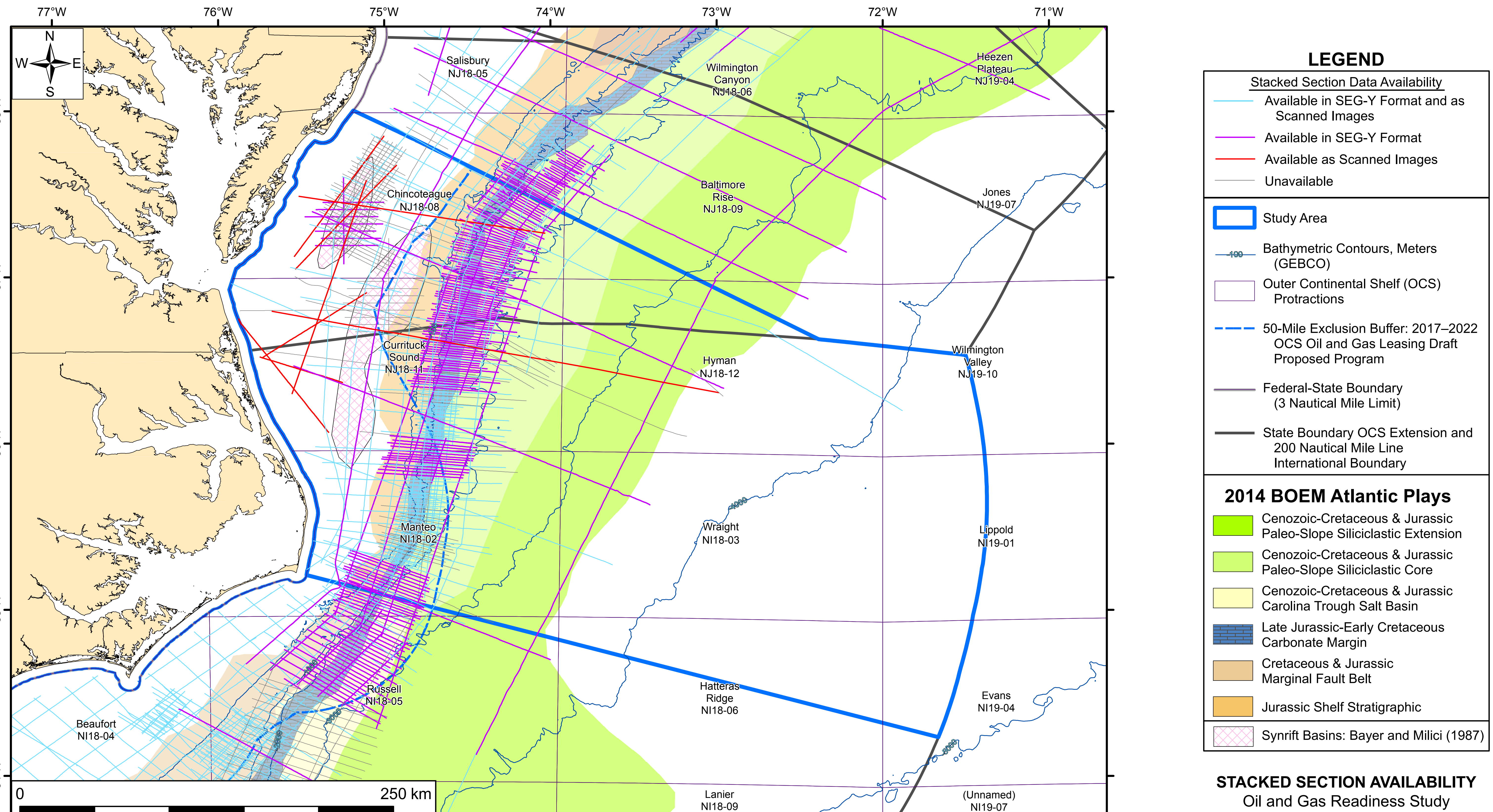
N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-4-3-1_Depth_Section_Availability.mxd, 3/13/2015, sullivans



MIGRATED SECTION AVAILABILITY
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 4.3-2

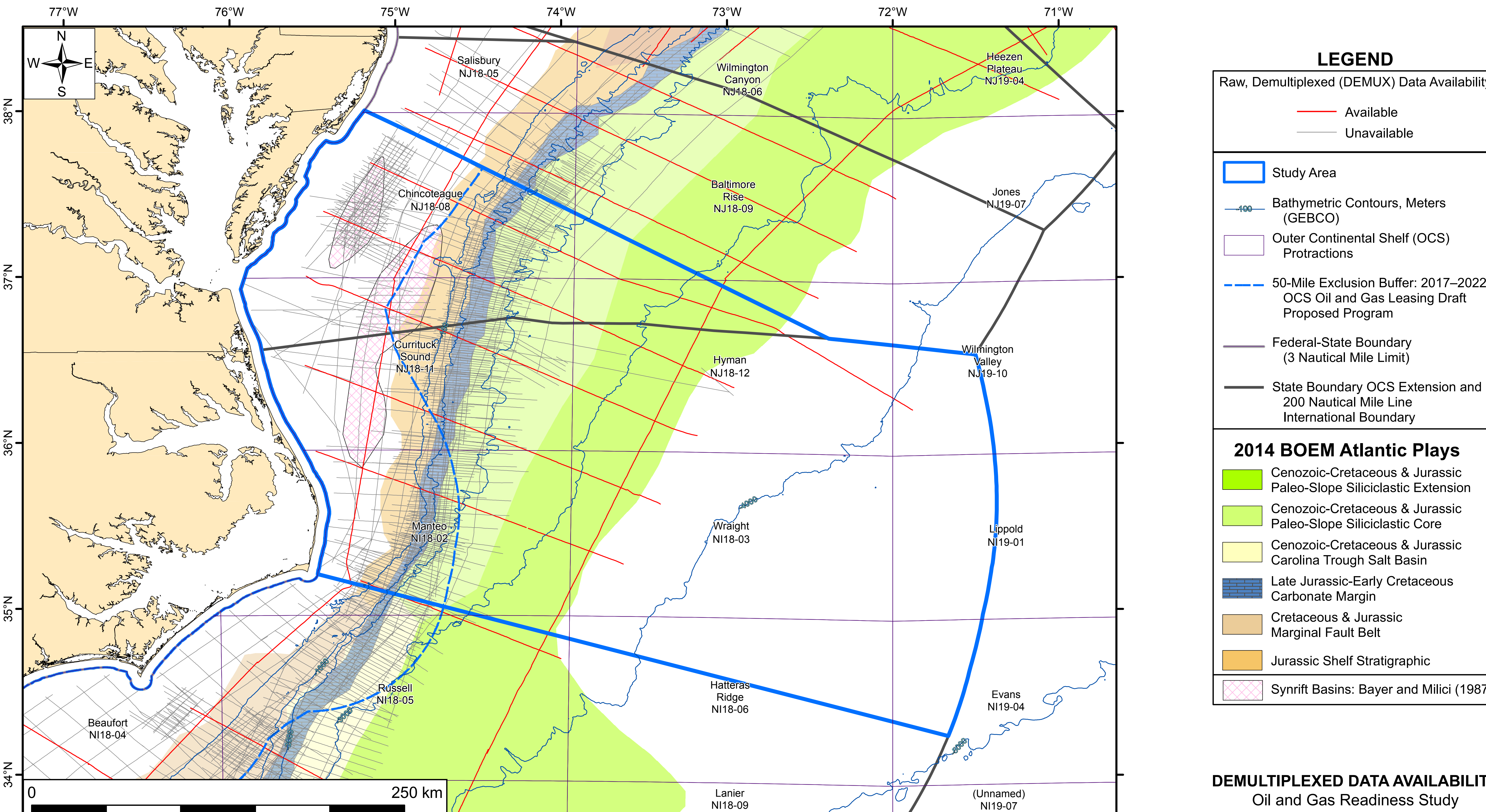
N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-4-3-2_Migrated_Section_Availability.mxd, 3/13/2015, sullivans



STACKED SECTION AVAILABILITY
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 4.3-3

N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-4-3-3_Stacked_Section_Availability.mxd, 3/13/2015, sullivans



DEMULTIPLEXED DATA AVAILABILITY
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 4.3-4

N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-4-3-4_Demultiplexed_Data_Availability.mxd, 3/13/2015, sullivans

5.0 THE APPLICABILITY OF REPROCESSING LEGACY DATA AND THE POTENTIAL TO ACQUIRE NEW DATA

5.1 EXPLORING A FRONTIER BASIN

Modern offshore O&G exploration in frontier basins requires a cost-effective approach that includes reanalysis of existing G&G data to better define the major structural and stratigraphic trends within a basin in order to focus future research efforts. Many times incorrect lithologic correlations are interpreted over large distances with widely spaced data and/or poor well control. Conventional hydrocarbon plays that are unproven have risks associated with respect to one of the four key elements of a viable petroleum system (source, reservoir, seal and overburden) and/or two of the key geologic processes (trap formation and the generation, migration and accumulation of hydrocarbons). In order to minimize these risks, existing geophysical data can be reprocessed and reinterpreted if the data is of high enough quality to provide additional, cost-effective geologic information for potential plays. Additional data may then be collected prior to lease sales by geophysical and geochemical companies on a speculative basis (in hopes that companies will pay for all or some of the data acquired) or through financing of a single exploration company or a multi-client group of companies.

Surface geochemical exploration companies aim to assess the presence and maturation of a source rock by using pre-existing seismic and/or bathymetric data to target areas of potential hydrocarbon seepage at the seafloor, termed “seep hunting”. By collecting additional geophysical data and cores at hydrocarbon seeps and geochemically analyzing interstitial gases and heavier hydrocarbons, geochemists can determine whether the seeping hydrocarbons are of a biogenic or thermogenic origin and what type of kerogen is present in the source rock, indicating if it is oil- or gas-prone.

In the past, seeps were often targeted based on limited vintage seismic data acquired using pre-GPS navigation. This resulted in a significant decrease in coring targets imaged on the seismic data with sub-par navigation. Even when mounds or seismic anomalies were seen on the ship’s echo sounder or Chirp system, the cores that were acquired often sampled an area away from the center of hydrocarbon seepage and geochemical analyses would indicate a mixed biogenic/thermogenic system below even when a working petroleum system was present. Recently, Fugro has made use of high-resolution multibeam bathymetric data in real-time so that the targeting of seeps is more precise.

The collection of pre-lease seismic data on a speculative basis is common throughout the industry. In 2014, several permit applications were submitted to BOEM to collect new seismic data in anticipation of a future lease sale. The majority of the applications received by BOEM were submitted by geophysical contractors intending to perform speculative surveys and only one multi-client 3D survey application. Likely reasons most of the permits received by BOEM were for regional 2-D surveys are due to the more modest cost to both acquire and process 2-D data and the lack of up-front funding by O&G companies for 3-D surveys in a high-risk basin. Regional 2-D lines that are carefully designed can cover the entire area of a potential 2017-2022 Atlantic lease sale and act as a screening tool while also providing superior imaging of the subsurface compared to the legacy data.

For the third subtask for phase 1 of the Virginia Oil and Gas Readiness Project, we have focused on reprocessing the legacy data to determine its effectiveness and applicability for future lease sales data and also designed a potential regional 2-D seismic survey to evaluate whether new data can be acquired, processed and interpreted over the Mid-Atlantic OCS prior to possible inclusion in the planned 2017-2022 Lease Program.

5.2 REPROCESSING LEGACY SEISMIC DATA

Reprocessing vintage data must consider the interpretation objectives, which are generally divided into structural or stratigraphic. Structural interpretation focuses on mapping faults, folds, salt domes, unconformities and other geological features in the subsurface that may serve as traps for hydrocarbon accumulation. Stratigraphic interpretation focuses on identification of the depositional sequences, recognition of sedimentary facies and possible hydrocarbon indicators (HCI).

The ability to map structure is improved by normalizing seismic amplitudes to show a more coherent image where both stratigraphically equivalent horizons and faults that disrupt this coherency can be observed. On the other hand, relative amplitude processing is used for stratigraphic interpretation and attribute analysis which enable identification of HCIs such as bright spots or other amplitude anomalies. While paper copies (or scanned paper copies converted to SEG-Y format) may provide information needed for an adequate structural interpretation, in order to perform more accurate stratigraphic interpretation, true amplitudes need to be preserved which require access to the original raw or processed data.

5.2.1 Utilizing Unprocessed Data

The only raw data available for complete reprocessing from original field data are the regional seismic lines collected for the USGS between 1973 and 1978. Demultiplexed SEG-Y files of Line 28 (USGS Survey C-1-78) were therefore downloaded from the USGS NAMSS website and processed in order to assess the possibility of improving the original imaging of the subsurface and to help assess whether the procedure was cost-effective.

The seismic data acquired for USGS Survey C-1-78 utilized 48 channels with a hybrid streamer configuration with mixed group intervals of 100 meters near the ship and 50 meters at far offsets. The sparse and irregular data sampling limited the potential for image improvement via reprocessing. Trace interpolation to produce a uniform 50-m group interval (25-m CDP bin spacing) helped address this issue, but spatial aliasing limits the ultimate image resolution (50-m groups have spatial Nyquist frequency of only 15-Hz for water-borne coherent noise, e.g., source-generated backscatter in shallow water). The time consuming and labor intensive effort required to apply appropriate geometries and apply modern processing techniques to these vintage datasets was therefore cost-prohibitive.

A preliminary or “brute” stack of Line 28 was created by applying a seismic velocity of 1500 meters per second (Figure 5.2-1A). This brute stack section highlights many forms of noise that exist in the data and which were attenuated in subsequent processing. Around CMP 700 (and to a lesser extent elsewhere in the section) there is a large section contaminated by high-frequency background noise between 3-5 seconds TWTT that may be due to sideswipe from seafloor features or other nearby noise sources. Linear, coherent noise was also observable on the brute stack section and dip at high angles from the left to right (northwest to southeast) portion of the image. Attenuation of this linear, coherent noise was shown in the final stacked section at approximately CMP 700 (Figure 5.2-1B) while primary reflections were enhanced such as the extensional half-graben of the Norfolk basin at 2 to 4 seconds TWTT between CMP 350 to 600. The seafloor reflection was not preserved in the shallow section because the near trace offset (333 meters) was too far to obtain normal-incidence reflections due to the arrival of the water bottom arriving as a wide-angle reflection or head wave refraction which was muted as a function of NMO stretching and distorting the waveform. Line 28 was time-migrated and the imaging of the structure within the Norfolk basin was improved considerably due to the collapse of diffractions and the proper positioning of the northwest bounding fault (Figure 5.2-1C).

Reprocessing from raw data (Field Records) may then provide some improvement if acquisition parameters are accurately known and sufficient for addressing data processing issues. Knowledge of velocity structure from original data processing may help speed up the reprocessing effort. However, quality control is essential to avoid errors that may have occurred during original processing or publication of results. Migration velocity structure must be developed from raw data or expert judgment on regional velocity structure, if the existing data do not include migration velocity data.

5.2.2 Scanning Paper Sections

Much of the data available for the offshore Atlantic comes from scanned and vectorized paper copies which have a limited dynamic range. When digital SEG-Y files of scanned sections are unavailable, scanning and converting those images to SEG-Y format is the only option available. Amplitude information is often lost in paper sections since AGC gains are frequently applied to the images for better display. Unlike today, where most geoscientists in the O&G industry have access to a seismic workstation, computers were rare in the 1970's and 1980's when much of the interpretation effort was done from paper copies.

Mapping deep geologic layers using true amplitude paper sections was very difficult due to the decrease in the strength of the original signal as a function of distance traveled and due to attenuation. In Figure 5.2-2, two versions of a migrated section for Line PR82-130 (Permit E02-82) are displayed to compare the difference between a scanned, frequency migrated section with AGC applied (provided by BOEM) and a Frequency-Wavenumber (FK) migrated version of the stacked SEG-Y file retrieved from the USGS/NAMSS and migrated specifically for this project. In the scanned section (upper image), amplitude anomalies are not easily seen due to the AGC application while the migrated version (lower image) shows high amplitudes abutting unconformities and other features typical in a gas-bearing reservoir.

5.2.3 Migrating Stacked Sections

Based on the analysis above, migration of stacked data should provide the most cost-effective image improvement for interpretation. An example of the improvement in the quality of the seismic image produced after a simple migration using a constant velocity of 1500 meters/second (water velocity) is shown in Figure 5.2-2. More refined migration velocity structure could be developed based on the stacking velocities or re-analysis of field records. Analysis of diffractions recorded on stacked data profiles could provide additional velocity information, but would require a substantial processing effort. It is also possible to apply migration to scanned paper sections that have been converted to SEG-Y format to help collapse diffractions and improve the image quality if no migrated sections exist.

5.3 ACQUISITION OF NEW SEISMIC DATA

The applicability of reprocessing legacy data and the potential to acquire new data task included an exercise to determine whether or not new seismic data could be acquired, processed, and interpreted in time for inclusion in the planned Mid-Atlantic lease sale in the upcoming 2017-2022 BOEM offshore oil and gas leasing program. The challenges the petroleum exploration industry face in the new millennium are far more complex than a generation ago when conventional resources were more readily available in areas more conducive to extraction. The hydrocarbons being sought after today lie in deeper, sub-salt and complex geological structures that may be located in ecologically sensitive or harsh environments.

5.3.1 Survey Area Rationale

The regional 2-D seismic survey shown in Figure 5.3-1, and approved by DMME, was designed with the intent of providing a preliminary assessment of the portion of the Atlantic Margin designated for possible inclusion in BOEM's 2017-2022 OCS O&G Leasing Program. Using modern acquisition equipment and processing techniques, the regional survey would illuminate deep subsurface structures not properly imaged with the legacy seismic data and would help guide further exploration efforts in the Atlantic. The proposed survey consists of 14 lines totaling approximately 4370 nautical miles (8100 kilometers). There are nine dip lines that extend from Georgia to Maryland with varying lengths of approximately 160 to 230 nautical miles (300 to 425 kilometers) and five strike lines with lengths of approximately 450 to 600 nautical miles (825 to 1125 kilometers).

The dip lines were designed to image the area mainly east of the 50-mile coastal buffer zone although in order to improve the correlation into the deep water region, some lines extend inshore where there is at least some well control from shallow penetrating wells. Only one dip line lies outside of the prospective leasing area and this dip line was included to provide stratigraphic correlation from the Shell 93-1 well into Virginia waters and regions farther to the south. The dip lines are oriented oblique to the hydrocarbon plays identified by BOEM in the area and the strike lines were designed to image each play in the area while also being adequately spaced apart to provide a broad view of the region. All dip lines extend to the seaward limit of the U.S. Exclusive Economic Zone (EEZ) and some project farther offshore to improve well control.

Many of the lines nearest the shore were designed to image areas leased during the 1970's and 1980's since these regions were most-likely studied in greater detail in the past by oil industry members and likely include high-potential targets. These previously-leased areas may include potentially hydrocarbon-bearing structures that extend farther offshore in areas that were not accessible for oil exploration in the past due to technological limitations of drilling rigs at that time.

5.3.2 Survey Design

The survey parameters that we recommend are listed below as well as a detailed project plan can be found in Appendix D and shown on Figure 5.3-1.

- Survey Size: 8,100 kilometers
- Number of Lines: 14 lines (Average lengths of approximately 600 km)
- Streamer Length: 8 kilometers

- Single Source: 5,860 cubic inches
    - 138.3 bar-meter peak-to-peak amplitude
    - Pulse to bubble ratio (P/B) = 18.0:1
- Shotpoint Interval: 25 meters
- Record Length: 12 seconds
    - Deepwater delay available for increased recording length

5.3.3 Timeframe

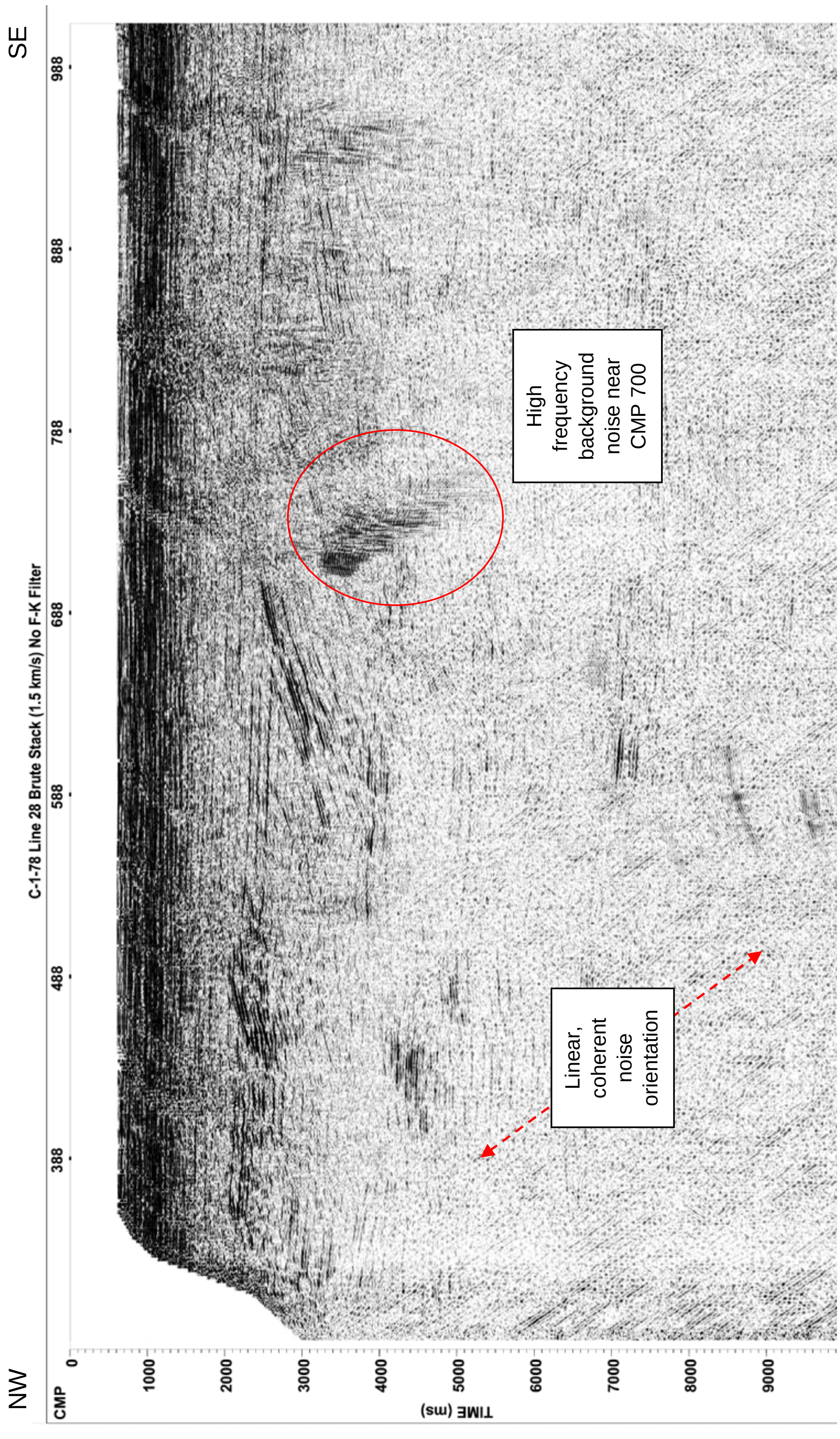
Our estimates for the durations of the survey are as follows:

• Mobilization from the Gulf of Mexico	15 days
• Operational (Production and Line change)	67 days
o *Standby for third party factors; fishing activity or identified presence of marine mammals (Estimated at 8% of Operational Time)*	*5 days*
o *Port Calls (Assumed 1 port call during survey)*	*5 days*
o *Technical Downtime (Estimated at 15% of Operational Time)*	*10 days*
• Retrieval, transit from survey area and demobilization	2 days
• Processing of seismic data	28 days
• Interpretation of seismic data and report writing	28 days
Total Survey Duration	***160 days***

The total time frame for the bidding process is listed below.

- 3 weeks to issue tender and have contractors submit proposals
- 2 weeks to evaluate tenders and award
- 6 to 8 weeks to get permit

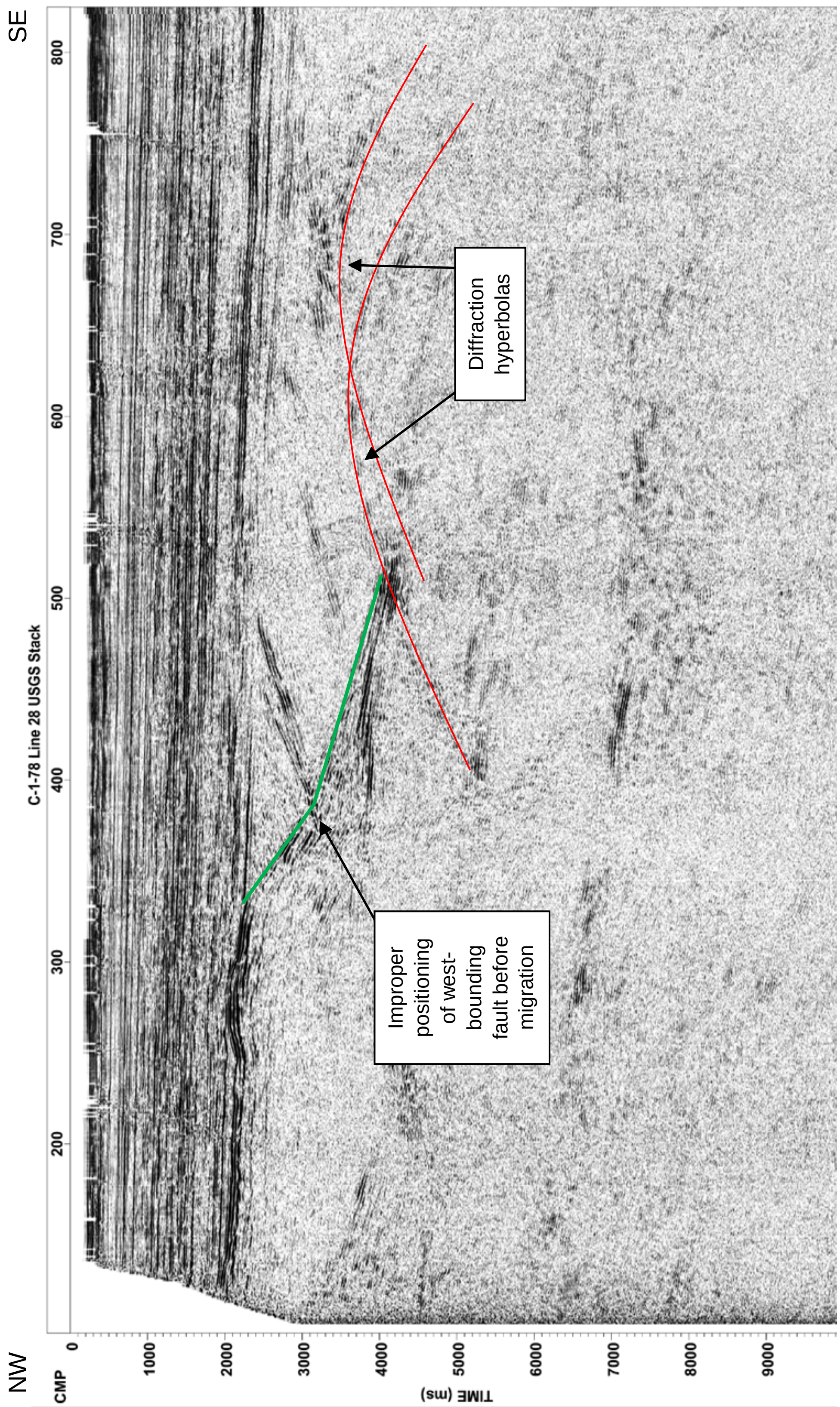
From this exercise, we have determined that a new, interpreted regional seismic program could be accomplished in less than a year. If seismic acquisition were begun by the end of 2016, the seismic data could provide enough information for an interested exploration company to participate in the 2017-2022 leasing program.



Line showing zone of high frequency background noise which is an artifact of the data and does not represent a real geological feature. No obvious fault identified in the brute stack data (see Figure 5.2-1C).

BRUTE STACK SECTION OF LINE 28 (USGS SURVEY C-1-78)
Oil and Gas Readiness Study
Offshore Virginia

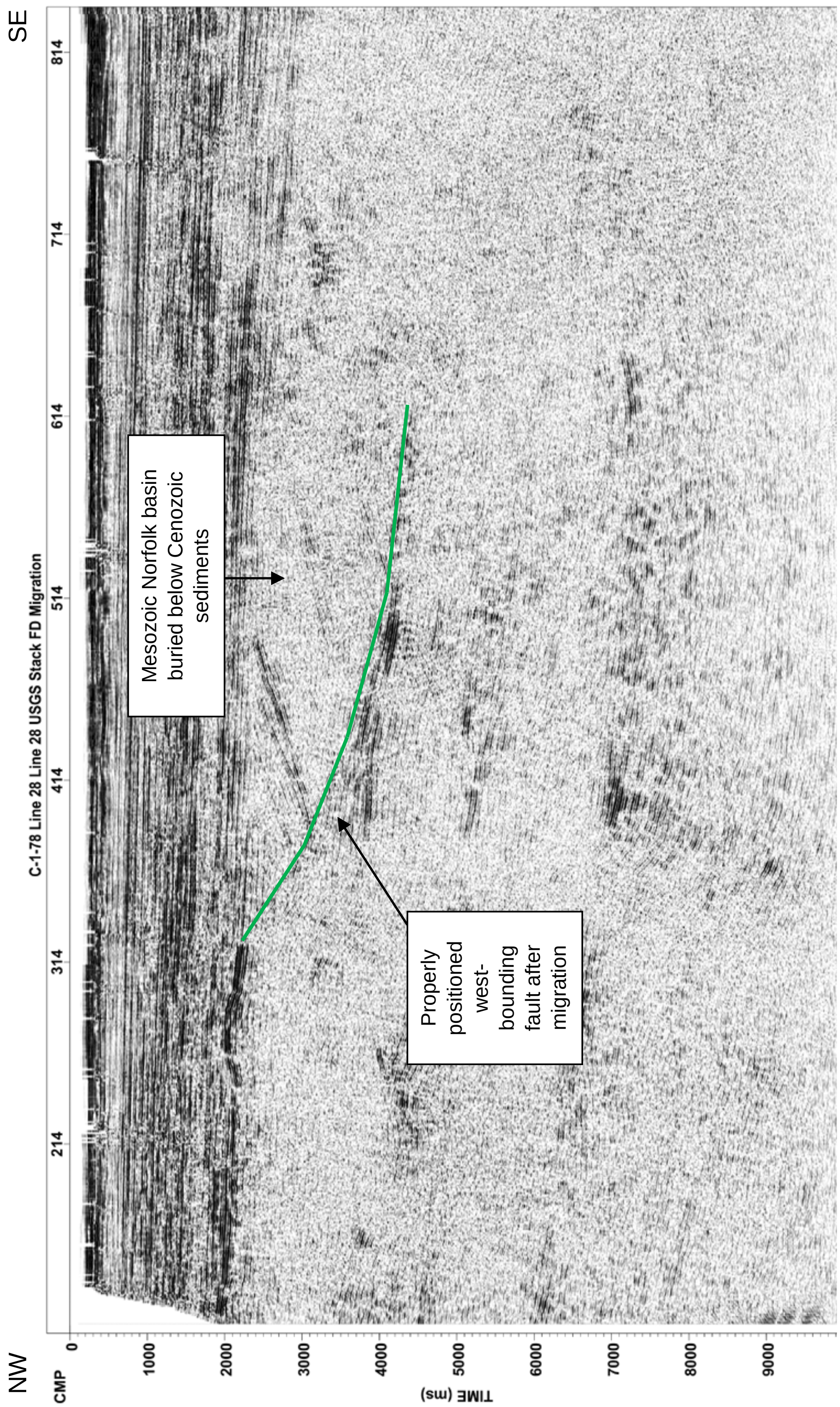
FIGURE 5.2-1A



Line showing apparent location of NW-SE dipping fault location which is not accurately located as the line has not been migrated (see Figure 5.2-1C).

FINAL STACK SECTION OF LINE 28 (USGS SURVEY C-1-78)
Oil and Gas Readiness Study
Offshore Virginia

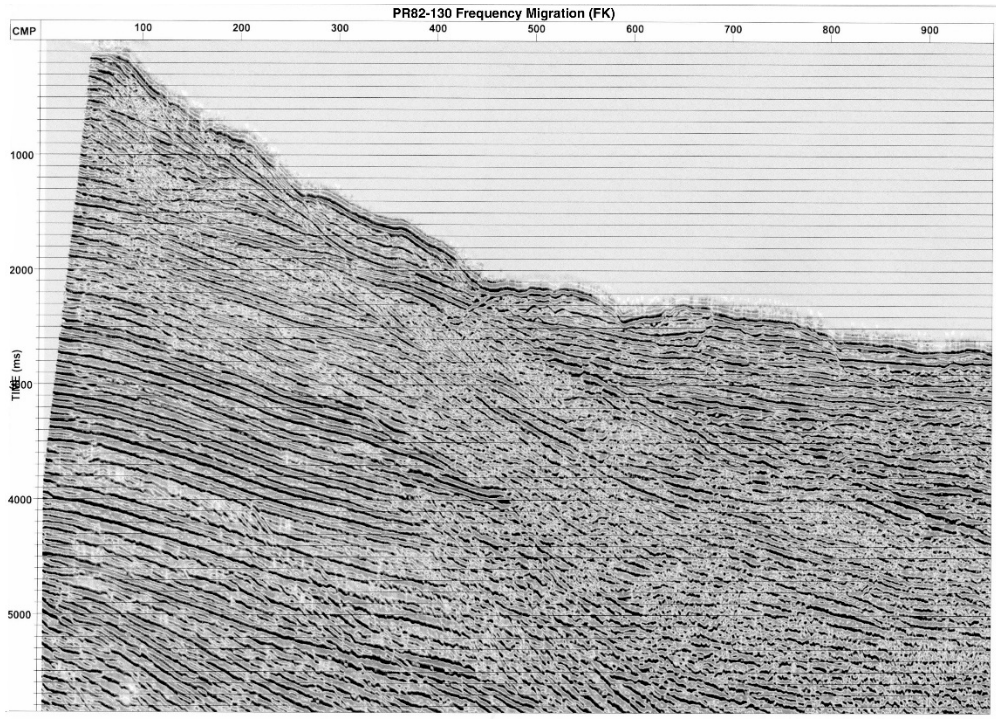
FIGURE 5.2-1B

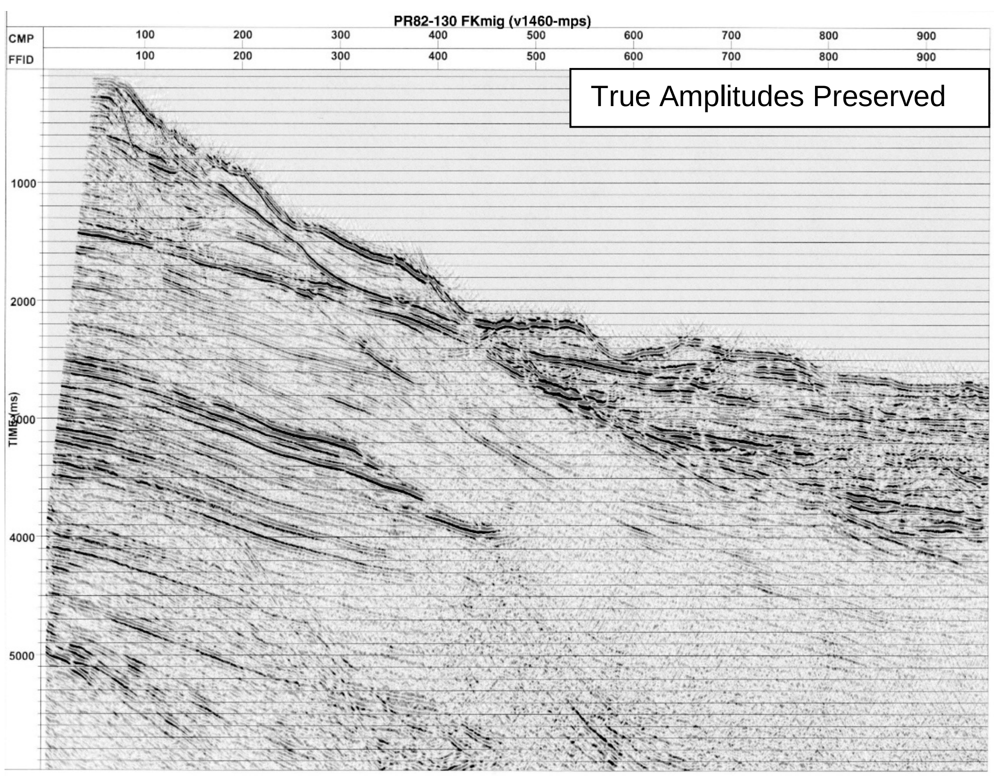


Line showing proper location of NW-SE dipping fault after correct migration of the data (see Figure 5.2-1B).

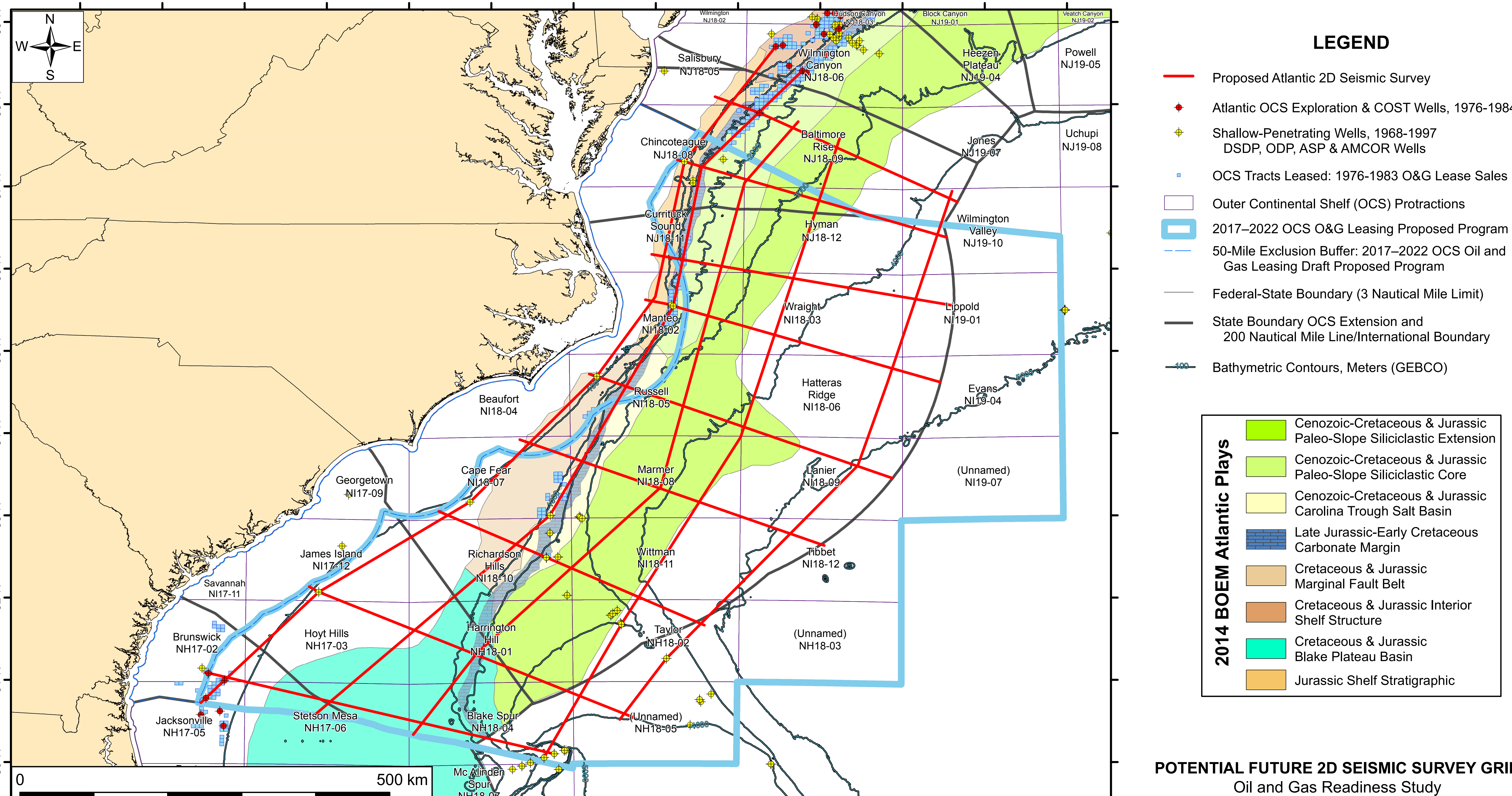
MIGRATED SECTION OF LINE 28 (USGS SURVEY C-1-78)
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 5.2-1C





MIGRATED SECTIONS OF LINE PR82-130 (PERMIT E02-82)
WITH AND WITHOUT AUTOMATIC GAIN CONTROL (AGC)
Oil and Gas Readiness Study
Offshore Virginia



POTENTIAL FUTURE 2D SEISMIC SURVEY GRID
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 5.3-1

N:\Projects\04_2014\04_8114_0015_VA_Oil_and_Gas_Readiness\Outputs\Working\mxd\Figures\Phase_1_Final_Report\Fig-5-3-1_Theoretical_Survey.mxd, 3/13/2015, sullivans

6.0 PROFILE OF U.S. GULF COAST OIL AND GAS SUPPORT TERMINAL INFRASTRUCTURE

As BOEM is considering the Mid-Atlantic region for future offshore oil and natural gas (O&G) exploration, one key concern that has appeared in earlier reports is the lack of onshore support services for exploration, drilling and production on the east coast. This section represents the first step of a three step process to determine the adequacy of existing infrastructure in the Mid-Atlantic region as well as to quantify the timing and phasing of infrastructure development. Where an infrastructure gap is found, the capabilities of other regions to supply the necessary supplemental resources will be evaluated.

The initial step of this process, is to develop a typical profile of oil and gas infrastructure as found on the U.S. Gulf Coast. That profile was obtained by examining eleven major offshore support terminal complexes, including three Louisiana ports: Fourchon, Grand Isle and Cameron. These three complexes, along with eight other terminal sites from Freeport, Texas to Pascagoula, Mississippi were evaluated to develop a relationship between overall port acreage and offshore platforms served.

This section also quantifies the extent of the existing industry in the US Gulf Coast, including number of active lease blocks and existing platforms. Comparing those figures to the support terminal areas necessary to maintain platforms provides an approximate ratio of platforms that could be maintained for a given acreage of future support terminal facilities in the Mid-Atlantic area. Example terminals found at Port Fourchon, Grand Isle and Cameron were evaluated to derive a profile of terminal infrastructure necessary to support offshore exploration and production. This profile compared the design criteria for a new, purpose-built offshore O&G support terminal currently under construction in Brazil to obtain specific cargo handling capacities, tank volumes and warehouse area necessary for operation of an all-in-one support terminal.

6.1 OVERVIEW OF OFFSHORE OIL AND GAS EXPLORATION AND PRODUCTION INFRASTRUCTURE REQUIREMENTS

6.1.1 Typical Gulf Coast Offshore Oil and Gas Infrastructure

Active production of offshore O&G in the Gulf of Mexico has been underway since the mid-20th Century. Presently the Gulf oil and natural gas fields include over 2,200 active well platforms installed over a lease area of 30 million acres. Therefore, U.S. Gulf Coast offshore O&G production represents a mature industry that can serve as a reasonable model for the infrastructure required to support similar activities in the Mid-Atlantic region.

U.S. Gulf Coast O&G exploration and production was evaluated from the perspective of total lease blocks, total lease area, and active platforms. As volume of production varies significantly with world oil price and does not correlate with onshore support infrastructure, this parameter was not used in the evaluation. A database of ArcGIS shape files containing specific production information related to offshore lease blocks is maintained by BOEM. Queries to this database resulted in a general profile of offshore production activities.

6.1.1.1 Lease Blocks

Presently, exploration and production leases in the Gulf of Mexico have been let in the Western Gulf and the Central Gulf planning areas. The Eastern Gulf has not been opened by

BOEM. Federal lease blocks on the Outer Continental Shelf (OCS) are approximately 5,000 acres in area with a few exceptions. Lease blocks can be offered for exploration but returned if there is no drilling activity and no petroleum resources are discovered or if development and production is not economically viable. Therefore, active leases are scattered throughout the planning areas. Within the Western and Central lease areas, there are 5,477 active lease blocks over an area of 29.65 million acres.

6.1.1.2 Platforms

Within the current OCS lease blocks there are 2,286 active platforms in the Gulf of Mexico. This number does not include platforms that are labeled “Removed”, including those that had been demolished in a hurricane or vessel collision. Also, any platforms that were located outside of an active lease block were removed from the dataset as likely to be abandoned or inactive.

6.1.1.3 Summary of Metrics

Based on the BOEM offshore leases and active platforms, a set of metrics was developed to relate the lease areas to actual platform development. As initial exploration will be driven by leased area, the relationship between lease areas and platform development will be the more important metric for determining infrastructure in the early stages. Later, as production wells are drilled, the platforms will become the key driver of infrastructure needs. Table 6.1-1 provides a comparison of land, leases and platforms found in the Gulf:

Table 6.1-1 Active Lease Acres and Operating Platforms

Total OCS Lease Area (acres)	29,648,000
Total Lease Blocks	5,477
Total Active Platforms	2,286
Platforms per Lease Block	0.42
Leased Acres per Platform	13,000

6.1.2 Offshore Oil and Natural Gas Support Terminals

6.1.2.1 Terminal Areas

For this study, U.S. Gulf Coast ports were inventoried to determine the type and extent of offshore O&G support terminals that are present within each port area. Eleven port areas were determined to have significant offshore support terminals:

1) Freeport, TX
2) Galveston, TX
3) Port Arthur, TX
4) Cameron, LA
5) Abbeville, LA
6) Morgan City, LA
7) Amelia, LA
8) Port Fourchon, LA
9) Grand Isle, LA
10) Venice, LA

11) Pascagoula, MS

Of these, Port Fourchon in Louisiana is the predominant location for support terminals, having more terminal area than all of the other ports combined (Keithly, 2001; Loren, 2014). A graphical representation of the relative land areas dedicated to offshore O&G support terminals is shown in Figure 6.1-1.

The land area in active use by support terminals, as shown in Table 6.1-2, was estimated from geographic information system (GIS) data and satellite images. The analysis was based on the type of vessel using the terminal, the equipment and support infrastructure present and the terminal location. Many terminals are a combination of general offshore construction and repair yard, offshore O&G support and other maritime use such as barge construction and repair. For these terminals, an estimate was made of actual acreage dedicated to supporting offshore O&G exploration and production. Additionally, floating and jack-up oil rigs are often staged or stored within a sheltered harbor without specific onshore facilities. These instances were not included in the inventory of terminals.

Table 6.1-2 Available Support Terminal Acreage by Port

Port	Acres
Freeport	27.6
Galveston	61.2
Port Arthur	90.4
Cameron	95.0
Abbeville	57.8
Morgan City	7.3
Amelia	22.7
Port Fourchon	1,068
Grand Isle	163
Venice	23.7
Pascagoula	6.1
Total	**1,622**

Offshore O&G support terminals have been constructed primarily by private businesses in response to the growth of the exploration and production industry. The location of support terminal sites is primarily driven by proximity to the offshore O&G fields and the availability of a sheltered harbor for safe vessel berthing and transfer of supplies (Dismukes, 2014; EIA, 2010; EIA). Figure 6.1-2 illustrates the distribution of support terminals relative to the location of active platforms in the Western Gulf and Central Gulf planning regions.

6.1.2.2 Support Terminal Activity

Offshore O&G exploration and production requires a broad spectrum of supporting marine activity. Primary functions that can take place at a support terminal include:

1) Drill-string, pipe and equipment storage and delivery

2) Drilling fluids, dry components, and chemical additive (mud) storage, preparation and delivery
3) Resupply of offshore platforms including diesel fuel and maintenance parts
4) Loading and dispatch of anchor handling and towing vessels
5) Underwater cable storage and cable vessel loading
6) Berthing and dispatch for support and service vessels
7) Helicopter and crew-boat landing, berthing and dispatch
8) In-water vessel repair
9) Lay-berthing for jack-up construction equipment and floating drill rigs

Most support terminals have a flexible layout that allows them to “tool up” for any specific offshore exploration or production effort that the operator has contracted for. Figure 6.3-1 was taken from the Halliburton Baroid terminal in Fourchon, Louisiana. It illustrates a typical large 24 acre support terminal and the type of activities that could be included:

In Figure 6.1-3, multiple units of terminal elements such as mud and chemical tanks are present on the same terminal. This enables the operator to service multiple rigs or multiple driller contracts from the same facility. At the same time, elements such as private vehicle parking and diesel fuel storage are located off terminal and shared by multiple operators.

6.2 SUPPORT TERMINAL AREA NEEDS

One significant difference between the offshore O&G support terminals in the Gulf and what will be required for the Mid-Atlantic is the degree of industry development. In the initial stages of exploration, a moderate level of support will be needed for seismic survey vessels and exploratory platforms. As discoveries are made, more extensive support terminal developments will become necessary for production platforms and associated facilities. To estimate the level of support required as the Mid-Atlantic OCS is developed, a comparison has been made between the onshore support terminal acreage and the offshore production area metrics. These area relationships will be used in subsequent sections of this report to estimate onshore terminal needs for the Mid-Atlantic region.

6.2.1 Support Terminal Area by Lease Area

In the initial stages of offshore O&G exploration, support terminals will be necessary for seismic survey vessels and exploratory drilling. As there will be no active platforms, the only applicable metric is a lease area relationship to onshore facilities. If U.S. Gulf operations are used as benchmark, this becomes a very conservative approach due to the ongoing support of active offshore platforms that also takes place. Currently in the Gulf there are about 18,000 acres of offshore lease area per acre of onshore support terminal.

6.2.2 Support Terminal Area by Lease Block

A second approach would be to consider each offshore lease block as a discrete unit requiring a certain area of onshore terminal for support. This too is a conservative approach as it does not distinguish between producing blocks and blocks still under exploration. However, it can be equated to projected lease sales and could provide guidance as to support terminal phasing.

In the U.S. Gulf, one acre of onshore support terminal is required for every 3.5 active offshore lease blocks.

6.2.3 Support Terminal Area by Active Platform

According to a report prepared by the American Petroleum Institute, Atlantic OCS offshore production could begin in 2026. This would mean that at that time, support terminals would be more associated with active platforms than exploration. This would represent a transition to a steady state when support terminal activity would be more closely related to the number of active platforms. Based on the U.S. Gulf Coast model, approximately one acre of support terminal is required for every1.5 active platforms in the region.

6.3 OFFSHORE OIL AND GAS SUPPORT TERMINAL TYPICAL INFRASTRUCTURE

6.3.1 Offshore Support Vessels

6.3.1.1 Crew Boats

Crew boats, also known as fast support vessels or fast supply vessels, are vessels specializing in the transport of offshore support personnel, deck cargo, and below-deck cargo such as fuel and potable water to and from offshore installations such as oil platforms and drilling rigs. Crew boats range in size from small, 30 foot to 60 foot vessels working on bays, sounds and inland waterways to 200 foot vessels that work as much as 200 miles offshore. A typical crew boat suitable for the Mid-Atlantic region would be 110 feet in length, 24 feet in breadth, and draw 6 feet fully laden. Typically these vessels are owned by contractors and not typically by the oil companies themselves (Leffler, 2003; The Maritime Network).

6.3.1.2 Platform Supply Vessels

A Platform supply vessel (PSV) is a ship designed to supply offshore oil platforms. These ships range from 120 feet to 300 feet in length. The primary function for most of these vessels is transportation of goods and personnel to and from offshore oil platforms and return waste material to shore. Cargo tanks for drilling mud, dry cement, diesel fuel, potable and non-potable water, and chemicals used in the drilling process comprise the bulk of the cargo spaces. Supplies and drilling tools are carried on the open decks of these vessels. A typical offshore PSV would be 225 feet in length, 55 feet in beam and draw 20 feet.

6.3.1.3 Anchor Handling Tug Supply Vessels

Anchor handling tug supply (AHTS) vessels are mainly built to handle anchors for oil rigs, tow them to location, anchor them and when necessary, serve as an emergency rescue and recovery vessel. They are also used to transport supplies to and from offshore drilling rigs. AHTS vessels differ from PSVs in being fitted with winches for towing and anchor handling, having an open stern to allow the decking of anchors and having more power to increase the bollard pull. A typical AHTS vessel is 250 feet to 350 feet in length, 50 feet in beam and 25 feet draft.

6.3.1.4 Marine Oil Spill Response Vessels

Marine oil spill response vessels (OSRV) are designed for responding to offshore oil spill emergencies. Available in a range of sizes, OSRV designed for offshore use range between 150 feet and 250 feet in length. These craft feature large, open decks and full-width bow or stern ramps for deployment of oil boom and skimmers. These vessels can also be equipped for additional duties, including cargo hauling, construction, and diving operations. A typical OSRV would be the Responder class vessels operated by a company such as Marine Spill Response Corporation. This vessel is 207 feet in length, 43 feet in beam and draws 16 feet (Marine Spill Response Corporation).

6.3.1.5 Other Service Vessels

Many of the other offshore services such as seismic exploration, firefighting, and diver support can be provided by PSVs. Undersea pipelines are usually installed by a specialized offshore vessel similar in dimensions to a large PSV that has the ability to join short lengths of pipe into a continuous pipeline and lay it on the sea floor. Pipeline layers can use the same type of support terminal as PSVs.

Exploration and production drilling rigs generally do not require a specialized marine terminal and can be staged within a sheltered anchorage prior to deployment. The exception may be jack-up service barges used for construction and heavy maintenance of offshore platforms. When a jack-up is necessary, material and supplies such as power units or crew modules are often loaded at a public general cargo terminal. A typical offshore service jack-up barge is 150 feet long and 100 feet wide. It draws from 18 feet to 20 feet of water including mud-mats that extend below the barge hull.

6.3.2 Location, Inland Access and Channel Dimensions

Offshore O&G support terminals do not rely so much on inland transportation as they do on proximity to the offshore oil or natural gas fields. Most of the offshore support terminals are within four to eight hours sailing time from the oil or natural gas fields they serve and any increase in vessel sailing time results in a significant increase in operating costs. From the land side, almost all of the material supplied to the offshore operations will arrive by truck. Few, if any support terminals have rail access. However, rail could be beneficial for delivery of bulk products such as dry cement, bentonite and barite.

Most offshore support terminals have a maintained access channel width of 200 feet to 400 feet and an authorized dredged depth of 25 feet. The trend in support vessels has been toward larger size and deeper draft as offshore exploration moves into deeper water. In the case of a large AHTS vessel, 25 feet of channel depth may not be adequate for 24-hour, all weather navigation.

6.3.3 Wharf and Cargo Loading Area

Offshore O&G support terminals usually have a high ratio of berthing to upland storage. Because service vessels are relatively shallow draft, this is often in the form of a reinforced quay wall. Where channel and turning basin geometry permit, PSVs and AHTS vessels can be berthed perpendicular to the quay wall. This permits denser berthing and allows material such as pipe, cable and chain to be spooled directly onto the deck. For a ten to twelve acre terminal, 1,000 feet or more of quay wall may be required depending on vessel berthing configuration.

Specialized locations along the quay wall may be equipped with petroleum risers for fuel or mobile loading equipment for dry bulk mud components. Typically, the wharf behind the quay wall should be rated at 2,000 pounds per square foot ground pressure and some areas directly behind the quay may be further reinforced for heavy-lift mobile crane operation.

6.3.4 Terminal Storage Areas

A typical service port will have six to twelve acres of paved and covered storage located directly behind the quay wall for staging and loading supplies. This storage area will include shop and warehouse buildings of 20,000 square feet to 40,000 square feet, lay-down area for containerized supplies, and open storage for pipe, cable, drill string and other large components. An additional six to twelve acres of land adjacent to the storage and loading area will be necessary for dry bulk cement and mud components either stored in silos or in super-sacks. Total dry storage capacity will be about 25,000 cubic feet. In the same area, the terminal will include tanks for liquid supplies such as polymers, hydrochloric acid, brine and other drilling mud additives. Drilling mud additives are stored in relatively small tanks or in portable tank containers. However, if drilling mud is prepared on-terminal then storage tanks total about 100,000 cubic feet will be necessary as well as mixing facilities of 25,000 square feet to 50,000 square feet (Dismukes, 2003).

A separate area for diesel fuel storage and waste oil (slops) processing will also be needed. Diesel fuel will require about 30,000 gallons of on-site storage with an associated containment structure. Waste oil generally will require the same storage capacity. However a small water separation plant may also be needed.

Therefore, a typical offshore O&G support terminal that provides all of the functions necessary to supply and support offshore drilling and production will require approximately 12 acres to 24 acres of upland area with approximately 1,000 feet of quay wall. In practice, many of the support terminal functions such as drilling mud storage and preparation are performed by a separate, specialized terminal.

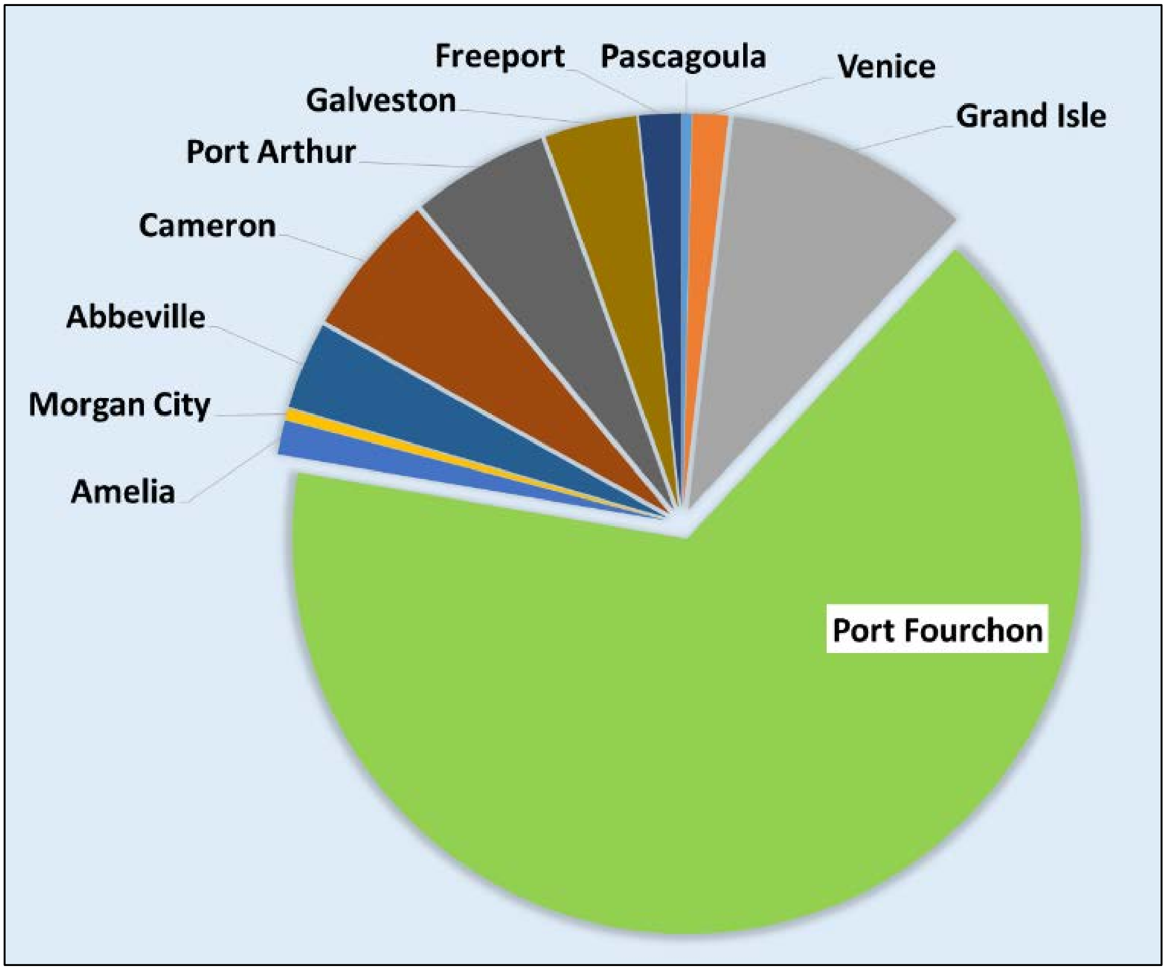
6.3.5 Other Infrastructure

The successful operation of the U.S. Gulf of Mexico offshore production fields include significantly more infrastructure than the support terminals. This infrastructure has been developed over a several decades and includes pipelines, shipyards, heliports and onshore storage facilities. Evaluation of this infrastructure in the Mid-Atlantic region will be discussed in subsequent sections.

6.4 SUMMARY OF SUPPORT TERMINAL REQUIREMENTS

Figure 6.4-1 illustrates the general layout of an offshore O&G support terminal that includes all of the necessary components for survey, exploration and production. The total area is approximately 18 acres which represents the mid-range of support terminal areas as described in Section 6.3.4. Using the metrics developed in Section 6.2, this 18 acre terminal will support about 300,000 acres of offshore lease area, 60 lease blocks, or 26 active offshore platforms.

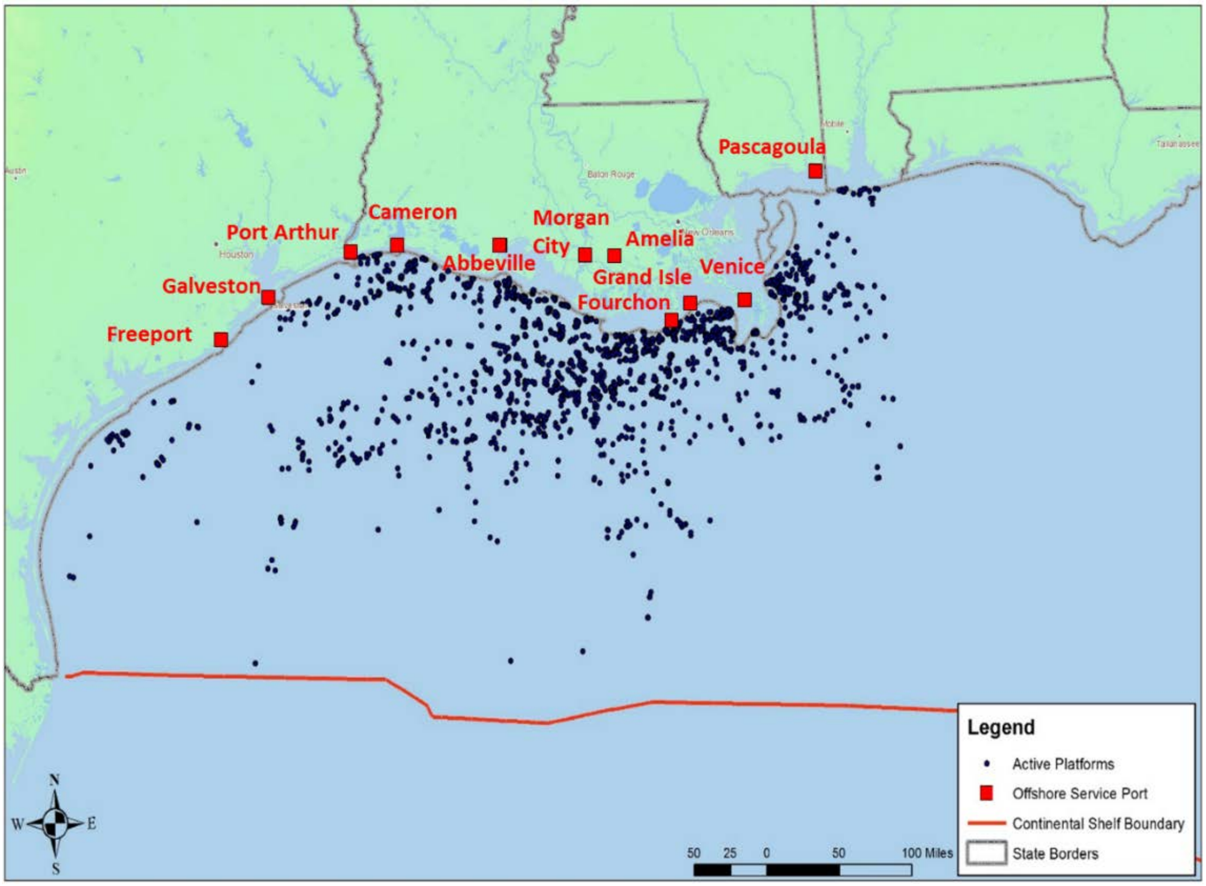
The vessel berth area is sufficient for three large PSVs, AHTS vessels or pipeline and cable-laying vessels berthed alongside. If the berths are perpendicular to the quay wall, then even more vessels can be serviced at one time. Two mud storage and mixing units ensures that two PSVs can be loaded at once.



RELATIVE LAND AREAS DEDICATED TO OFFSHORE OIL AND GAS SUPPORT TERMINALS

Oil and Gas Readiness Study

Offshore Virginia



Data modified from BOEM

LOCATION OF PRODUCTION PLATFORMS IN RELATION TO SUPPORT TERMINALS

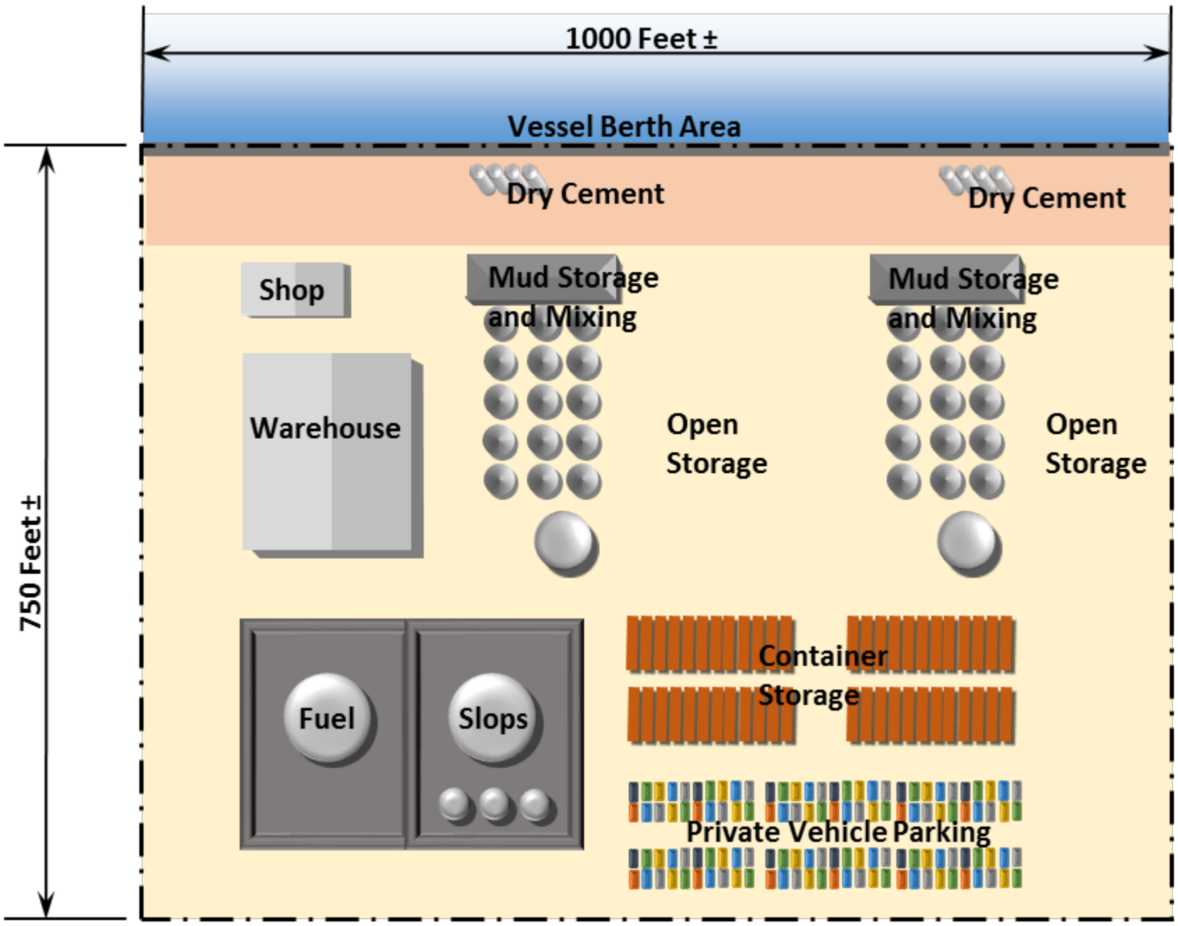
Oil and Gas Readiness Study

Offshore Virginia

Satellite Photo: Google Earth, Terrametrics

TYPICAL 24-ACRE SUPPORT TERMINAL
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 6.1-3



REPRESENTATIVE 18-ACRE SUPPORT TERMINAL
Oil and Gas Readiness Study
Offshore Virginia

7.0 ASSESSMENT OF EXISTING MID-ATLANTIC INFRASTRUCTURE

The second step of the three step process to determine the adequacy of existing infrastructure in the Mid-Atlantic region as well as to quantify the timing and phasing of infrastructure development, is to determine the existing support facilities for offshore oil and natural gas (O&G) production. This section evaluates the individual development stages for O&G production and the types of infrastructure necessary to support that development. It also documents the extent of the existing facilities in the states of Virginia, Maryland and North Carolina that could fulfill the Mid-Atlantic O&G exploration and production needs.

The Mid-Atlantic Region, as defined by the BOEM extends from the mouth of the Delaware River at Cape May, New Jersey to an extension of the North Carolina – South Carolina border. The federal lease jurisdiction begins three miles from the shore and extends approximately 200 miles out to sea. Figure 7-1 delineates the Mid-Atlantic Region relative to the adjacent states, and the outer continental shelf.

This section has found that most of the supporting infrastructure is concentrated in the Hampton Roads, Virginia region. However, both Maryland and North Carolina have port, shipyard or pipeline features that could also support offshore O&G exploration and production. Key infrastructure examples have been selected for evaluation and description.

7.1 TYPES AND ROLES OF INFRASTRUCTURE IN O&G DEVELOPMENT

7.1.1 Offshore Oil and Natural Gas Development Phases

An offshore oil and natural gas deposit or "play" follows five broad stages from a potential resource to a producing field. The initial leasing stage opens the process with a transfer of exploration rights to private exploration companies. To determine the presence of O&G resources, a geophysical survey must be commissioned. Once the survey is evaluated and the indications are favorable, then exploratory wells will be drilled and a production plan created. The process concludes with development of the play, production and finally capping and decommissioning of the wells and production platform (API, 2013b). This process is illustrated graphically in Figure 7.1-1.

Each development stage of an offshore O&G play requires a different subset of waterfront and inland infrastructure. At the beginning of the cycle, small harbors are required for environmental research and seismic survey vessels. When exploration is underway, a dedicated terminal for offshore supply, anchor-handling vessels and drilling vessels will be required. Finally, in the production stage, multiple support terminals and onshore developments will be needed.

7.1.2 Activity Support

7.1.2.1 Leasing and Survey

The initial stages of issuing a BOEM lease for offshore O&G require a programmatic environmental impact statement (EIS) before leases can be offered. Development of this EIS will involve offshore bathymetry, marine mammal observations, migratory fish and bird counts and other scientific surveys. After successfully securing an offshore block(s), the private exploration company will acquire detailed seismic data.

These activities require special-purpose vessels in the 80-foot to 160-foot size range. Environmental survey activities would be conducted by vessels located on the East Coast engaged in similar activities. Seismic surveys, and particularly high-resolution 3D seismic imaging would be conducted by specialized geotechnical survey vessels, likely relocated from the U.S. Gulf Coast. These operations would require secure berthing for resupply and refueling, but little additional supporting infrastructure (Cruickshank, 2014; Dellagiarino et al, 2012)).

7.1.2.2 Exploration

Once an offshore O&G play has been identified with a reasonable prospect for economic viability, then exploratory drilling can begin. Usually, this operation is conducted from a jack-up rig in water depths down to about 120m (~400 ft.) and a drilling vessel or a semi-submersible drilling unit in deep water. The exploratory drilling rig will typically drill and plug several wells, each taking a few months to complete. A "show", or positive find is followed by more exploratory wells to verify the quality of the play (Leffler, 2003).

Exploratory drilling requires a deep-water general cargo terminal for equipping and supplying the drilling vessel or semi-submersible. The deep-water terminal should have at least 35 feet of depth at berth and have 800 feet to 900 feet of contiguous marginal wharf in the case of handymax to Panamax size vessels ranging from 800 feet to 950 feet in length. The wharf apron must be capable of supporting basic cargo handling equipment such as mobile cranes and forklifts.

Resupply and support of the drilling vessel (or semi-submersible) will likely be provided by offshore supply (OSV) or anchor handling tug and supply (AHTS) vessels. These smaller ships can be accommodated at a terminal with approximately 250 feet (minimum) of marginal wharf. The offshore oil field sustainment functions of a typical service terminal are described in more detail in Section 6 of this report. In general, a smaller terminal footprint would be required for exploration than is necessary for sustainment and resupply of a drilling and production platform.

7.1.2.3 Development and Production

If exploratory drilling finds that a show contains economically recoverable hydrocarbon resources, then a development plan is prepared, the exploration drill rig is replaced with a drilling/production platform and commencement of production well drilling begins. An average well can produce hydrocarbons for decades, so offshore production platforms are built with a long stay in mind.

The development and production phase of a typical offshore O&G field requires dedicated terminals to serve the OSV and AHTS vessels that serve the drilling rigs and production platforms scattered throughout the offshore area. Exploration and production drilling rigs generally do not require a specialized marine terminal and can be loaded from an existing general cargo terminal. The exception may be jack-up service barges used for construction and heavy maintenance of offshore platforms. When a jack-up is necessary, material and supplies such as power units or crew modules are often loaded on its deck and transported to the site. A typical offshore service jack-up barge is 150 feet long and 100 feet wide. It draws from 18 feet to 20 feet of water including components of the jack-up legs that may extend below the barge hull.

Offshore production platforms also require ancillary facilities such as dedicated heliports, a system for receiving and distributing crude oil and natural gas, specialized manufacturing of pipeline components and offshore drilling equipment, offshore vessel repair services, vessel and equipment fabrication, oilfield waste disposal, and oil spill response services.

7.1.3 Supporting Infrastructure

7.1.3.1 Marine Terminals

During the leasing and survey stages of Mid-Atlantic O&G development, marine terminal requirements will be minimal. Survey companies will need lay-berth and port of call for mid-sized research vessels. Regular ship calls at a general cargo terminal will become necessary once the offshore block lessees move into the exploration stage. However, it is not likely that an offshore services company will invest in dedicated terminal facilities until one or more lease blocks moves into the development and production stages.

An investment in dedicated support and service terminals will be justified only after a discovery is made with economically recoverable amounts of oil and natural gas. At this time, a suitable site or sites must be selected and support terminals developed similar to those found in the U.S. Gulf Coast.

7.1.3.2 Onshore Infrastructure

7.1.3.2.1 Heliports

Heliports for the offshore O&G industry are essential for transporting personnel to and from the drill rigs and production platforms located far offshore. In the survey and exploration stages, adequate helicopter service could be maintained from existing commercial and private airports along the Mid-Atlantic coast. If enough production platforms are installed to justify a dedicated heliport, then a new site or sites can be constructed. An offshore service helicopter such as the Eurocopter EC225 Superpuma has a range of about 520 miles. Therefore, three heliports or commercial airports would be sufficient to serve the Mid-Atlantic Region.

Figure 7.1-2 illustrates a large heliport that is operated by Energy XXI Limited at Grand Isle, Louisiana on the Gulf Coast. This Heliport features twelve helipads and a mechanical service hanger on approximately 7.5 acres of land. It is capable of serving 750,000 acres of offshore lease at platforms operated by Energy XXI and its partners.

7.1.3.2.2 Oil and Natural Gas Receiving and Distribution

If economically recoverable O&G reserves are discovered in the Mid-Atlantic Region, then infrastructure will be required to receive the crude oil or natural gas and process it or transship it to market. Liquid gaseous petroleum products are often transported from an offshore oilfield to receiving facilities on the shore by submarine pipelines constructed specifically for that field. Offshore production platforms can be interconnected by “flowlines” that combine crude oil from several sources and direct them to the “export pipeline” that is used to bring the product ashore.

Shuttle tankers are used when economics or site conditions prevent installation of an export pipeline. Shuttle tankers are specialized ships built to transport crude oil and condensate from offshore oil field installations to onshore terminals and refineries and are often referred to as “floating pipelines”. Most often, shuttle tankers are used in conjunction with floating production, storage and offloading (FPSO) units permanently installed on the site. The advantages of shuttle tankers include the ability to segregate product from different wells and the flexibility for delivery to different markets (Barkwick, 2007; McCaul, 2001).

In the Mid-Atlantic Region, typically deep water, long distances and high storm surge may favor FPSOs over pipeline distribution. The cost of developing shore-based receiving and distribution infrastructure may also favor the economics of FPSOs. Floating liquefied natural gas (FLNG) vessels are under construction for various international markets. It has not yet been determined whether the cost of building a FLNG and distributing the gas by liquefied natural gas (LNG) carrier can compete with conventional pipeline construction.

7.1.3.3 Support Services

7.1.3.3.1 Offshore Vessel Service and Repair

Offshore O&G exploration vessels, service vessels, and production vessels require commercial shipyard facilities to perform periodic inspections and maintenance. Some specialty vessels, such as jack-up barges and exploratory rigs may be too wide for most available commercial dry-docks. These specialty vessels must be raised by a semi-submersible transport ship for an extensive repairs below the waterline.

The cost to remove an operating FPSO or semi-submersible offshore platform is prohibitive. Therefore, if repairs are required, they often must be performed by underwater service while the vessel is on station.

7.1.3.3.2 Offshore Platform and Rig Construction

Offshore platforms and fixed production rigs are not classified as merchant vessels in coastal trade. Therefore, this equipment can be sourced from international fabrication yards. Much of the offshore production equipment installed in the Gulf of Mexico was partially, or wholly constructed overseas. Often major components such as hulls or support legs are fabricated in Asia and joined with domestic parts in a U.S. construction yard.

7.1.3.3.3 Oil Field Waste Disposal

Oil field waste is composed of used drilling fluid and cuttings, entrained water, and other waste generated in the drilling and oil production process. Clean drilling fluid and cuttings are primarily mineral byproducts and can be safely disposed of on the ocean floor. Fluid contaminated with oil must be cleaned to an acceptable level before disposal. However, fluid containing polymer additives cannot be disposed of at sea. Similarly, contaminated water can be cleaned prior to disposal or it can be re-injected to stimulate production. However, all of these processes result in a waste stream that cannot be disposed of at sea and must be transported to land for processing and disposal. Special EPA certified inland disposal sites are required to support this operation.

7.1.3.3.4 Oil Spill Response Services

Offshore operators are required to file a regional oil spill response plan (OSRP) prior to exploratory drilling, production and pipeline operations, and oil handling and storage. This plan must demonstrate that the supplied equipment, materials, and vessels are of sufficient quantity and capacity and are suitable within the limits of current technology. For the OSRP to be acceptable, it will have to include response vessels and equipment stationed near the drilling activity.

Most oil spill response is conducted under a pre-arranged contract between the offshore lessee and a certified responder. Vessels, vessel berthing areas and response equipment storage are the responsibility of the responder. For the Mid-Atlantic Region, an adequate response capability will include vessels and facilities within a reasonable operating distance to the offshore facilities (Cruickshank; 2014; NOAA, 2013).

7.1.3.3.5 Communication and Emergency Response

Full cellular and land-line communication is available onshore throughout the Mid-Atlantic Region. However, cellular communication is only useful ten to fifteen miles offshore. Very high frequency (VHF) marine radio commonly has a range of 60 miles for commercial vessels. The U.S. Coast Guard monitors VHF channel 16 for offshore distress calls.

Emergency response inland is the responsibility of local counties and municipalities. Hospital services and medical evacuation is available in all of the urbanized areas. In Chesapeake Bay and offshore, emergency response is handled by the U.S. Coast Guard. The location of Coast Guard stations having response vessels or helicopters is shown in Figure 7.2-1 (Sivils, 2011).

7.2 MID-ATLANTIC REGIONAL INFRASTRUCTURE

7.2.1 Service Areas

The Mid-Atlantic Region covers approximately 450 miles of coastline and encompasses three states plus a portion of Delaware. Within the states of Maryland, Virginia and North Carolina, there are four major service areas; Baltimore, MD; Hampton Roads, VA; and Morehead City and Wilmington, NC. Because of the extensive maritime activity in Hampton Roads, the majority of infrastructure is found in that area. Underutilized facilities in Baltimore Harbor could be attractive locations for drill rig fabrication and repair. However, navigation distance from Baltimore makes it less attractive for offshore support terminal operations. Since service costs are dependent on distance and travel time, most offshore support terminals try to work within 150 miles of the lease block (Dismukes, 2014; NOAA, 2015). Therefore, the southern portion of the Mid-Atlantic Region may be better served by seaports and airports in North Carolina. Figure 7.2-1 illustrates the four service areas including the three potential support terminal locations.

7.2.2 Virginia Hampton Roads Port Infrastructure

Most of the public port activity is conducted in the Hampton Roads cities of Norfolk, Portsmouth or Newport News. However, there are multiple private terminals in the same region plus the City of Chesapeake on the Elizabeth River and at Cape Charles on the Eastern Shore. This report evaluates seven terminals including four public ports and three private sites that represent a spectrum of potential offshore O&G support terminals. The seven sites were selected in part because they have been previously considered for offshore wind energy support terminals, but also because they could be most readily adapted to offshore O&G support industry (Rondorf, 2009; VMA, 2014; VPA, 2015).

Private terminals on the Elizabeth River south of the City of Norfolk represent another potential for support terminal development. However, their present status and future availability is uncertain. If offshore O&G exploration is supported from Hampton Roads, then these terminals should be given closer evaluation. There are also port facilities farther west on the James River including the Port of Richmond. However, these terminals are too far from the ocean to be effective support facilities. Figure 7.2-2 illustrates the locations of the terminal sites that were considered.

7.2.2.1 Public Marine Terminals

7.2.2.1.1 Norfolk International Terminal

The Norfolk International Terminal Roll-on/Roll-off (NIT Ro-Ro) berth is located in a mixed-use section of the terminal. It includes approximately 22 acres of backland (operating area located inland of the wharf or bulkhead) and an 880 foot marginal wharf. It also includes two 1,300 foot berths at Pier 2. The backlands are occupied by two warehouses. The 880 foot marginal wharf is in good condition and has a stated depth of 33 feet. There is rail access to this site. The north and south faces of Pier 2 are used for equipment lay berthing. Water depths at the north face and south face are stated at 33 feet and 30 feet respectively. Figure 7.2-3 illustrates a schematic view of Norfolk International Terminal.

Summary:

- Owner – Virginia Port Authority
- Onshore Area – 22 acres
- Working Berth – 880 feet long with 33 feet of depth
- Lay-Berth – 2 Berths 1,300 feet long with 33 feet and 30 feet of depth
- Comments – Requires significant demolition and paving in the onshore area to create sufficient storage. Some portion of the warehouses may be salvageable.

7.2.2.1.2 Portsmouth Marine Terminal

Portsmouth Marine Terminal (PMT) was designed to be operated as a container terminal. PMT has a total of 4,500 feet of marginal wharf at a stated depth of 43 feet and a design depth of 45 feet. PMT has 287 acres of paved backlands, including 45 acres leased to Skanska USA until 2017 and 13 acres leased to Ecofuels, and about 44 acres used as a container terminal. Presently, 185 acres of backlands with access to the container berths and six container gantry cranes may be available. There is rail access to this site. Figure 7.2-4 illustrates a schematic view of Portsmouth Marine Terminal.

Summary:

- Owner – Virginia Port Authority
- Onshore Area – 185 acres presently available
- Working Berth – 4,500 feet long with 43 feet of depth
- Comments – The 45 acre Skanska USA operating area includes 1,000 feet of wharf

7.2.2.1.3 Half Moone Cruise Center

The Half Moone Cruise Center includes a 725 foot marginal wharf that was upgraded in 2007 to take large cruise vessels. The Cruise Center includes an 80,000 square foot passenger and baggage handling facility but does not have adjacent storage. Water depth at the berth is about 34 feet.

The Cruise Center wharf is available much of the year for transient vessels, research ships and visiting naval vessels. It includes truck and forklift access as well as passenger amenities. Figure 7.2-5 illustrates a schematic view of Half Moone Cruise Center.

Summary:

- Owner – City of Norfolk
- Onshore Area – Short-term truck circulation only
- Working Berth – 725 feet long with 34 feet of depth
- Comments – The Half Moone Cruise Center is suitable for short-term vessel calls that require good passenger access and the ability to load small equipment and supplies.

7.2.2.1.4 Newport News Marine Terminal, Pier C

Newport News Marine Terminal (NNMT) was constructed as a general cargo terminal and now handles automobiles and paper as well as other non-containerized general cargo. NNMT Pier C had been converted to container handling, but is no longer in use. Pier C has two 940 foot berths and one 560 foot berth at the end. The depth is stated to be 40 feet for all three berths. Approximately 20 acres of backlands could be developed adjacent to Pier C and an additional 10 acres of storage could be used on the Pier itself. The pier and onshore area includes two existing warehouses. There is rail access to Pier C. Figure 7.2-6 illustrates a schematic view of Newport News Marine Terminal, Pier C.

Summary:

- Owner – Virginia Port Authority
- Onshore Area – 20 acres onshore and 10 acres on the pier.
- Working Berth – 2 Berths, 940 feet long plus 1 berth, 560 feet long. All three berths have 40 feet of depth.
- Comments – The south face of Pier C has a single container gantry crane for cargo handling. Additional onshore storage at Newport News Marine Terminal may become available.

7.2.2.2 Private Marine Terminals

7.2.2.2.1 Cape Charles South Port

The City of Cape Charles and various property owners have several proposals for mixed-use projects at the Cape Charles South Port Site. However, it is presently undeveloped. There is sufficient waterfront for about 900 feet of wharf but the existing wharf is deteriorated and must be replaced before it can be used. Water depth at the site is said to be about 14 feet in the Harbor Basin, but the access channel limits at about 12 feet in the entrance. Immediately behind the wharf area there are approximately 20 acres of undeveloped upland. Further inland there is a total of 117 acres. However inland site and the waterfront sites are owned by different developers. Figure 7.2-7 illustrates a schematic view of Cape Charles South Port.

Summary:

- Owners – Harbour Development Group (waterfront) and South Port Investors (inland).
- Onshore Area – 20 acres adjacent to the wharf with 117 acres of inland property

- Working Berth – Potential for 900 feet of working berth at 14 feet of depth
- Comments – This site has no current use or usable improvements. Without dredging, the current channel depth limits the maximum vessel size that could use this site.

7.2.2.2.2 Lambert's Point Piers N, L and P

Lambert's Point Piers N, L and P were originally constructed to be rail-served general cargo terminals with extensive transit-shed warehouses on-dock and in the uplands. There are eight berths at the terminal. Pier N and Pier P are in usable condition. However Pier L is deteriorated and can only be used for lay-berthing. Berth dimensions are shown in the Berth Schedule in Table 7.2-1.

Table 7.2-1 Lambert Point Berthing Schedule

Berth Schedule	Length	Depth[1]
Pier N		
• North Face	1,100 Feet	32 Feet
• South Face	1,100 Feet	31 Feet
• End	390 Feet	34 Feet
Pier P		
• North Face	1,200 Feet	36 Feet
• South Face	1,200 Feet	32 Feet
• End	400 Feet	31 Feet
Pier L (lay-berth)		
• North Face	755 Feet	31 Feet
• South Face	755 Feet	32 Feet

The Lambert's Point site has about 45 acres of onshore in various states of development including unimproved, paved and with warehouse improvements. Pier N and Pier P also have 10 acres of surface each. This site is rail-served. Figure 7.2-8 illustrates a schematic view of Lambert's Point Piers N, L and P.

Summary:

- Owner – Norfolk Southern Railroad
- Onshore Area – 45 acres backlands and 10 acres each on two piers.
- Working Berths – 6 Berths with a total of 5,390 feet long and a depth ranging from 31 feet to 36 feet.
- Lay Berths – 2 Lay berths of 755 feet each and 31 to 32 feet depth.
- Comments – Pier N or Pier P would likely require warehouse demolition to create sufficient working area. Considerable demolition, paving and construction would be required in the backlands.

7.2.2.2.3 CSX Piers 14 and 15

Piers 14 and 15 were originally constructed for coal loading but were replaced by an adjacent modern facility in the mid-1980s. Presently they are used for lay-berthing and occasional cargo handling. Pier 14 appears to be in fair condition, but Pier 15 has deteriorated and likely is only suitable for lay berthing in its present condition. Pier 14 has two berths, each 1,088 feet long with

[1] Source: NOAA Chart 12253

a design water depth of 45 feet and a reported water depth of 40 feet. Pier 15 is shown with a depth ranging from 30 to 35 feet. The 47 acre upland parcel is largely unimproved. Of that, about 30 to 35 acres are useable due to the narrow, elongated site configuration at the north of the parcel. Rail access is possible at this site. Figure 7.2-9 illustrates a schematic view of CSX Piers 14 and 15.

Summary:

- Owner – CSX Railroad
- Onshore Area – 47 acres total uplands with 30 to 35 acres usable.
- Working Berths – 2 Berths of 1,088 feet each and a depth of 40 feet.
- Lay Berth – 2 Lay berths of 980 feet each and a depth ranging from 30 to 35 feet.
- Comments – The ability of Pier 14 to bear cargo handling equipment is unknown and both piers will require some repair for long-term use. The backlands will also require significant improvements. Jerry O. Talton Inc. operates this terminal. Pier 14 is currently under lease to the U.S. Transportation Command for Large, Medium-Speed Roll-on/Roll-off vessel lay-berthing.

7.2.2.1 Summary Matrix

The seven Virginia sites reviewed in this report section represent marine terminals that have been previously considered as construction centers for bridges, tunnels and offshore wind developments. Their actual condition and the disposition of the sites may differ from the publicly available data. Their condition and future availability will have to be determined on a case-by-case basis if offshore O&G in the Mid-Atlantic Region is to be supported from Virginia.

Not all of the terminals reviewed are suitable for all offshore O&G functions. The matrix below compares potential uses for each of the Virginia sites.

Table 7.2-2 Terminal Summary Matrix

Terminal	Leasing	Seismic Survey	Exploration	Development	Production	Fabrication	Notes
NIT Ro-Ro			X	X	X		Less suitable for small vessels[2]. Requires landside investment.
PMT	X	X	X	X	X		Ready for use. Small vessel facility on site at Skanska lease.
Half Moone Cruise	X	X					Suitable for personnel transport and equipment transfer.
NNMT Pier C			X	X	X		Less suitable for small vessels. Ready for use.
Cape Charles					X	X	Requires significant investment in dredging and construction.
Lambert's Point				X	X		Less suitable for small vessels. Requires significant investment.
CSX Piers 14 & 15				X	X	X	Less suitable for small vessels. Requires significant investment.

[2] Survey and crew vessels of less than 100 feet length

7.2.2.2 Other Hampton Roads Infrastructure

There are over seventy marine terminals, construction yards and waterfront sites in Newport News and along the Elizabeth River that could support offshore O&G exploration and production. These terminals have various levels of use and existing tenants.

A detailed inventory of all waterfront facilities is not an objective of this study and these terminals have not been included in this evaluation. However, they should be considered if sufficient terminal capacity cannot be developed at the larger ports. Figure 7.2-10 illustrates the relative location of most of these facilities.

Hampton Roads also has a mature network of highways and railroad lines. Truck traffic generally arrives and departs the area on Interstate Highway 64/664 from Richmond, U.S. Route 460 from Petersburg or U.S. Route 58 from Emporia. Rail commerce, including intermodal, tank car trains and carload traffic is served by two Class 1 railroads, CSX and Norfolk Southern. Distribution, switching and manifest traffic can be handled by the local short-lines, Commonwealth Railway, and Norfolk-Portsmouth Beltline Railroad. Figure 7.2-10 illustrates the major roadways as well as the rail lines serving Hampton Roads.

7.2.3 Onshore Infrastructure

7.2.3.1 Heliports

Offshore helicopter support is most often used for personnel transfer, medical evacuation and delivery of small parts and supplies. Helicopters used in this service generally have a range of 300 miles to 500 miles depending on their size and configuration. Due to the high hourly cost of helicopter operations, offshore service companies locate their heliports as close to the center of drilling and production as is practical.

Very few commercial airports are located along the U.S. Gulf coast. Therefore, offshore service companies have constructed private heliports to serve the offshore drilling and production platforms. However, in the Mid-Atlantic Region, there are at least nine small to mid-sized public airports with sufficient infrastructure to support a helicopter operation on or near the coast. The airports identified in this study are shown on Figure 7.2-1 and include:

1) Woodbine Municipal Airport – Woodbine, New Jersey
2) Salisbury Wicomico Regional Airport – Salisbury, Maryland
3) Accomack County Airport – Melfa, Virginia
4) Patrick Henry International Airport – Newport News, Virginia
5) Norfolk International Airport – Norfolk, Virginia
6) Chesapeake Regional Airport – Chesapeake, Virginia
7) Dare County Regional Airport – Manteo, North Carolina
8) Beaufort Morehead City Airport – Beaufort, North Carolina
9) New Hanover County Airport – Wilmington, North Carolina

Together, these airports cover the entire Mid-Atlantic Region. Until there is significant offshore activity, one or more of these existing airports could be used as a helicopter base. When offshore O&G production justifies significant helicopter traffic, the offshore service providers may elect to permit and construct a dedicated heliport to support individual offshore O&G fields.

7.2.3.2 Oil and Natural Gas Receiving and Distribution

If economically developable offshore oil or natural gas resources are discovered in the Mid-Atlantic Region, then infrastructure will be necessary to transport this product to market. There are no crude oil pipelines in the states bordering the Mid-Atlantic. Therefore, liquid product distribution will likely be by shuttle tanker to an east coast refinery. In the Region, there are four crude oil refineries, all located on the Delaware River in Pennsylvania, Delaware, or New Jersey, as shown on inset a of Figure 7.2-11. As an alternative, crude oil could be delivered by larger ships to the U.S. Gulf Coast or to international markets. In all cases, this operation will require an FPSO vessel (described in Section 7.1.3.2.2) as part of the offshore oil field infrastructure (EIA, 2006; EIA, 2014).

Raw natural gas is usually delivered to market through a network of pipelines. The wellhead product must be processed before it can be delivered as pipeline-quality dry natural gas. This process usually involves several stages to remove oil, water, carbon dioxide, and natural gas liquids. Elements such as sulfur and helium can also be recovered from the product stream. Processing generally takes place at a natural gas compression plant located where the product comes ashore. There are no natural gas processing plants in the Mid-Atlantic Region. However, there is an extensive network of intra-state and interstate natural gas pipelines as shown in Figure 7.2-11.

All of the coastal pipelines connect to a trunk line that runs from the Louisiana Gulf Coast through Virginia to New York and Pennsylvania (as shown on Figure 7.2-11). This line, owned by Transcontinental Pipeline LLC carries over 10 billion cubic feet of natural gas per day. If natural gas from the Mid-Atlantic region is distributed into the Transcontinental Pipeline, then natural gas processing plants will be required wherever the pipelines come ashore.

In some international markets, it has been found that liquefying the natural gas offshore and delivering by LNG carrier is more economical than constructing the necessary underwater and surface pipelines. If this is found to be true in the Mid-Atlantic, then a floating liquefaction plant would be sited at the center of production and liquid product could be delivered to an onshore LNG receiving terminal such as in Cove Point, Maryland shown on inset a of Figure 7.2-11.

7.2.4 Support Services

7.2.4.1 Offshore Vessel Service and Repair

There are eight large commercial ship repair yards in the Hampton Roads area capable of handling offshore service vessels. Of these, five have sufficient ship lift or dry-dock capacities for vessels of 1,000 tons light displacement and greater (VMA, 2014; The Maritime Network):

1) A.N.A. Shipyard Division of East Coast Repair and Fabrication
    - Four marine railways with capacities up to 1,000 tons.
    - Wet berth accommodations for vessels up to 300 feet in length and 20 feet draft.
2) BAE Systems, Norfolk Ship Repair
    - Floating dry-dock Titan with a capacity of 52,500 tons
    - Floating dry-dock Old Dominion with a capacity of 14,000 tons
    - Four wet-berth piers over 3,000 feet in length
3) Colonna's Shipyard, Inc.

- Floating dry-dock Captain Will with a capacity of 17,200 tons
- Floating dry-dock Willoughby III with a capacity of 2,800 tons
- Marine Travelift with a capacity of 1,000 tons
- Eight berths of various lengths for ship repair

4) Lyon Shipyard, Inc.
   - Two floating dry-docks with capacity up to 4,900 tons
   - Three marine railways with a capacity of up to 3,100 tons
   - Two wet berths of 450 and 500 feet
5) Newport News Shipbuilding Division of Huntington Ingalls Industries
   - Graving dock #12 with capacity for ships up to 250 feet wide and variable length up to 2,100 feet
   - Five graving docks with capacity for ships between 500 feet and 1,000 feet
   - Floating dry-dock with a capacity of 40,000 tons
   - Over 6,500 feet of wet berth with depth up to 45 feet

Some of the Hampton Roads shipyards are not suitable for all offshore O&G vessels and some of the larger yards may be cost-prohibitive for maintenance of smaller vessels. The matrix below compares potential uses for each of the Virginia shipyards.

Table 7.2-3 Potential Use Summary Matrix for Each of the Virginia Shipyards

Shipyard	Survey and Crew Boats	Offshore Service Vessels	Anchor Handling Tugs	Jack-up Service Ships	Jack-up Drill Rigs	Drilling vessels	Semi-Submersibles	FPSO Units	Fabrication	Notes
A.N.A. Shipyard	X	X								May not handle larger offshore service vessels
BAE Systems				X	X	X		X		May handle smaller semi-submersibles
Colonna's Shipyard	X	X	X	X					X	May not handle larger jack-up service ships
Lyon Shipyard	X	X	X							May not handle larger anchor handling tugs
Newport News Shipbuilding					X	X	X	X	X	May not be economical for smaller vessels

7.2.4.2 Offshore Equipment Fabrication

Offshore platforms and fixed production rigs are often sourced from international fabrication yards or the U.S. Gulf states and are unlikely to be constructed on the East Coast. However, pipeline fabrication, drill-string, drilling equipment and possibly offshore platform foundation elements could be fabricated at one of the Hampton Roads, Virginia, or Baltimore, Maryland shipyards (API, 2014b).

7.2.4.3 Oil Field Waste Disposal

Hampton Roads has as history of marine commerce and ship repair. In support of this commercial activity, several companies offer tank cleaning and oily "slops" disposal. Accurate Marine Environmental has recently constructed a wastewater and oil treatment plant at their Portsmouth, Virginia terminal with storage capacity of over 10,000 barrels that can treat up to

3,500 barrels per day. If drilling and production begins in the Mid-Atlantic Region, companies such as Accurate Marine could bid on waste disposal contracts and build additional capacity to accept offshore drilling waste.

7.2.4.4 Oil Spill Response Services

The Marine Spill Response Corporation, located in Herndon, Virginia, is the largest, dedicated oil spill and emergency response organization in the United States. They maintain 16 offshore response vessels nationally. The vessel New Jersey Responder is home-ported in Perth Amboy, New Jersey and can be dispatched to oil spills anywhere on the east coast. In addition, oily waste disposal companies such as Accurate Marine Environmental have local support, based in Portsmouth, capability for oil spill cleanup and disposal. If offshore production is initiated in the Mid-Atlantic Region, additional oil spill response capability may become necessary.

7.2.5 Maryland Infrastructure

The Maryland terminals that could serve offshore O&G are all located in Baltimore Harbor. Although the Baltimore terminals are not central to the Mid-Atlantic Region, they could potentially support developments in the northern area via the Chesapeake and Delaware Canal. Five terminal and fabrication sites are located in Baltimore Harbor. These sites were evaluated to determine their existing capabilities and to estimate the degree to which they could support offshore O&G operations. Figure 7.2-12 shows the relative location of the facilities within Baltimore Harbor.

7.2.5.1 Rukert Terminals

Rukert Terminals operates two general cargo berths: Berth A is a 544 foot wharf with 36 feet of draft and Berth B is a 950 foot berth with 50 feet of draft. Berth B is rated for 2,000 pounds per square foot of load and supports a 500 ton Liebherr mobile harbor crane. Rukert Terminal is rail served. Figure 7.2-13 shows the relative location of the facilities within Rukert Terminals.

Summary:

- Owner – Rukert Terminals, Inc.
- Onshore Area – 37 acres onshore adjacent to the wharf.
- Working Berths – 2 Berths of 544 feet and 950 feet with depths of 36 feet and 50 feet respectively.
- Comments – Currently used for import of project cargo and dry bulk material. Additional onshore is available in non-contiguous lots. Backlands have heavy paving; a 500 ton mobile harbor crane is available on-site.

7.2.5.2 AmPorts

AmPorts operates a Ro-Ro auto terminal that includes multiple properties, both contiguous and separate that are primarily dedicated to automobile receiving and preparation. Approximately 175 acres are owned or leased by AmPort with 66 acres available for offshore O&G support. About 200 additional acres could be available for lease if needed. The AmPorts terminal has direct rail access. Figure 7.2-14 shows the relative location of the facilities within AmPorts.

Summary:

- Owner – AmPorts Terminals

- Onshore Area – 175 acres onshore with 66 acres available.
- Working Berths – 2 Berths of 600 feet and 544 feet with depths of 25 feet and 35 feet respectively.
- Comments – Currently used for import of automobiles. Additional onshore is available in non-contiguous lots. Contiguous with Marine Applied Physics Corporation (MAPC) that is interested in leasing land and facilities for fabrication. Long term use would require construction or reconstruction of a dedicated wharf.

7.2.5.3 Cianbro Corporation

Cianbro Corporation operates a fabrication and coating yard in Baltimore for preparation of pipe and structural steel piles. The facility includes a 400 foot wharf with a 100 foot wide apron constructed for heavy lift crane operation. The wharf is on Curtis Creek which is a federal channel maintained to 14 feet at mean lower low water with a federally authorized depth of 22 feet. Figure 7.2-15 shows the relative location of the facilities within Cianbro Corporation.

Summary:

- Owner – Cianbro Corporation
- Onshore Area – 15 acres onshore adjacent to the wharf.
- Working Berths – 1 Berths of 400 with a depth of 14 feet
- Comments – Currently used for import of project cargo and dry bulk material. Additional onshore is available in non-contiguous lots. Backlands have heavy paving and a 500 ton mobile harbor crane is available on-site. This site is limited by depth, but may be suitable for barge loading of piles and pipe.

7.2.5.4 Sparrows Point Shipyard

Sparrows Point Shipyard covers approximately 180 acres on the west side of the former Bethlehem Steel Mill site. It is currently in use for ship-breaking and maintenance. The yard has a working dry-dock that is 200 feet wide, 1200 feet long and 28 feet in depth. A dry-dock of this size is capable of taking large offshore equipment such as semi-submersible rigs. It also has two piers; Pier 3 with two working berths and a 50 ton whirley crane, and Pier 1 with two lay-berths Sparrows Point Shipyard has rail access. Figure 7.2-16 shows the relative location of the facilities within Sparrows Point Shipyard.

Summary:

- Owner – Sparrows Point Shipyard
- Onshore Area – 180 acres onshore with 66 acres available on the northern end.
- Working Berths – 2 Working berths at Pier 1, 1,050 feet on the south and 740 feet on the north with depths of 40 feet and 30 feet respectively.
- Lay-Berths – 2 Lay-berths at Pier 3, approximately 700 feet usable on the north and south with depths of 28 feet and 24 feet respectively.
- Dry-dock – Graving type dry-dock 1,200 feet by 200 feet with 28 feet of working depth.
- Comments – Currently the graving dock is under contract with Kiewit Construction for assembling immersed tube tunnel sections. The yard also features associated warehouses and shops as well as a pier and a 50-ton shipyard crane. Significant

demolition, reconstruction and paving would be necessary to use this shipyard for fabrication

7.2.5.5 Sparrows Point Kinder Morgan

The decommissioned Bethlehem Steel mill at Sparrows Point includes over 1,000 acres of former smelter, rolling mill and associated infrastructure. The mill also includes a Turning Basin for receiving ore and coal and for shipping product. The existing berths within the Turning Basin were configured for receipt of coal and are in need of repair. Figure 7.2-17 shows the relative location of the facilities within Kinder Morgan Sparrows Point.

Summary:

- Owner – Kinder Morgan Corporation
- Onshore Area – 1,000 acres upland
- Working Berths – Marginal wharf 2,000 feet long and a finger pier 1,000 feet long with a depth of approximately 40 feet
- Comments – Currently the onshore site is being demolished and multiple aggregate operations are taking place at the marginal wharf. The finger pier is designed for bulk iron ore unloading and may require significant modifications to make it suitable for other uses. Significant demolition, reconstruction and paving would be necessary to use this site for fabrication or offshore support. Sparrows Point has rail access.

7.2.6 North Carolina Infrastructure

In addition to airport and pipeline infrastructure, North Carolina has two ports that could provide support to offshore O&G exploration and development. These ports include Morehead City with deep-water dry bulk cargo terminals and Wilmington with general cargo facilities (North Carolina State Ports Authority, 2015). The location of these ports is shown in Figure 7.2-1.

7.2.6.1 Port of Morehead City

The marine terminal at Morehead City was originally constructed to support forest products, petroleum and mixed break-bulk. A 177,000 square foot warehouse was constructed in 2007. The terminal is in good condition. It has two adjacent wharfs of 1,340 feet long and 1,000 feet long with a design water depth of 35 feet. There is rail access at this site. Figure 7.2-18 shows the relative location of the facilities within Port of Morehead City.

North Carolina State Ports Authority also has a 150 acre site on Radio Island that is entirely undeveloped and could support a large project such as a fabrication yard. However, all waterfront structures and dredging would have to be permitted and constructed at the developer's expense.

Summary:

- Owner – North Carolina State Ports
- Onshore Area – Approximately 30 acres onshore including three warehouses covering approximately 9 acres.
- Working Berths – 2 marginal wharfs 1,340 feet long and 1,000 feet long, both having depths of 35 feet

- Comments – Currently the terminal is used for mixed dry bulk and general cargo. Warehouse demolition may be necessary to make full use of the site.

7.2.6.2 Port of Wilmington

The terminal was originally constructed to support mixed break bulk and forest product. There are three older warehouses on the site plus an equipment garage. The site has an adjacent wharf of 1,200 feet long with a design water depth of 42 feet. The wharf is in good condition. However, some of the warehouses would have to be demolished to make full use of this site. Adjacent terminal areas and wharf frontage may be available. There is rail access at this site. Figure 7.2-19 shows the relative location of the facilities within Port of Wilmington.

North Carolina State Ports Authority also has a 160 acre site at the Port of Wilmington that is entirely undeveloped and could support a large project such as a fabrication yard. However, all waterfront structures and dredging would have to be permitted and constructed at the developer's expense.

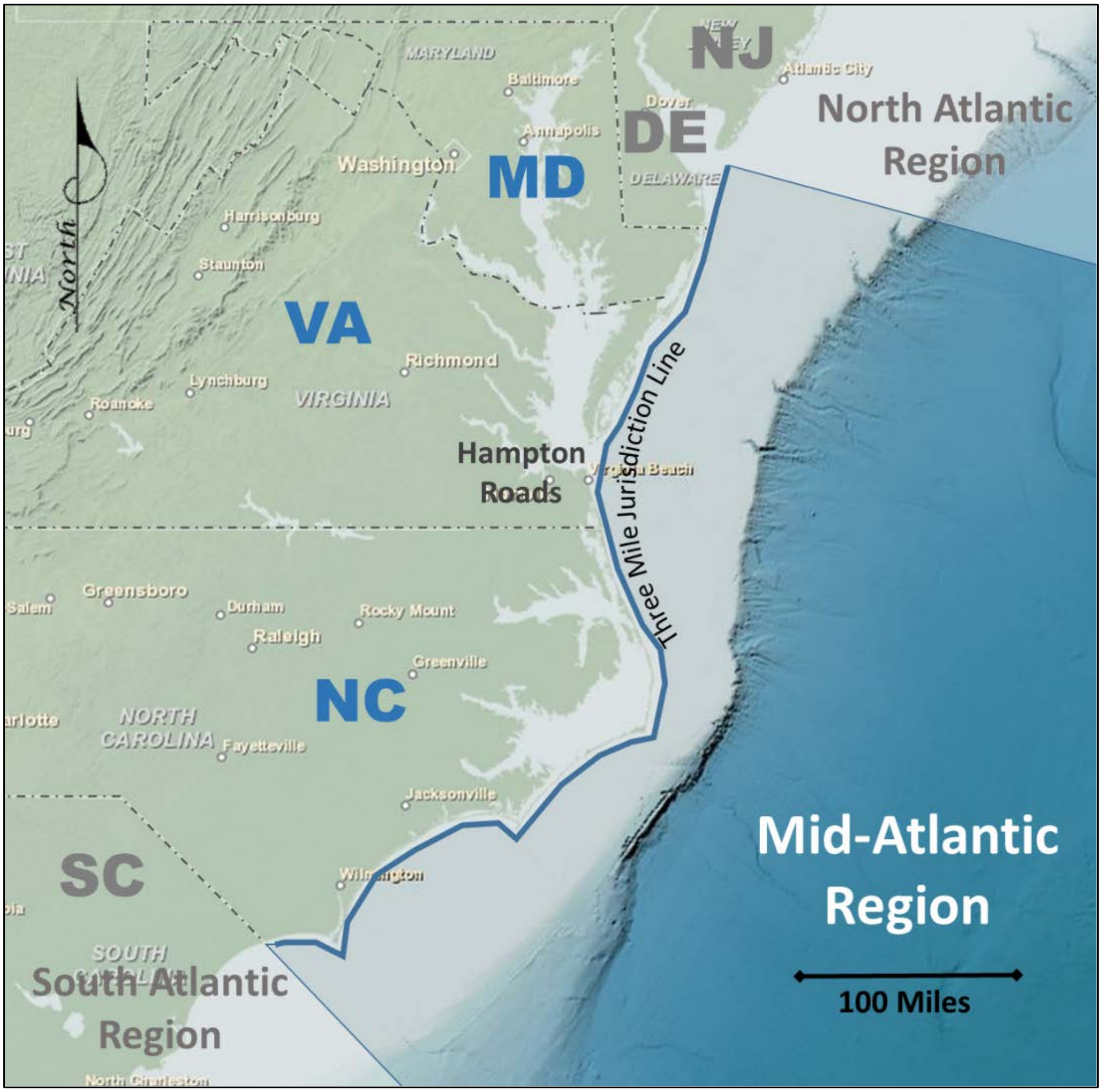
Summary:

- Owner – North Carolina State Ports
- Onshore Area – 20 acres onshore of which 5.5 acres are covered by warehouses
- Working Berths – Marginal wharf 1,200 feet long with a depth of 42 feet.
- Comments – to make full use of this terminal the warehouses must be demolished and the pavement repaired. The Port of Wilmington may have other tenants or uses at this site.

7.2.7 Maryland and North Carolina Site Capability Matrix

Table 7.2-4 Maryland and North Carolina Port Compatibility Matrix

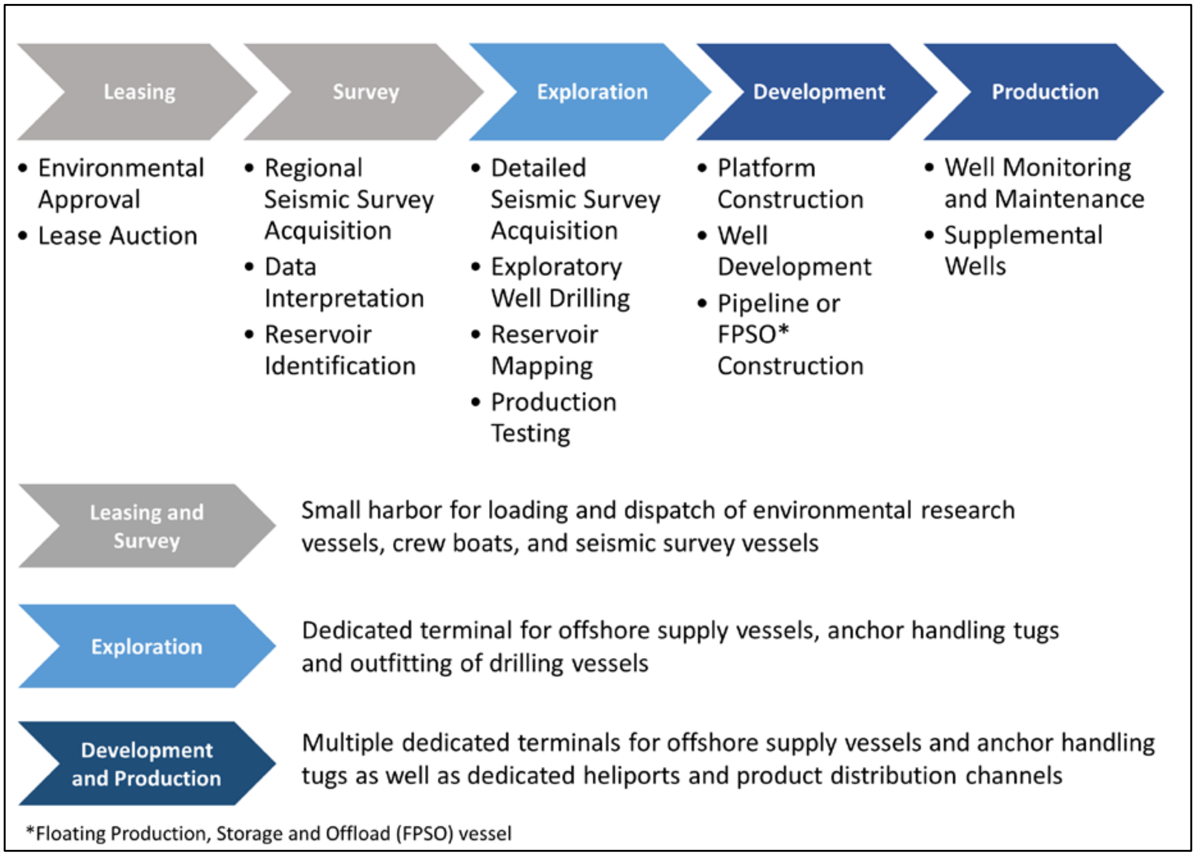
Site	Leasing	Seismic	Exploration	Development	Production	Ship Repair	Fabrication	Notes
Rukert Terminals			X	X	X			May not be suitable for smaller vessels
AmPorts			X	X			X	May conflict with existing uses
Sparrows Point Shipyard						X	X	Could take semi-submersible, room for jacket fabrication
Sparrows Point Kinder Morgan				X	X		X	Not suitable for immediate use, room for jacket fabrication
Cianbro	X	X					X	Not suitable for larger vessels, could support pipe fabrication
Morehead City			X	X	X		X	Small vessel facilities may also be available within the harbor
Wilmington			X	X	X		X	Small vessel facilities may also be available within the harbor



Data modified from BOEM, NOAA and EIA

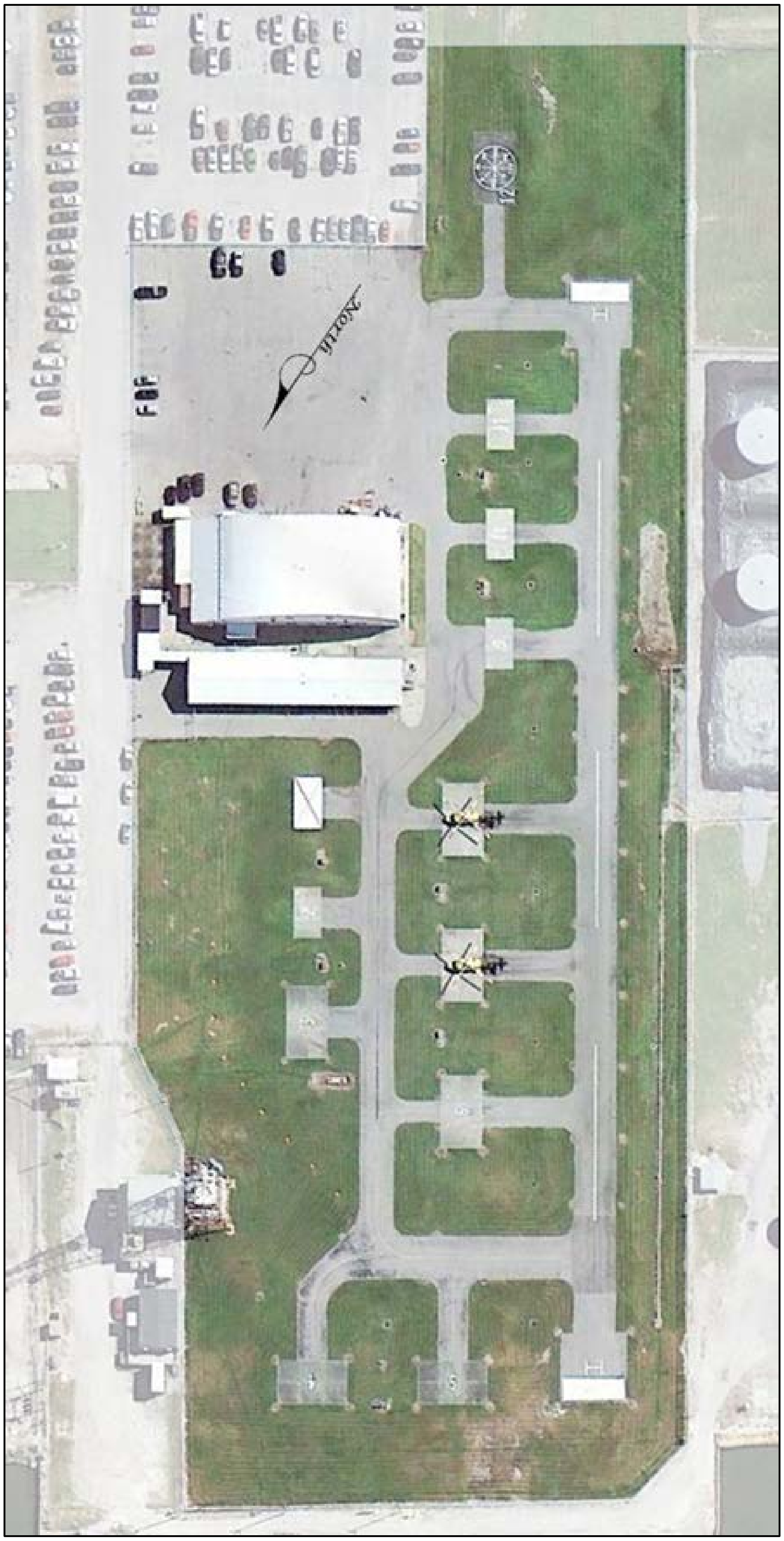
MID-ATLANTIC REGION
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7-1



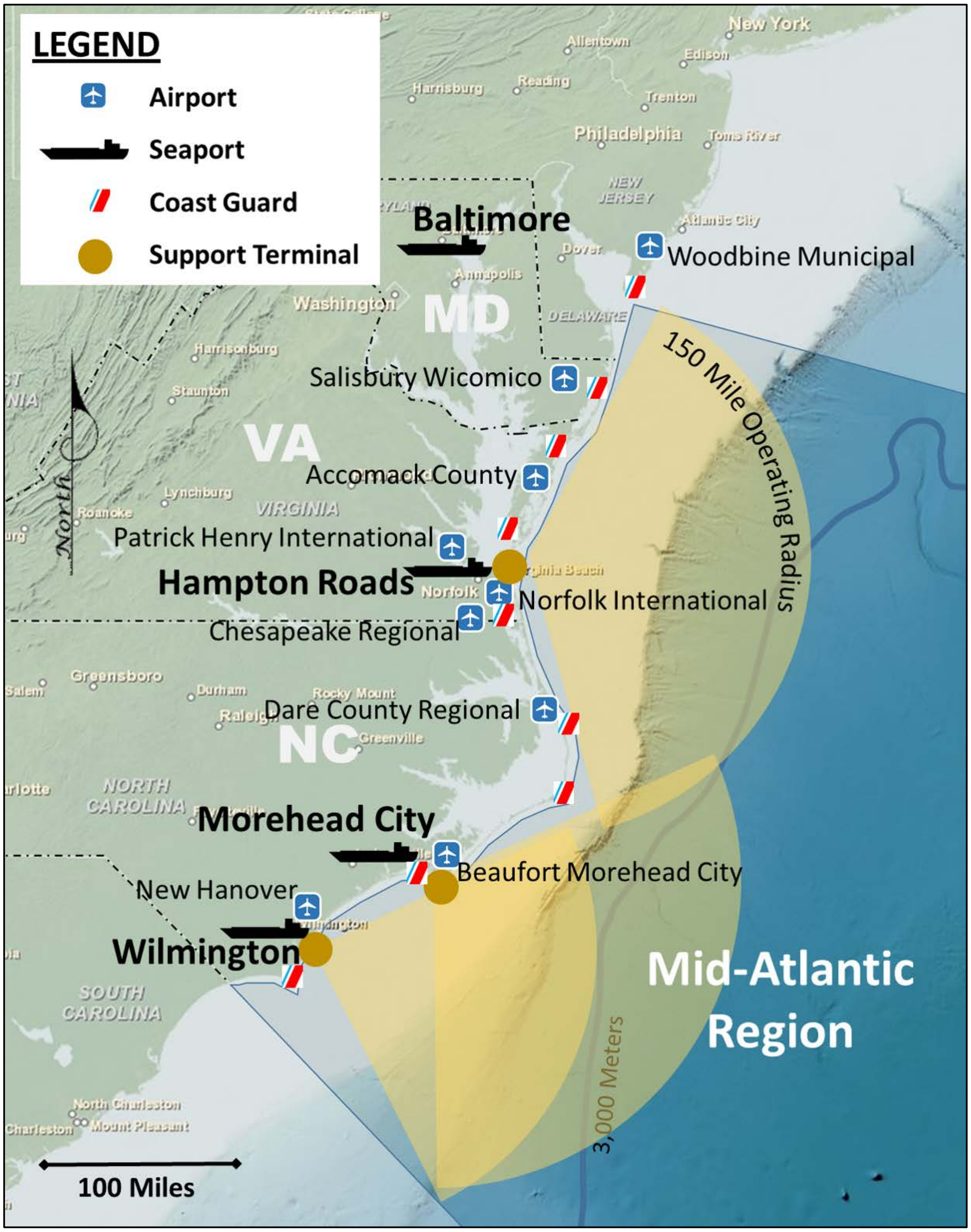
OFFSHORE OIL AND NATURAL GAS DEVELOPMENT STAGES AND NEEDS

Oil and Gas Readiness Study
Offshore Virginia



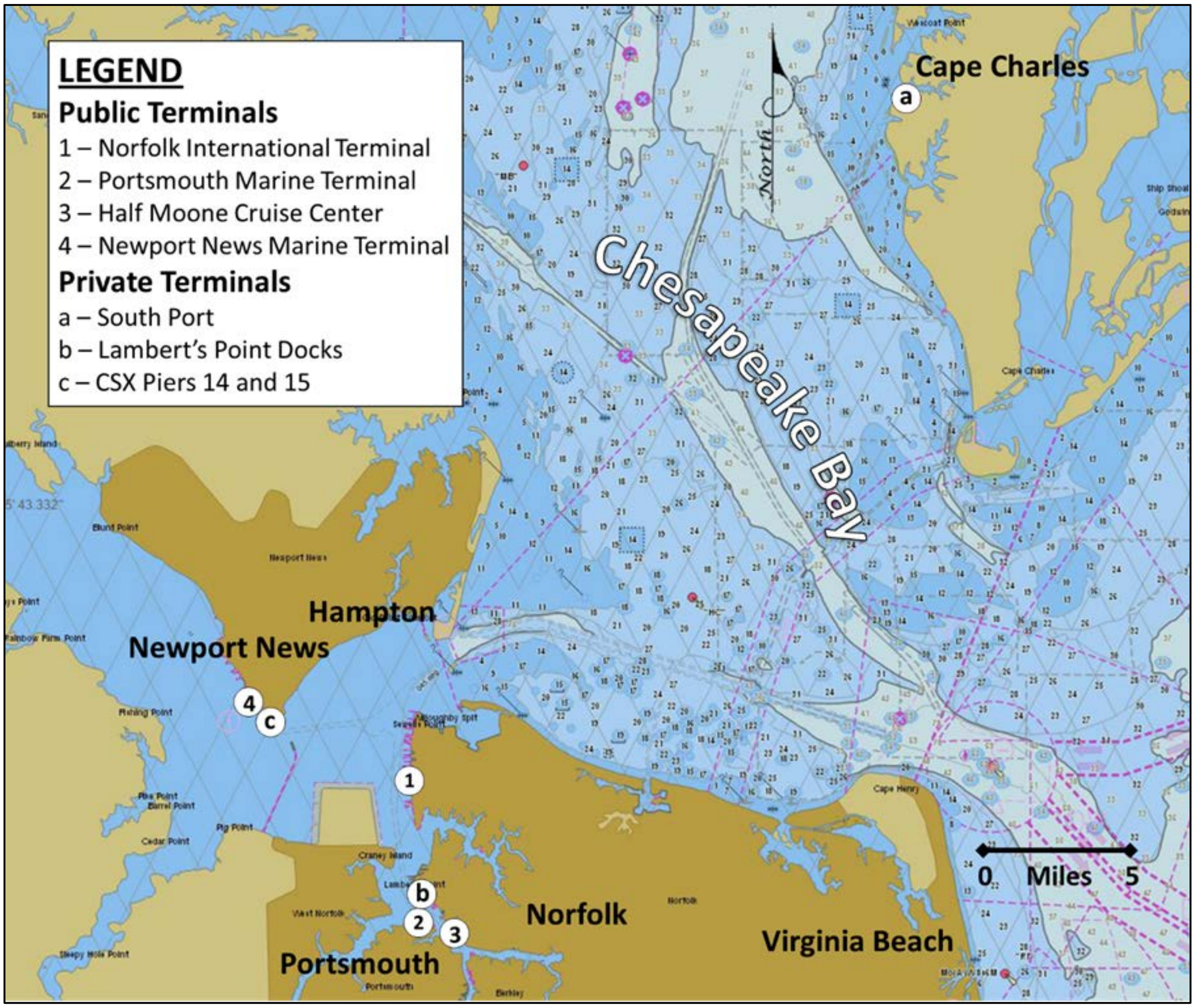
Satellite Photo: Google Earth, Terrametrics

OFFSHORE SERVICE HELIPORT
Oil and Gas Readiness Study
Offshore Virginia



Data modified from BOEM, NOAA and EIA

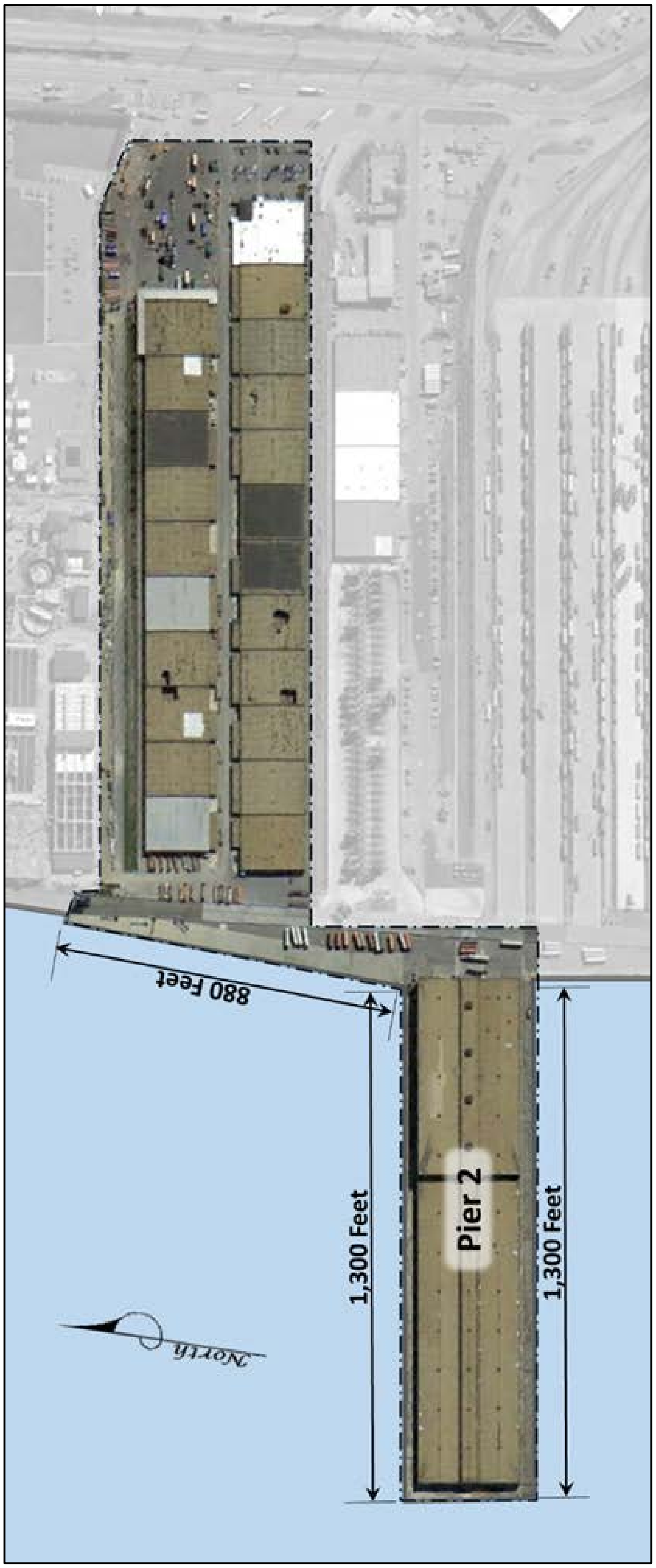
MID-ATLANTIC REGIONAL INFRASTRUCTURE
Oil and Gas Readiness Study
Offshore Virginia



Data modified from NOAA

HAMPTON ROADS PORT INFRASTRUCTURE
Oil and Gas Readiness Study
Offshore Virginia

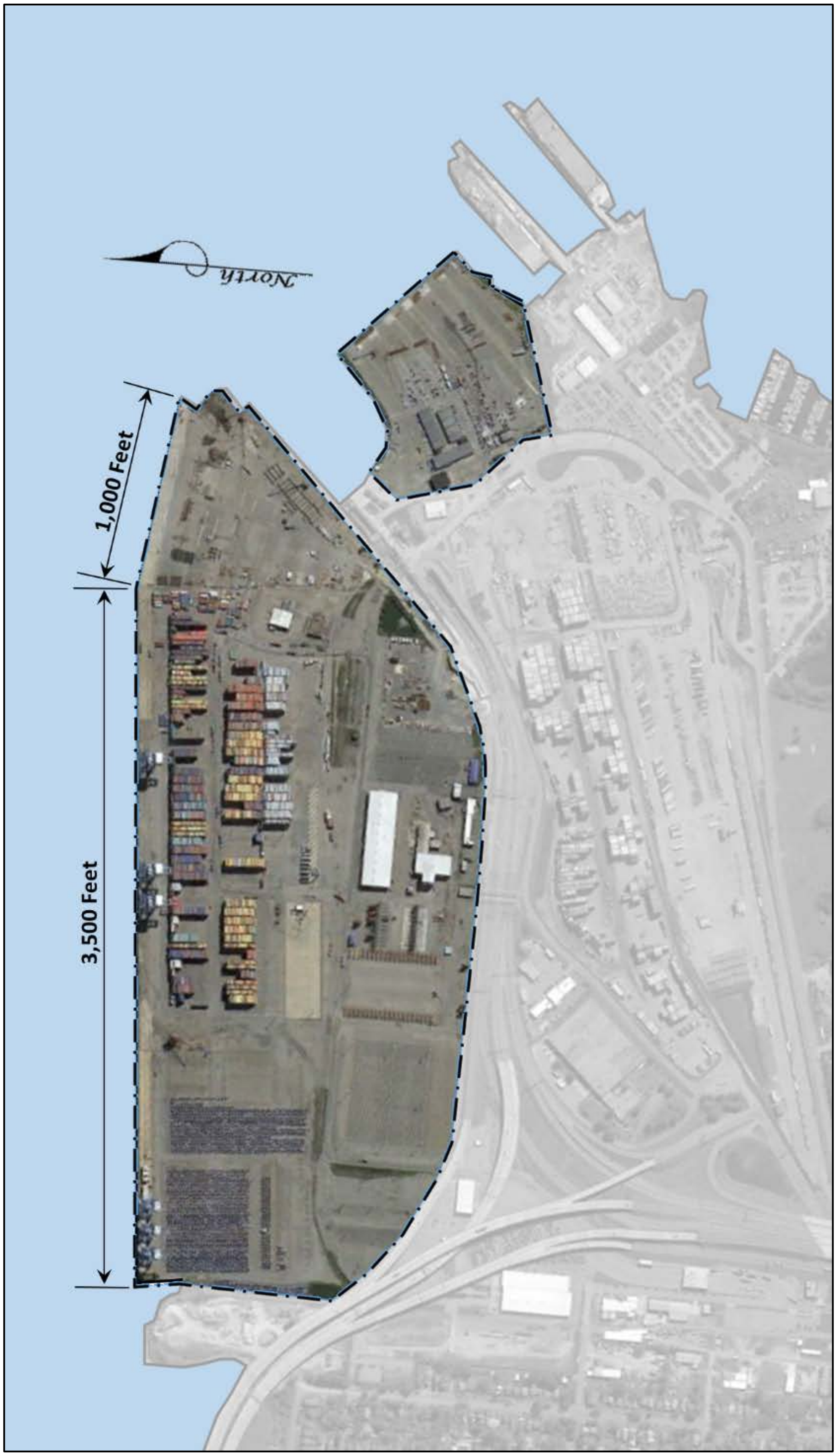
FIGURE 7.2-2



Satellite Photo: Google, Terrametrics

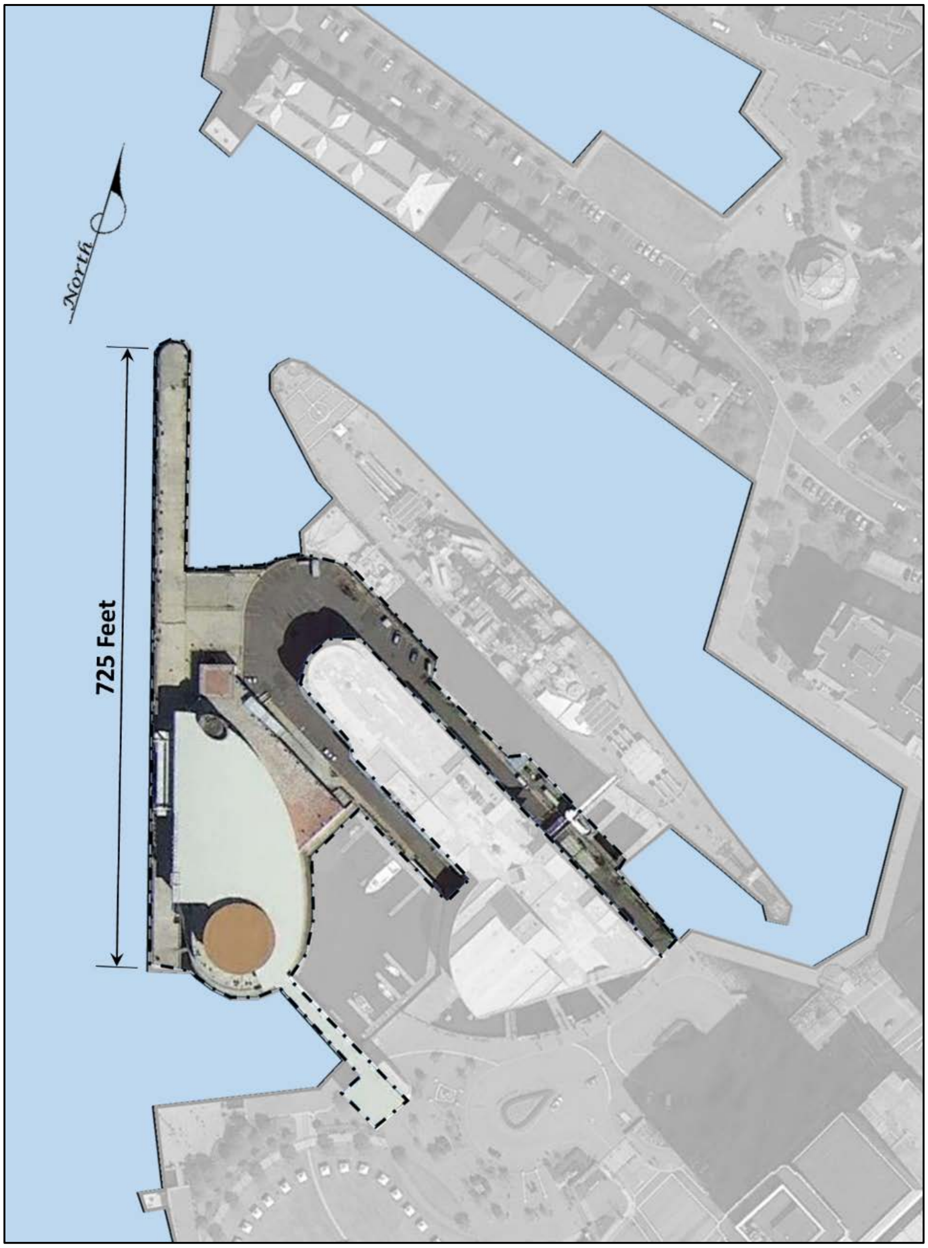
NORFOLK INTERNATIONAL TERMINAL RO-RO BERTH
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-3



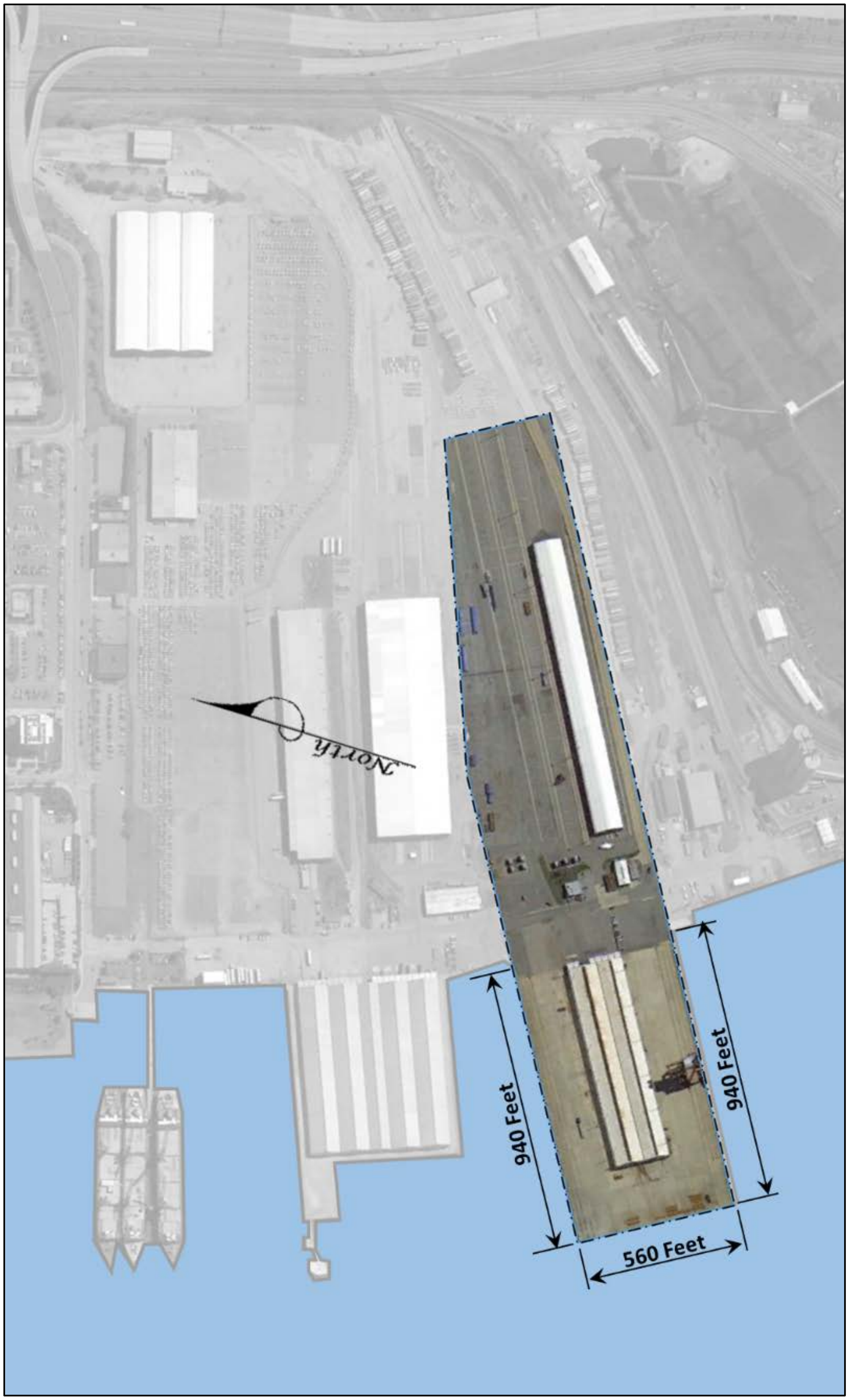
Satellite Photo: Google, Terrametrics

PORTSMOUTH MARINE TERMINAL
Oil and Gas Readiness Study
Offshore Virginia



Satellite Photo: Google, Terrametrics

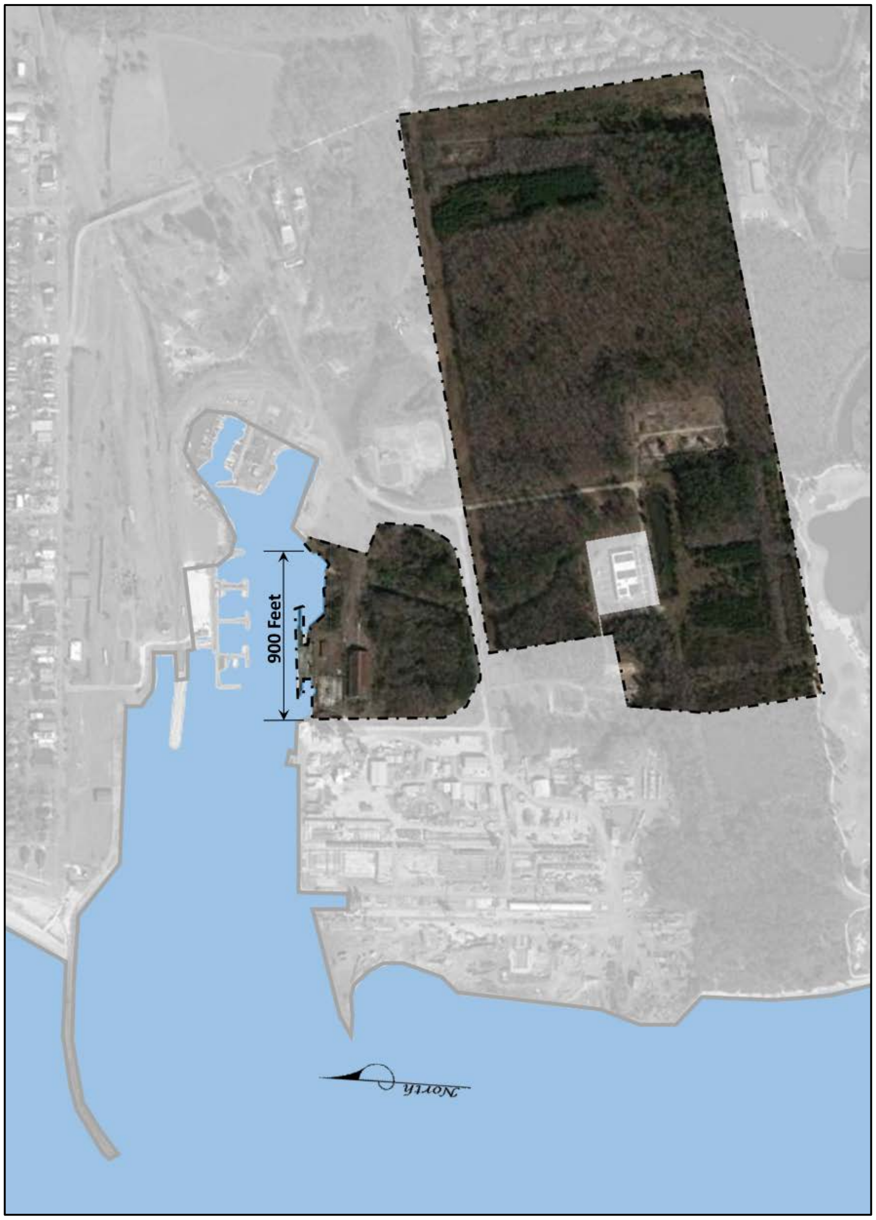
HALF MOONE CRUISE CENTER
Oil and Gas Readiness Study
Offshore Virginia



Satellite Photo: Google, Terrametrics

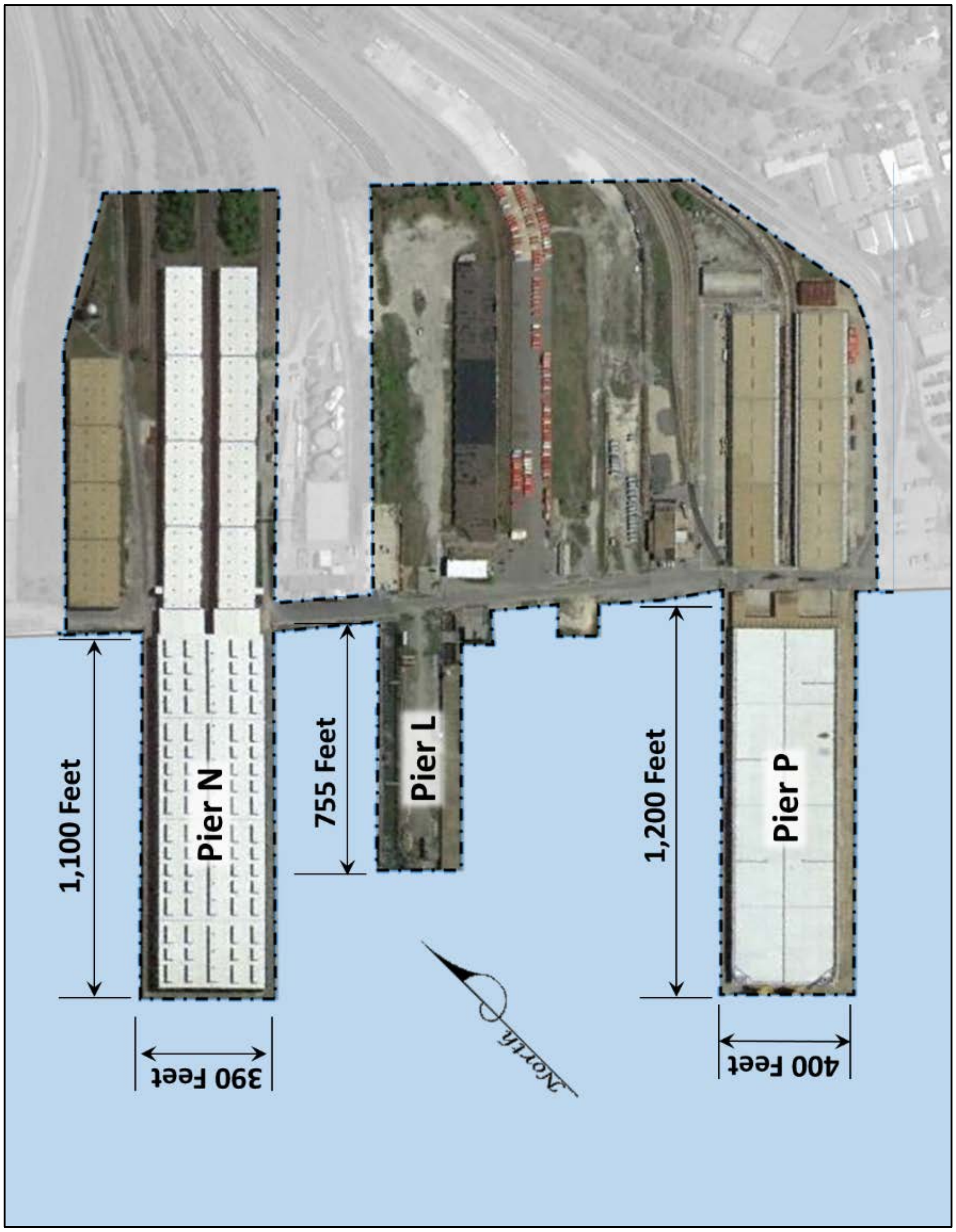
NEWPORT NEWS MARINE TERMINAL PIER C
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-6



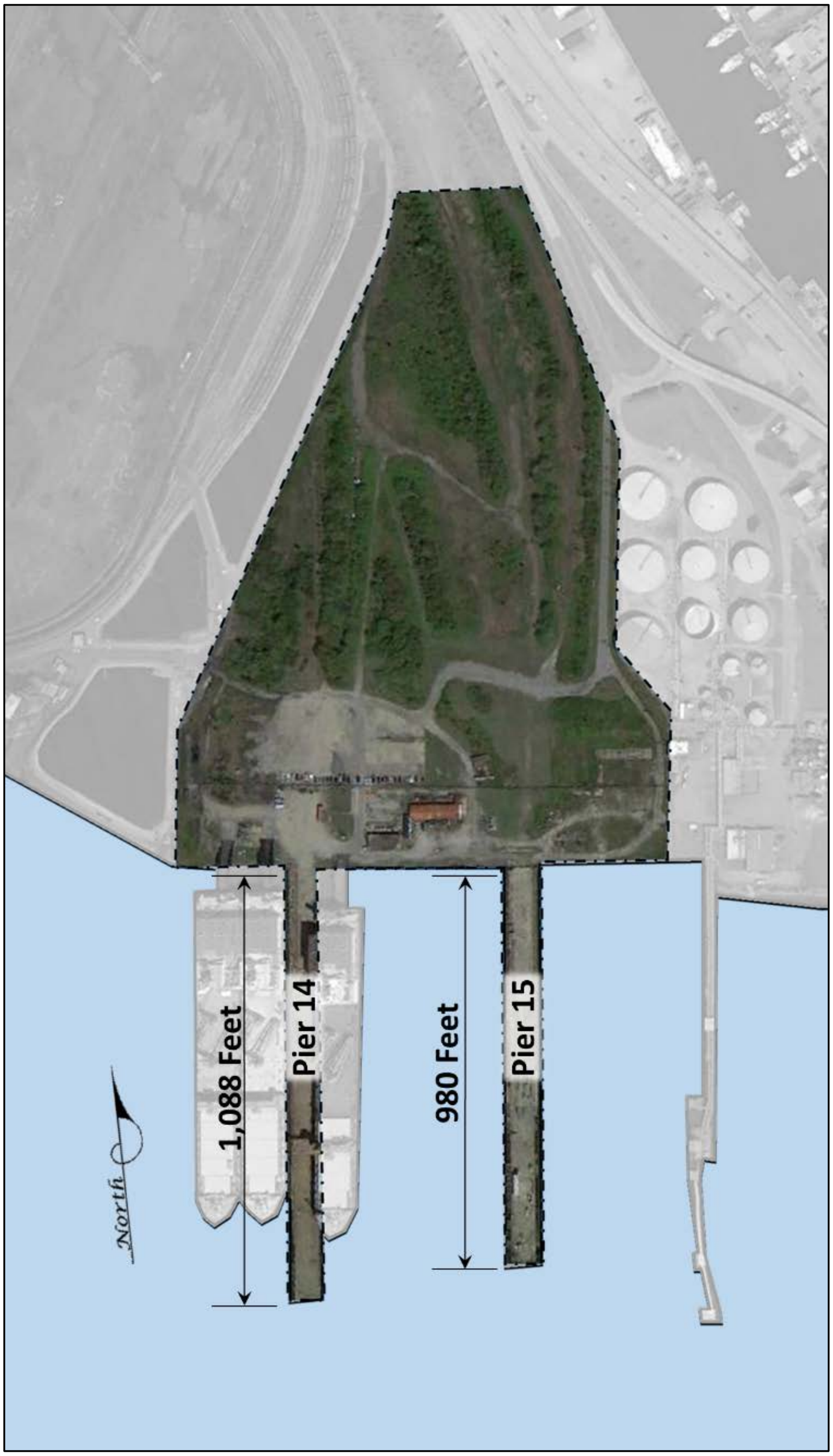
Satellite Photo: Google, Terrametrics

CAPE CHARLES SOUTH PORT
Oil and Gas Readiness Study
Offshore Virginia



Satellite Photo: Google, Terrametrics

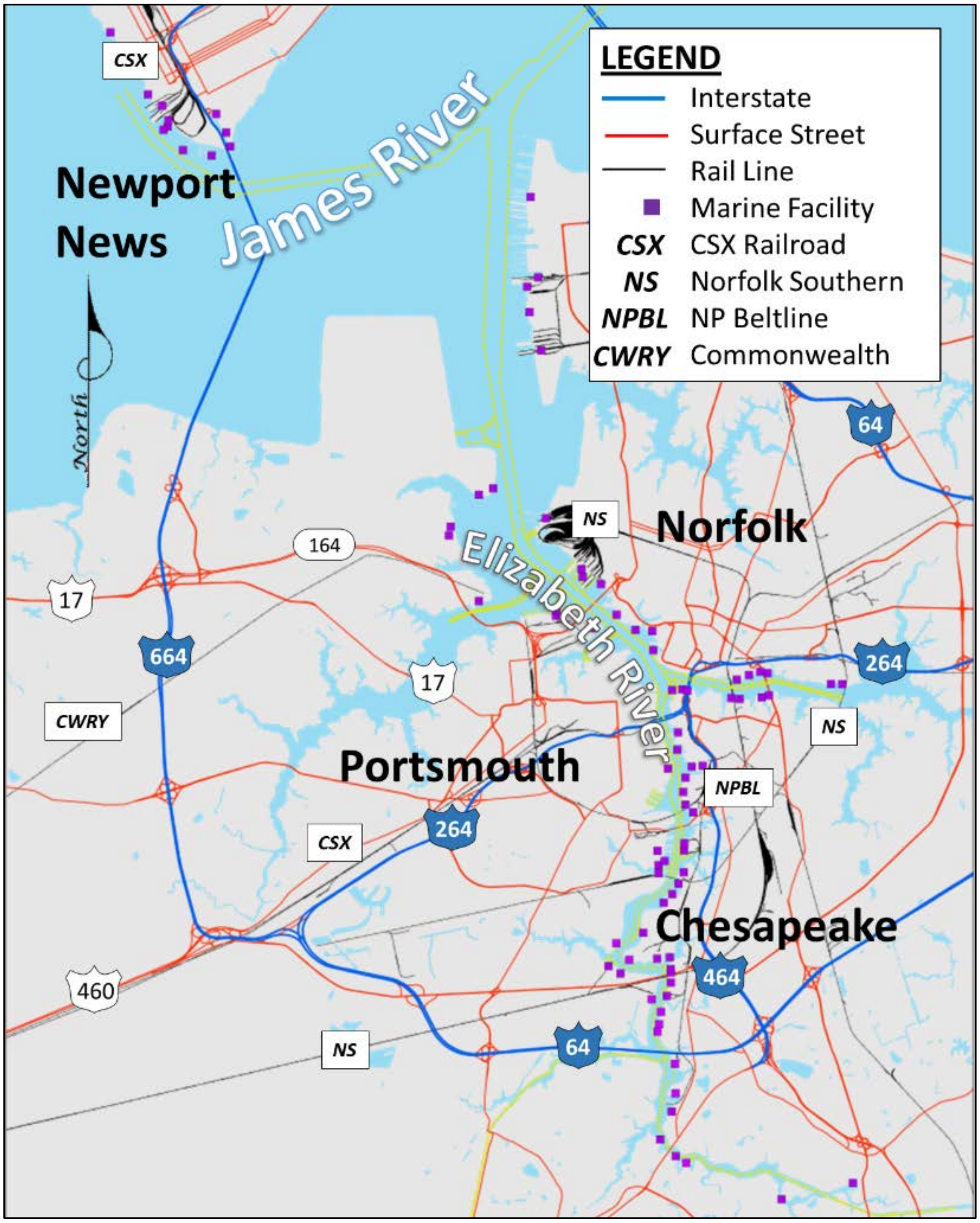
LAMBERTS POINT PIERS N, L AND P
Oil and Gas Readiness Study
Offshore Virginia



Satellite Photo: Google, Terrametrics

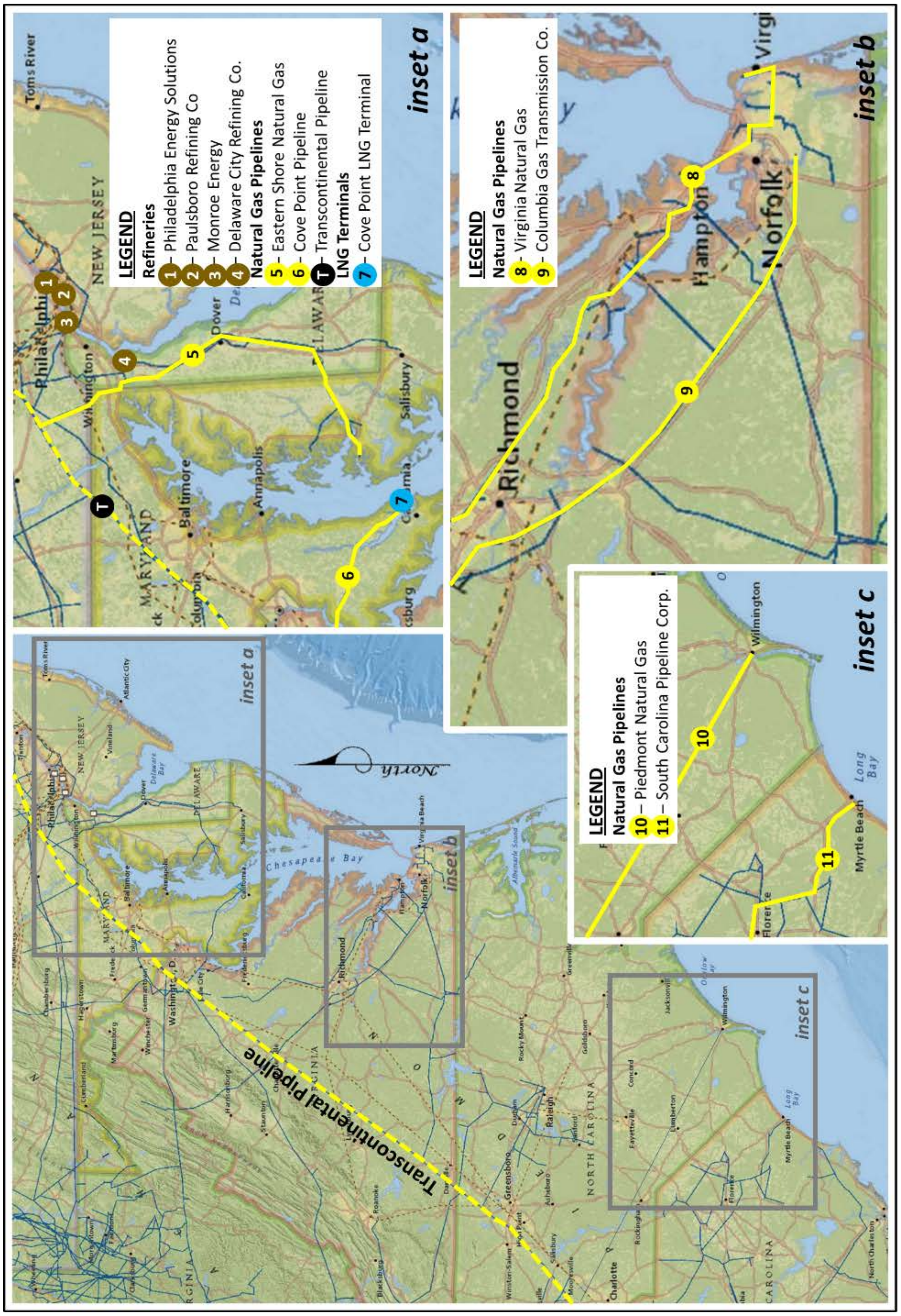
CSX PIERS 14 AND 15
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-9



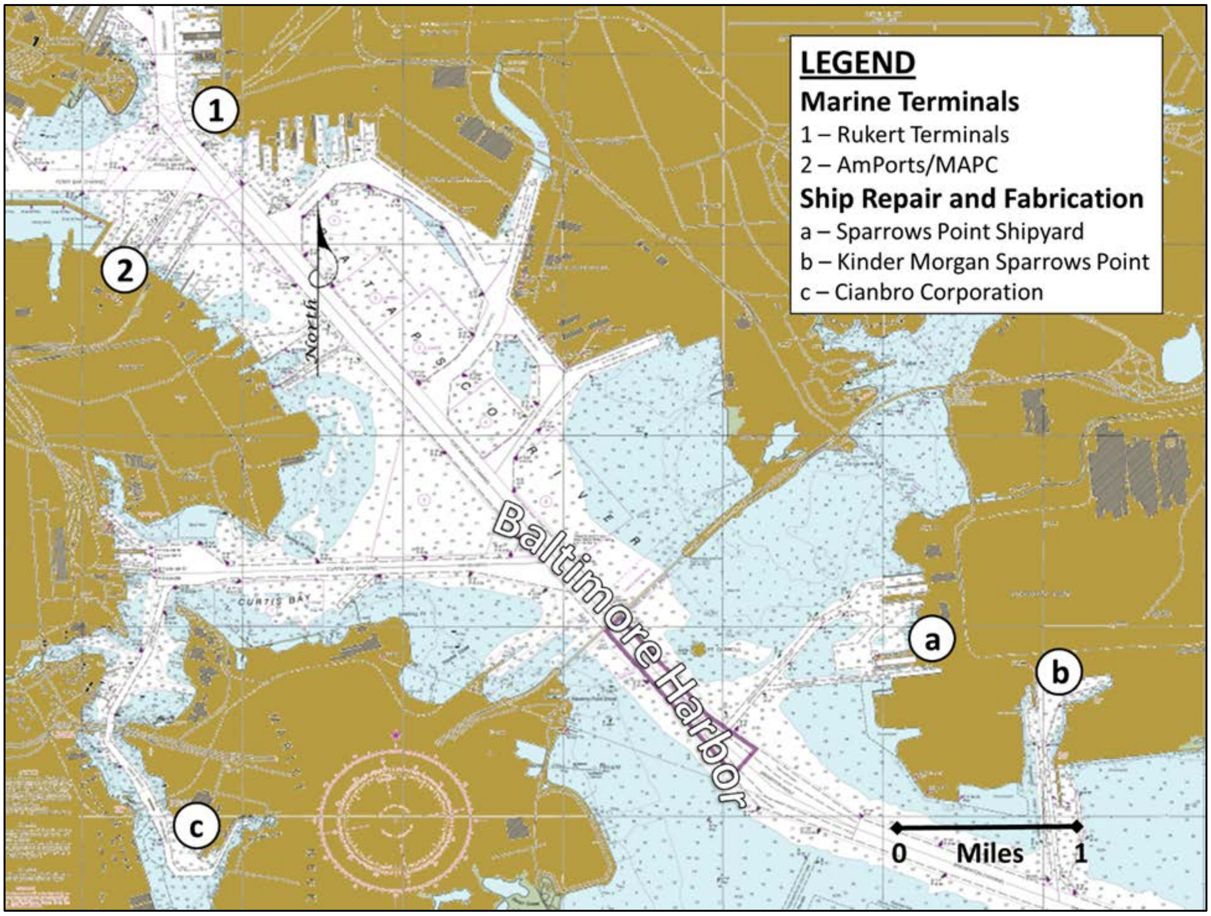
OTHER HAMPTON ROADS INFRASTRUCTURE
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-10



Data modified from EIA

PIPELINES, REFINERIES AND TERMINALS
Oil and Gas Readiness Study
Offshore Virginia



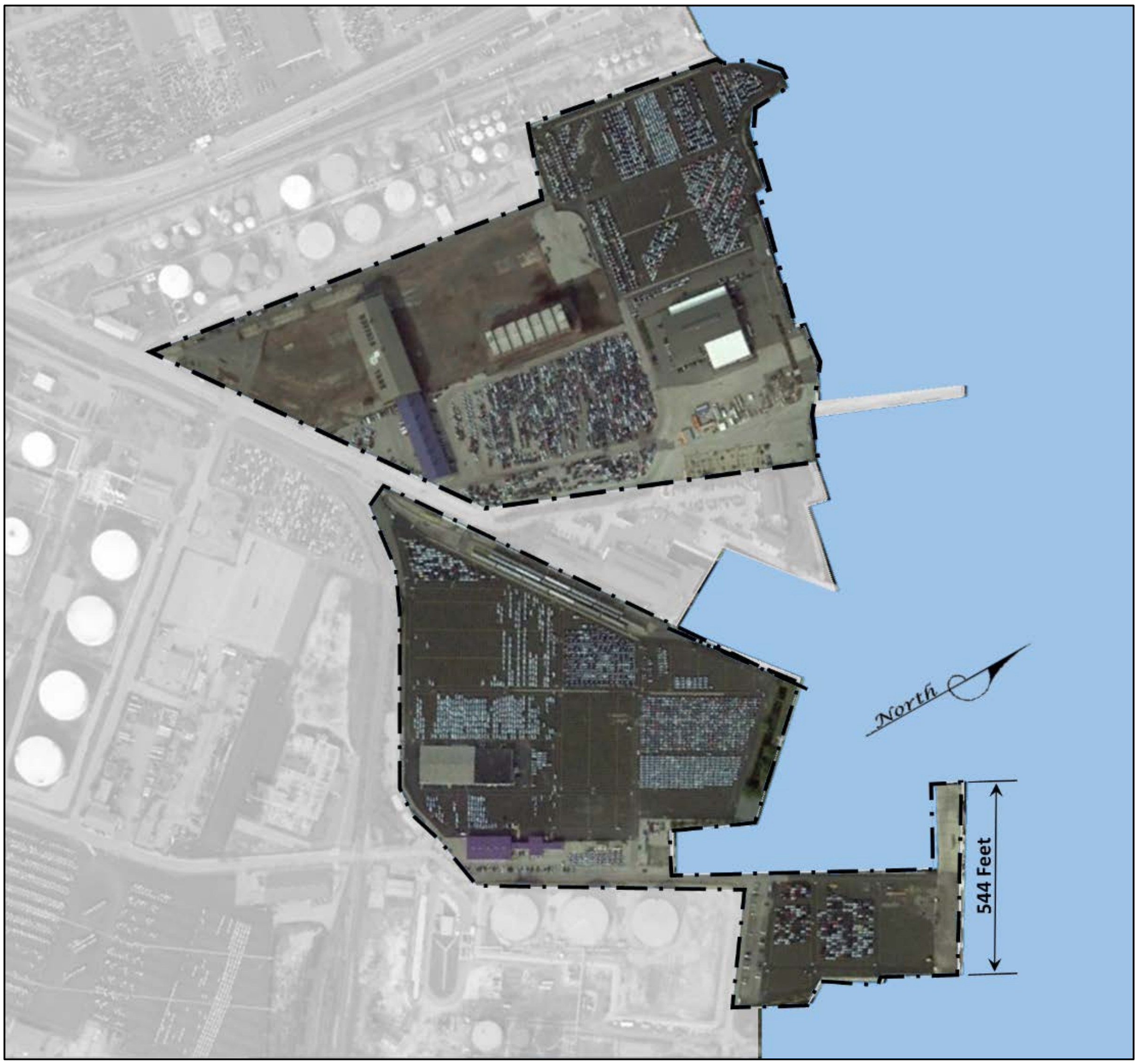
Nautical chart from NOAA

BALTIMORE HARBOR
Oil and Gas Readiness Study
Offshore Virginia

Satellite Photo: Google, Terrametrics

RUKERT TERMINALS PRIMARY PORT AREA
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-13



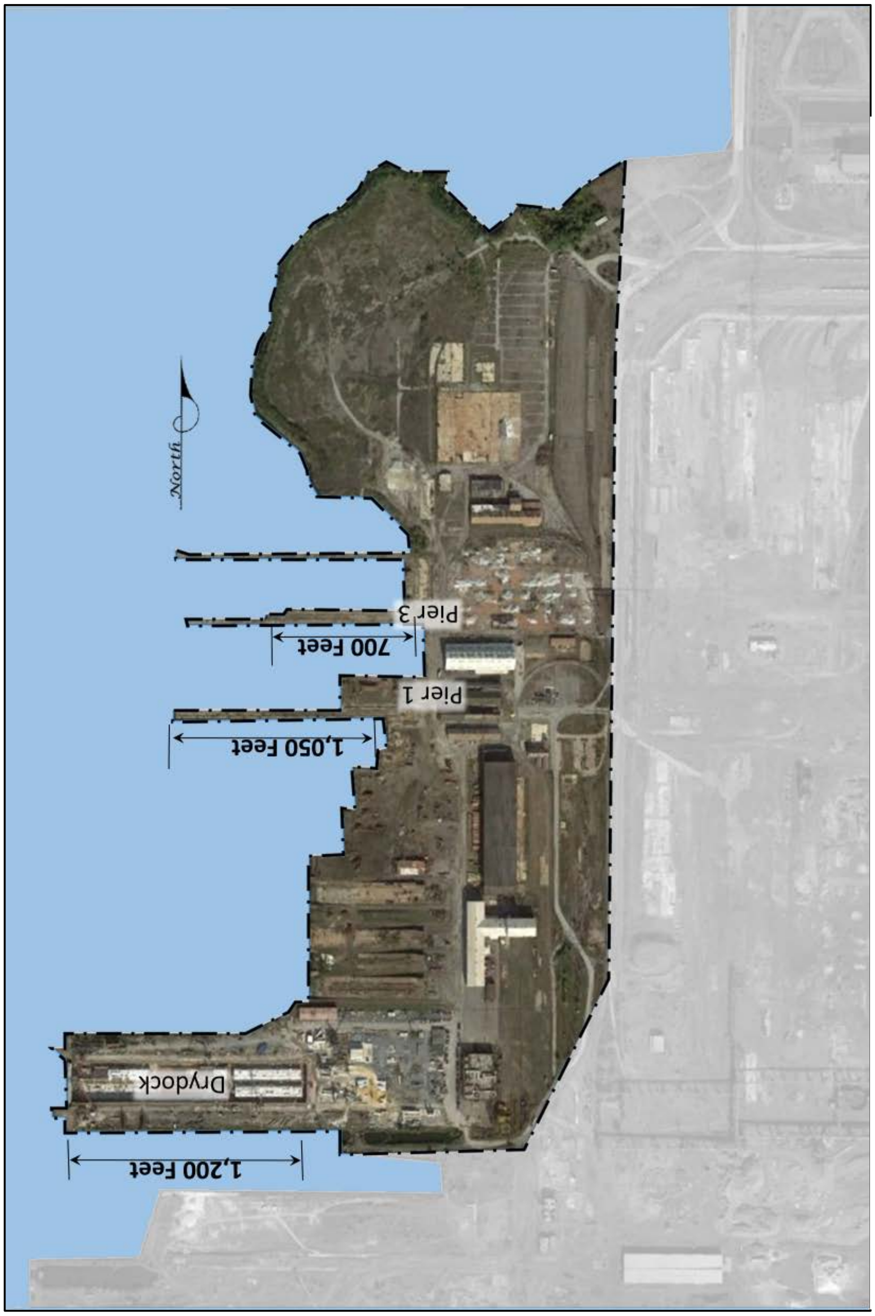
Satellite Photo: Google, Terrametrics

AMPORTS TERMINAL
Oil and Gas Readiness Study
Offshore Virginia

Satellite Photo: Google, Terrametrics

CIANBRO CORPORATION FABRICATION YARD
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-15



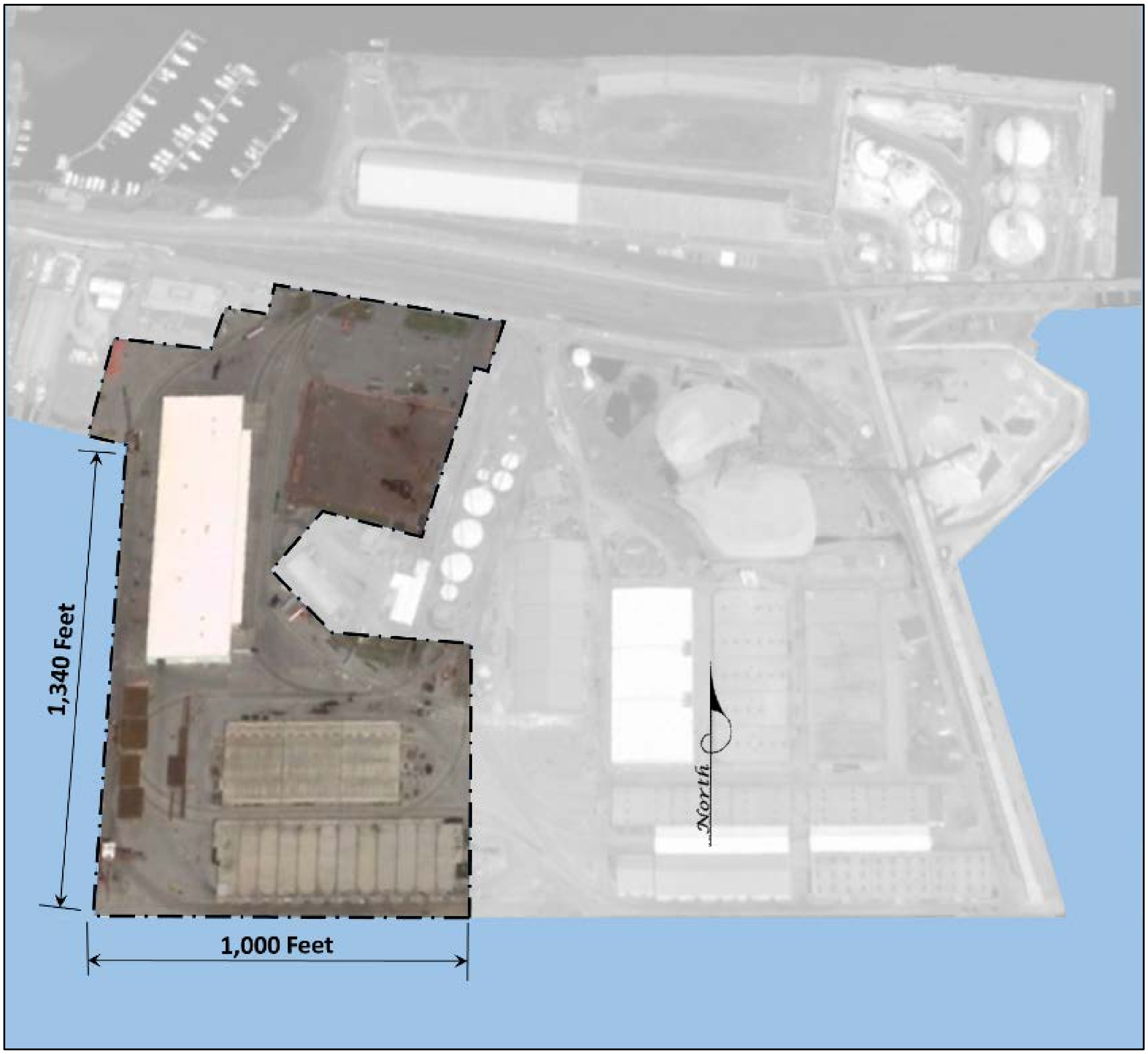
Satellite Photo: Google, Terrametrics

SPARROWS POINT SHIPYARD
Oil and Gas Readiness Study
Offshore Virginia

Satellite Photo: Google, Terrametrics

SPARROWS POINT KINDER MORGAN SITE
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-17

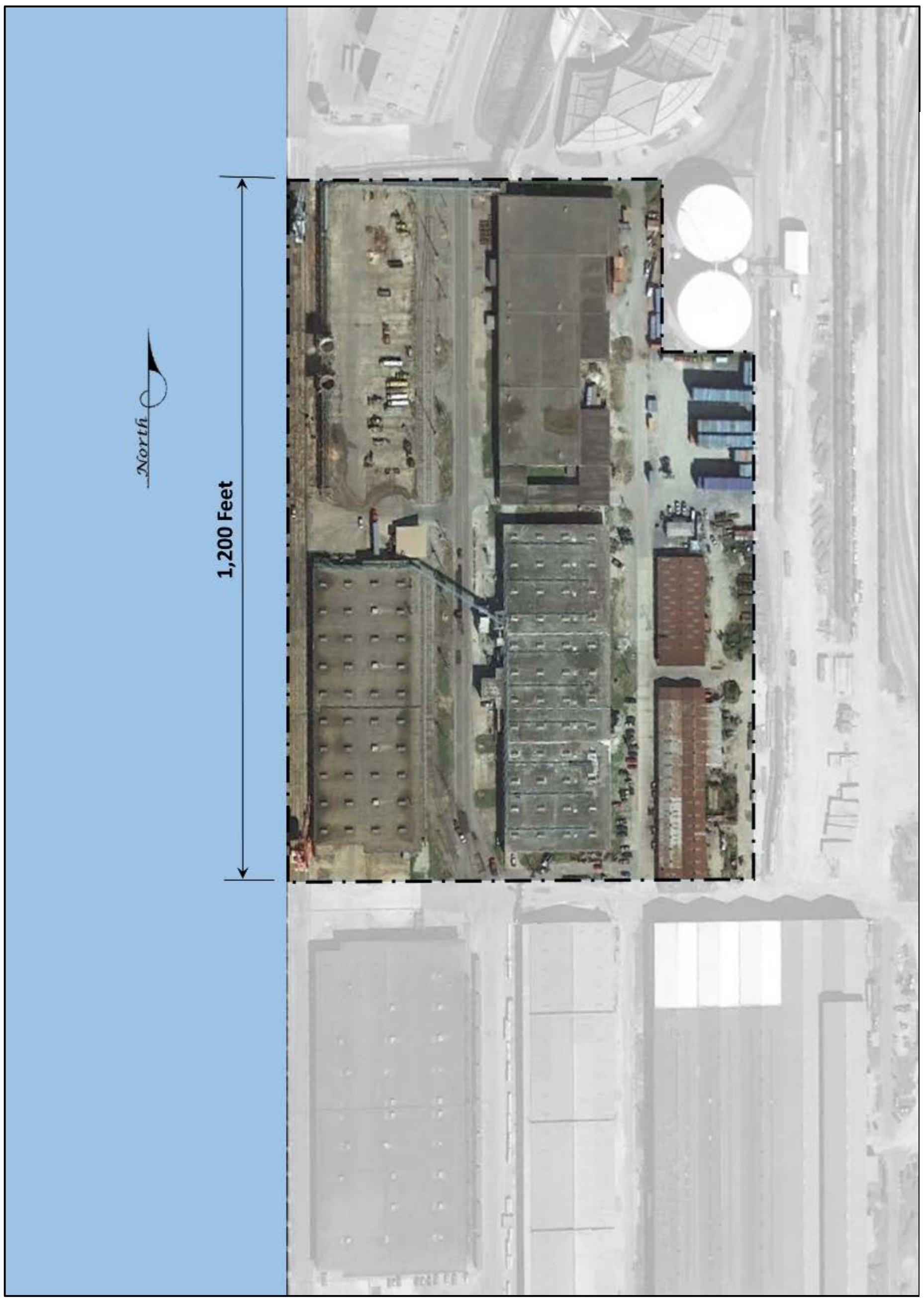


Satellite Photo: Google, Terrametrics

PORT OF MOREHEAD CITY SITE

Oil and Gas Readiness Study

Offshore Virginia



Satellite Photo: Google, Terrametrics

PORT OF WILMINGTON SITE
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 7.2-19

8.0 ASSESSMENT OF ADDITIONAL MID-ATLANTIC INFRASTRUCTURE NEEDS

The final step of the three step process to determine the adequacy of existing infrastructure in the Mid-Atlantic region, as well as to quantify the timing and phasing of infrastructure development, is to determine the necessary support facilities for offshore oil and natural gas (O&G) production. This section will quantify the need for vessel activity and supporting marine terminals based on an estimate of active lease blocks and offshore platforms. The infrastructure needs for Atlantic outer continental shelf (OCS) development will be determined by comparing those figures to the support terminal areas. Surveys of existing Mid-Atlantic O&G resources and the potential timeline for their development will be used to create estimates of regional infrastructure gaps.

8.1 METHODOLOGY

The analysis performed for this report assesses Mid-Atlantic O&G infrastructure requirements relative to projected offshore activity. The analysis is based on four steps:

1) Estimates of the sequence and timeline for Mid-Atlantic exploration and production based on preliminary work performed by the BOEM.
2) Analysis of Mid-Atlantic O&G geologic plays to evaluate depths, distances and proportion of Mid-Atlantic activity to total Atlantic OCS leasing and production.
3) Estimates of the marine support terminal needs based on future Atlantic OCS discoveries projected by the American Petroleum Institute (API).
4) Discussion of current infrastructure resources and gaps.

The BOEM data and the API resource estimates form the basis for assessment of the Mid-Atlantic Region used in this report. However, some of the data has aggregated for the entire Atlantic OCS. Therefore, it was necessary to proportion the resource estimates based on geologic data for the region. In addition, some portions of the Mid-Atlantic Region are deeper than 3,000 meters (10,000 feet) and may not be accessible, or economically feasible, using current drilling and production technologies. Therefore, a small adjustment to the data was necessary to account for this limitation.

This analysis assumes a 2017 start date for exploration and a 2035 planning horizon. These dates were chosen to reflect the scenarios used by BOEM and API. The report also assumes that current drilling and production technologies will be used in future scenarios. The API estimates are based on "Technically Recoverable" reserves which are often greater than "Economically Recoverable" reserves. This results in a conservative estimate of the infrastructure requirements and potential infrastructure gaps. However, all of the present estimates are based on very sparse data and will likely change with additional survey results. Finally, it is understood that only a small subset of the potential Mid-Atlantic lease block area is currently under consideration for exploration and leasing. For the purpose of evaluating infrastructure needs, this report assumes that the entire Mid-Atlantic Region could become available during the planning horizon.

8.2 DEVELOPMENT AND INFRASTRUCTURE TIMELINE

BOEM assumes that existing equipment brought in from the Gulf of Mexico will be sufficient to support the Leasing, Exploration, and Development stages of offshore O&G

operations in the Mid-Atlantic Region for the first seven to nine years of offshore activity (NOAA, 2013). Therefore, the need for homeport facilities and rig construction activities will only become significant after producing discoveries are brought on-line. Figure 8.2-1 illustrates a general development timeline that starts with leasing in the 2017 to 2018 time frame and concludes at the planning horizon of 2035. This timeline assumes that economically recoverable resources are found during the exploration stages and that there are sufficient reserves to justify the development of the resources and of the necessary supporting infrastructure (API, 2013b).

The activity sequence portrayed in Figure 8.2-1 is driven by a timeline of events that could follow initiation of the BOEM's 2017-2022 OCS Oil and Gas Leasing Program. Initial exploratory surveys and environmental benchmarking surveys will likely take place in the first two years of the program, with exploratory drilling and detailed survey following the first round of leases. This survey/lease/exploration activity will proceed until the first economically viable discoveries are developed in the 2024 to 2026 time frame. Following 2026, the Atlantic O&G industry will mature, with production platforms in place and dedicated support infrastructure in operation.

8.3 ESTIMATE OF MID-ATLANTIC ACTIVE LEASE BLOCKS AND OFFSHORE PLATFORMS

Much of the current data about the Atlantic OCS is based on studies and surveys that were performed in the 1970 to 1980 time frame. In order to evaluate the specific equipment types and infrastructure needs for the Mid-Atlantic Region, this existing data must be disaggregated by geologic "play." The plays identified by the BOEM must also be evaluated to determine their depth and accessibility, as well as their proximity to existing infrastructure (BOEM, 2012a; BOEM, 2014b).

8.3.1 Mid-Atlantic Region and Atlantic OCS Resources

The BOEM has evaluated potential resources of the Atlantic OCS in ten geologic plays that range from the Gulf of Maine to east-central Florida:

1) Late Jurassic-Early Cretaceous Carbonate Margin
2) Cretaceous & Jurassic Marginal Fault Belt
3) Cenozoic-Cretaceous & Jurassic Carolina Trough Salt Basin
4) Jurassic Shelf Stratigraphic
5) Cenozoic-Cretaceous & Jurassic Paleo-Slope Siliciclastic Core
6) Cenozoic-Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension
7) Cretaceous & Jurassic Interior Shelf Structure (not in Mid-Atlantic)
8) Cretaceous & Jurassic Blake Plateau Basin (not in Mid-Atlantic)
9) Triassic-Jurassic Rift Basin (not in Mid-Atlantic)
10) Cretaceous & Jurassic Hydrothermal Dolomite (not in Mid-Atlantic)

These plays are largely conjectural, based on on-shore geology and limited offshore drilling. However, they form the only body of direct information available. Of these ten plays, only the first six listed are significant in the Mid-Atlantic Region. Five of these six plays are located completely within the 3,000 meter (10,000 foot) contour. However, approximately half of the Cenozoic-Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension (CSE) extends toward the outer basin beyond the 3,000 meter contour beyond which development may not be economically viable. Therefore, the estimate of Mid-Atlantic reserves was revised downward to compensate for resources beyond the 3,000 meter contour.

Based on 2014 BOEM assessments by geologic play and adjusting for resources outside of the 3,000 meter limit, about 58% of the Atlantic OCS resources are found in the Mid-Atlantic Region. Figure 8.3 1 shows the six Mid-Atlantic plays overlain as a single band on a map of the region and the 120 meter contour, the general depth limit of jack-up drill rigs. Drilling in water that is deeper than 120 meters (400 feet) usually requires floating equipment such as drill ships or semi-submersibles (Leffler, 2003).

BOEM has estimated the undiscovered technically recoverable reserves (UTRR) in the three Atlantic Regions. Figure 8.3-2 illustrates the relative proportion of UTRR by region as adjusted for the 3,000 meter depth limitation. It shows the importance of the Mid-Atlantic Region, but also shows how general Atlantic OCS resources are disaggregated for this analysis.

8.3.2 Projected Mid-Atlantic Offshore Activity

The American Petroleum Institute (API) has recently released a study report of the Atlantic OCS that estimates the level offshore activity based on the BOEM estimates of UTRR (API, 2014b). Although the offshore activity is not given by region, a general estimate of offshore activity can be obtained by factoring the API data by the percentage of Mid-Atlantic Resources (58%) relative to the total Atlantic OCS.

A recent API information release states that approximately one discovery results from every 100 leases granted by the BOEM (API, 2014a). Figure 8.3-3 illustrates how leases granted by the BOEM are down-selected, first through survey and drilling, and then as a result of economic analysis. The handoff from geology and geophysics to economic analysis generally occurs where prospects transition to drillable projects.

8.3.2.1 Offshore Leases

The API Economic Benefits Study (API, 2013a) cites approximately 350 leases per year in the Mid and South Atlantic OCS during the planning period (2017 to 2035) or about 203 leases per year (58% of OCS total) in the Mid-Atlantic based on the individual reserves in each play as projected by the BOEM. The initial leases will be issued beginning in 2018. For the purpose of this evaluation, it should be assumed that seismic surveys will begin one year prior to leasing and accelerate as more leases are issued every year.

8.3.2.2 Offshore Discoveries

Drilling the production wells is expected to begin in 2024, once sufficient exploratory well data has been obtained to identify and map an economically viable reservoir. Production of oil and natural gas is expected to begin in 2026 and continue past the 2035 planning horizon. Over the development cycle of the Atlantic offshore geologic plays, the API report predicts approximately 69 total development projects (discoveries) in the Atlantic OCS by 2035, or approximately 40 discoveries in the Mid-Atlantic Region (API, 2013a) .

Figure 8.3-4 illustrates the projected growth of Mid-Atlantic discoveries through 2035. The initial discoveries that are found to be economically viable are expected to be larger oil fields that can support the needed infrastructure investment. These fields are also likely to be within the 120 meter depth contour where they can be developed with bottom founded equipment (jack-up drill rigs) and are closer to support terminals and natural gas pipelines. As support infrastructure comes on-line, smaller discoveries beyond the 120 meter contour may become economically viable.

8.3.2.3 Operating Platforms

In the adjusted API scenario there will be almost 4,000 leases issued in the Mid-Atlantic of which about 425 will be considered drillable prospects. Significantly fewer of those will show enough promise to justify an AFE and support exploratory drilling, and fewer yet will become producing oil fields (API, 2013a).. For this section it is assumed that each discovery will comprise an area of approximately 30 square miles or four lease blocks.

The U.S. Gulf of Mexico OCS is a mature oilfield environment where many of the older platforms have been replaced or decommissioned. Production in the Gulf has been consolidated onto larger, more efficient platforms at a higher capital cost. The well-established offshore reserves in the Gulf justify the additional investment. In the Gulf, there are approximately 2.38 active leases per producing platform as reported in Section 7 of this report. In the Mid-Atlantic Region, more platforms and smaller platforms will be installed per discovery, until the reserves can be firmly established. For the purpose of estimating support terminal needs, this report assumes 1.00 active leases per platform with four platforms initially installed at each discovery. Therefore, by 2035 there could be 40 discoveries supporting 160 operating platforms in the Mid-Atlantic Region.

8.4 MARINE TERMINAL NEEDS ASSESSMENT

8.4.1 Survey

The BOEM has developed a program for seismic survey of the Mid-Atlantic Region that was originally expected to start in 2013. However, the 2012 BOEM five year OCS leasing plan did not include the Mid-Atlantic Region. With the approval of the 2017-2022 plan, the beginning of any offshore survey will more likely correspond with the 2017/2018 start projected by the API. Multiple surveys will be conducted throughout the Lease-Exploration-Production cycle. Initially, broad range, two-dimensional (2-D) seismic surveys will be conducted to identify major geologic structures. After leasing, more detailed three-dimensional (3D) surveys will be necessary. In addition, various high-resolution seismic studies, as well as gravity and magnetic surveys will be conducted.

Based on the BOEM estimate of geologic and geophysical activities, the graph shown in Figure 8.4-1 indicates the total estimated number of survey vessels in operation prior to the production stage (NOAA, 2013). In practice, the early seismic survey activity will be considerably lower than what can be expected after the lease process is initiated.

In their survey program, the BOEM estimates that up to five shore bases (terminals) could be needed to support survey vessels over the entire Atlantic OCS. It is reasonable to expect that these shore bases would be distributed along the coast during the exploration stages. At 58% of the OCS resources, the Mid-Atlantic Region can be expected to need up to three shore bases for the initial exploration stages. At the relatively low level of activity between 2017 and 2022 illustrated in Figure 8.4-1, seismic survey vessels could be based from existing mixed-use marine cargo terminals.

Once production begins, additional 2-D seismic data will become less important and higher resolution 3D surveys, along with reservoir mapping and monitoring efforts will be needed. These surveys will be based at the dedicated terminals constructed in support of offshore O&G exploration and production.

8.4.2 Exploration

According to the API report, the first exploratory drilling could be expected in 2019, if favorable prospects are discovered on the initial leases. However, a longer evaluation time may be necessary to adequately define the potential drillable projects in the Mid-Atlantic and obtain an authorization for expenditure (AFE) from the exploration company's financial department. In the first five years after leases have been issued, the API assumes that 20 exploratory wells will be drilled in the Mid-Atlantic. In that time period, half to three quarters of the initial leases may be abandoned as having little prospect for future discoveries (API, 2013a).

Figure 8.4-2 illustrates the growth of exploratory and production drilling activity from 2019 through 2035. Exploratory drilling is expected to increase through 2032 as leases are issued in the Mid-Atlantic Region. After 2032, production drilling continues to grow to the 2035 planning horizon while exploratory drilling declines.

In the time period from 2019 to 2024 up to five exploratory wells per year are anticipated by the API report. The time to drill a well is normally between 60 days and 120 days including resupply and travel between sites according to Diamond Offshore, *Offshore Drilling Basics* (http://www.diamondoffshore.com/offshore-drilling-basics). This study assumes 90 days per exploratory well and 180 to 270 days per year of favorable weather conditions. At this production rate, two rigs would be sufficient to cover the Mid-Atlantic drilling needs during the first five years.

The initial Mid-Atlantic exploratory drilling will take place from either jack-up rigs or drill ships. Bottom founded equipment, such as jack-ups, generally operate in water that is less than 400 feet or 120 meters deep and do not require anchoring or positioning systems. Drill ships offer high mobility and the ability to drill in deeper water but are more costly to operate. Daily rates for jack-up rigs currently run between $100,000 and $200,000, while drill ships go for approximately $250,000 to $500,000 per day; therefore, both types of rigs tend to minimize time spent in port. Once drilling has started, the rig must be resupplied from shore.

Resupply of the exploratory rigs could be conducted from existing commercial marine terminals during the first five years of drilling, and a single marine terminal will be sufficient to support drilling vessels during that time. As formations in different areas of the Mid-Atlantic Region are explored, the supporting public marine terminal will likely be chosen from the closest available commercial port.

8.4.3 Production

The API economic benefits report suggests that initial discoveries could come on-line in the Mid-Atlantic starting in 2026. The growth is reasonably linear, starting with one field (4 platforms) in 2026 and growing by two to nine fields per year to a total of 40 fields (as shown in Figure 8.3-4) and 160 platforms in 2035 (API, 2013a). In that time period, some of the platforms could be retired or consolidated into a single floating production, storage and offload (FPSO) vessel at the offshore field. However, for determining the Mid-Atlantic Region's support capability, it is assumed that all 160 platforms will be in operation by the end of the planning horizon.

Section 6 identified a general ratio of 1.5 active platforms per acre of offshore support terminal and concluded that an 18 acre terminal represented a reasonable model for offshore O&G support. This size terminal has the capability of supporting 25 to 30 offshore platforms. At the ratio of 1.5 platforms per terminal acre, approximately 100 to 115 acres of offshore support terminal could be required by 2035.

8.5 CURRENT INFRASTRUCTURE RESOURCES AND INFRASTRUCTURE GAPS

8.5.1 Marine Terminals

In the Gulf of Mexico, onshore marine terminals provide general cargo handling facilities for the supply vessels and anchor handling tugs in support of offshore O&G platforms. For similar offshore O&G activity to take place in the Mid-Atlantic Region, specialized marine terminals will be required to provide the same services. However, there will be a ramp-up period when offshore activity will not justify construction of these dedicated support terminals and existing general cargo terminals will be used in their stead.

The initial activities, as shown in Figure 8.2-1, will center on seismic exploration, an activity that does not require a dedicated marine terminal. This seismic exploration phase is anticipated to proceed for about two years before exploratory drilling begins. Exploratory drilling could take another five years before production drilling and platform construction begins. Drill rigs in the Mid-Atlantic Region will require port facilities for outfitting and resupply during the exploratory drilling stage. A few of the general cargo ports that are currently available to support exploratory drilling include:

1) Rukert Terminals, Baltimore, MD
2) AmPorts, Baltimore, MD
3) Norfolk International Terminal, Norfolk, VA
4) Portsmouth Marine Terminal, Portsmouth, VA
5) Newport News Marine Terminal, Newport News, VA
6) Port of Morehead City, Morehead City, NC
7) Port of Wilmington, Wilmington, NC

These general cargo facilities are available to handle cargo on a contract basis and all of them have the equipment and infrastructure to provide this service. Therefore, sufficient terminal capacity can be found along the Eastern Seaboard to support exploration during the seven year period following the initial Mid-Atlantic offshore leasing program.

Should economically recoverable O&G resources be discovered, then one or more dedicated support terminals will be needed. This additional infrastructure need is anticipated to begin in 2024. Evaluation of ports and marine terminals in Virginia, Maryland and North Carolina has shown that significant capacity could be developed in underutilized facilities along the Eastern Seaboard and that existing commercial marine properties are available for development. A detailed description of available marine terminal and heliport/airport infrastructure was presented in Section 7 of this report. The marine terminal capacity from that report, in terms of acres, is summarized as:

- Hampton Roads, VA – 460 acres of terminal upland
- Baltimore Harbor, MD – 1,184 acres of upland (including 1,000 acre Kinder-Morgan site)
- Morehead City, NC – 180 acres of terminal upland including warehouses (including 150 acre Radio Island property)
- Wilmington, NC – 180 acres of terminal upland including warehouses (including 160 acres at the North Property)

Evaluation of offshore production and support terminals in the Gulf of Mexico shows a general ratio of 1.5 active offshore platforms can be supported by an acre of onshore terminal. Analysis of Gulf support terminals also shows that they range in size from six acres to over 30 acres, but that the average terminal is about 18 acres in area.

Section 8.4.3 of this report discussed the potential for approximately 160 platforms requiring between 100 and 115 acres of support terminal in the Mid-Atlantic Region. Sufficient available commercial marine terminal sites have been identified for this use. Some of these sites could be used immediately and some of them will require infrastructure investment before they can be used. Within the timeline considered for O&G development in the Mid-Atlantic Region, there is no gap in available support terminal infrastructure that would significantly limit offshore exploration and development.

8.5.2 Heliports

Helicopter service becomes important when drill-rigs and platforms are operational in the offshore O&G field. The practice in the Gulf of Mexico is to construct dedicated heliports for the O&G industry. This is driven by the lack of existing airports directly on the Gulf Coast, as well as by the economy of operating from a private facility.

The Mid-Atlantic Region has at least nine commercial airports within a few miles of the coast. These existing airports could be used for helicopter service in the initial stages of exploratory drilling. In many cases, these airports are suitable for long term support after offshore platforms have been constructed. If the cost of operating a private heliport is lower than the landing fees charged by the existing public airports, then an offshore service company may elect to construct a dedicated facility. However, there is no infrastructure gap in heliport capacity that would limit offshore O&G production in the Mid-Atlantic Region.

8.5.3 Oil and Natural Gas Receiving and Distribution

Oil and Gas pipeline and receiving facilities on the east coast have not been developed to support offshore production. Therefore, there is an infrastructure gap, particularly in the lack of crude oil pipeline capacity. Gas pipelines connect the Mid-Atlantic coastal communities with the Transcontinental Gas Pipeline trunk. The existing regional natural gas pipeline is shown on Figure 7.2-11 in Section 7 of this report. However, shore-based natural gas processing plants and underwater export pipelines would be needed to connect offshore natural gas production to the existing land based pipeline network.

A significant investment will be necessary to fill this infrastructure gap. The investment can take several forms depending on the quantity of resources developed and the type. For offshore natural gas, a network of flow-lines will be required between wells and one or more export pipelines must be constructed to bring the gas ashore. Where the export pipeline connects with the existing natural gas distribution pipelines, a natural gas processing plant will be needed to separate the water, the natural gas liquids and other components of the raw natural gas.

The Atlantic Seaboard does not have crude oil pipeline infrastructure for receipt of offshore oil. As with natural gas, flow-lines and possibly export pipelines will be required for crude oil. If economically recoverable deposits are discovered, one or more of the following measures must also be taken to ensure a market for the crude oil produced:

1) New crude oil pipeline infrastructure is constructed on the land or existing petroleum product pipelines are repurposed to accept crude oil.
2) The crude oil export pipeline is connected to a tank-farm on shore and a crude oil loading dock is constructed to transload oil to a barge or tanker.
3) A floating production, storage and offload (FPSO) vessel is moored at the offshore oil field and crude oil is exported by shuttle tankers to an existing refinery.

Of these options, the FPSO would be the least disruptive and would likely generate the least public controversy. The cost of construction and installation of the FPSO would be factored into consideration of whether an offshore oil field had economically recoverable reserves.

8.5.4 Ship Repair and Fabrication

Hampton Roads has an active ship-repair and dry-dock industry with at least five yards having a combined capacity for almost any size vessel that may need repair. Additionally, under-utilized dry-dock capacity and fabrication facilities can be found at Sparrows Point Shipyard in Baltimore Harbor. Between these two commercial maritime centers, there is sufficient existing capacity to support offshore O&G vessel repair needs (API, 2014b).

If offshore drilling equipment, production platforms and pipeline equipment can be manufactured in the Mid-Atlantic Region, there are several existing sites that would be suitable for this activity.

Baltimore Harbor:

- Sparrows Point Shipyard and Kinder-Morgan Sparrows Point Terminal both have sufficient land area and underutilized waterfront facilities.
- AmPorts has a large site with two vacant manufacturing buildings available.
- Cianbro Construction has a fabrication and coatings plant that could produce welded pipe, steel piling and platform components.

Hampton Roads:

- Cape Charles South Port includes a large area adjacent to an existing Precast Concrete plant that could support fabrication
- CSX Pier 14 & 15 has sufficient land area and underutilized waterfront that would be suitable for fabrication.
- Colonna's Shipyard has sufficient land, plant and fabrication capabilities for jacket or platform construction
- Newport News Shipbuilding has extensive plant, infrastructure and waterfront facilities that could handle almost any fabrication project.

North Carolina:

- Port of Morehead City has a 150 acre vacant tract on Radio Island that could be developed to support fabrication.
- Port of Wilmington has a 160 acre vacant tract known as the North Property that could be developed to support fabrication.

8.5.5 Oil Field Waste Disposal

Existing facilities in Hampton Roads and other Mid-Atlantic ports are equipped for receiving oily waste from ship's slops, de-bunkering, tank cleaning, and other maritime sources. However, these facilities may not have the specific equipment or capacity to receive liquid oilfield wastes. This infrastructure gap would have to be filled through commercial investment in additional oilfield waste disposal capacity at one or more of the existing marine waste service companies.

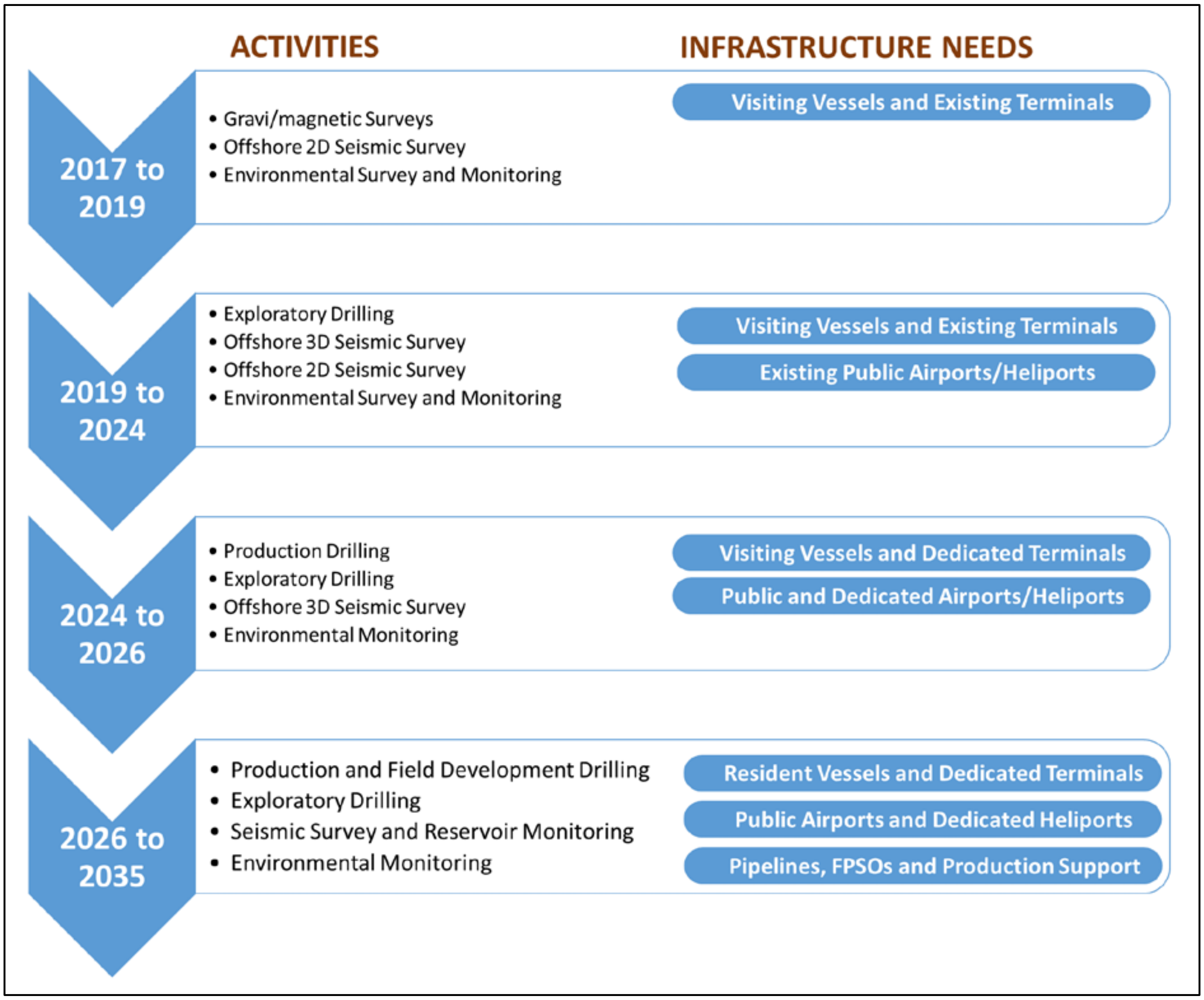
8.5.6 Oil Spill Response

The Mid-Atlantic Region does not have an offshore oil spill response vessel stationed at any of the four commercial maritime centers (Baltimore, Hampton Roads, Morehead City, and Wilmington). However, a response vessel operated by Marine Spill Response Corporation is stationed at Perth Amboy, New Jersey. The gap in oil spill response capability could be filled by either relocating the existing vessel, or by stationing a second vessel in Hampton Roads. A listing of offshore oil spill response agencies, organizations, and private companies that could provide service to the Mid-Atlantic Region is given in Table 8.5 1.

Recent legislation established a Virginia Offshore Energy Emergency Response Fund (VLIS, 2015). This fund will accumulate based on revenues and royalties paid to the Commonwealth as a result of offshore natural gas and oil drilling or exploration. The designated fund maximum balance is $50 million. The Fund is intended for emergency preparation, emergency response, emergency environmental protection, or mitigation. Therefore, some of the initial expense of establishing offshore oil spill response could potentially be financed from this fund.

Table 8.5-1 Oil Spill Response Agencies, Organizations, and Private Companies within the Mid-Atlantic Region

Organization	Description
Ocean Energy Safety Institute (OESI); College Station, TX	Provides a forum for dialogue, shared learning and cooperative research among academia, government, industry, and other non-governmental organizations.
National Response Framework (FEMA); Washington, DC	Provides context for how the whole community works together and how response efforts relate to other parts of national preparedness.
Global Industry Response Group	Tasked with identifying learning opportunities both on causation and in respect of the response to the incident.
Marine Spill Response Corp. (MSRC); Herndon, VA	U.S. Coast Guard Classified Oil Spill Removal Organization. MSRC was formed in 1990 to offer oil spill response services and mitigate damage to the environment.
Net Environmental Benefit Analysis (NEBA)	Developed for effective oil spill preparedness and response.
Parker Systems, Inc. (PSI); Chesapeake, VA	Manufacturer of oil spill cleanup and containment products.
Spill Control Assoc. of America; Alexandria, VA	Represents spill response contractors, manufacturers, distributors, consultants, instructors, government & training institutions and corporations working in the industry.
Hepaco; Charlotte, NC	Created to manage incidents for both public and private sector clients, including marine oil spill response and restoration.
Ohmsett; Atlantic Highlands, NJ	The National Oil Spill Response Research & Renewable Energy Test Facility provides independent and objective performance testing of full-scale oil spill response equipment and marine renewable energy systems.
PCCI; Alexandria, VA	Operates the world's largest inventory of pollution response and salvage equipment for the U.S. Navy, and manages the dedicated network of worldwide response bases



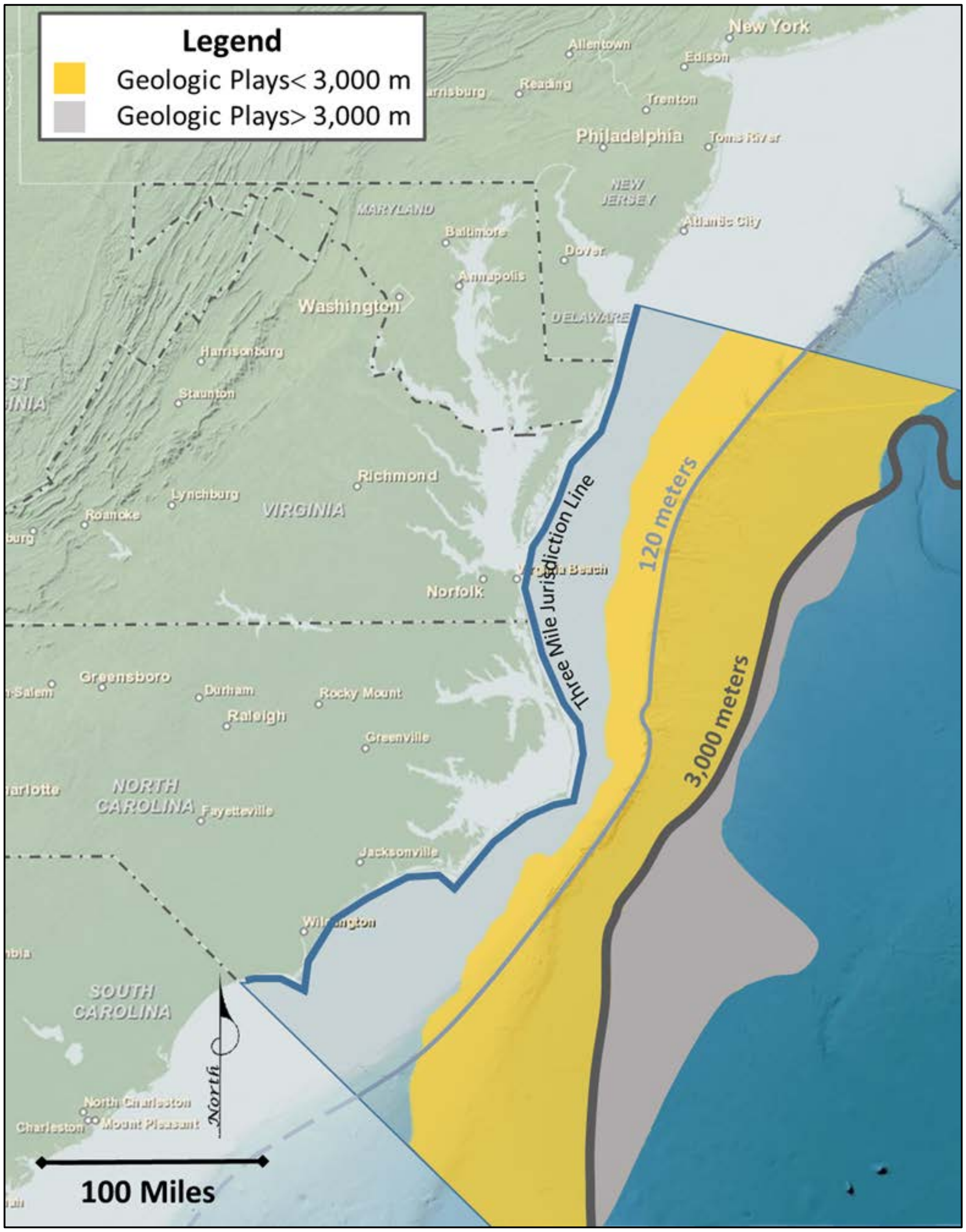
Source: API

OFFSHORE OIL AND GAS DEVELOPMENT TIMELINE

Oil and Gas Readiness Study

Offshore Virginia

FIGURE 8.2-1

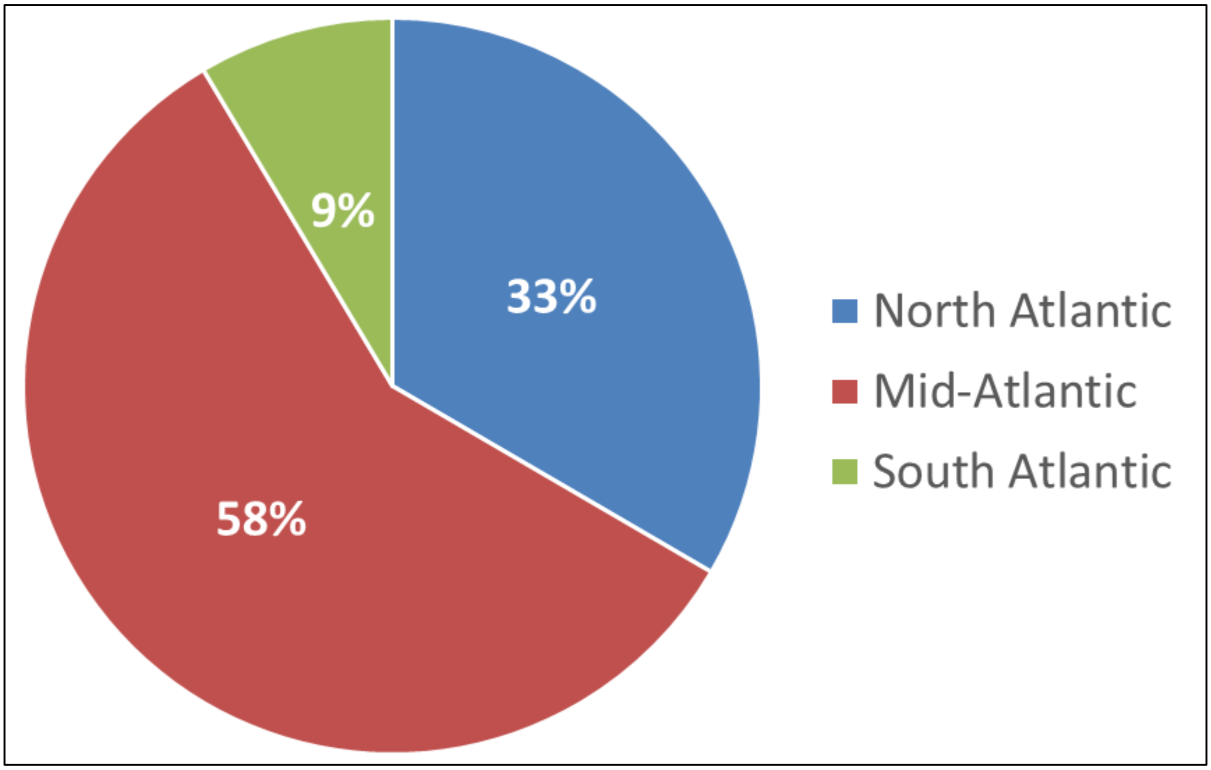


Data modified from BOEM, NOAA and EIA

MID-ATLANTIC GEOLOGIC PLAYS

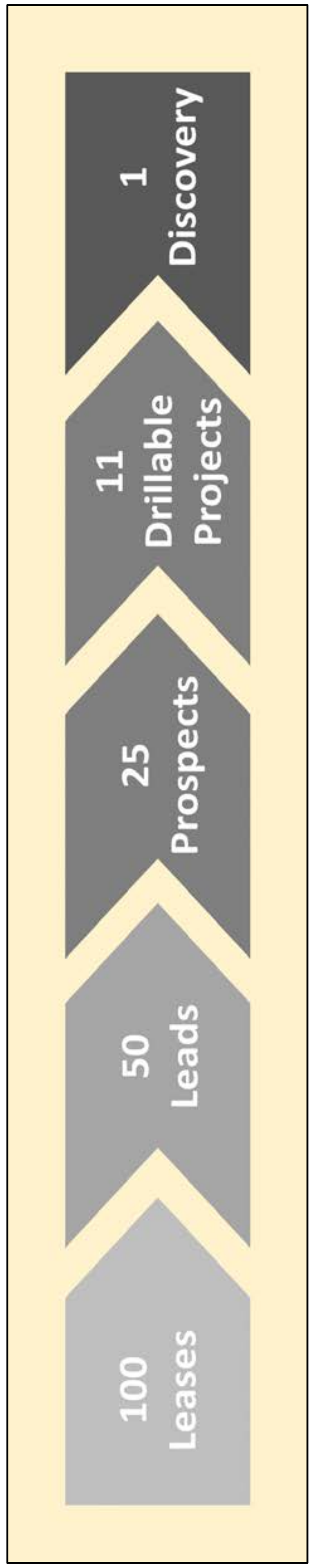
Oil and Gas Readiness Study

Offshore Virginia



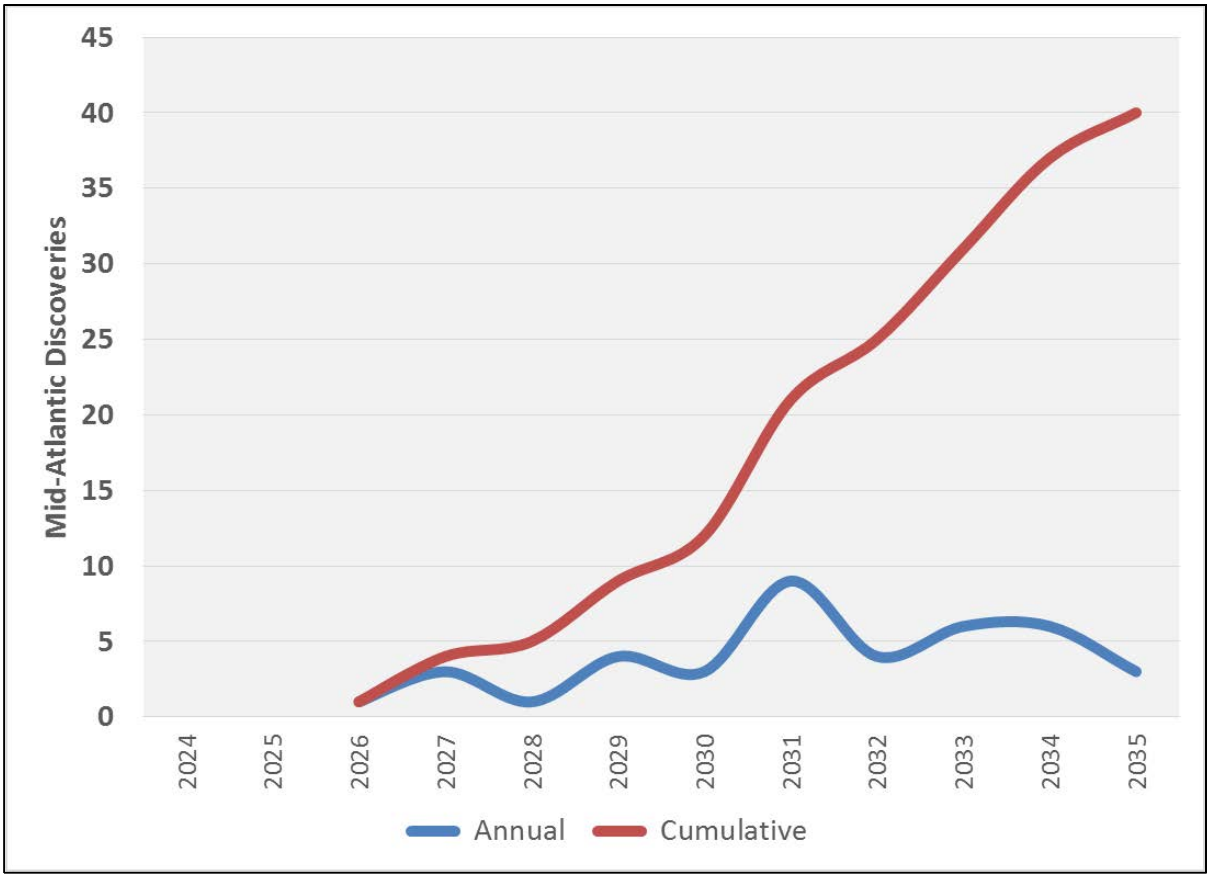
Data modified from BOEM

UTRR PROPORTION BY REGION
Oil and Gas Readiness Study
Offshore Virginia



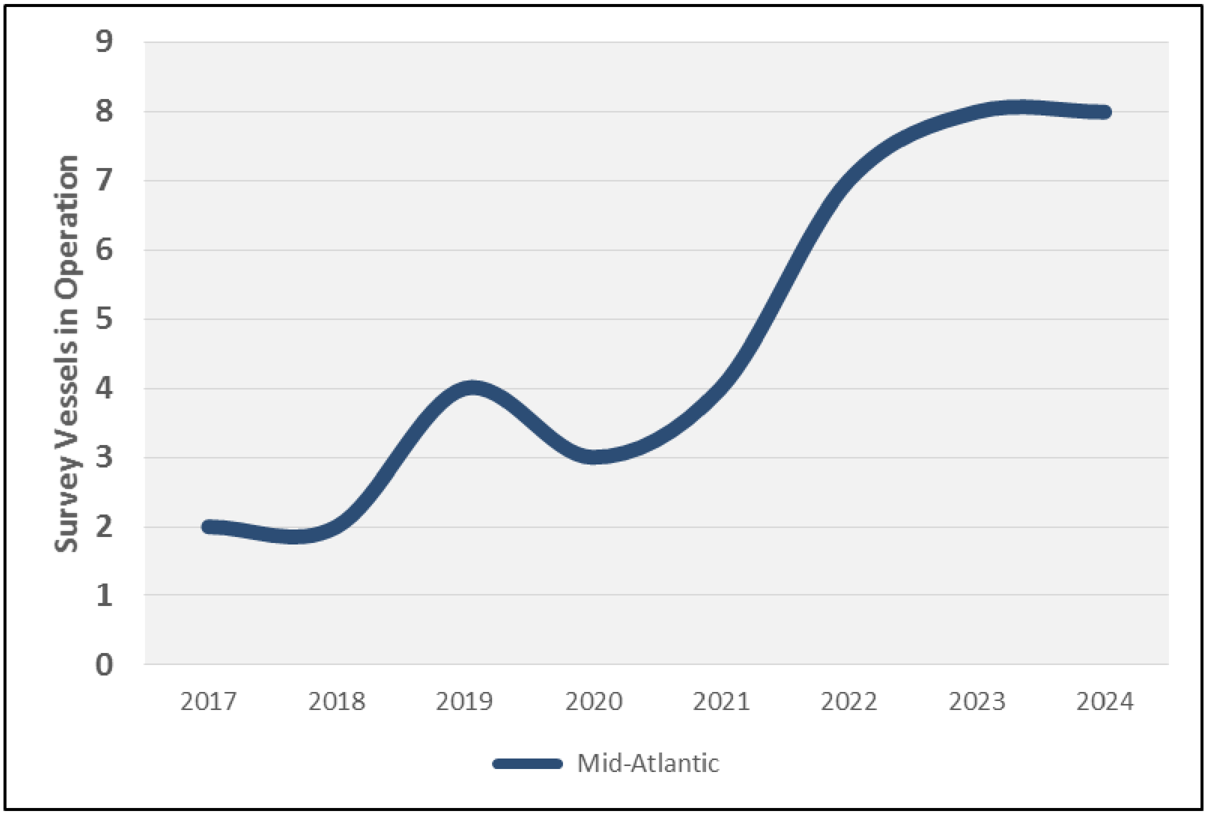
Source: API

OFFSHORE LEASE PROGRESSION
Oil and Gas Readiness Study
Offshore Virginia



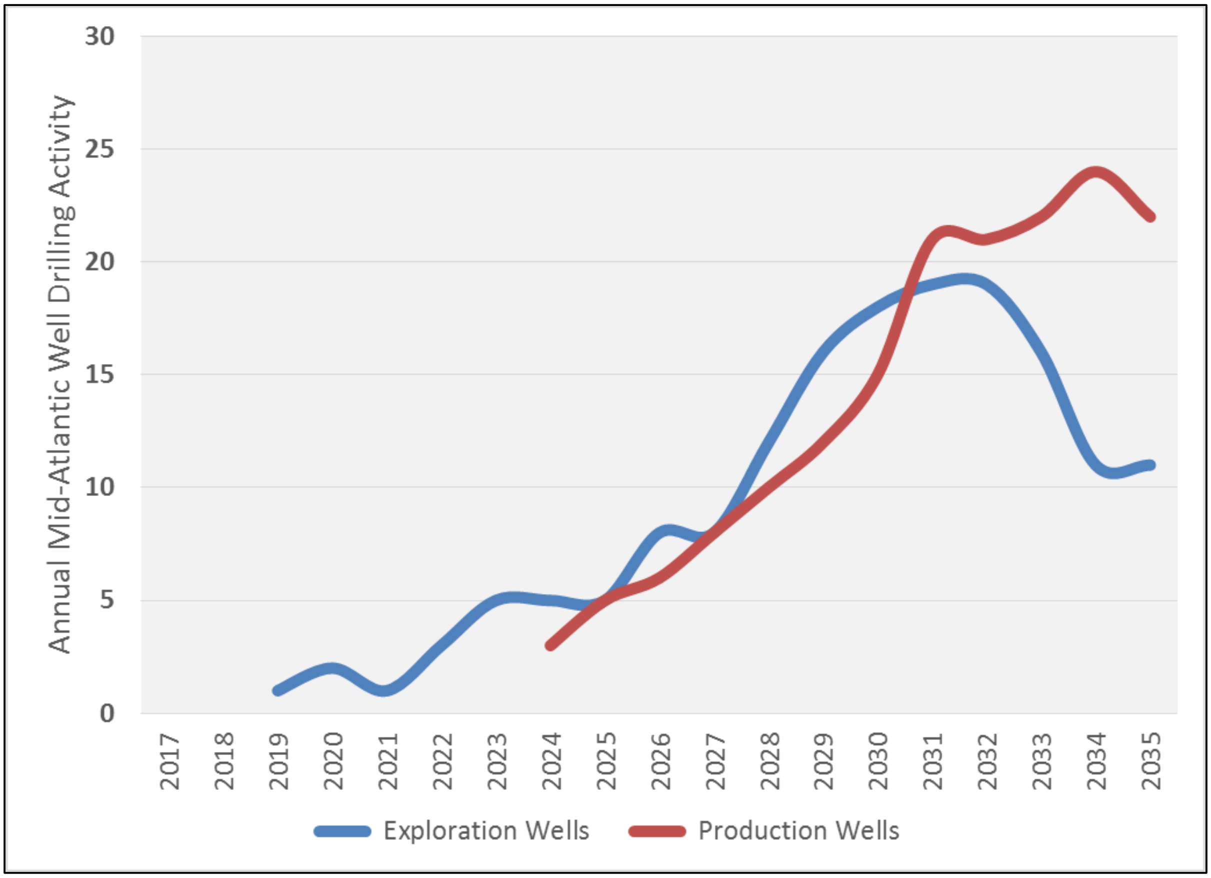
Source: API

ANNUAL AND CUMULATIVE
MID-ATLANTIC ECONOMIC DISCOVERIES
Oil and Gas Readiness Study
Offshore Virginia



Source: BOEM (2014a)

SURVEY VESSELS IN OPERATION
Oil and Gas Readiness Study
Offshore Virginia



Source: API (2013)

MID-ATLANTIC ANNUAL DRILLING PROJECTIONS
Oil and Gas Readiness Study
Offshore Virginia

FIGURE 8.4-2

9.0 VIRGINIA'S PLAN TO ADDRESS CONCERNS THAT MAY BE RAISED BY THE MILITARY

The United States Bureau of Ocean Energy Management (BOEM) is considering the Mid-Atlantic Planning Area for future offshore oil and natural gas (O&G) exploration. One of three main concerns raised by BOEM in earlier reports was that of potentially conflicting uses of the area, including Department of Defense (DoD) uses. This section presents a plan to address concerns raised by the military.

The first step in the planning process is an understanding of the background and historical context. The background includes a legislative overview of Virginia's Energy Plan, the BOEM five-year leasing program planning process, and stated DoD concerns regarding O&G exploration in the Mid-Atlantic Planning Area. The DoD concerns regarding O&G exploration are captured by DoD Service branch and other DoD ocean program offices. The background also clearly establishes the overall DoD perspective (the sum of its Services and program offices) as set forth in the 2010 DoD compatibility assessment (DoD, 2010) and recorded in subsequent meetings with DoD representatives. The DoD has made it clear that the 2010 assessment only applies to the 2012-2017 lease sale program and that a new assessment, now underway, will be the Department's response and input to BOEM's 2017-2022 lease sale program.

The next portion of this section explores examples of O&G and DoD conflict resolution in other Outer Continental Shelf (OCS) regions. Two examples are provided for conflict resolution in the Gulf of Mexico where Navy training and testing (e.g., Naval Support Activity Panama City) and Air Force (USAF) training (e.g., Eglin Gulf Test and Training Range) occur in the vicinity of one of the most developed O&G regions of the world.

Two additional examples of conflict resolution are presented from the Pacific OCS (one from the Hawaiian Islands and another from Southern California). The goal of this section is to glean success stories from other OCS regions and look at these areas as models for how conflicts might be resolved in the Mid-Atlantic.

The final portion of this section sets forth several plan elements for successful DoD conflict resolution in the Mid-Atlantic Planning Area. Some plan elements borrow from successful conflict resolution in other OCS regions. Other suggested plan elements are natural outcomes from DoD meetings or involve technological considerations. The conclusion summarizes the plan to address concerns raised by the military.

"The challenge is to find solutions that will enable the nation's development of needed energy and other infrastructure while enabling the Navy to carry out its national defense mission through continuous training and testing at sea, ashore and in the air."
-John P. Quinn, Deputy Director, Chief of Naval Operations, Energy & Environmental Readiness Division (November 26, 2011)

9.1 BACKGROUND AND CONFLICT IDENTIFICATION

9.1.1 Legislative Background

In 2006, the Virginia General Assembly amended the Code of Virginia by adding Title 67 – Virginia Energy Plan[1]. Chapter 3, *Offshore Natural Gas and Wind Resources,* was made a part of that statute (VA Code §67-300 [2006]), as follows:

> *§ 67-300. Offshore natural gas and wind resources.*
>
> *A. In recognition of the need for energy independence, it shall be the policy of the Commonwealth to support federal efforts to determine the extent of natural gas resources 50 miles or more off the Atlantic shoreline, including appropriate federal funding for such an investigation. The policy of the Commonwealth shall further support the inclusion of the Atlantic Planning Areas in the Minerals Management Service's draft environmental impact statement with respect to natural gas exploration 50 miles or more off the Atlantic shoreline. Nothing in this Act shall be construed as a policy statement on the executive or Congressional moratoria on production and development of natural gas off the Atlantic shoreline.*
>
> *B. It shall be the policy of the Commonwealth to support federal efforts to examine the feasibility of offshore wind energy being utilized in an environmentally responsible fashion.*

In 2010, the Chapter 3 title was changed, and the Chapter was amended and reenacted (VA Code §67-300 [2010]), as follows:

> *§ 67-300. Offshore energy resources.*
>
> *A. In recognition of the need for energy independence, it shall be the policy of the Commonwealth to support federal efforts to:*
>
> *1. Determine the extent of oil and natural gas resources 50 miles or more off the Atlantic shoreline, including appropriate federal funding for such an investigation; and*
>
> *2. Permit the production and development of oil and natural gas resources 50 miles or more off the Atlantic shoreline taking into account the impact on affected localities, the armed forces of the United States of America, and the mid-Atlantic regional spaceport.*
>
> *B. The policy of the Commonwealth shall further support the inclusion of the Atlantic Planning Areas in the Minerals Management Service's draft environmental impact statement with respect to oil and natural gas exploration, production, and development 50 miles or more off the Atlantic shoreline.*
>
> *C. It shall be the policy of the Commonwealth to support federal efforts to examine the feasibility of offshore wind energy being utilized in an environmentally responsible fashion.*

[1] The 2014 Virginia Energy Plan (developed pursuant to Title 67) is available at the Commonwealth of Virginia Department of Mines, Minerals and Energy website at http://www.dmme.virginia.gov/DE/2014_VirginiaEnergyPlan2.shtml.

As the offshore energy portion of Title 67 evolved between 2006 and 2010, oil was added to the mix of offshore resources (in addition to wind and natural gas). Virginia also formally recognized limitations on offshore oil and gas production and development, taking into account impacts that such activity may have on affected localities, the military, and the mid-Atlantic regional spaceport located on Wallops Island.

Oil and natural gas resources on the OCS are managed by the U.S. Department of the Interior's (DOI) Bureau of Ocean Energy Management (BOEM). The BOEM offers leases for the rights to explore for and produce oil and natural gas through its Five-Year OCS Oil and Gas Leasing Program. A lease sale for an area 50 miles off the Virginia coastline (See Proposed Sale 220 depicted on Figure 9.1-1) was scheduled in the 2007-2012 Five-Year Program, but the sale was cancelled after the April 2010 *Deepwater Horizon* accident. Subsequently, Virginia's offshore area was excluded from the 2012-2017 Five-Year Program. In its Summary of Decision (BOEM, 2012b), BOEM explained that planning areas in the Atlantic were excluded because:

1) Existing geological and geophysical data are outdated and inadequate to enable the agency to make informed decisions about whether and where to allow leasing to occur;
2) There are concerns about potentially conflicting uses of the area, including those raised by the Department of Defense; and
3) Existing infrastructure in the region is inadequate to support the oil and gas industry.

In its Proposed Final Program (BOEM, 2012b), BOEM stated that there are complex issues relating to potentially conflicting uses, including but not limited to, those of the DoD, which must be addressed so any potential future leasing activity in these areas is configured appropriately. For example, in response to the 2012-2017 Draft Proposed Program (DPP) (BOEM, 2009), the DoD identified significant conflicts in the Proposed Sale 220 area offshore of Virginia. The DoD assessment, as provided to BOEM, of the proposed sale area categorized 72% of the area as incompatible for any oil and gas activity, and an additional 5% as incompatible for permanent oil and gas surface infrastructure. The DOI respects the military's mission to protect the United States and will continue to work closely with the DoD to understand and deconflict the military's needs in these areas as it considers future energy development in the Mid- and South Atlantic planning areas.

9.1.2 Potential Conflicts

In 2010, the DoD issued its final report on the 2012-2017 DPP and the compatibility of DoD activities with oil and gas resource development on the OCS (DoD, 2010). The report applied only to the 2012-2017 DPP (not to the current 2017-2022 DPP). This 2010 report (hereinafter referred to as the, "Compatibility Report") identified locations within six BOEM Planning Areas where there are potential conflicts between testing, training, and other DoD activities with offshore oil and gas development. Most of these potential conflicts are attributable to the frequent use of live munitions in support of fleet gunnery exercises; air-to-surface bombing; and anti-submarine warfare and test operations.

In its Compatibility Report, the DoD used a comprehensive approach for its analysis of activities on the OCS. Four categories of potential compatibility were developed as part of this analysis. Definitions of these four categories are provided below with the color coding applied as shown in Figure 9.1-2.

1) **No Oil and Gas Activity**: Areas where any oil and gas development infrastructure and activity would jeopardize DoD operations.

2) **No Permanent Oil & Gas Surface Structures**: Areas where subsurface oil and gas infrastructure may be compatible; e.g., where scheduled temporary surface activities from a drillship or moveable platform are pre-coordinated with the DoD and subsurface and seabed infrastructure remains in place.

3) **Site-Specific Stipulations**: Areas where, with specific stipulations, above-surface oil and gas infrastructure may be feasible. Examples of currently used stipulations include: "hold harmless" provisions; electromagnetic emission controls; site evacuation protocols; location pre-coordination; density limitations; and planned periods of lease operations. Appendix A contains actual stipulation language applied to some Eastern Gulf of Mexico Planning Area OCS leases.

4) **Unrestricted**: No DoD-requested restrictions on oil and gas infrastructure or related activities. However, the DoD requests early and prior coordination if oil and gas activity is contemplated in these areas. These areas encompass the remainder of the Mid-Atlantic Planning Area east of the Navy's Virginia Capes (VACAPES) Operating Area (OPAREA) and the Cherry Point OPAREA and are not color-shaded on Figure 9.1-2.

The DoD assessment is the sum of the input from all DoD Services. The subsections that follow describe in greater detail, some examples of conflicts recognized by the individual DoD Services and program offices. At the request of BOEM and the Department of the Interior, the DoD is currently conducting a new mission compatibility assessment of the OCS, to include the Mid-Atlantic Planning Area. This new DoD assessment will be used to inform the 2017-2022 OCS O&G Proposed Lease Sale Program, and will replace the 2010 assessment.

The DoD 2010 assessment of the Mid-Atlantic Planning/Program Areas is set forth in Table 9.1 1. Even though 64% of the area is unrestricted, the majority of this unrestricted area is located >150 nautical miles (nm) offshore, beyond the boundaries of the Navy-controlled Special Use Airspace (SUA). The 9% area assessed for "No Oil & Gas Activity" is primarily located near shore, off the coast of Virginia (Virginia Beach [home of Naval Air Station Oceana], Norfolk [home of Naval Station Norfolk], and Eastern Shore [home of the National Aeronautics and Space Administration (NASA) Wallops Flight Facility (WFF) and Mid-Atlantic Regional Spaceport]), and off the coast of Jacksonville, North Carolina near Marine Corps Base (MCB) Camp Lejeune. These areas are concentrated DoD training and testing areas with associated hazards. The Navy's Surface Combat Systems Center (SCSC) is co-located with NASA at the WFF and test activities are conducted from this Eastern Shore site. The remaining 27% of DoD-assessed areas (No Permanent Oil & Gas Surface Structures, and Site Specific Stipulations) are also located within the confines of SUA and OPAREAs between areas of heavy and light training and testing use.

Table 9.1-1 Mid-Atlantic Summary

DoD Assessment Category	Percentage (%)
No Oil & Gas Activity	9%
No Permanent Oil & Gas Surface Structures	5%
Site Specific Stipulations	22%
Unrestricted	64%

Source: DoD 2010.

In support of Virginia Offshore Oil and Gas Study, a meeting was held at the Pentagon in November 2014 (Engle, 2014). Representatives of DoD, Service branch representatives, Commonwealth of Virginia, Department of Mines, Minerals and Energy (DMME), and contractors were in attendance. Several other follow-on teleconference meetings were held and email communications were exchanged with Service branch representatives. The following subsections provide a summary of some of the perceived conflicts noted by DoD and the Service branches. Later in this section, several DoD-suggested conflict-resolution solutions are described and summarized as recommended steps forward.

9.1.2.1 Navy and Marine Corps

The Navy and Marine Corps face increasingly difficult encroachment/compatibility challenges that can affect readiness training and research, development, and testing, and evaluation (RDT&E) activities onshore and at sea. Examples of challenges include: residential and commercial development adjacent to installations, ranges, and OPAREAs; increased competition for waterfront property, airspace, and frequency spectrum[2]; establishment of protected areas for species and/or cultural resources conservation; and development of energy in proximity to airfields and training areas, both ashore and at sea. These external factors can limit fleet training as well as RDT&E activities and certification, especially with regard to live fire training. The ocean also supports a wide and growing range of uses, including commercial shipping, fisheries, oil and gas exploration, aquaculture, renewable energy development, resource extraction, tourism, and recreation. Coastal and marine spatial planning efforts continue under Executive Order 13547 (The White House, 2010) and the National Ocean Policy Implementation Plan (National Ocean Council, 2013). Any of these uses could potentially be incompatible with national defense use of established offshore ranges and OPAREAs.

The Norfolk Fleet Concentration Area is the world's largest concentration of carriers, cruisers, destroyers, submarines, amphibious and logistics vessels. In addition to routine unit level training, the VACAPES OPAREA off the Norfolk coast, hosts large scale exercises on a regular basis. Most recently, exercise Bold Alligator 2014 was held during a two-week period in November 2014. It was hosted by the U.S. Navy and the U.S. Marine Corps. This coalition exercise included

[2] As explained in Chief of Naval Operations Instruction 11010.40 (DoN, 2007), competition for available frequency spectrum may lead to a reduction in available spectrum for training and developmental/operational testing activities. The lack of spectrum may decrease the effectiveness of exercises by restricting the number of war-fighting systems that can participate. In addition, spectrum limitations may restrict the use of state-of-the-art instrumentation systems, resulting in less data for evaluators to use in training assessments, and may also limit development testing of new technologies. As the potential for residential and commercial encroachment increases, so does the risk of increased radio frequency emitters and receivers, which could result in electromagnetic interference problems between Navy systems and public or commercial systems.

participants from the North Atlantic Treaty Organization and allied partner nations. This large exercise required a large contiguous and unobstructed space. Bold Alligator 2014 involved 8,500 Marines and 6,500 Sailors from 19 different countries on 17 different ships.

The types of Navy and Marine Corps training conducted in the Mid-Atlantic Planning Area include, but are not limited to, the following[3] (DoD, 2010):

- Northern VACAPES OPAREA (and associated SUA [Warning Area {W}-386] [Figure 9.1-2])
  - Aerial, surface, and subsurface training
  - Airborne use of defensive expendables (chaff and flares)
  - Homing torpedo training
  - Surface-to-air missile exercise (MISSILEX)
  - Aerial target hazard pattern
  - Live ordnance release and impact
  - Fleet gunnery
  - Towed target operations
  - Air-to-surface MISSILEX
  - Air-to-surface bombing exercise (BOMBEX)
  - Live fire ordnance operations
  - Chaff and flare exercises
  - Laser targeting operations
  - Aircraft carrier operations and training
  - Air crew landing qualifications (day and night)
  - Extensive aircraft launch and recovery operations
  - Aircraft carrier transit/course
  - Mine countermeasure operations
  - Dynamic towed sonar systems
  - In-water active acoustic decoy training
- Southern VACAPES OPAREA (and associated SUA [W-72])
  - Mine countermeasure operations
  - Dynamic towed sonar systems
  - Surface-to-air MISSILEX
  - Drone transit operations
  - Surface-to-surface gunnery live fire/ordnance operations
- Cherry Point OPAREA (and associated SUA [W-122])
  - Live fire training
  - Air-to-surface gunnery
  - Air-to-surface MISSILEX
  - Live fire/ordnance operations
  - Laser operations

[3] The listed Navy training events are those conducted within DoD-assessed areas where DoD recommends no oil and gas activity (DoD, 2010).

The W-386 SUA covers 9,765 nm^2 and overlies the northern half of the VACAPES OPAREA. The W-72 SUA covers 15,274 nm^2 and overlies the southern half of the VACAPES OPAREA. The W-122 SUA covers 18,718 nm^2 and overlies the Cherry Point OPAREA. As additional context to the foregoing list of training event types, Table 9.1-2 provides a summary of total annual training events and associated total ordnance items within the VACAPES OPAREA (Northern and Southern) and the Cherry Point OPAREA (the OPAREAs within the Mid-Atlantic Planning Area) (DoN, 2013). The values reflect those annual training needs identified in the recently completed Atlantic Fleet Training and Testing Environmental Impact Statement/Overseas Environmental Impact Statement.

Table 9.1-2 Summary of Annual Navy and Marine Corps Training Events and Ordnance Expenditure within the Mid-Atlantic Planning Area

	VACAPES OPAREA	**Cherry Point OPAREA**
	Fleet Training	Fleet Training
Total Events	15,236	11,978
Total Ordnance	4,736,995	803,361

Source: DoN 2013.

Note 1: An event varies in duration depending on the type of training conducted. It can range from one hour for certain unit-level training events to several weeks for advanced level training.

The total training event count set forth in Table 9.1-2 includes unit level events and major exercise events. The total ordnance item count consists primarily of small-caliber rounds, but also includes high explosive bombs (64 in VACAPES and 32 in Cherry Point) and high explosive missiles (190 in VACAPES and 91 in Cherry Point). As shown in Table 9.1-2, Navy training activity in the VACAPES and Cherry Point OPAREAs is frequent and potentially hazardous. In many parts of the VACAPES OPAREAs and Cherry Point OPAREA oil and gas activities would not be compatible for safety reasons, and planning infrastructure in the area would jeopardize DoD operations.

Training and testing with live weapons requires vast areas cleared for safety purposes. These areas, called weapons danger zone footprints, vary based on the complex interaction of multiple factors, including net explosive weight of the ordnance, firing angle, platform type, platform airspeed, altitude, target characteristics, etc. Drawing on another Service example, USAF weapons testing in the eastern Gulf of Mexico generated a composite safety footprint of 301 square miles (USAF, 2014). This area is proposed for live ordnance delivery consisting of bombs, missiles, rockets, and medium- and small-caliber rounds. As set forth in the Navy Ranges Required Capabilities Document, air warfare training for aircraft events ideally require an area 50 nm x 80 nm (4,000 nm^2), from surface to 60,000 feet above ground level (AGL), and cleared for supersonic flight; and for surface combatant events: an area 75 nm x 75 nm (5,625 nm^2), from surface to 60,000 feet AGL (Department of the Navy, 2005). Navy air warfare training often includes air combat maneuvers, air-to-air gunnery, and expenditure of surface-to-air missiles and air-to-air missiles against target aircraft and drones replicating typical airborne threat tactics and profiles.

Training requirements are subject to change based on the nature of any potential threat and the resultant response required to effectively train for mitigation of the threat. For example, a shift is underway to train less for small-scale counter insurgency response, but move to train more for large-scale defense. This shift requires training in large battle groups with coordinated exercises, all of which necessitates larger exclusive sea and air spaces. Training events require certain specialized conditions such as a particular depth, distance from shore, airspace, targets, opposition forces, systems, and other requirements that can limit the available options for event host location. Evolving technology is incorporated into training, including the use of unmanned aircraft and vessels. In some cases, this technology is expanding the training space requirements due to the hazards associated with unmanned systems.

9.1.2.2 USAF

Air Force pilots at Joint Base Langley-Eustis, Virginia and Seymour Johnson Air Force Base, North Carolina train offshore in SUA areas, including but not limited to, Warning Area (W)-72, W-386 and W-122 (Figure 9.1-2). Training event types include air-to-air and air-to-surface events, air intercept control, and exclusive air operations. Placement of oil and gas structures (whether surface or subsurface structures) within this training space would present a risk. USAF aircraft training in that region train in air-to-surface bombing, which involves expenditure of inert training ordnance. Should inert ordnance (concrete-filled or iron bombs without warheads) land on any O&G infrastructure, they are heavy enough to damage or even destroy them, and may be a hazard to personnel, as well.

The quantity of Air Force training conducted in the Mid-Atlantic Planning Area includes, but is not limited to, the following data shown in Table 9.1-3. The data were retrieved from the Environmental Impact Statement (United States Air Force, 2001), but is indicative of the regular Air Force use of SUA in the Mid-Atlantic Planning Area. For the location of each SUA unit, refer to Figure 9.1-2. More recent data from the 1st Fighter Wing stationed at Joint-Base Langley-Eustis indicate an average of 7,000 sorties (by F-22 and T-38 platforms) are flown each year in W-386/W-387 (Nelson, 2015). Inert ordnance expenditure occurs in several sub-unit blocks of W-386 extending approximately 150 nm east-northeast of the air force base.

Table 9.1-3 Air Force SUA Utilization in the Mid-Atlantic Planning Area (2001)

Special Use Airspace Unit	Total Annual Use
W-72	33,329
W-110	301
W-122	14,798
W-386	11,187
W-387	1,203

Source: USAF 2001.

9.1.2.3 Navy Sea Floor Cable Protection Office

The Navy owns over 40,000 nm of various active seafloor cables (NSCPO, 2014c). The Naval Sea Floor Cable Protection office (NSCPO) protects the Navy's interests with respect to seafloor cables by providing internal coordination and external representation of Navy's interest and concerns to the DoD, other government agencies, and industry (both foreign and domestic) (Naval Sea Floor Cable Protection Office, 2014a). Both military and civilian cables exist offshore. These cables are extremely sensitive and conflict resolution is required on a case-by-case basis.

For example, conflict resolution may be achieved via an established lateral offset for activities conducted in the vicinity of a cable. A certain lateral offset allows Navy service boats the periodic opportunity to access the cables.

The NSCPO coordinates with developers who plan offshore activities. While commercial cables are present on charts, locations of military cables are not publicly available. Figure 9.1-3 illustrates the location of civilian/commercial cables in the Mid-Atlantic and South-Atlantic Planning Areas. Cables may be buried or lie on the seafloor. Either circumstance is vulnerable to damage, through expended ordnance, drilling, etc. To ensure that new commercial or government cable projects are routed clear of any DoD cable systems, NSCPO requests system planners and installation contractors to contact NSCPO early in the planning process (NSCPO, 2014b).

9.1.2.4 Navy Test Community Concerns

Navy test areas can be distinct from training areas, but they can also overlap with training areas. For example, in the northern VACAPES OPAREA, many training and testing events occur within the same geographic area off the coast of Virginia. Like training, test events may include the use of live fire, and drones. Areas suitable for test events are restricted due to the large area required to safely conduct these exercises. Potential fallout from downed drones and the live fire events pose a significant hazard to any O&G infrastructure in the vicinity.

The types of RDT&E conducted by Navy test community organizations (Naval Air Systems Command [NAVAIR] and Naval Sea Systems Command [NAVSEA]) in the Mid-Atlantic Planning Area include, but are not limited to the following[4]:

- Northern VACAPES OPAREA
    - Live fire tests
    - Supersonic flight tests
    - Aerial target launch
    - Operational Test/Development Test
    - Combat System Ship Qualification Test
    - Testing and weapons employment/assurance
    - Aerial, surface, subsurface testing
    - Follow-On Operational Test & Evaluation
    - Homing torpedo testing
    - NAVAIR, NAVSEA sensor evaluations (live fire)
- Southern VACAPES OPAREA
    - Operational Test/Development Test
    - Combat System Ship Qualification test
    - Fleet test and evaluation events

To add context to the foregoing list of test events, Table 9.1-4 provides a summary of total Navy test events and associated total ordnance items within the VACAPES OPAREA and the Cherry Point OPAREA (the two OPAREAS within the Mid-Atlantic Planning Area) (DoN, 2013). The values reflect those annual testing needs identified in the recently completed Atlantic Fleet

[4] The listed Navy test events are those conducted within DoD-assessed areas where DoD recommends no oil and gas activity (DoD 2010).

Training and Testing Environmental Impact Statement/Overseas Environmental Impact Statement (DoN, 2013).

Table 9.1-4 Summary of Navy Test Events and Ordnance Expenditure within the Mid-Atlantic Planning Area

	VACAPES OPAREA		Cherry Point OPAREA	
	NAVAIR	NAVSEA	NAVAIR	NAVSEA
Total Test Events	858	7,709	439	2,848
Total Ordnance	26,887	178,027	573	9

Source: DoN 2013.

Test requirements evolve over time as new weapon systems and platforms are readied for introduction to the Fleet. Like training, test events often require certain specialized conditions such as a particular depth, distance from shore, and other requirements that can limit the available options to perform these events elsewhere. For example, NAVSEA recently completed an Environmental Assessment for testing of hypervelocity projectiles and an electromagnetic railgun (DoN, 2014). According to the Environmental Assessment, suitable locations for testing of this gun and hypervelocity projectiles must meet several requirements, one of which is that it must be situated adjacent to a sea range controlled by the DoD capable of supporting projectile flight distances of at least 100 nm. According to the assessment, the only installation that meets all the criteria is NASA's WFF at Wallops Island, Virginia (Figure 9.1-2). The area off the coast from Wallops Island contains DoD-controlled SUA (W-386) and a surface/subsurface OPAREA which extends southeastward for more than 140 nm. This vast space is needed for safety purposes for the railgun program which is expected to fire hundreds of projectiles over the next five years. Each railgun projectile travels at an estimated 1.2 to 1.6 miles per second.

9.2 EXAMPLES OF CONFLICT RESOLUTION

Despite conflict between users such as the DoD and offshore O&G activities, examples exist where conflicts have been resolved to the satisfaction of stakeholders. The following subsections are examples of successful conflict resolution.

9.2.1 The Gulf of Mexico

The Gulf of Mexico is one of the most developed O&G regions of the world. As of 18 February 2015, there are 2,341 active platforms at water depths from 0 to 656 ft. (0 to200m), 20 platforms at 659 to 1,312 ft. (201 to 400m), 10 platforms at 1,315 to 2,625 ft. (401 to 800m), 9 platforms at 2,628 to 3,281 ft. (801 to 1,000m), and 26 platforms at depths greater than 3,281 ft. (1,000m) (BOEM, 2015a). Additionally, there are over 25,000 miles of oil and gas pipeline on the Gulf of Mexico sea floor (National Oceanic and Atmospheric Administration [NOAA], 2014).

In preparation for drilling for oil and gas in the Gulf of Mexico, coordination between the DoD and BOEM has allowed both entities to ensure that their respective interests were protected. For example, BOEM, and its precursor MMS, provided geological data to the DoD for the Gulf of Mexico to highlight where industry interest would be for leasing. Most of the geological data showed that the oil was located in the western portions of the gulf, and in deeper water. With these data and an understanding of the nature of DoD training in the Gulf of Mexico, the DoD was able to expeditiously support OCS leasing in the eastern Gulf of Mexico with stipulations (i.e., no above surface platforms). The DoD provided BOEM the locations where mission-critical exercises occur. Using this information, BOEM removed those areas from the OCS lease programs. Working together, BOEM was able to maximize the potential for O&G exploration while protecting the DoD's ability to conduct its mission critical training and testing.

In another example, industry and DoD coordination proved mutually beneficial regarding a 2001 proposed natural gas pipeline to be installed across 419 miles from Mobile Bay in Alabama to Port Manatee in Tampa Bay (see Gulfstream pipeline in Figure 9.2-1). During construction of this pipeline, the DoD and the pipeline developer were able to coordinate their schedules. For example, the pipeline developer shared its construction schedule daily with the DoD, and the DoD in turn, advised the developer of upcoming training exercises and test events. This coordination achieved the following:

- Avoided costly delays for the developer;
- Avoided potential damage to the pipeline; and
- Allowed the DoD to meet its training and testing requirements without interruption.

9.2.2 Texas Wind Group

The Texas Wind Group (TWG) *Riviera I Wind Turbine Farm* was anticipated to interfere with Navy precision approach and air surveillance radars in the vicinity of Naval Air Station (NAS), Kingsville, Texas. To mitigate this adverse impact, an agreement was reached between TWG and the DoD that a voluntary contribution of funds would be made by TWG to the DoD prior to the start of ground-disturbing activity. The funds would be transferred to the appropriate Navy accounts to offset the cost of measures undertaken to mitigate the impacts of the *Riviera I* project on military operation and readiness.

Further, TWG agreed to keep the Navy apprised of all turbine placement; any changes were required to be submitted and not implemented until prior written agreement was received from the Navy. The TWG agreed to provide the Navy a final "as built" drawing, including actual turbine coordinates (after construction) within 30 days of completion of the project. Additionally, details for scheduling were worked out and agreed upon to protect both the Navy and TWG. For additional details, see the Memorandum of Agreement on *Riviera I* Wind Turbine Farm, Kingsville, TX – Signature Version – Friday, February 24, 2012. (DoD, Department of the Navy and Texas Wind Group, 2012).

While this example concerns an onshore, renewable energy project, the DoD coordination efforts may have bearing on offshore O&G development projects. However, one distinguishing factor for the Mid-Atlantic Planning Area is the presence of hazardous training and testing activities in addition to conflicts with precision approach and air surveillance radars.

9.2.3 Pacific OCS (Southern California) Compatibility

For the past 50 years, the Navy and Air Force have utilized the Point Mugu Sea Range (Figure 9.2-2) for testing and training activities conducted by the Naval Air Warfare Center Weapons Division. The Point Mugu Sea Range is an approximately 36,000 square mile area of ocean and controlled airspace, 200 nm long (Naval Air Systems Command, 2007).

The Sea Range extends west into the Pacific Ocean from its nearest point on the mainland coast to approximately 180 nm offshore and includes San Nicolas Island and portions of the Northern Channel Islands. Airspace preclusions include Warning Areas, as well as Restricted Areas. The Restricted Areas are located over San Nicholas Island, the NAS Point Mugu Airfield at Naval Base Ventura County, and coastline adjacent to the airfield.

According to the Navy, there have been no accidents involving non-participants within the Point Mugu Sea Range. There are four platforms located within the Sea Range boundary (Parisi, 2014). Testing activities do occur in the vicinity of the platforms within the range boundary, but test activities in that particular part of the Sea Range are of a non-hazardous nature (compatible). Missile launches from Vandenberg Air Force Base, California are also a concern for offshore platforms in this area.

A proposed platform in the Carpinteria Field (Figure 9.2-2) was evaluated in a Development and Production Plan. It was anticipated that the project would not result in any conflicts with military activities in the Santa Barbara Channel (BOEM, 2011). Port Hueneme serves as the principal staging area for supplies, equipment, and crews for oil platforms off the coast of Southern California.

9.2.4 Pacific OCS (Hawaii) Compatibility

The area around the Hawaiian Islands is of significant interest to those seeking development of renewable energy. Consistent offshore winds represent an untapped clean energy resource. While there are no current plans for offshore oil or gas development in Hawaii, renewable energy efforts share many of the same preparatory and coordination efforts. Lessons learned from Hawaii's push for offshore renewable energy against the backdrop of multiple use conflict resolution can yield useful approaches applicable to Virginia's offshore energy policy initiatives in the Mid-Atlantic Planning Area. One such example is the Hawaii Ocean Uses Atlas, one of the three state-level mapping efforts that comprise the Pacific Regional Ocean Uses Atlas project (MacDowell, 2014).

The Pacific Regional Ocean Uses Atlas project is an interagency collaboration between the NOAA and the BOEM designed to document where coastal communities use the ocean across a full range of typical human activities and sectors (BOEM and NOAA, 2014). Using participatory mapping techniques, the project offers a proven, flexible, and scalable approach that empowers coastal communities to paint an accurate picture of human use on a scale appropriate for local-, state-, or regional-level ocean planning. Figure 9.2-3 illustrates some of the geospatial layers generated based on community participation and input.

The Ocean Uses Atlas interactive mapping technique allows input from ocean stakeholders, including, but not limited to, surfers, paddlers, commercial and recreational fishermen, extractive industries, underwater cable programs, and the military. BOEM and NOAA worked together with the States of Hawaii, Washington, and Oregon to generate this interactive mapping tool, with information gathered during public workshops and town hall meetings held across the states.

In Hawaii, the Hawaii Ocean Uses Atlas is a collaboration among NOAA, BOEM, and the State of Hawaii Office of Planning. Stakeholders were provided an opportunity to inform BOEM and NOAA of the areas they use to conduct their activities. The project information is not to be used to designate suitable offshore renewable energy areas, but to inform the planning process (for which there will be future opportunities for the public engagement). Federal and state agencies can use the information to help inform their decision-making, permitting, coastal zone and ocean planning efforts. Products include geographic information system data and online mapping services, digital and paper maps of ocean patterns and maps of ocean use hotspots and potential use conflict areas. In Hawaii, this represented the first time that the DoD was involved in an ocean planning project of this nature. The Services were able to provide input not only as to the areas used for training and testing, but also the general nature of the training or testing exercises conducted in these areas. This additional level of mapping detail allows identification of DoD activities that could co-exist (or be compatible with stipulations) with other offshore uses.

9.2.5 Virginia Offshore Wind Energy Experience

The road to wind energy production off the Virginia coast is a case study in successful conflict resolution. Although not an O&G example, much can be learned from the Virginia offshore wind energy efforts, given the project location and multitude of OCS stakeholders, including DoD. Many of the efforts are expected to be the same for offshore O&G conflict resolution. The now firmly established Virginia offshore Wind Energy Area (WEA) (Figure 9.2-4) gained its final form through rigorous planning and consideration of potential stakeholder impacts.

Virginia's Energy Plan has long called for the support of federal efforts to examine the feasibility of offshore wind energy being used in an environmentally-responsible manner. While offshore wind energy production has been underway in northern Europe since 1991, the U.S. does not yet have any offshore operational projects. This could change within a few years as many projects are now under consideration, including the Virginia offshore commercial WEA. Figure 9.2-4 illustrates the current status of the overall lease area, two DMME research lease areas, and transmission lines.

The Virginia WEA had been identified in BOEM's February 9, 2011 Notice of Intent (NOI) (76 FR 7226), and was delineated through consultation with BOEM's Virginia Intergovernmental Renewable Energy Task Force (BOEM, 2012c). The Virginia WEA was created taking into consideration sensitive ecological habitat and shoals along the coast north of the mouth of the Chesapeake Bay, as well as a number of other important use areas, such as:

- DoD training areas,
- A charted dredge disposal site,
- Areas of concern specified by the NASA's WFF,
- Ocean shipping traffic separation schemes, and
- A renewable energy research lease to be held by the Virginia DMME.

During preparation of its 2012 Environmental Assessment (BOEM, 2012c), BOEM received comments from the American Waterways Operators (AWO) and continued consultation with the Coast Guard. The AWO raised concerns regarding navigational safety in inclement weather affecting tugboats, barges and articulated tug barges offshore Virginia. They recommended the preservation of a channel (free of wind turbines) along the western edge of the proposed Virginia WEA currently used by members during inclement weather (full OCS blocks[5]

[5] For the location of referenced OCS lease blocks, see BOEM, 2012c.

6111 and 6161 and parts of four other lease blocks), while making a large block of undeveloped ocean available for alternative energy development (east and within the proposed Virginia WEA). The Coast Guard identified the same western edge area (and three additional aliquots in OCS block 6012) as presenting navigational risks should these leases be ultimately developed in the future. These areas were considered Category "A"[6] areas. Based on the Coast Guard recommendation and BOEM's own preliminary analysis of vessel traffic data, BOEM refined the Virginia WEA and identified the alternative with a refined Virginia WEA as its Environmental Assessment preferred alternative.

As noted throughout this section, one primary stakeholder in the Mid-Atlantic OCS is the DoD. Figure 9.2-5 depicts the Virginia WEA lease area in relation to the Navy's shaded SUA blocks (W-386 and W-72). The orange outlined area is a surface danger zone and outlines another SUA block (W-50 [not shown]). The zone between W-386 and W-72, where the current WEA lease area is situated, is categorized in DoD's Wind Assessment as acceptable with stipulations (Figure 9.1-2); whereas areas north and south of that area were categorized wind exclusion zones. The transmission line route also requires coordination with DoD as portions of the route run below SUA, through ocean surface and subsurface operating areas, surface danger zones, and ashore at Camp Pendleton State Military Reservation, Virginia.

According to the 2012 Environmental Assessment (BOEM, 2012c), the following proposed mitigation measures were developed with the intent to reduce or eliminate potential impacts of site characterization surveys and the installation, operation, and decommissioning of meteorological towers/buoys on military activities, shipping, and navigational safety. BOEM proposed that these mitigation measures to be incorporated into any future decision to issue a lease or approve a Site Assessment Plan (SAP). The following proposed mitigation measures were developed in consultation with the DoD to eliminate or reduce the potential impacts of commercial and research wind energy leases on military activities:

- Lessees would be required to consult with the appropriate command headquarters prior to any construction or decommissioning activity, regarding the location, density, and planned periods of operation, to minimize potential conflicts with DoD activities.
- Lessees would be required to control their own electromagnetic emissions and those of its agents, employees, invitees, independent contractors, and subcontractors emanating from individual designated defense warning areas in accordance with requirements specified by the appropriate command headquarters to the degree necessary to prevent issues with DoD flight, testing, or operational activities conducted within individual designated warning areas.

BOEM may make these proposed mitigation measures mandatory via lease stipulations and/or conditions of approval of a SAP should the specific conditions associated with a particular lease or SAP so warrant.

In September 2013, approximately one and a half years after publication of the Final Environmental Assessment, BOEM awarded Dominion Virginia Power a commercial lease of

[6] Category A areas are areas that the U.S. Coast Guard believes should not be leased because, should these leases be ultimately developed in the future, they would pose navigational risks due to existing and anticipated future increase in vessel traffic density.

112,800 acres in the Virginia WEA (Dominion Virginia Power, 2015). This represented a milestone, as the second competitive lease sale for renewable energy on the OCS. Although not directly connected with the larger lease, Dominion Virginia Power is currently involved in the Virginia Offshore Wind Technology Advancement Project (VOWTAP). Applying Department of Energy grants, the VOWTAP team proposes designing, developing and demonstrating a grid-connected 12-megawatt offshore wind facility consisting of two Alstom 6-megawatt turbines mounted on innovative foundations (Dominion Virginia Power, 2015). One megawatt of offshore wind can help power up to 250 homes at peak demand. If the entire 112,800-acre lease area were developed, it could generate an estimated 2,000 megawatts of wind energy and power about 500,000 homes.

According to the Virginia Energy Plan, offshore wind has the potential to provide the largest scalable renewable energy resource for Virginia (Commonwealth of Virginia, Department of Mines, Minerals and Energy, 2014). Virginia is unique with a shallow continental shelf that extends out 30 miles. With its proximity to load centers, supply chain infrastructure, a trained work force and best in class ports, offshore wind can provide substantial benefits to the state. The ultimate delimitation of the Virginia WEA and its current lease sprang forth from thorough planning. Of particular note are the efforts of the BOEM’s Virginia Intergovernmental Renewable Energy Task Force in facilitating the formation and use of the WEA. The Task Force was an effective group because: (i) it promoted efficient and effective communication; (ii) provided a way to disseminate information in a timely and consistent manner; and (iii) by having all government parties at the table, facilitated early information sharing. Participation in the Task Force gave interested and affected parties the opportunity to actively provide input into the leasing process rather than simply reacting to BOEM actions. This group was able to see the Virginia WEA through to fruition while navigating a sea of stakeholder concerns, including those expressed by the DoD.

9.3 PREPARING FOR COMPATIBILITY IN THE MID-ATLANTIC PLANNING AREA

On 29 January 2015, BOEM published its 2017-2022 DPP (BOEM, 2015b). A sixty-day public comment period ensued thereafter (ending 30 March 2015). After analyzing 26 OCS planning areas, BOEM selected 14 potential lease sales in 8 OCS planning areas for the 2017-2022 DPP. Among the potential lease sales is Sale Number 260 for the Mid-Atlantic and South Atlantic, proposed for sale in 2021. Before lease sales are actually conducted, the areas selected for the DPP still must pass through further analysis in the planning process, including the Proposed Program (PP) and associated Draft Programmatic Environmental Impact Statement (PEIS). Should Lease Sale Number 260 be selected for inclusion in the PP, then it will be analyzed in the Proposed Final Program and the Final PEIS. The final decision on the Program may adopt geographic exclusions and/or restrictions that BOEM considers necessary for environmental protection. Exclusions or restrictions not chosen at the Program stage may, as appropriate, be considered at later, more focused stages in the leasing process, including the pre-lease sale and plans processes.

During the DPP winnowing process, BOEM selected only a portion of the Mid-Atlantic Planning Area and South Atlantic Planning Area (see Figure 9.3-1). Portions of the Mid-Atlantic Planning Area offshore from Maryland and Delaware were excluded in accordance with expressed opposition from those States (BOEM, 2015b). Portions of the South Atlantic Planning Area were excluded in deference to the request from the Florida Department of Environmental

Protection that primary consideration be given to long-term protection of marine and coastal environments. The program area was further winnowed across its entire length through placement of a 50-mile no-leasing buffer from the coastline. According to BOEM, excluding the nearer-shore areas will minimize potential impacts on the coastal zone and protected species and potential conflicts with renewable energy projects, and other uses of the areas, while not significantly impacting potential resource availability (BOEM, 2015b). For the DoD, the 50-mile buffer is likely to decrease some potential impacts in the Mid-Atlantic Planning Area. The Commonwealth of Virginia would agree that, in addition to the environmental benefits, the DPP selection of Option 1 for Mid-Atlantic and South Atlantic Planning Areas minimizes conflicts with DoD activities. The program area selection aligns with policies contained in the Commonwealth's Energy Plan including support for offshore energy production 50 miles offshore while minimizing impacts to local communities, the military and space exploration.

With the preliminary DPP step taken, the following elements in Section 9.3 are measures available to address likely concerns that may still be raised by the military within the winnowed Mid-Atlantic and South Atlantic DPP Program Area and suggested means to alleviate some of those concerns in order to allow offshore O&G exploration, and later extraction to proceed.

9.3.1 Early DoD Coordination is Key

The DoD supports the production of offshore O&G and actively seeks to employ a workable solution whenever possible. As outlined above, the earlier stakeholders are engaged, the greater the opportunities for a mutually acceptable outcome.

Another example of the importance of early coordination is illustrated in the NSCPO program recommendations. According to NSCPO, the best way to ensure a clear route for a new cable installation is to notify NSCPO early in the planning stages (Creese, 2006). This recommendation could apply to O&G pipelines, as well as cable installation. The industry's best tool to avoid Navy equipment, and the easiest way for the Navy to avoid commercial systems is to communicate early about a new route. When possible, the parties will exchange detailed information. When that is not practical, NSCPO will work with the company to find a mutually acceptable route or burial plan. NSCPO requests that system planners, surveyors, and installation contractors contact them early in the planning process of a new system. Advanced notice makes it easier to reduce conflicts rather than having to make last minute changes to avoid a system. When convenient, NSCPO requests being included on distribution lists of as-built information that is provided to charting organizations such as NOAA and the United Kingdom Hydrographic Office. NSCPO requests that when practical, cable owners making repairs contact it with route position updates. Data provided to NSCPO will be treated as commercially proprietary and will not be releasable.

BOEM and DoD coordination has been shown to be fruitful in many other areas (Engle, 2014). BOEM and the DoD are coordinating with one another and other agencies through interagency working groups formed to avoid conflicts and through established state-federal interagency task forces and regional planning efforts. For example, BOEM and the Navy (along with the National Marine Fisheries Service) sponsor interactive Marine Mammals and Sound Workshops. BOEM and DoD are members of the Mid-Atlantic Regional Planning Body, which is an ocean planning coordinating entity between the states and federal agencies, tribes, Mid-Atlantic Fisheries Management Council and stakeholders. The Mid-Atlantic Ocean Data Portal will help prioritize, coordinate, and synchronize previously overlapping or competing ocean uses. The Data Portal is an online toolkit provided by the Mid-Atlantic Regional Council on the Ocean. The Mid-Atlantic Regional Planning Body will be in a position to help minimize duplication of efforts and potentially help to move projects forward more quickly (Mid-Atlantic Regional Planning Body, 2013).

9.3.2 Form an Intergovernmental O&G Task Force

Closely related to the general need for early coordination mentioned in Section 9.3.1 is the specific need to form a dedicated intergovernmental task force, governed by an adopted Charter. An O&G Task Force could be modeled after the highly successful efforts achieved by the BOEM Virginia Renewable Energy Task Force (See Section 9.2.5). For example, an O&G Task Force would be a forum to disseminate information. It would allow coordination and information gathering. The Task Force should consist of various stakeholders including relevant Federal agencies, state government officials designated by the Governor, local elected government officials, and tribal elected officials. Participation would give interested and affected parties the opportunity to actively provide input into the leasing process rather than simply react to BOEM actions. Task Force members would have the ability to provide meaningful and timely input to the BOEM regulatory framework without altering the framework or leasing process.

9.3.3 Understand the DoD Compatibility Report and OCS Assessment

Another facet of conflict resolution is a clear understanding of the DoD Compatibility Report and assessment process. As previously mentioned, the most recent assessment is contained within the 2010 Compatibility Report (DoD, 2010). This was prepared as the DoD's detailed response to the call for comments on the draft proposed OCS 2012-2017 Oil and Gas Leasing Program. A new DoD report will be released at the same juncture for the 2017-2022 Program. The new report will likely address concerns raised by the Committee on Foreign Investment in the United States (CFIUS) regarding technology transfer to foreign entities. For example, in 2005, this issue came to the public's attention, where a group of Oregon wind farms were slated for operation by a company owned by Chinese nationals. The DoD expressed concerns due to the proximity of the wind farms to the Naval Weapons Systems Training Facility (NWSTF) Boardman, Oregon. The U.S. military flies unmanned drones and electronic warfare planes on training missions at NWSTF Boardman. In 2012, President Obama, citing national security risks, blocked the transaction from taking place (Committee on Foreign Investment in the United States, 2013). As noted in the CFIUS Annual Report to Congress for Calendar Year 2012, this was the only transaction specifically prohibited by the President, although 114 notices were filed with CFIUS during 2012.

Current regulations permit the sale of O&G leases to any company in the world. As such, there is a good chance that a foreign-owned company would obtain a lease or leases offered in the Atlantic OCS. Subsequent transfer of leases after the sale is also a concern for the DoD (Engle, 2014). One of the site-specific stipulations the DoD may request, is the need to know whether a U.S. or foreign company is operating any rig or platform located near training or testing areas. Therefore, foreign ownership is a factor that the DoD may evaluate in certain instances. The DoD's compatibility assessment boundaries will take into consideration the limits of technology including air, surface and subsurface surveillance capabilities.

Drawing from the lessons learned in the Gulf of Mexico example in Section 9.2.1, once the O&G areas of interest are identified, depending on the location, an equitable solution may be reached with the DoD that allows each to conduct its respective mission.

The DoD raised significant concerns in response to the 2009 Draft Proposed 5-Year OCS O&G Leasing Program (BOEM, 2012b). Regarding the area proposed for lease sale offshore of Virginia (Proposed Sale 220 [Figure 9.1-1]), the concerns were so great that the DoD requested that no oil and gas activity be allowed in 72% of the area proposed for leasing, and that no permanent facilities be allowed in another 5% of the area. However, it should be noted that Proposed Sale 220 encompassed only a small portion of the overall Mid-Atlantic Planning Area. The Proposed Sale 220 area was located almost entirely over active, heavily-used testing and training space within the VACAPES Range Complex. As such, a large percentage of the area was deemed inaccessible either entirely or with stipulations by the DoD for O&G production.

In contrast, the DoD noted in the 2010 Compatibility Report that 64% of the Mid-Atlantic Planning Area is unrestricted to oil and gas activity. The majority of this unrestricted area is located >150 nm from shore, beyond the boundaries of the Navy-controlled SUA. Working with distant areas already known to be compatible is a viable option, as deep water far offshore Gulf of Mexico examples show. In the Gulf of Mexico, the Lower Tertiary trend lies 200 miles off the Gulf Coast (National Geographic News, 2011). One of the deepest oil producing structures in the world is floating here – Shell's Perdido production platform. The Perdido complex retrieves both oil and gas while moored at water depths of 8,000 feet (2,450 m) (Shell, 2014). It is the world's deepest direct vertical access spar. The spar acts as a hub for and enables development of three fields – Great White, Tobago, and Silvertip. Perdido has a peak production of 100,000 barrels of oil per day and 200 million cubic feet of gas per day.

As shown in Figure 9.3-1, the 2017-2022 DPP excludes that portion of the Mid-Atlantic Planning Area within 50 miles of the coastline. According to the DoD 2010 Compatibility Report, this zone contained a high percentage of areas categorized for "no oil and gas activity," which if encroached upon would degrade military training and testing and potentially jeopardize national security. In choosing DPP Option 1, BOEM recognized that the 50-mile coastal buffer would minimize conflicts with DoD activities (BOEM, 2015b). If history is a guide, the remaining 2017-2022 Program Area will still likely contain some areas categorized by DoD for "no oil and gas activity", but the majority of the Program Area will likely be available either without restriction or subject to lease stipulations. Industry is well accustomed to lease stipulations contained in certain Gulf of Mexico leases and offshore from Southern California. These are further discussed in Section 9.3.4.

One final point on the DoD assessment process is the expected change to the assessment category mapping method. In the 2010 Compatibility Report, the assessment mapping was done by overall special use airspace unit. The next DoD assessment (to be conducted in response to the 2017-2012 Five-Year Program) will map compatibility categories at the lease block level. This level of detail will be more useful for BOEM and may allow more flexibility in leasing and drilling (Engle, 2014).

9.3.4 Understand the DoD Project Evaluation Coordination Process

The DoD will provide the ultimate perspective, gathering input from the Services. In response to Section 358 of the 2011 National Defense Authorization Act, the Office of Secretary of Defense established a Siting Clearinghouse to coordinate Service review of proposed onshore energy projects having the potential to present an unacceptable risk to the national security of the United States. The DoD Siting Clearinghouse offers two levels of review for onshore projects (informal and formal). The formal evaluation process is executed through the Federal Aviation Administration's Obstruction Evaluation process. The evaluation process is documented in federal rule, 32 Code of Federal Regulations (CFR) Part 211.

Unlike onshore projects, the DoD evaluates offshore mission compatibility evaluation (MCE) projects in collaboration with the BOEM offshore leasing process (30 CFR 585) (DoD, 2013a). The Office of the Deputy Assistant Secretary of Defense for Readiness (ODASD(R)), in coordination with the Clearinghouse and Test and Evaluation community, leads the DoD's offshore MCE process to ensure the Department's evaluation efforts are consistent with the statutory objectives expressed in Section 358 and 32 CFR Part 211. Additionally, the DoD's assessments produced for BOEM leasing purposes can be used when applicants ultimately file their projects under Federal Aviation Administration/ Obstruction Evaluation (FAA/OE) process – at least for those projects sited within the confines of FAA's authority out to the 12 nautical mile territorial sea boundary[7].

Evaluating mission compatibility furthers DoD policy set forth in DoD Directive 3200.15 (DoD, 2013b). DoD Directive 3200.15 defines and updates established policy and assigned responsibilities to sustain full operational use of, and access to, the DoD live training and test domain (DoD, 2013b). The DoD achieves its policy objectives through planning and risk management to avoid or mitigate constraints and restrictions from encroachment or competing non-DoD interests. Encroachment includes factors and influences that constrain or have the potential to inhibit the full access or operational use of the live training and test domain such as radio frequency spectrum, maritime restrictions, physical obstructions, and [renewable] energy projects. Lease stipulations are designed to minimize some of these encroachments and the OCS assessment process likewise serves to avoid or mitigate potential encroachment issues. Other means for the DoD to achieve and maintain its sustainability objectives include environmental management, strategic engagement with federal and state entities, partnerships for multi-lateral communication, and clear articulation of mission requirements to inform stakeholders.

Given its significant presence in the OCS, the Navy developed a detailed process for evaluating impacts to readiness from OCS initiatives. Through this process, the Navy will provide its feedback to the DoD for the ultimate perspective. In April 2011, the Office of the Chief of Naval Operations (CNO) announced the formation of and established charter for the Task Force Compatibility and Readiness Sustainment (CNO, 2011a). Its purpose is to address growing challenges pertaining to encroachment management and its impact on mission sustainment for all Navy installations, test and training ranges, air and water OPAREAs, SUA, and military training routes.

The Office of the Chief of Naval Operations, Energy and Environmental Readiness Division (OPNAV (N45)) has the lead in coordinating readiness and sustainability issues (CNO, 2011b). The Navy uses a Compatibility Assessment process designed to ensure the appropriate level of analysis is conducted to evaluate impacts to readiness and compatibility with proposed

[7] This would not be applicable under the 2017-2022 Draft Proposed Program (published in January 2015), as the Mid-Atlantic and South Atlantic Program Area begins eastward of a 50-mile coastal buffer.

non-Navy activities. Figure 9.3-2 illustrates the Compatibility and Readiness Sustainment Coordination Process.

9.3.5 Understand Common Stipulations

Several common stipulations may apply to O&G activities in military areas. For example in the Gulf of Mexico's Eastern Gulf Lease Sale 224 the following stipulations applied:

- Stipulation No. 1 – **Military Areas**
  - ***Hold and Save Harmless*** – provides that lessee assumes all risks of damage or injury to persons or property.
  - ***Electromagnetic Emissions*** – provides that lessee will control its electromagnetic emissions.
  - ***Operational*** – provides that lessee will agree with the appropriate command headquarters to maintain positive control of personnel and property.
- Stipulation No. 2 – **Evacuation** – in order to avoid interference with tactical military operations, provides that the lessee will recognize the right of the U.S. to temporarily suspend lessee's operations and/or require evacuation in the interest of national security.
- Stipulation No. 3 – **Coordination** – provides that lessee shall consult with the appropriate military command headquarters regarding the location, density, and planned periods of operations of structures to maximize exploration time and minimize conflicts with the DoD activities. An Operating Agreement may be required.

Appendix E of this report provides the full text of these common stipulations. The Gulf of Mexico's Eastern Gulf Lease Sale 224 was held in 2008. The sale included a small part of the Eastern Gulf of Mexico Planning Area, more than 125 miles off the Florida coast and completely west of the Military Mission Line (BOEM, 2008). Nevertheless, the above-listed stipulations applied.

The evacuation stipulation applies similarly to several platforms offshore from Vandenberg Air Force Base in Southern California. The evacuation stipulation has been in place at least since 1984 (MMS, 1984). Launches from Vandenberg Air Force Base occur approximately once per month (Parisi, 2014). Some of the trajectories of these launches require evacuation of platform personnel for safety reasons. This stipulation may be necessary in potential leases in the Northern and Southern VACAPES OPAREA given proximity to DoD training and testing events and the NASA WFF and Mid-Atlantic Regional Spaceport.

The coordination stipulation is seen in some Gulf of Mexico leases and may be appropriate for leases in the 2017-2022 DPP Mid-Atlantic and South Atlantic Program Area. The coordination stipulation contains what is referred to as a "drilling window" program. Several industry groups mentioned the drilling window program in their comments submitted to BOEM in response to BOEM's Request for Information and Comments published in the Federal Register on 16 June 2014 (BOEM, 2015b). Drilling windows are calendar-scheduled (typically 90-day intervals) and ensure that exploration activities can be conducted predictably, safely, and in an orderly manner, without interfering with scheduled military activities or jeopardizing the national defense mission.

For the Mid-Atlantic Planning Area, the command headquarters list for coordination could be assumed to be (subject to actual publication of the contact list in a future Final Notice of Sale Package) that shown in Table 9.3-1. Identification of the command headquarters is referenced in Stipulation No. 1-Military Areas (Operational).

Table 9.3-1 Designated Mid-Atlantic Warning Areas and Command Headquarters

Warning Areas	Command Headquarters Contact Details
W-50 W-72 W-110 W-122 W-386 W-387	Fleet Area Control and Surveillance Facility, Virginia Capes (FACSFAC VACAPES) Attention: Schedules Officer 601 Oceana Blvd, Bldg. 3030 Virginia Beach, VA 23460-2205 Telephone: (757) 425-2671 Email: FFAECC@navy.mil

Note: FFAECC = Fleet Forces Atlantic Exercise Coordination Center.

Source: Casey, 2014.

The identified stipulations for the Gulf Lease Sale 224 may apply to the Mid-Atlantic Planning Area where appropriate given the widespread presence of military training and testing activities which occur in this area.

9.3.6 Use Technology to Maximize Space for Development

Offshore drilling structures have evolved in the last 90 years or so from the original semi-submersible oil platform in the early 1920s. As technology advanced, drilling structures became larger and their ability to house equipment and personnel to drill in deeper water increased significantly. Expanded capabilities of drill structures mean that production can occur in a larger range of depths/areas.

Horizontal drilling technology has been available since 1929, with the first recorded true horizontal oil well drilled near Texon, Texas (DOE, 1993). However, little practical application occurred until the early 1980s, by which time the advent of improved downhole drilling motors and the invention of other necessary supporting equipment, materials, and technologies, particularly downhole telemetry equipment, brought applications within the realm of commercial viability. Horizontal drilling length records are continually being broken. A rig off the coast of Qatar holds the world record with its nearly 7-mile horizontal segment (Drilling Contractor, 2009). As technology continues to improve, current horizontally drilled well length records will undoubtedly be broken in the near future.

Advanced technology such as horizontal drilling may be ideally suited to the Mid-Atlantic Planning Area. Some of the area assessed by the DoD in 2010 was categorized as incompatible with O&G activities. However, there are adjacent areas assessed as compatible with stipulations. In these areas compatible with stipulations, horizontal drilling may be employed to reach beyond those boundaries to reserves underneath areas otherwise demarcated as incompatible. Despite the promises offered by horizontal drilling, such techniques are likely to warrant close scrutiny by the DoD and potentially CFIUS (should foreign ownership come into play).

Another technology that could potentially serve well in DoD-assessed areas of, “no permanent oil and gas surface structures” is the subsea completion. Although only 5% of the Mid-Atlantic Planning Area was categorized in this way in the 2010 Compatibility Report, should these areas be found to contain economic O&G reserves, subsea completions could be a viable option, depending on the economic analysis. Subsea completions are used in lieu of an above-surface platform with the O&G transported to a processing facility via an undersea pipeline or flow line to a floating production vessel. This type of completion may fit within the DoD OCS assessment category definition of “no permanent oil and gas surface structures.” Stipulated drilling windows could support this approach. Seafloor structures would still need to be designed to avoid interfering with submarine operations. This technology has been in use for over 50 years. For example, the Shell Mensa natural gas project is a grouping of subsea trees connected via flow lines to a subsea manifold south of New Orleans in the Gulf of Mexico (FMC Technologies, 2014). A single pipeline transports the gas 63 miles to a shallow-water platform. The Shell Mensa platform was installed in 1997 and has been in production since 1998. It was the world’s deepest (5,300 ft.) subsea production development at completion with the longest tieback to host. As records continue to be routinely broken, by 2011, Shell began producing oil from the world’s deepest subsea completed well at its Perdido Development (at 9,627 ft. water depth), located in the Tobago Field 200 miles southwest of Houston (Shell, 2011). Construction is now underway at Stones field (200 miles southwest of New Orleans at water depth of ~9,500 ft.) with production targeted for 2016, and will start with two subsea production wells tied back to a floating production, storage, and offloading (FPSO) host vessel (Shell, 2015).

9.3.7 Coordination with Other Stakeholders

A wealth of information exists among numerous federal and state agencies and organizations regarding the offshore environment. Although the DoD was identified as a stakeholder with potentially conflicting use of the waters offshore of Virginia, they are by no means the only stakeholder in this region. Actively engaging relevant stakeholders in the process can be beneficial in terms of information sharing, lessons learned, and cost savings. The next several subsections describe some of those stakeholders and their interest in the Mid-Atlantic Planning Area.

> *“DoD speaks to mission impact. DoD speaks for DoD only.”*
>
> *-Fred Engle, Associate Director Energy & Mission Compatibility, Office of Secretary of Defense, ODASD (Readiness) TR&S (03 November 2014)*

9.3.7.1 NASA Wallops Flight Facility and the Mid-Atlantic Regional Spaceport

NASA Goddard Space Flight Center (GSFC) owns and operates NASA WFF (NASA, 2012). The WFF is located in the northeast portion of Accomack County, Virginia on the Delmarva Peninsula (Figure 9.3-3). The 6,000-acre facility employs nearly 1,700 civil service and contractor employees in addition to military personnel assigned to the U.S. Navy’s SCSC at WFF. The Fiscal Year 2014 estimated annual economic impact of the facility’s operations on the Commonwealth was $248.4 million and 2,132 jobs.

Wallops operates one of four launch ranges in the United States capable of launching payloads into orbit, making it a vital national asset for assuring access to space. For over 70 years, WFF has launched thousands of research vehicles in the quest for information on the flight characteristics of airplanes, launch vehicles, and spacecraft, and to increase the knowledge of the earth's upper atmosphere and the near-space environment. Research vehicles vary in size and power from small unmanned aircraft systems to orbital class rockets. Annually, the facility launches 10 to 15 suborbital sounding rockets from Wallops at varying times of the year supporting scientific investigations, technology demonstrations, and DoD missions.

The Virginia General Assembly created the Virginia Commercial Space Flight Authority (VCSFA) in 1995 to promote development of the commercial space flight industry, economic development, aerospace research, and Science, Technology, Engineering, and Math education throughout the Commonwealth (Mid-Atlantic Regional Spaceport, 2014). In 1997, VCSFA entered into a Reimbursable Space Act Agreement with NASA, which provided for the lease of land at NASA Wallops Island, and applied for and was granted an FAA license to launch to orbit (Mid-Atlantic Regional Spaceport, 2014). This led to establishment of the VCSFA Mid-Atlantic Regional Spaceport (MARS), located on the southern portion of Wallops Island. MARS is approved for launch azimuths (launch compass heading) from 38 to 60 degrees, making it an ideal location from which to launch to the International Space Station (ISS) (Mid-Atlantic Regional Spaceport, 2014). Since its establishment, six missions (five supporting the DoD) have launched from MARS Pad 0B on the Orbital ATK Minotaur launch vehicles:

- TacSat-2 in 2006
- NFIRE (Near Field Infra-Red Experiment) in 2007
- TacSat-3 in 2009
- ORS-1 in 2011
- LADEE in 2013
- ORS-3 in 2013

MARS also operates Pad 0A approximately 1,250 feet north of Pad 0B on Wallops Island. Recently reconstructed to support liquid-fueled orbital rockets, Pad 0A has supported five launches of Orbital ATK’s Antares rocket since April 2013, the primary purpose which has been to resupply the ISS with cargo on an approximately twice per year basis. Pad 0A is currently undergoing rehabilitation following an October 2014 launch mishap and is expected to resume Antares launches in early 2016.

In addition to Navy and Air Force identified SUA (and the Northern and Southern VACAPES OPAREA) and hazardous training and testing space, the NASA WFF has its own range hazard area (Figure 9.3-3). While each launch or flight will have specifically defined hazard areas, the extent of WFF’s hazard area may be generally characterized as overlaying most of the Northern and Southern VACAPES OPAREA and extending eastward beyond the OPAREA boundary, still within the Mid-Atlantic Planning Area. The extent of this safety-driven hazard area is necessary due to the launch trajectories, as well as potential for falling debris.

Ensuring public safety during launch operations is the primary mandate of any U.S. launch range. Unless a mission’s risk to persons or property is within acceptable limits, WFF cannot allow a launch to occur. In the case of high value missions with short allowable launch windows (i.e., Antares launching to the ISS), the ability to maintain a clear range is of particular importance.

Therefore, OCS leasing must take into consideration overlapping hazard areas established for safety purposes by multiple federal agencies. Whereas the DoD may categorize an OCS region as unrestricted for O&G activities or allow O&G activities with stipulations, leasing compatibility, particularly with permanent surface infrastructure, would also require consideration of the hazards of NASA WFF and MARS operations.

In addition to the NASA WFF and the MARS activities, the Navy conducts launches in support of training and testing from Wallops Island. Furthermore, the U.S. Navy SCSC operates from Wallops Island. The mission and vision of SCSC is to provide live integrated warfare systems in a maritime environment for fleet operations, testing, evaluation, training, research and development.

9.3.7.2 U.S. Coast Guard

The U.S. Environmental Protection Agency (USEPA) is the lead federal response agency for oil spills occurring in inland waters, and the U.S. Coast Guard is the lead response agency for spills in coastal waters and deep water ports (United States Environmental Protection Agency, 2011). The Fifth Coast Guard District ensures the safety and security of the oceans, coastal areas, and marine transportation system within America's Mid-Atlantic region (USCG, Fifth Coast Guard District, 2014). Any situation involving oil or gas release in the Mid-Atlantic Planning Area requires coordination with the U.S. Coast Guard Fifth District.

At no time in recent memory has the Coast Guard spill response mission been put to the test more than during the Gulf of Mexico *Deepwater Horizon* spill. On April 20, 2010, watch standers at the U.S. Coast Guard District Eight command center received a report of an explosion and fire aboard the *Deepwater Horizon*, located approximately 42 miles southeast of Venice, LA (United States Coast Guard, 2011). The Commanding Officer of Marine Safety Unit Morgan City, LA, became the first Federal On-Scene Coordinator (FOSC) to direct the oil spill response. Once it was determined that the response had the potential to eclipse all others and impact a large portion of the Gulf Coast region, the Commandant of the Coast Guard reassigned the FOSC role to the Commander of the Eighth Coast Guard District.

Oil spill response plan requirements for OCS facilities are contained in 30 CFR Part 254, Subpart B. The plan must include an introduction, emergency response action plan, and appendices, including equipment inventory, contractual agreements, worst case discharge scenario, dispersant use plan, in situ burning plan, and training and drills.

In addition to its spill response mission, the Coast Guard (along with the Bureau of Safety and Environmental Enforcement [BSEE]) has OCS facility inspection authority. BSEE is authorized to perform inspections on fixed OCS facilities engaged in OCS activities and to enforce Coast Guard regulations in accordance with 33 CFR Parts 140-147. Inspections may be conducted with or without advance notice and at any time deemed necessary. Annual inspection requirements apply to fixed OCS facilities. The Coast Guard also establishes fairways, precautionary zones, anchorages, safety zones, and traffic separation schemes. Certain lease blocks may have such designations, as contained in Coast Guard regulations at 33 CFR Part 150.

9.3.7.3 Commercial and Recreational Fishing

Marine commercial and recreational fishing are important industries in the Mid-Atlantic Planning Area. In Virginia alone, the industries generate hundreds of millions of dollars in economic activity, support thousands of jobs, and generate millions of dollars in tax revenue. In 2011, the marine ecosystem off the coast of Delaware, Maryland, New Jersey, New York, and Virginia supported 26,714 jobs and generated $3,804,715,000 in sales related to recreational fish species (Southwick Associates, 2013). This same region also supported 8,428 jobs and $516,497,000 in sales related to all commercial finfish species fishing.

Recreational fishing is popular not only for individuals, but for groups fishing via chartered excursions. Numerous offshore shipwrecks and bathymetric features provide habitat for sought-after fish species. According to a recently completed study by NOAA, in Virginia, the annual total economic activity generated by marine recreational fishing is an estimated $969,571,000 and supports 9,454 jobs (National Oceanic and Atmospheric Administration, 2013). Economic activity includes expenditures on offshore trips (for-hire and private), shore fishing, and durable goods.

Commercial trawlers fish the offshore areas of the Mid-Atlantic Planning Area for fish such as croaker, spot, striped bass, dogfish, menhaden, scup, and black sea bass. Tuna, dolphin, shark, sea scallops, surf clams and ocean quahogs are also harvested from the offshore area. In 2013, commercial finfish landings in Virginia totaled 36,315,649 pounds, valued at $32,638,230; and commercial shellfish landings in Virginia totaled 29,057,839 pounds, valued at $107,668,151 (Virginia Marine Resources Commission and National Oceanic and Atmospheric Administration, 2014).

Development of O&G infrastructure offshore has the potential to conflict with commercial and recreational fishing. The infrastructure associated with oil and gas activities may consist of a platform and pipelines extending to support facilities onshore. In addition to the obvious threat of accidental spills, offshore energy infrastructure and operations have the potential to impact commercial and recreational fishing by:

- Creation of temporary obstacles that preclude the use of former fishing grounds;
- Interference associated with infrastructure supporting vessel traffic;
- Discharge of drill muds and their associated impacts to water quality and habitat; and
- Potential conflicts with fishermen due to some lost opportunity for fishing.

Therefore, in addition to addressing the concerns of the DoD, planning for introduction of the O&G industry in the Mid-Atlantic Planning Area will need to address those of the commercial and recreational fishing industries.

9.3.7.4 Commercial Shipping

The waters off the coast of Virginia constitute one of the busiest areas in the world for maritime traffic (DoN, 2014). The lower Chesapeake Bay is home to the Port of Virginia in Norfolk, Virginia. In 2012, the port handled 2,866 vessel calls, an average of about eight per day. In 2013, the port handled 2,840 vessel calls and maintained its standing as the third busiest port facility on the east coast (with 13% of the east coast market share, behind New York/New Jersey [32%] and Savannah [18%]) (Virginia Port Authority, 2014).

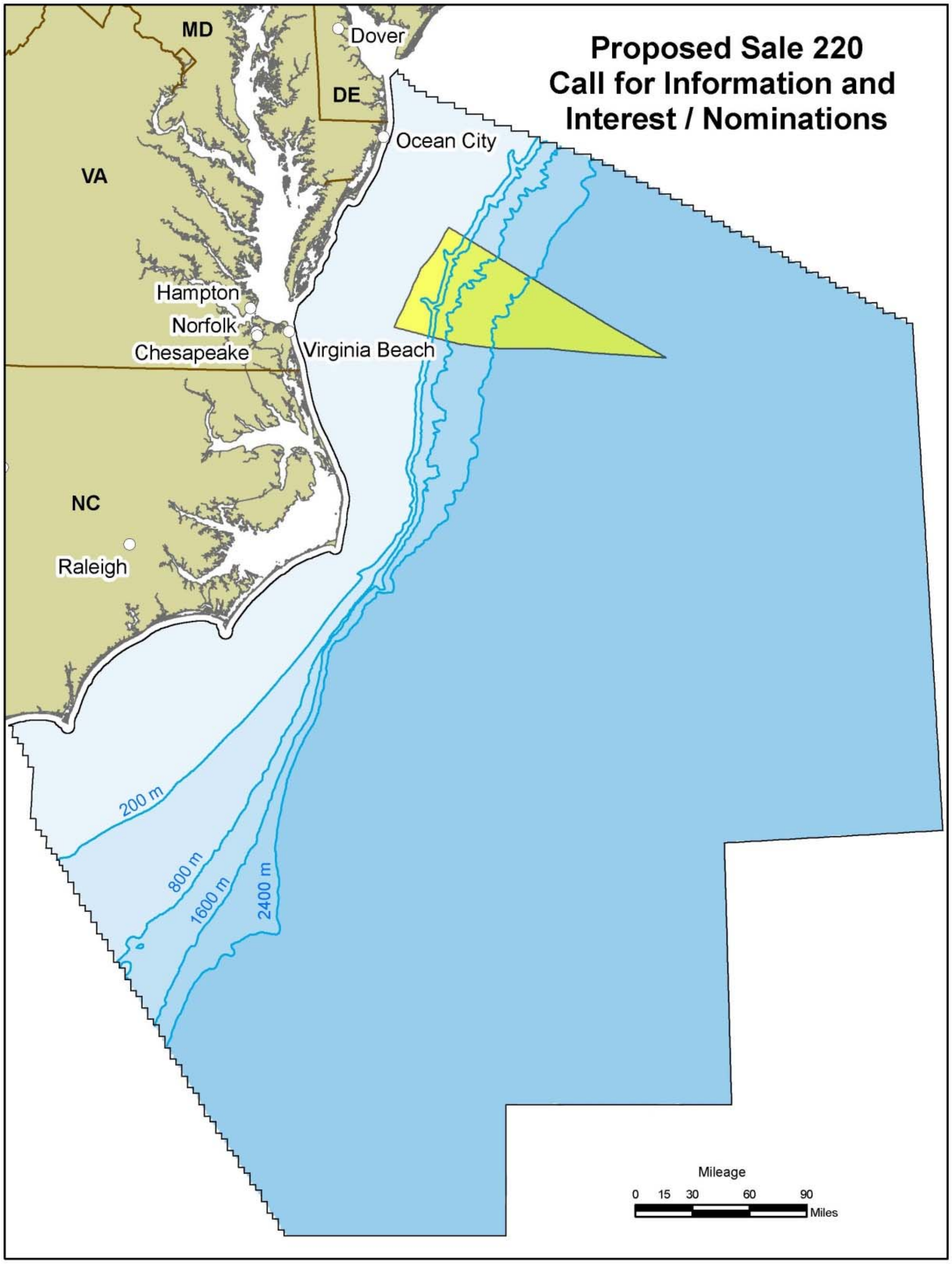
The shipping industry is a major economic sector in the Hampton Roads area as well as the entire state and region. Given the extent of maritime transportation activities and location of shipping lanes, this industry has a major OCS presence with potentially conflicting use. Any O&G activities would need to be coordinated with commercial shipping interests.

9.3.7.5 Non-Government Organizations and Regulatory Agencies

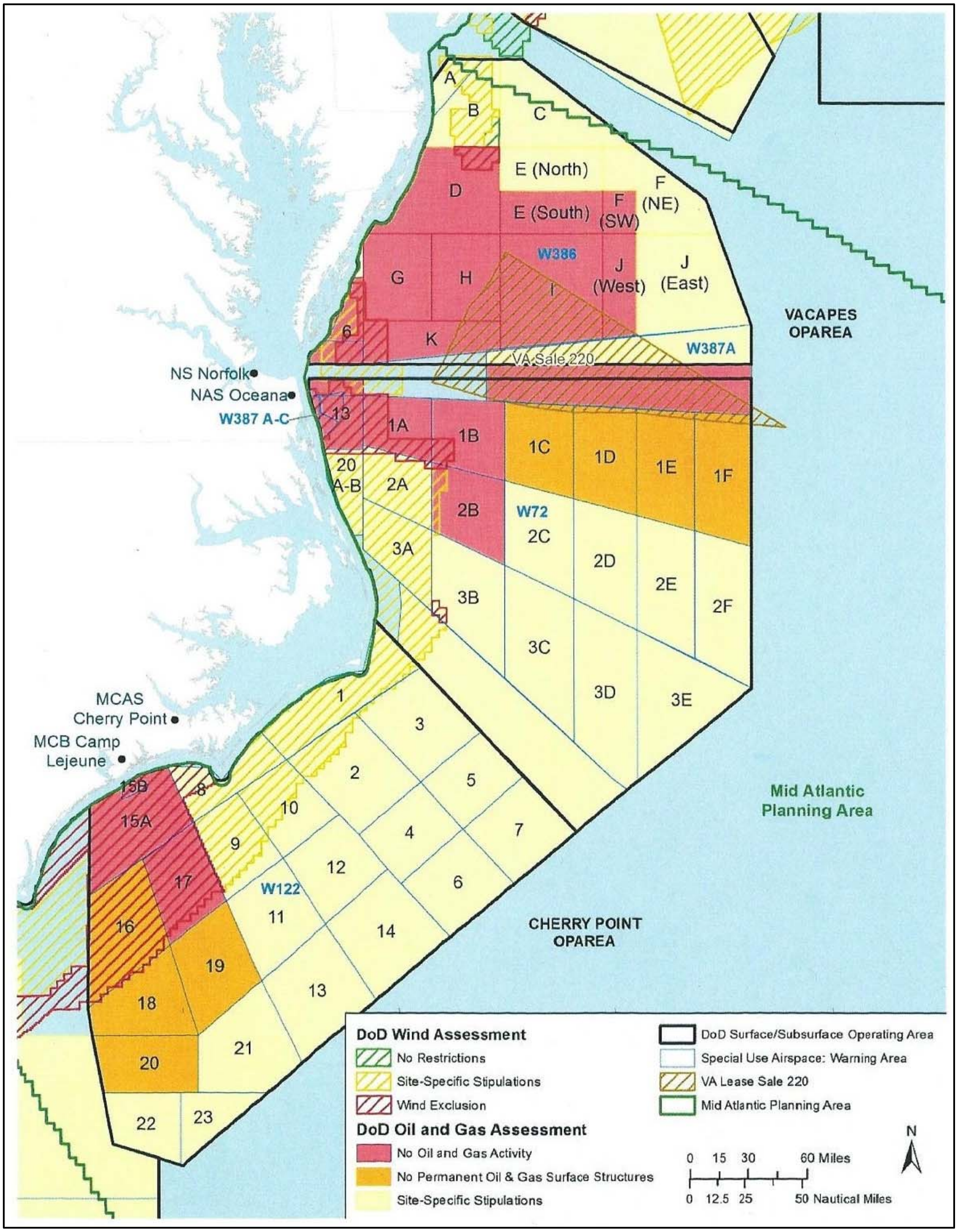
In addition to the previously listed OCS stakeholder groups, future Mid-Atlantic Planning Area O&G activity will likely require either coordination with, permits from, or redress of concerns expressed by numerous non-governmental organizations (NGO) and regulatory agencies. Table 9.3-2 lists several NGOs and regulatory agencies with likely OCS stakeholder status.

Table 9.3-2 Other Non-DoD OCS Stakeholders – NGOs and Regulatory Agencies

Non-Governmental Organizations	Regulatory Agencies (Federal and State)
Virginia Pilots Association	Bureau of Ocean Energy Management (BOEM)
Virginia Maritime Association	National Marine Fisheries Service (NMFS)
Sierra Club	U.S. Environmental Protection Agency (USEPA)
The Nature Conservancy	Federal Energy Regulatory Commission (FERC)
Virginia Institute of Marine Science	U.S. Army Corps of Engineers (USACE)
Surfrider Foundation	Federal Aviation Administration (FAA)
American Littoral Society	U.S. Coast Guard (USCG)
Ocean Conservancy	Bureau of Safety and Environmental Enforcement (BSEE)
Marine Education, Research & Rehabilitation Institute, Inc.	U.S. Fish and Wildlife Service (USFWS)
National Ocean Policy Coalition	Mid-Atlantic Fishery Management Council (MAFMC)
Natural Resources Defense Council	Department of Energy (DOE)
Chesapeake Bay Foundation	Virginia Department of Environmental Quality (VA DEQ)
Conservation Law Foundation	Virginia Marine Resources Commission (VMRC)
The Ocean Foundation	Virginia Coastal Energy Research Consortium (VCERC)
Virginia Aquarium & Marine Science Center	



PROPOSED SALE 220 (CIRCA 2008/2009)
OIL AND GAS READINESS STUDY
OFFSHORE VIRGINIA

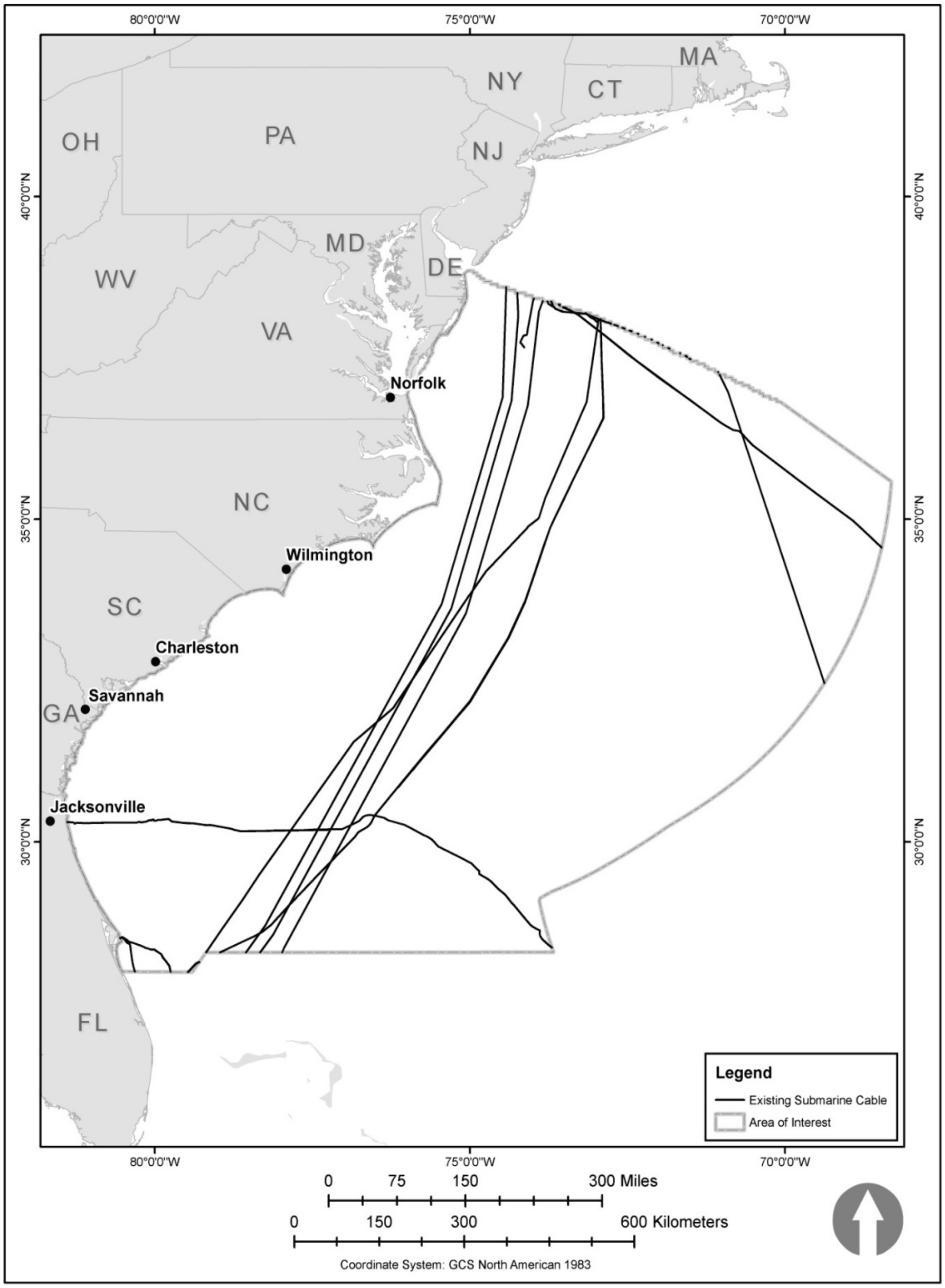


DOD ASSESSMENT OF THE MID-ATLANTIC PLANNING AREA (2010)

OIL AND GAS READINESS STUDY

OFFSHORE VIRGINIA

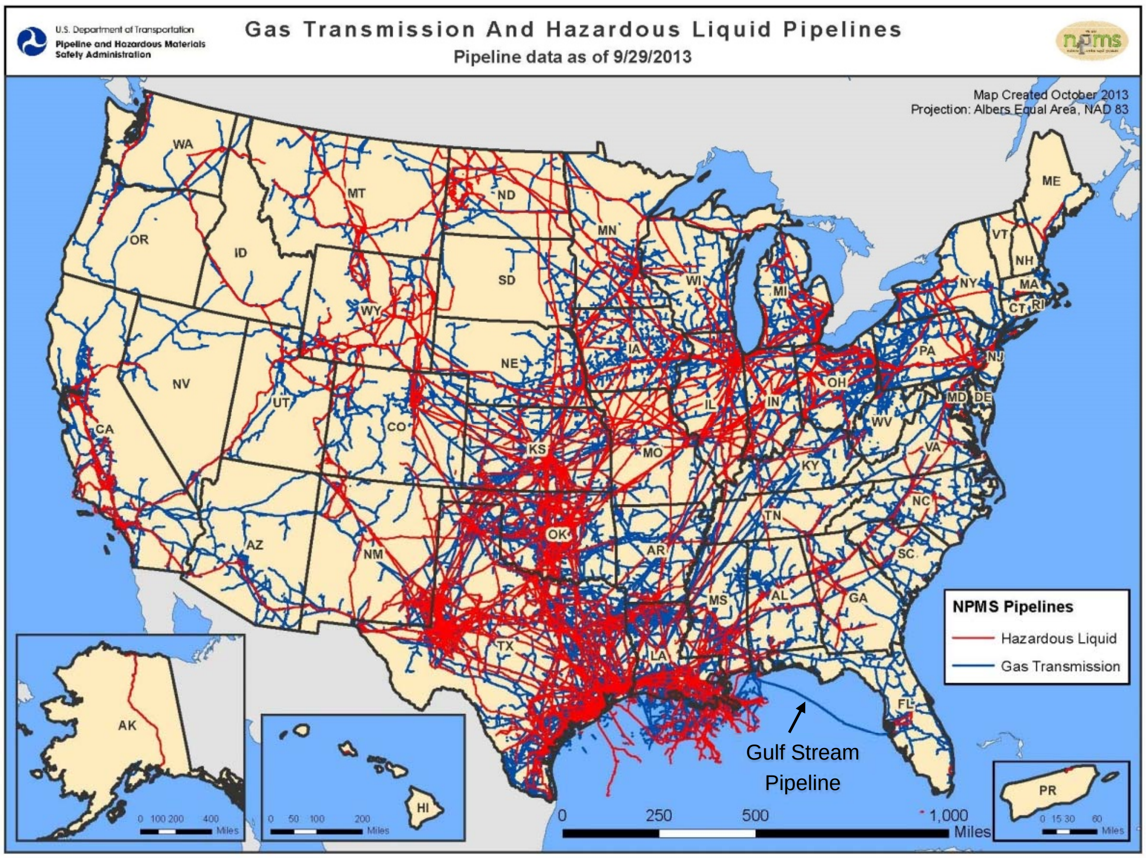
FIGURE 9.1-2



EXISTING CIVILIAN/COMMERCIAL SUBMARINE CABLES IN THE MID-ATLANTIC AND SOUTH ATLANTIC PLANNING AREAS

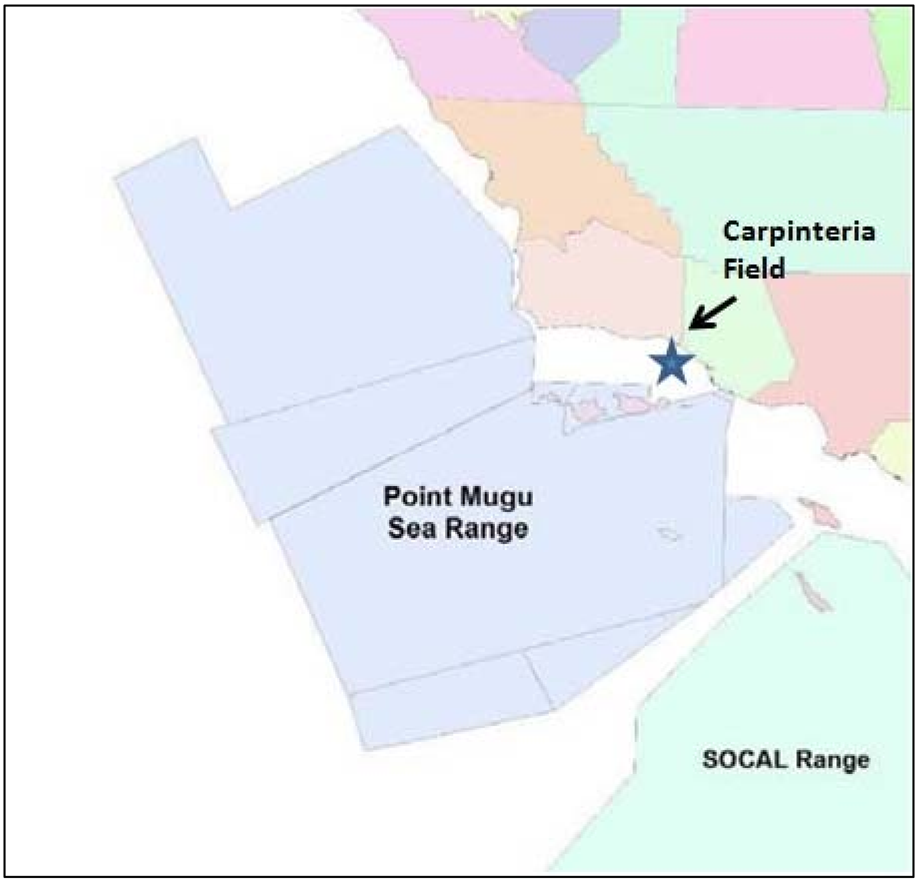
OIL AND GAS READINESS STUDY

OFFSHORE VIRGINIA



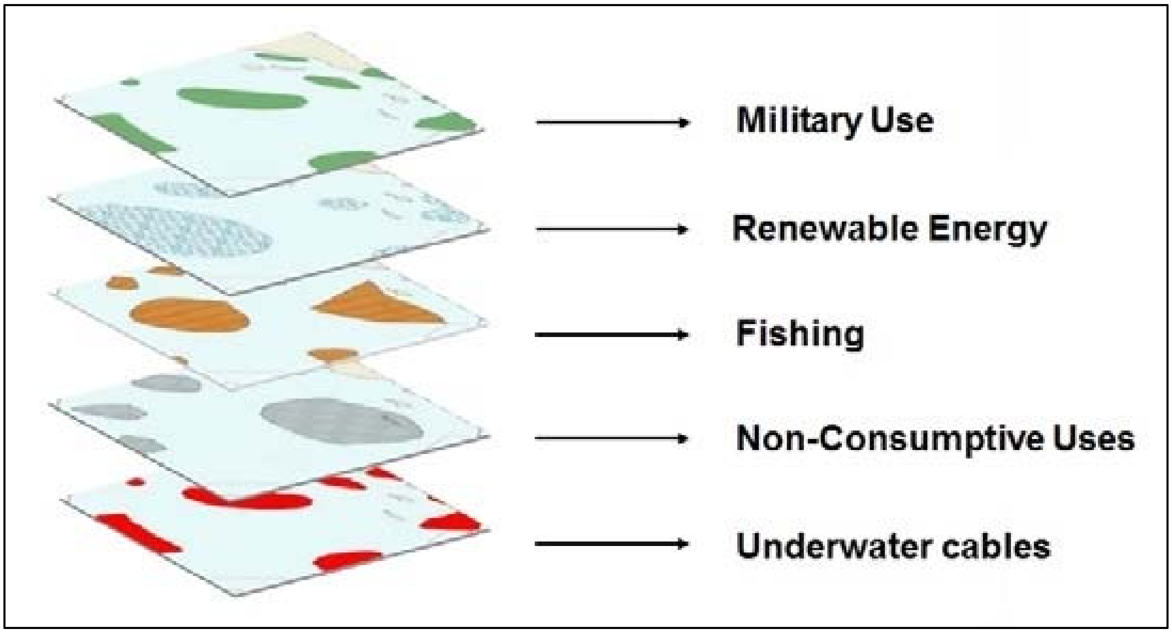
United States Department of Transportation (2013)

GAS TRANSMISSION AND HAZARDOUS LIQUID PIPELINES
OIL AND GAS READINESS STUDY
OFFSHORE VIRGINIA



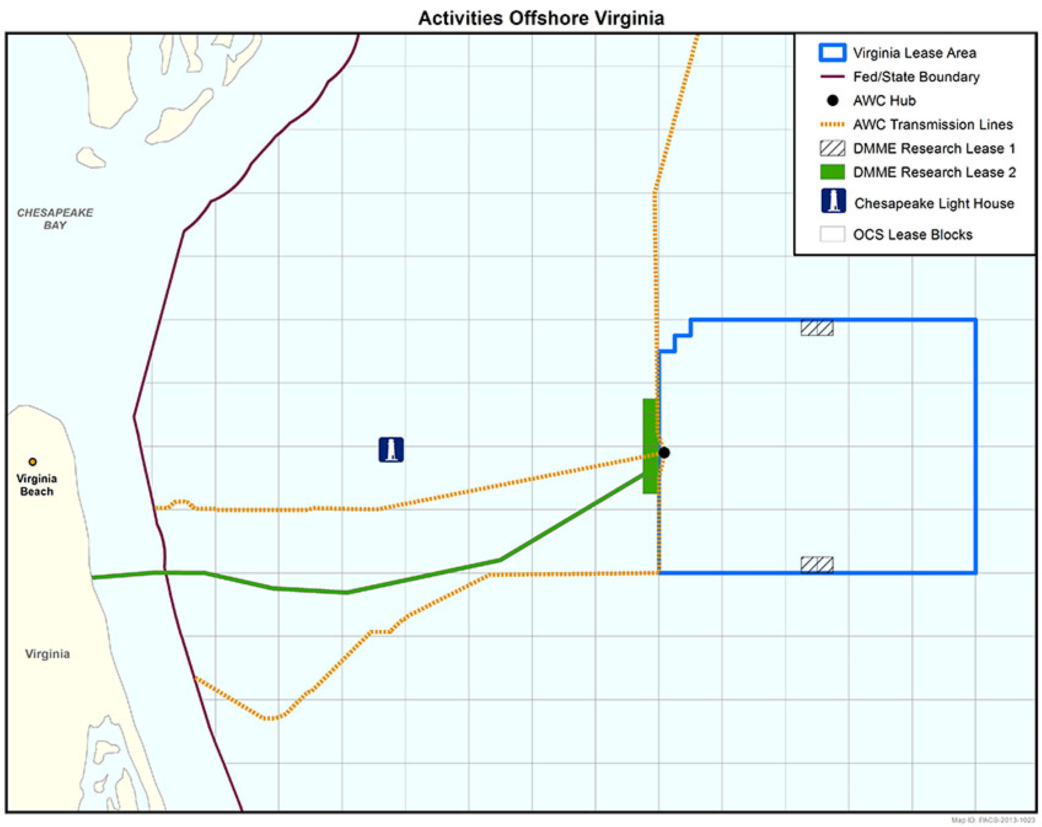
POINT MUGU SEA RANGE
OIL AND GAS READINESS STUDY
OFFSHORE VIRGINIA

FIGURE 9.2-2



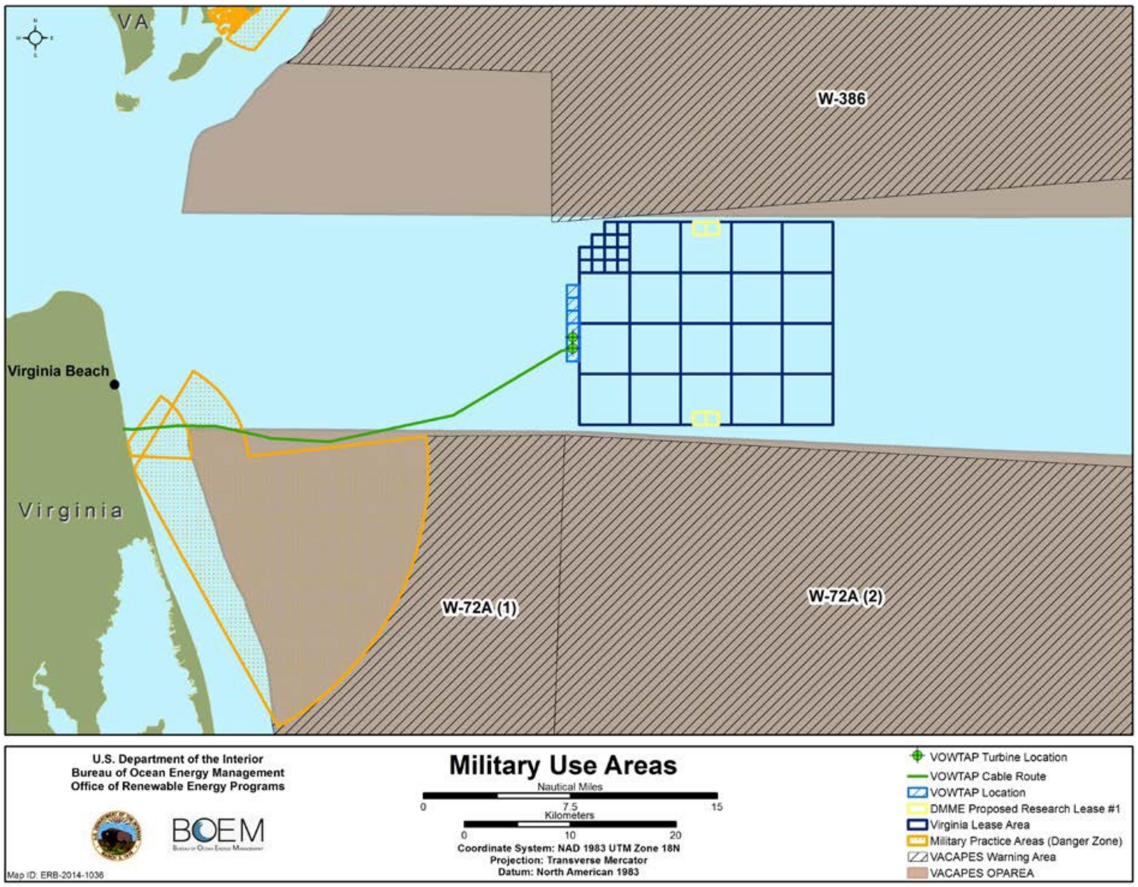
PACIFIC REGIONAL OCEAN USES ATLAS GEOSPATIAL LAYERS
OIL AND GAS READINESS STUDY
OFFSHORE VIRGINIA

FIGURE 9.2-3



VIRGINIA OFFSHORE WIND ENERGY AREA
OIL AND GAS READINESS STUDY
OFFSHORE VIRGINIA

FIGURE 9.2-4



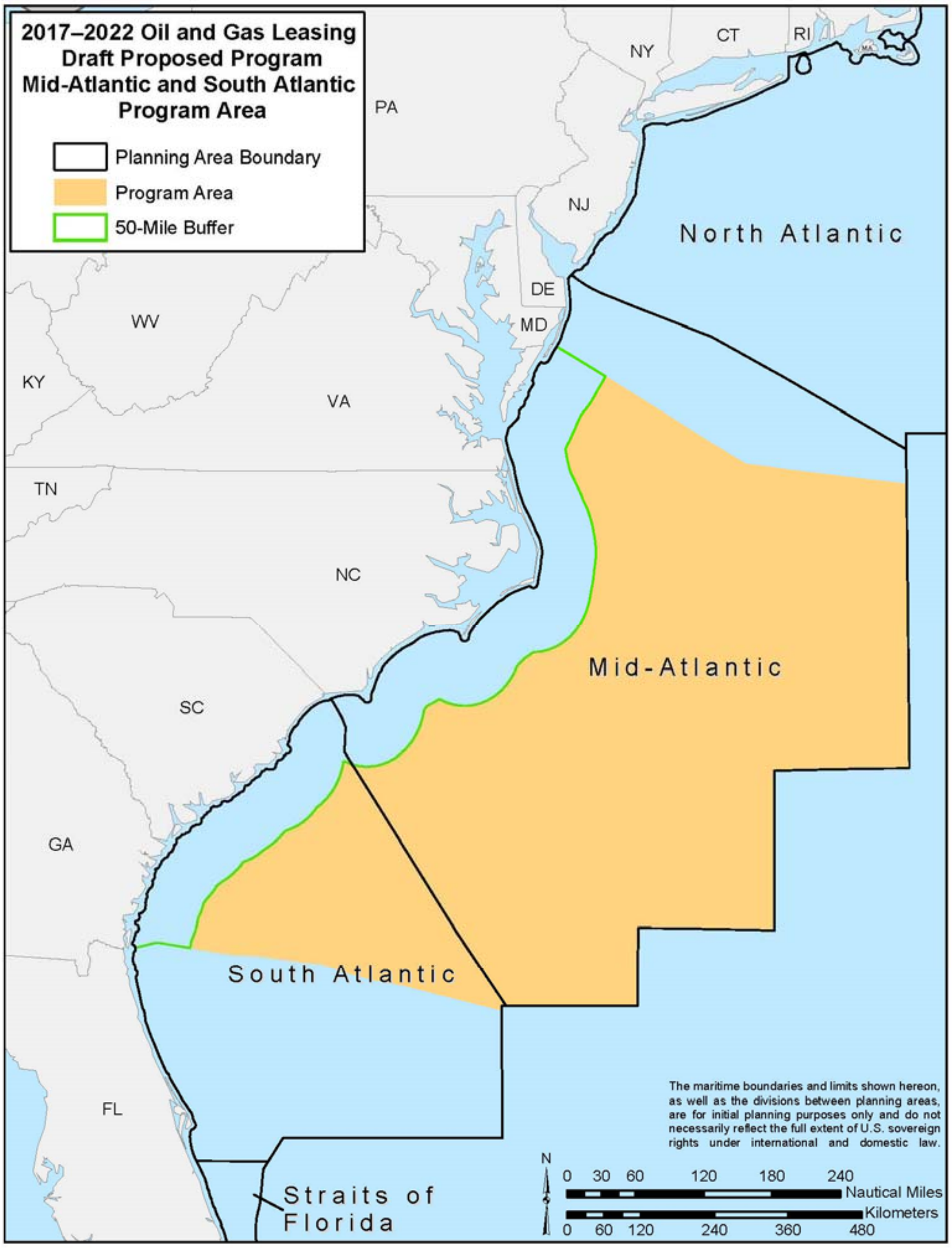
Source: BOEM (2014a)

MILITARY USE AREAS IN THE VICINITY OF THE VIRGINIA WIND ENERGY AREA

OIL AND GAS READINESS STUDY

OFFSHORE VIRGINIA

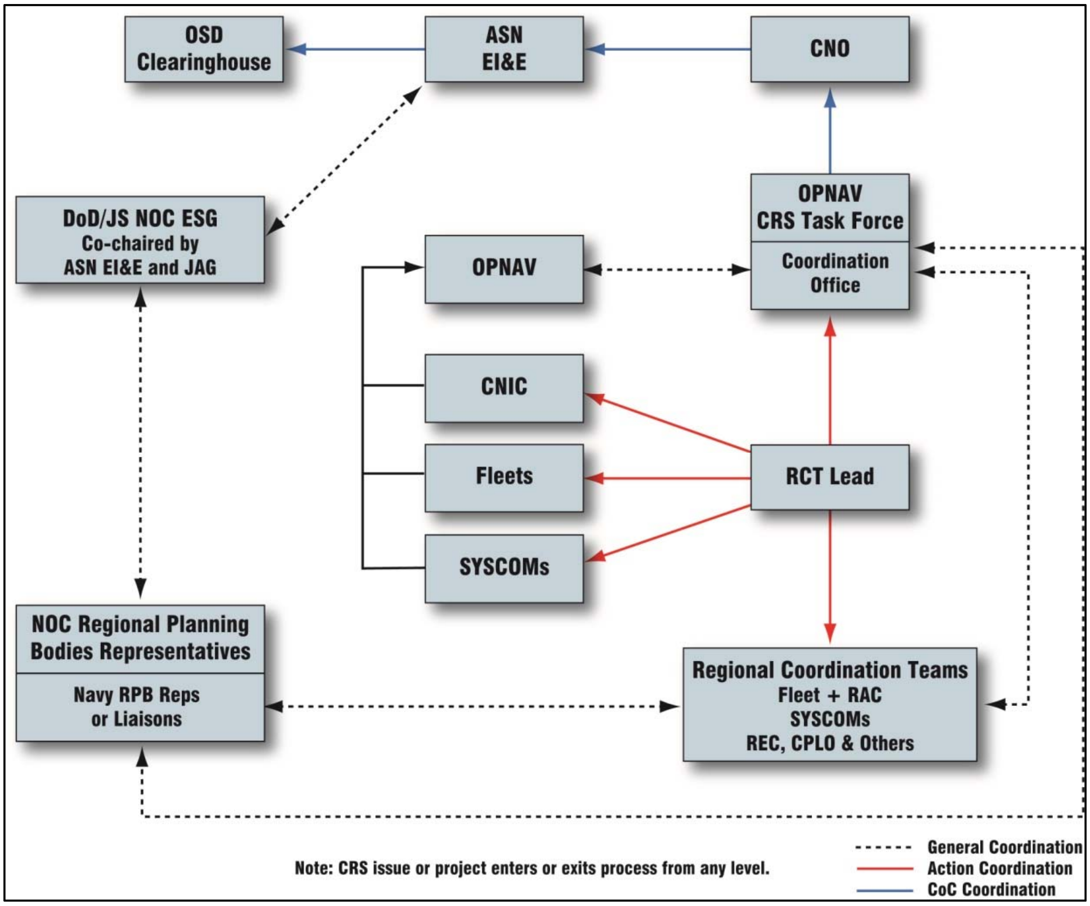
FIGURE 9.2-5



2017-2022 DPP - MID-ATLANTIC AND SOUTH ATLANTIC PROGRAM AREA

OIL AND GAS READINESS STUDY

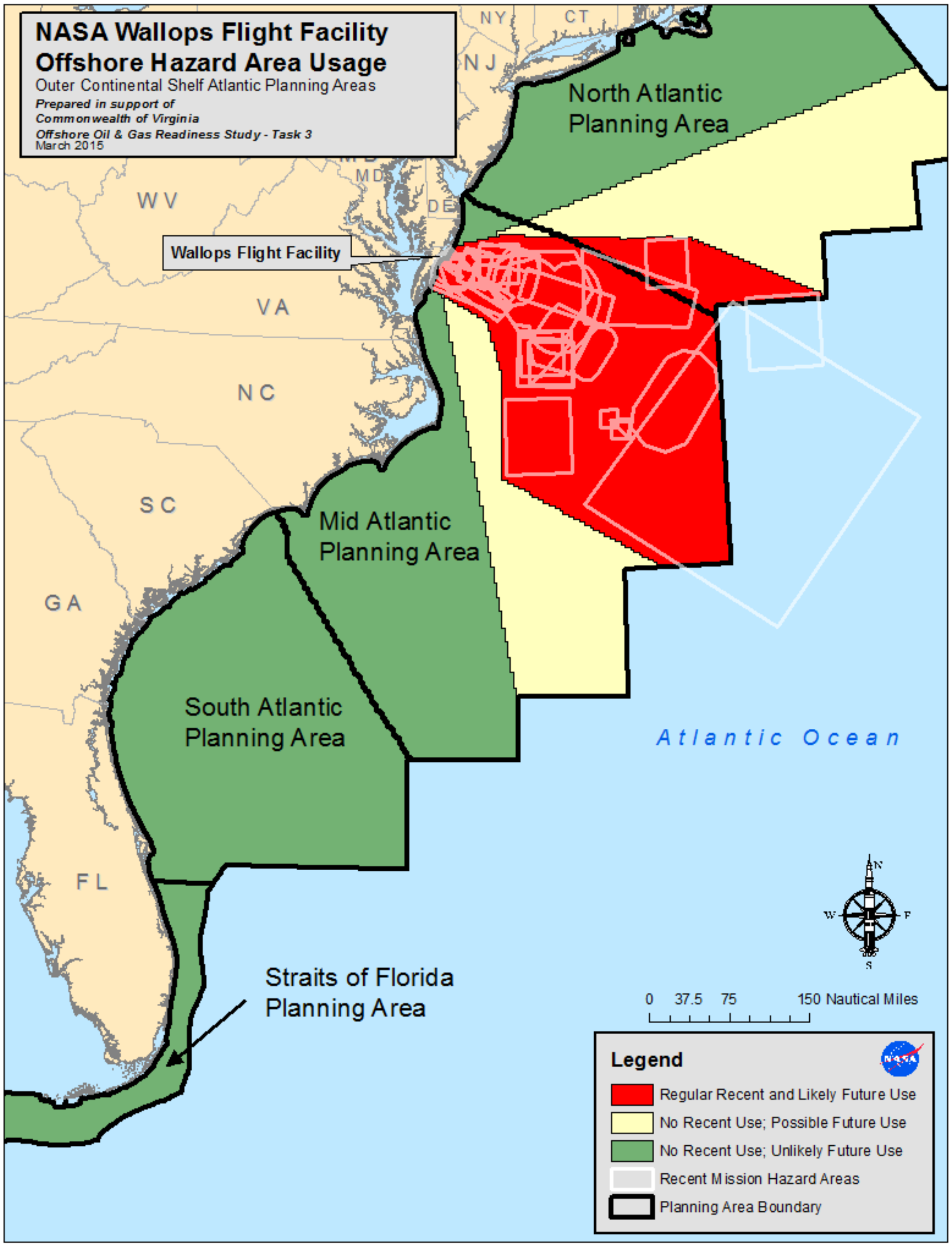
OFFSHORE VIRGINIA



COMPATIBILITY AND READINESS SUSTAINMENT COORDINATION PROCESS

Oil and Gas Readiness Study

Offshore Virginia



NASA (2015) – "Map of the NASA Wallops Flight Facility Offshore Hazard Area Usage, Prepared in support of Commonwealth of Virginia Offshore Oil and Gas Readiness Study"

NASA WFF RANGE HAZARD AND RELATIVE USE AREAS

Oil and Gas Readiness Study

Offshore Virginia

10.0 CONCLUSIONS AND RECOMMENDATIONS

10.1 ADEQUACY OF GEOPHYSICAL DATA

From 1973 to 1990, the OCS of Virginia and northern North Carolina were imaged by 19 MCS reflection surveys as documented in this report. Over 46,200 line-miles (74,350 line-kilometers) of seismic data were acquired within the study area as part of these 19 surveys, utilizing various survey designs and acquisition equipment.

Three acquisition parameters stood out as limiting both the vertical resolution and depth of penetration of the seismic data: 1) the acoustic source volume, 2) the streamer length and 3) the CDP fold. All but three surveys (VAEDGE 1990, E03-88 and E11-82) used source volumes that were much smaller compared to air gun volumes used in modern seismic data acquisition and, therefore, limited the penetration depth of the acoustic source. Cable lengths for all but the VAEDGE and E03-88 surveys were less than four kilometers (13,000 ft.). This length cable could not adequately image targets below four kilometers suitable for exploration purposes. Multiplicity (or CDP fold) was typically 48 or less and only five surveys used 60-fold or better to allow for a better signal-to-noise ratio in the resulting stacked seismic image. Each of these factors significantly limited the quality of the legacy surveys when compared to modern day 2-D surveys.

Of the four hydrocarbon plays identified by BOEM (2012a), only the narrow Late Jurassic to Early Cretaceous Carbonate Margin Play contains enough seismic lines of an exploration-scale nature to provide adequate coverage for an advanced understanding of the subsurface (although acquisition parameters of the legacy surveys may limit the accurate interpretation of these plays due to the depth of penetration and resolution of the potential reservoirs). The Jurassic Shelf Stratigraphic Play and the Cenozoic-Cretaceous and Jurassic Slope Core Play contain significant seismic coverage but only where they abut against the Carbonate Margin Play. The Cenozoic-Cretaceous and Jurassic Slope Extension Play contains only sixteen seismic lines covering this large area and, therefore, before selection of exploration targets begin in this portion of the OCS, it is likely that a significant amount of new data will need to be acquired.

The availability of seismic data in the study area was inventoried in a project GIS database and the amount of data available as depth sections, migrated sections and stacked sections were documented. Data existing only as paper copies and not in SEG-Y format were also documented and may require vectorization and conversion to be of use to future O&G exploration. Stacked and migrated sections cover the majority of the OCS area, while depth sections are limited to the area near the shelf break. It is noted that the Norfolk Basin and other acreage landward of the shelf break will not be included for leasing in the 2017-2022 program due to the 50-mile coastal environmental buffer zone that has been designated by BOEM.

Improvements in the coverage and quality of seismic data available in the OCS study areas can come in two forms: reprocessing vintage data and acquisition of new data. Reprocessing opportunities are limited since the only data publically available for a complete reprocessing are the regional lines collected by the USGS from 1973 to 1978. Hybrid streamers with group intervals changing along the length of the cable also make data reprocessing cumbersome and potentially costly. Migration of these datasets (which previously only existed as stacked sections) does provide a significant improvement in the seismic image, but this migration may not be cost-effective. The best solution to reprocessing the data would be to migrate stacked sections, especially when true amplitudes are preserved in the SEG-Y files.

A theoretical 2-D seismic survey was designed and described herein to show it is possible to collect a survey of significant regional scale covering the key geologic plays within the area outlined by BOEM as the possible leasing area in the Atlantic for the 2017 to 2022 proposed leasing plan. New, deep-penetrating seismic lines funded by National Science Foundation, and of an academic nature, were recently acquired in northern North Carolina waters at the end of 2014 and are currently in the data processing stage. This newly acquired data, along with the collection of new seismic data for O&G exploration, along the Atlantic Margin will provide a modern day opportunity for re-interpretation within a frontier basin that was only partially explored over 30 years ago.

10.2 ASSESSMENT OF PORTS AND INFRASTRUCTURE

The infrastructure review as part of this report is not meant as an exhaustive inventory of all potential offshore O&G support facilities in the Mid-Atlantic Region. However, it is intended to encompass the major infrastructure resources for each of the five steps of O&G development and the functions necessary for exploration and production. For each of the functions typically performed by support operations, this report has documented several existing facilities capable of supporting that function. The only major element identified as missing in the Mid-Atlantic Region is pipeline capacity for collecting and transporting crude oil. If sufficient liquid hydrocarbon resources are discovered, then the oil must be collected and distributed by FPSO and shuttle tanker until construction of an oil pipeline is justified.

Based on experience and the research compiled to prepare this report, it is evident that the Mid-Atlantic Region has sufficient marine terminal and shipyard facilities to support offshore O&G leasing, exploration, development, and production. If leases are issued in 2017, some commercial investment in marine support terminal improvements will be necessary by 2024. It may also be economically worthwhile for offshore support companies to invest in dedicated heliport facilities. However, there is significant commercial airport capacity in the region as well. The major infrastructure shortfall is in oil and gas receiving, processing and distribution infrastructure. Development of oil and natural gas resources in the Mid-Atlantic region will require a significant investment in pipeline facilities or in FPSO and shuttle tanker vessels in the future. However, this investment must be justified based on proven reserves of economically recoverable resources.

10.3 MILITARY AND DOD CONCERNS

The mission of the military is to protect and defend our freedom. The successful conduct of this mission is ongoing, dynamic, and changing rapidly with advances in technology and the ever-changing threats we endure. As the Norfolk Fleet Concentration area is the world's largest concentration of carriers, cruisers, destroyers, logistics vessels, amphibious vessels and military aircraft in the world, the multiple use of the Mid-Atlantic Planning Area is critically important. The DoD supports the production of offshore O&G and is a willing stakeholder in supporting a workable solution, whenever possible. This willingness has been demonstrated repeatedly, as captured in this study by the examples provided. In each case, early coordination with the DoD was the foundation that supported a successful outcome. The DoD will continue to protect its ability to conduct mission critical testing and training. Each situation and/or location is different and it is important that Atlantic O&G industry advocates understand the nature of the military's concerns.

The 2010 Compatibility Report delves into the rationale behind the assessments made on the ocean area locations as they relate to O&G activities. Future assessments will be at the lease block level versus the larger SUA block. This added level of detail potentially opens up more areas for exploration than before. Moreover, once the potential oil and gas areas are identified, the efforts on the part of Mid-Atlantic Planning Area O&G advocates and the military can be better focused. Therefore, while the challenges are significant, the Mid-Atlantic Planning Area can benefit from precedent setting cases supporting military mission and energy production, advances in drilling and extraction technology, and mutual understanding of respective stakeholder goals through early coordination and communication.

Offshore O&G production can represent one of many avenues in Virginia's aim for energy independence. Virginia can support federal efforts to explore and develop O&G in the Mid-Atlantic Planning Area. Virginia is also a supporter of the world's largest Navy port and Fleet Concentration Area in Hampton Roads, Virginia. The Services require frequent use of the offshore waters from Virginia and North Carolina to fulfill their training and testing requirements in order to maintain readiness. The DoD has voiced concerns about conflicting use of the Mid-Atlantic Planning Area. In some areas offshore (especially relatively near to the coast), the DoD has stated that O&G activities are not compatible with the hazardous nature of training and testing (with inert and live ordnance). In the majority of the Mid-Atlantic Planning Area, certain offshore O&G activities can co-exist with military training and testing. Other OCS areas (e.g., the Pacific and Gulf of Mexico) serve as models for what may be possible for cooperation with the military in the Mid-Atlantic Planning Area. The Commonwealth of Virginia can support federal efforts to explore and develop O&G offshore of its coast by employing several strategies.

Strategies should include early DoD coordination (including the formation of an intergovernmental O&G Task Force), and an understanding of the DoD assessment process and project evaluation process. Several military area stipulations (e.g., drilling windows) could be embraced in the Mid-Atlantic as they have in other OCS areas where military training and testing areas exist in close proximity to O&G facilities. Lessons can be drawn from the renewable energy industry, as well. Uniquely tailored funding options and memoranda of agreement may be entered in certain instances. Leaps in technological knowledge have led to minimization of platform footprints while maximizing resource production through horizontal drilling, hydraulic fracturing and subsea production systems. These technologies could serve particularly well in the Mid-Atlantic Planning Area in areas authorized for O&G development with stipulations to reach reserves held in areas otherwise demarcated as off-limits to O&G activities. Finally, although the DoD expressed concerns in the past and will in the future, O&G development in the Mid-Atlantic Planning Area will require coordination with numerous stakeholders, including the NASA WFF and the Mid-Atlantic Regional Spaceport. The OCS is a common space available to many stakeholders, and if managed justly among the stakeholders, its resources will be available for generations. If the aforementioned steps are taken, offshore O&G exploration and production can proceed within parts of the Mid-Atlantic and South Atlantic 2017-2022 DPP Program Area while respecting the concerns raised by the military.

11.0 REFERENCES

Adinolfi, F., 1990, Oil and Gas Developments in Atlantic Coastal Plain and Outer Continental Shelf in 1989, American Association of Petroleum Geologists Bulletin, v. 74, no. 10, p. 42-45.

Amato, R.V., ed. ,1987, Shell Baltimore Rise 93-1 Well: Geological and Operational Summary, US Department of the Interior, Minerals Management Service, Atlantic OCS Region, OCS Report MMS 86-0128, 55 p.

American Petroleum Institute (API), 2013a, National Ocean Industries Association; Quest Offshore; The Economic Benefits of Increasing U.S. Access to Offshore Oil and Natural Gas Resources in the Atlantic; December 2013.

American Petroleum Institute, 2013b, Offshore Leasing, Exploration and Development Process.

American Petroleum Institute, 2014a, Offshore Access to Oil and Natural Gas Resources, July 2014.

American Petroleum Institute, 2014b, Planning, Designing, and Constructing Fixed Offshore Platforms – Working Stress Design, 22nd Edition; November 2014.

Barwick, Kirk; Fernandes, Lincoln; Mastrangelo, Carlos; Theisinger Erich, 2007, FPSOs in the Gulf of Mexico, January 9-11.

Bayer, K.C., and Milici, R.C., 1987, Geology and petroleum potential of Mesozoic and Cenozoic rocks, offshore Virginia: Virginia Division of Mineral Resources Publication 73, pt. D, 111 p. and two plates.

Bureau of Ocean Energy Management (BOEM), 2008, Final Notice of Sale 224 – Eastern Gulf of Mexico, 13 February.

Bureau of Ocean Energy Management (BOEM), 2009, Draft Proposed Outer Continental Shelf (OCS) Oil and Gas Leasing Program 2010-2015: Considering Comments of Governors, Section 18 Factors and OCS Alternative Energy Opportunities, January.

Bureau of Ocean Energy Management (BOEM), 2011, Response to Comments –Revisions to Development and Production Plan –Platform Hogan in the Carpinteria Field, Submitted by: Pacific Operators Offshore LLC (PACOPS) and Signal Hill Services Inc, Revision No. 4, February.

Bureau of Ocean Energy Management (BOEM), 2012a, Assessment of undiscovered technically recoverable oil and gas resources of the Atlantic Outer Continental Shelf 2011 as of January 1, 2009, 40 p.

Bureau of Ocean Energy Management (BOEM), 2012b, Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017, June, 211 p.

Bureau of Ocean Energy Management (BOEM), 2012c, Final Environmental Assessment for Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore New Jersey, Delaware, Maryland, and Virginia, BOEM 2012-003, January.

Bureau of Ocean Energy Management (BOEM), CSA Ocean Sciences Inc., 2014a, Atlantic OCS Proposed Geological and Geophysical Activities Mid-Atlantic and South Atlantic Planning Areas Final Programmatic Environmental Impact Statement; February 2014.

Bureau of Ocean Energy Management (BOEM), 2014b, Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Atlantic Outer Continental Shelf, 2014 Update, BOEM Fact Sheet RED-2014-01, 3 p.

Bureau of Ocean Energy Management (BOEM), 2015a, Offshore Statistics by Water Depth, Statistics reflecting data through 18 February 2015.

Bureau of Ocean Energy Management (BOEM), 2015b, 2017-2022 Outer Continental Shelf Oil and Gas Leasing Draft Proposed Program, 299 p.

Bureau of Ocean Energy Management (BOEM), and NOAA, 2014, The Pacific Regional Ocean Uses Atlas Fact Sheet, February.

Burch, D., 2002, Sonic logs need troubleshooting, American Association of Petroleum Geologists Explorer, v. 23, no. 3, p. 46-47.

Carr, B., 1993, VAEDGE: Virginia 1990 EDGE experiment. PASSCAL Data Report 93-006, 3 p., accessed January 14, 2015 at http://ds.iris.edu/data/reports/misc_/93-006_VAEDGE.

Casey, James, 2014, Personal communication with James Casey regarding relevant command headquarters for the Mid-Atlantic Planning Area, 11 December.

Chief of Naval Operations (CNO), 2011a, Compatibility and Readiness Sustainment Task Force Charter, 15 April.

Chief of Naval Operations (CNO), 2011b, Interim Guidance on Compatibility and Readiness Sustainment Assessment and Coordination, 16 September.

Committee on Foreign Investment in the United States (CFIUS), 2013, Annual Report to Congress for Calendar Year 2012, December.

Commonwealth of Virginia, Department of Mines, Minerals and Energy, 2014. Virginia Energy Plan, 01 October.

Creese, Catherine, 2006, The U.S. Naval Seafloor Cable Protection Office, “Call Before You Dig!” Submarine Telecoms Forum, Issue 29, November.

Cruickshank, Walter D.; Bureau of Ocean Energy Management, 2014, Request for Information and Comments on the Preparation of the 2017-2022 Outer Continental Shelf (OCS) Oil and Gas Leasing Program, Federal Register/Vol. 79, No. 115; June 16, 2014.

Dellagiarino, G., Fulton, P., Meekins, K. and Zinzer, D., 2002, Geological & geophysical data acquisition a 25-year retrospective, 1976-2001, U.S. Dept. of the Interior, Minerals Management Service, Resource Evaluation Division, Herndon, VA., MMS Report 2002-079, 46 p.

Dellagiarino, George; Racicot, Obediah, Bureau of Ocean Energy Management, 2012, Geological & Geophysical Data Acquisition, Outer Continental Shelf through 2009-2010-2011; 2012

Department of Defense (DoD), 2010, Report on the compatibility of Department of Defense (DoD) activities with oil and gas resource development on the Outer continental Shelf (OCS), 15 February, 44 p.

DoD, 2013a, The Mission Compatibility Evaluation Process, Annual Report to Congress on the DoD Siting Clearinghouse – Calendar Year 2013.

DoD, 2013b, Department of Defense Directive 3200.15, Sustaining Access to the Live Training and Test Domain, 18 December.

DoD, Department of the Navy, and the Texas Wind Group, 2012, Memorandum of Agreement on Riviera I Wind Turbine Farm, Kingsville, Texas, March.

DOE, 1993, Drilling Sideways – A Review of Horizontal Well Technology and its Domestic Application, April.

DoN, 2007, Chief of Naval Operations Instruction 11010.40, Encroachment Management Program, 27 March.

DoN, 2013, Atlantic Fleet Training and Testing Final Environmental Impact Statement/Overseas Environmental Impact Statement, August.

DoN, 2014, U.S. Navy Testing of Hypervelocity Projectiles and an Electromagnetic Railgun at Wallops Flight Facility, Wallops Island, Virginia – Environmental Assessment, May.

Dismukes, David E.; Olatubi, Williams O.; Mesyanzhinov, Dmitry V.; Pulsipher, Allan G., 2003, U.S. Minerals Management Service; Modeling the Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Applications; July 2003.

Dismukes, D. E.; Acadian Consulting Group; Bureau of Ocean Energy Management, 2014, Onshore Oil and Gas Infrastructure to Support Development in the Mid-Atlantic OCS Region; July, 2014.

Dominion Virginia Power, 2015, Webpage: Virginia Offshore Wind Technology Advancement Project, Available at: https://www.dom.com/corporate/what-we-do/electricity/generation/wind/virginia-offshore-wind-technology-advancement-project as accessed on 27 February.

Doyle, R.G., 1982, History of oil and gas exploration in the Mid-Atlantic Region and Delaware's involvement in the Federal OCS Leasing Program, Delaware Geological Survey Report of Investigation 36, 78 p.

Drilling Contractor, 2009, *Continuous Improvements Lead to Maersk Oil Qatar's Longest Horizontal Well in the World*, July/August.

Engle, Fred, 2014, Commonwealth of Virginia DMME/DoD Meeting Minutes, 03 November.

FMC Technologies, 2014, Fact Sheet: Shell Mensa – Gulf of Mexico Block MC 687.

Gilbert, L.E., and Dillon, W.P., 1981, Multichannel seismic-reflection profiles collected by the Teledyne Exploration Company in 1977 south of Cape Hatteras, North Carolina, U.S. Geological Survey Open-File Report 81-726, 3 p.

Holbrook, W.S., Purdy, G.M., Sheridan, R.E., Glover, L., Talwani, M., Ewing, J. and Hutchinson, D., 1994, Seismic structure of the U.S. Mid-Atlantic continental margin, Journal of Geophysical Research: Solid Earth, v. 99, iss. B9, p. 17871-17891.

Hollister, C.D., Ewing, J.I., Habib, D., Hathaway, J.C., Lancelot, Y., Luterbacher, H., Paulus, F.J., Poag, C.W., Wilcoxon, J.A., and Worstell, P., 1972, Site 105: Lower continental rise hills, in Hollister, C.D., Ewing, J.I., et al., (eds.), Initial reports of the Deep Sea Drilling Project, v. 11: Washington, U.S. Government Printing Office, p. 219-316.

Hutchinson, D.R., Poag, C.W., Johnson, A., Popenoe, P., and Wright, C., 1996, Geophysical database of the East Coast of the United States: southern Atlantic margin - stratigraphy and velocity in map grids, U.S. Geological Survey Open-File Report 96-55, 165 p.

Hutchinson, D. R., Poag, C.W., and Popenoe, P., 1995, Geophysical database of the East Coast of the United States: southern Atlantic margin - stratigraphy and velocity from multichannel seismic profiles, U.S. Geological Survey Open-File Report 95-27, 176 p.

Keithly, Diane C., 2001, U.S. Minerals Management Service; Lafourche Parish and Port Fourchon, Louisiana: Effects of the Outer Continental Shelf Petroleum Industry on the Economy and Public Services, Part 1; May 2001.

Klitgord, K.D., Poag, C.W., Schneider, C.M., and North, L., 1994, Geophysical database of the East Coast of the United States: northern Atlantic margin - cross sections and gridded database (Georges Bank Basin, Long Island Platform, and Baltimore Canyon Trough), U.S. Geological Survey Open-File Report 94-637, 190 p.

Klitgord, K.D., and Schneider, C., 1994, Geophysical database of the East Coast of the United States: northern Atlantic margin - velocity analyses, U.S. Geological Survey Open-File Report 94-192, 74 p.

Leffler, William L.; Pattrozzi, Richard; Sterling, Gordon, 2003, Deepwater Petroleum Exploration & Production, A Nontechnical Guide; 2003.

Loren C. Scott & Associate, 2014, The Economic Impact of Port Fourchon: An Update; October 2014.

MacDowell, Ken, 2014, Personal communication with Ken MacDowell regarding Pacific OCS and Hawaii Range Complex compatibility issues, 15 December.

Marine Spill Response Corporation; https://www.msrc.org/

The Maritime Network; http://www.maritime-database.com/activity.php?aid=29

McCaul, James R., 2001, Future Requirements for Shuttle Tankers in the Gulf of Mexico; June 2001 Maritime Reporter and Engineering News.

Mid-Atlantic Regional Planning Body, 2013, Mid-Atlantic Regional Ocean Planning Workshop: Summary of Workshop Discussions, 04-05 April.

Mid-Atlantic Regional Spaceport, 2014, Webpage: Mid-Atlantic Regional Spaceport History, Available at URL: http://www.marsspaceport.com/mid-atlantic-spaceport-history as accessed on 08 December.

Minerals Management Service (MMS), 1984, Stipulations Attached To OCS Leases, PT, Arguello/PT, Conception Area, 12 September.

MMS, 2008, Call for Information and Interest/Nominations Map for Lease Sale 220, 13 November.

Mission Compatibility Evaluation Process, 32 C.F.R. § 211 (2013).

National Aeronautics and Space Administration (NASA), 2012, Final North Wallops Island Unmanned Aerial Systems Airstrip Environmental Assessment, June.

NASA, 2015, Map of the NASA Wallops Flight Facility Offshore Hazard Area Usage, Prepared in support of Commonwealth of Virginia Offshore Oil and Gas Readiness Study, March.

National Geographic News, 2011, "The Next Prospects: Four Offshore Drilling Frontiers," Article by Brian Handwerk for National Geographic News, Published 19 April.

National Oceanographic and Atmospheric Administration (NOAA), 2013, NOAA's National Marine Fisheries Service Endangered Species Act Section 7 Consultation, July 19, 2013.

NOAA, 2014, Webpage: "The Gulf Region's Contribution to U.S. Energy Production," Available via URL: http://stateofthecoast.noaa.gov/energy/gulfenergy.html as accessed on 18 December 2014.

National Oceanographic and Atmospheric Administration (NOAA), 2015; http://www.charts.noaa.gov/Catalogs/atlantic_chartside.shtml; Accessed January 2015.

National Ocean Council, 2013, National Ocean Policy Implementation Plan, April.

Naval Air Systems Command, 2007, Point Mugu Sea Range, Presentation by Tony Parisi, Head of the Sustainability Office for NAVAIR Ranges, 20 September.

Naval Sea Floor Cable Protection Office (NSCPO), 2014a, Introductory Webpage for the Naval Sea Floor Cable Protection Office, Available at URL: http://www.navfac.navy.mil/products_and_services/ci/products_and_services/naval_ocean_facilities_program/sea_floor_cable_protection_nscpo.html as accessed on 05 December 2014.

NSCPO, 2014b, NSCPO GIS Webpage for the Naval Sea Floor Cable Protection Office, Available at URL: http://www.navfac.navy.mil/products_and_services/ci/products_and_services/naval_ocean_facilities_program/sea_floor_cable_protection_nscpo/nscpo_maps.html as accessed on 05 December 2014.

NSCPO, 2014c, NSCPO Background: History of the NSCPO, Available at URL: http://www.navfac.navy.mil/products_and_services/ci/products_and_services/naval_ocean_facilities_program/sea_floor_cable_protection_nscpo/nscpo_background.html as accessed on 05 December 2014.

Nelson, Eric, 2015, Personal communication between Mr. Jeffery Butts (Parsons) and Mr. Eric Nelson (USAF ACC/A3A) via email regarding 1FW special use airspace utilization, 13 January.

North Carolina Port Authority, 2015, (http://www.ncports.com/), accessed January 2015.

Offshore energy resources, VA Code §67-300 (2010).

Offshore natural gas and wind resources, VA Code §67-300 (2006).

Oil-Spill Response Requirements for Facilities Located Seaward of the Coast Line, 30 C.F.R. §254 (2012).

Parisi, Anthony, 2014, Personal communication with Anthony Parisi regarding Pacific OCS and Pt. Mugu Sea Range compatibility issues, 16 December.

Peterson, S.D., Balch, A.H., Patterson, W.C., and Taylor, D.J., 1979, Examples of deep-water-bottom multiple dereverberation techniques applied to seismic-reflection data from the Atlantic Outer Continental Margin, U.S. Geological Survey Open-File Report 79-1572, 42 p.

Poag, C.W., 1978, Stratigraphy of the Atlantic continental shelf and slope of the United States, Annual Review of Earth and Planetary Sciences, v. 6, p. 251-280.

Poag, C.W., 1979, Stratigraphy and depositional environments of Baltimore Canyon Trough, American Association of Petroleum Geologists Bulletin, v. 63, no. 9, p. 1452-1466.

Poag, C.W., 1987, The New Jersey transect: Stratigraphic framework and depositional history of a sediment-rich passive margin, in Poag, C.W., Watts, A.B., et al., (eds.), Initial reports of the Deep Sea Drilling Project, v. 95: Washington, U.S. Government Printing Office, p. 763-817.

Purdy, G.M. and Holbrook, W.S., 1990, R/V *Endeavor* – Cruise 217 Report: A wide-angle reflection/refraction piggyback of the EDGE Chesapeake Bay Transact, Serial # 90033, 62 p., accessed January 14, 2015 at http://woodshole.er.usgs.gov/operations/ia/public_ds_info.php?fa=1990-033-FA.

Quinn, John P, 2011, "The U.S. Navy's Sustainability Imperative," Article published in Live Better Magazine, 26 November.

Richards, H.G., 1961, Development in Atlantic coastal states between New Jersey and South Carolina in 1960, American Association of Petroleum Geologists Bulletin, v. 45, no. 6, p. 910-911.

Rondorf, Neil; Turner, Justin; Wilkins, Tim, 2009, Virginia Coastal Energy Research Consortium; Hampton Roads Maritime and Ports Capacity Report; July 2009.

Schlee, J.S., and Hinz, K., 1987, Seismic stratigraphy and facies of continental slope and rise seaward of Baltimore Canyon Trough, American Association of Petroleum Geologists Bulletin, v. 71, no. 9, p. 1046-1067.

Schlee, J., Behrendt, J.C., Grow, J.A., Robb, J.M., Mattick, R.E., Taylor, P., and Lawson, B.J., 1976, Regional geologic framework off northeastern United States, American Association of Petroleum Geologists Bulletin, v. 60, no. 6, p. 926-951.

Shell, 2011, "Shell Sets World Record for Deepest Subsea Oil and Gas Well," PRNewswire, 17 November.

Shell, 2014, Webpage: "Perdido-Shell Global," As access on 29 December.

Shell, 2015, Webpage: "Stones," Available at URL: http://www.shell.us/aboutshell/projects-locations/gulf-of-mexico-deepwater/portfolio/stones-ultra-deep-water-project.html as accessed on 19 February.

Sheridan, R.E., Musser, D.L., Glover, L., Talwani, M., Ewing, J.I., Holbrook, W.S., Purdy, G.M., Hawman, R. and Smithson, S., 1993, Deep seismic reflection data of EDGE US mid-Atlantic continental-margin experiment: Implications for Appalachian sutures and Mesozoic rifting and magmatic under plating, Geology, v. 21, no. 6, p. 563-567.

Sheriff, R.E., and Geldart, L.P., 1999, Exploration seismology, 2nd ed. Reprinted with corrections: Cambridge University Press, Cambridge, UK. 592 p.

Sivils, Lieutenant Elisha, 2011, U.S. Department of Homeland Security; Hampton Roads Geographic Response Plan Development and PREP Exercise; August 14, 2011.

Southwick Associates, 2013, Comparing NOAA's Recreational and Commercial Fishing Economic Data, Produced for the American Sportfishing Association, May.

Twichell, D.C. and Polloni, C.F., 1993, CD-ROM atlas of the deep water parts of the U.S. Exclusive Economic Zone in the Atlantic Ocean, the Gulf of Mexico, and the eastern Caribbean Sea, U.S. Geological Survey Digital Data Series: DDS-15 (Digital Data on CD-ROM).

United States Air Force (USAF), 2001, Initial F-22 Operational Beddown Draft Environmental Impact Statement, April.

USAF, 2014, Final Environmental Assessment for the Maritime Weapons System Evaluation Program, Eglin AFB, FL, December.

United States Coast Guard (USCG), 2011, On Scene Coordinator Report *Deepwater Horizon* Oil Spill, Submitted to the National Response Team, September.

USCG, Fifth Coast Guard District, 2014, Webpage: "Welcome to the Fifth Coast Guard District", Available at URL: http://www.uscg.mil/d5/ as accessed on 09 December 2014.

United States Department of Transportation, 2013, Gas Transmission and Hazardous Liquids Pipelines Map, National Pipeline Mapping System data as of 29 September.

U.S. Energy Information Administration (EIA), 2006, Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market; January 2006.

U.S. Energy Information Administration (EIA), 2010, Gulf of Mexico: Producing Oil & Gas Fields; November 4, 2010.

U.S. Energy Information Administration (EIA), 2014, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves Summary Maps of Selected State Subdivisions.

United States Environmental Protection Agency, 2011, Webpage: "Oil Spills", Available via URL http://www.epa.gov/oilspill/ as accessed on 09 December 2014.

Van Avendonk, H.J.A., Christeson, G.L., Long, M.D., Dugan, B., Beatrice, M.M., Hornbach, M.J., Harder, S., Lizarralde, D., Shillington, D.J., Bécel, A., and Gaherty, J.B., 2012, Proposed scientific research in waters off North Carolina and Virginia, using the R/V *Marcus Langseth*, 45 p., accessed Jan. 14, 2015 at http://www.ig.utexas.edu/enam/expeditions.

Virginia Legislative Information System (VLIS), 2015, http://lis.virginia.gov/cgi-bin/legp604.exe?141+ful+CHAP0293, accessed February 2015

Virginia Marine Resources Commission and the National Oceanic and Atmospheric Administration, 2014, 2013 Annual Commercial Fisheries Statistics Summary Report, Printed 08 July.

Virginia Maritime Association (VMA), 2014, Ports of Virginia Annual of 2014.

Virginia Port Authority (VPA), http://www.portofvirginia.com/, access February 2015

Virginia Port Authority, 2014, The Port of Virginia 2013 Key Performance Indicators, Retrieved from: (http://www.portofvirginia.com/wp-content/uploads/2014/07/2013_key_performance_indicators.pdf) as accessed on 22 December.

Weed, E.G.A., Minard, J.P., Perry, W.J., Rhodehamel, E.C., and Robbins, E.I., 1974, Generalized pre-Pleistocene geologic map of the northern United States Atlantic continental margin, U.S. Geological Survey Miscellaneous Investigations Series Map I-861, 8 p. and 2 sheets, scale 1:1,000,000.

The White House, 2010, Executive Order- 13547: Stewardship of the Ocean, Our Coasts, and the Great Lakes, 19 July.

Wise, R.A., and Oliver, H.L., 1987, Reprocessing of marine multichannel seismic reflection profile line 12, Cape Hatteras, North Carolina, to Shell Mohawk well, Canada, U.S. Geological Survey Open-File Report 88-51, 17 p.

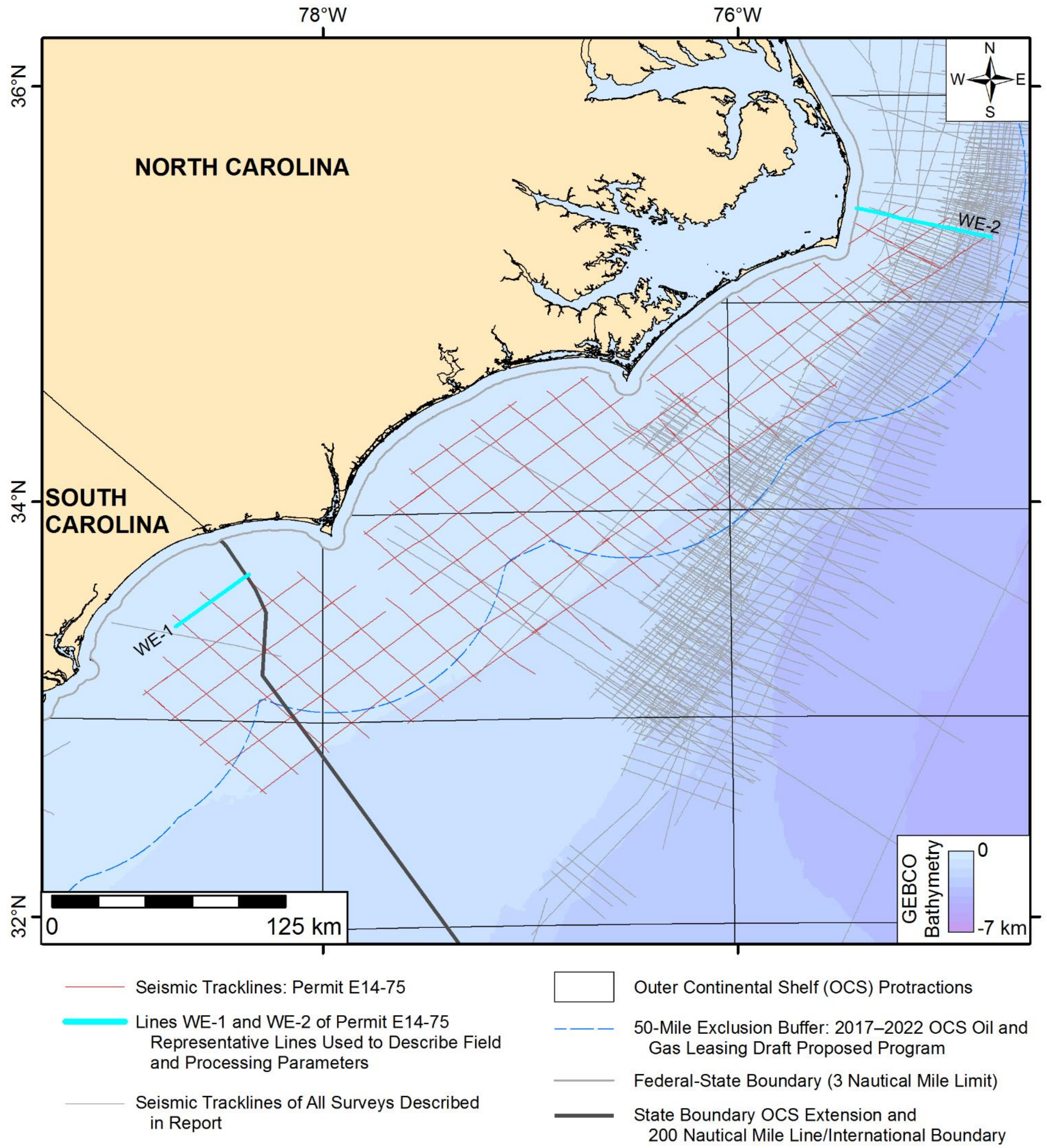
Wise, R.A., and Oliver, H.L., 1989, Marine multichannel seismic reflection profile line 13 reprocessed, Cape Hatteras to Georges Bank, U.S. Geological Survey Open-File Report 89-572, 25 p.

Yilmaz, O., 1987, Seismic data processing, Society of Exploration Geophysicists, Investigations in geophysics No. 2, Tulsa, OK, United States, 526 p.

APPENDIX A – RECORDING PARAMETERS

CONTENTS

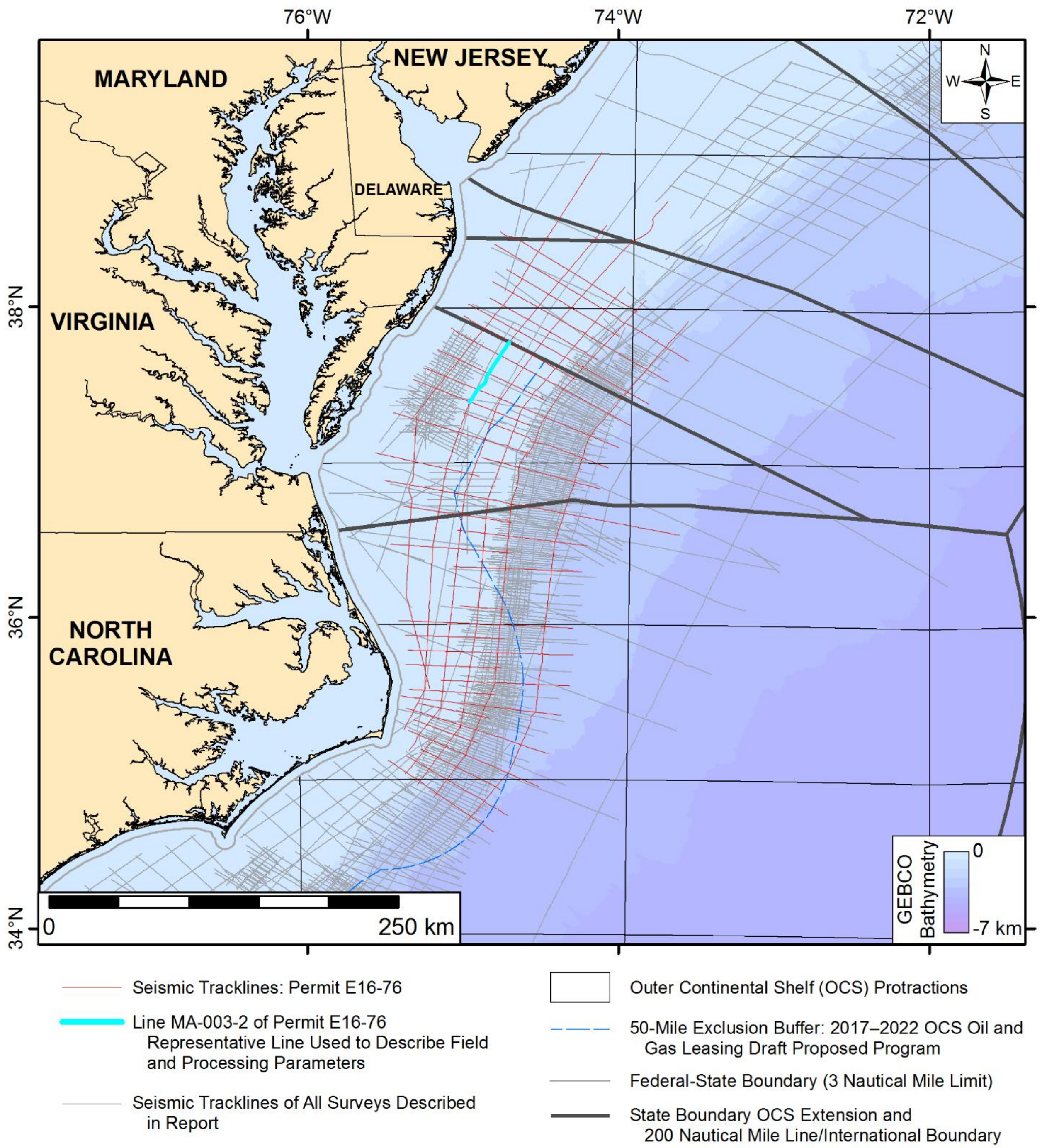
Western Geophysical E14-75 Map and Table of Field Parameters .... Plate A-1
OAG E16-76 Map and Table of Field Parameters .... Plate A-2
USGS E06-79 Map and Table of Field Parameters .... Plate A-3
SAG E01-80 Map and Table of Field Parameters .... Plate A-4
SAG E02-80 Map and Table of Field Parameters .... Plate A-5
Exxon E01-81 Map and Table of Field Parameters .... Plate A-6
Chevron E07-81 Map and Table of Field Parameters .... Plate A-7
MSAG E02-82 Map and Table of Field Parameters .... Plate A-8
Shell E04-82 Map and Table of Field Parameters .... Plate A-9
ARCO Exploration E11-82 Map and Table of Field Parameters .... Plate A-10
AMOCO E05-83 Map and Table of Field Parameters .... Plate A-11
Spectrum/Texaco E05-86 Map and Table of Field Parameters .... Plate A-12
Texaco E03-88 Map and Table of Field Parameters .... Plate A-13
USGS S-1-73 Map and Table of Field Parameters .... Plate A-14
USGS S-1-75 Map and Table of Field Parameters .... Plate A-15
USGS S-1-77 Map and Table of Field Parameters .... Plate A-16
USGS C-1-78 Map and Table of Field Parameters .... Plate A-17
BGR 79 Survey Map and Table of Field Parameters .... Plate A-18
VAEDGE Survey Map and Table of Field Parameters .... Plate A-19



Permit E14-75	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Western Geophysical
Acquisition Company	Western Geophysical
Year Acquired	1975
Processed by	Western Geophysical
Year Processed	1975
Total Number of Lines Collected	33
Kilometers Shot (Approximate)	4340 (2697 line-miles)
Recording Instruments	DDS-888 COBA I
Recording Filter	Low Cut: 8 Hz High Cut: 124 Hz
Recording Gain	Instantaneous Floating Point (IFP) Gain
Sample Rate (milliseconds)	4
Record Length (seconds)	5
Energy Source	Aquapulse System
Cable Length (km)	3.2
Number of Channels	48
Group Interval (m)	67
Multiplicity (CDP Fold)	24

WESTERN GEOPHYSICAL E14-75 MAP AND TABLE OF FIELD PARAMETERS

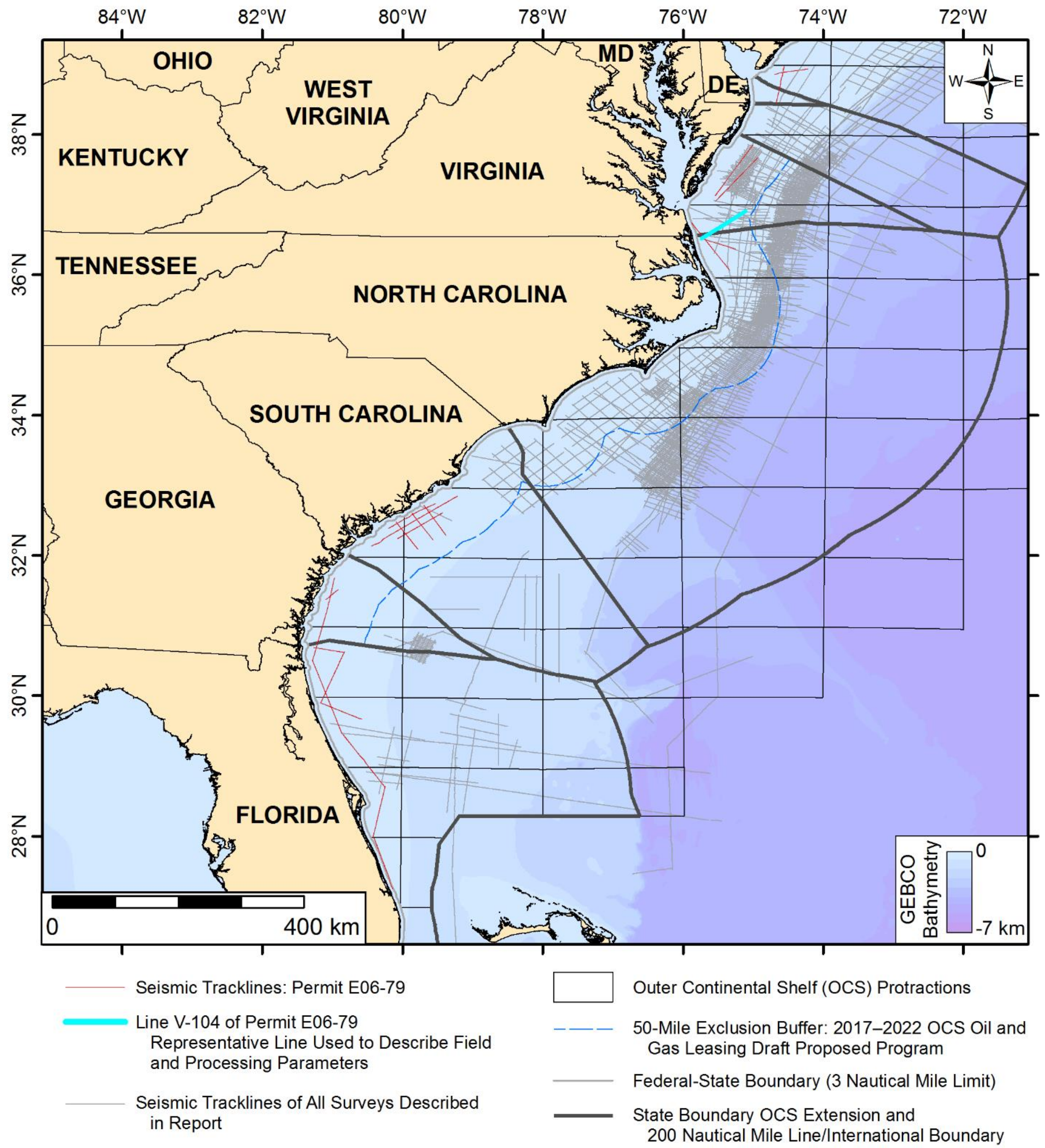
Oil and Gas Readiness Study
Offshore Virginia



Permit E16-76	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Offshore Atlantic Group
Acquisition Company	Digicon Geophysical Corporation
Year Acquired	1976
Processed by	Digicon Geophysical Corporation
Year Processed	1976
Vessel	M/V *Gulf Seal*
Total Number of Lines Collected	42
Kilometers Shot (Approximate)	5386 (3347 line-miles)
Number of Lines Collected in Virginia Waters	17
Kilometers Shot in Virginia Waters (Approximate)	1590
Recording Instruments	DFS III
Recording Filter	Out High Cut: 62 Hz
Recording Gain	Binary Gain
Sample Rate (milliseconds)	4
Record Length (seconds)	8
Energy Source	18 Air Guns 1700 CU. IN.
Source Depth (m)	14
Shotpoint Interval (m)	100
Cable Type	Non-linear Streamer
Cable Length (km)	3.6
Antenna to Source (m)	31 (shotpoints are ship antenna locations)
Near Offset Distance (m)	346
Near Offset Trace/Group	48
Far Offset Distance (m)	3915
Far Offset Trace/Group	1
Number of Channels	48
Group Interval (m)	traces: 48 to 25 = 100 m traces: 25 to 24 = 75 m traces: 23 to 1 = 50 m
CDP Interval (m) from SEG-Y Header	50
Multiplicity (CDP Fold)	36

OAG E16-76 MAP AND TABLE OF FIELD PARAMETERS

Oil and Gas Readiness Study
Offshore Virginia

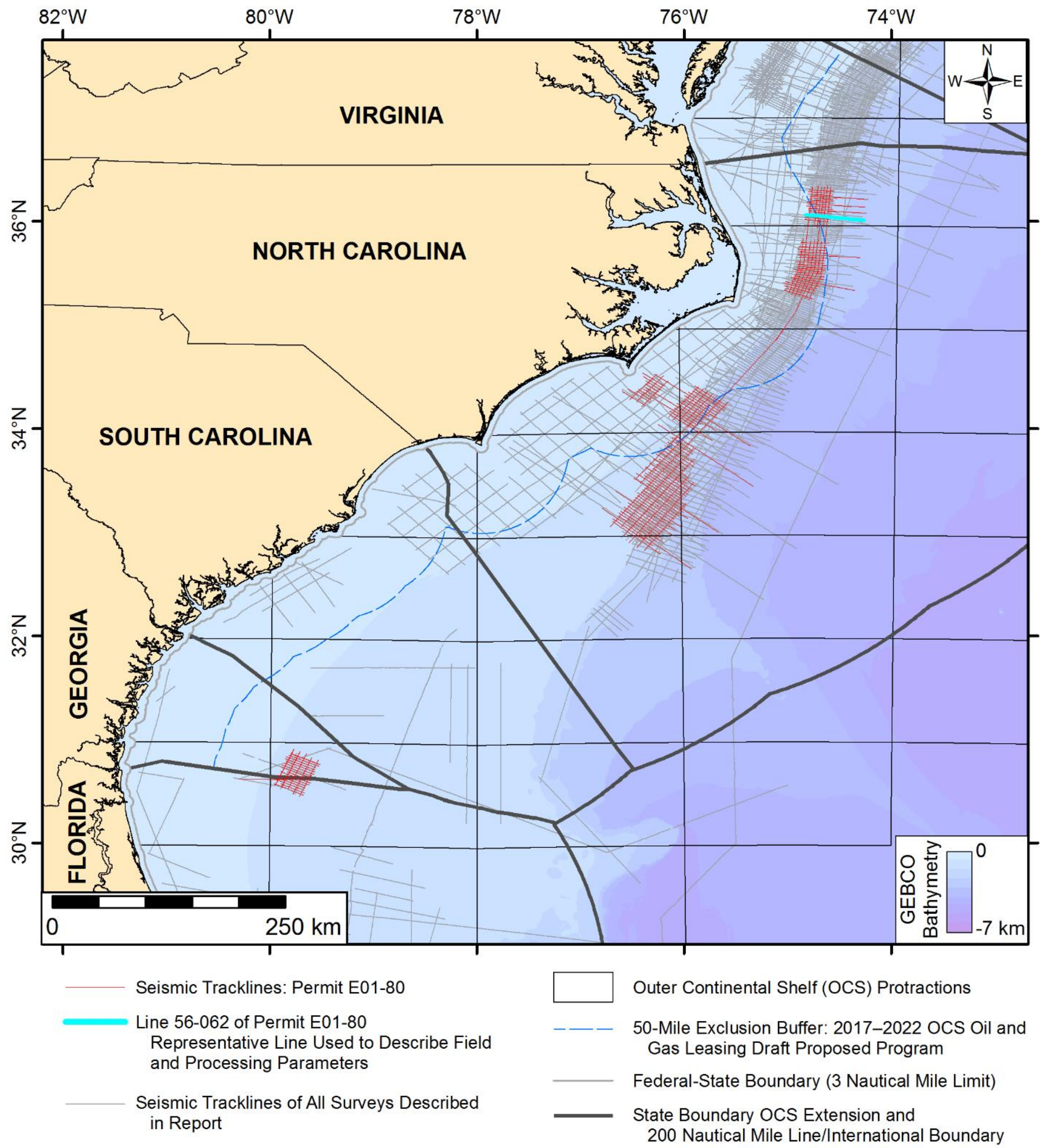


Permit E06-79 (ECOAST79)	
Source of Field Parameter	Scanned seismic section obtained from BOEM and cruise report downloaded at NOAA's NGDC.
Client	USGS Conservation Division, Eastern Region
Acquisition Company	Whitehall Corporation: Seismic Exploration International, S.A.
Year Acquired	1979
Processed by	Whitehall Corporation: Geophysical Data Processing Center, Inc.
Year Processed	1979 (Assumed)
Vessel	*M/V Seismic Explorer*
Total Number of Lines Collected	23
Kilometers Shot (Approximate)	1721 (1069 line-miles)
Number of Lines Collected - VA Waters	4
Kilometers Shot - VA Waters (Approx.)	265
Recording Instruments	Geosource MDS-10
Recording Filter	Low Cut: 9 Hz, Slope: 18 dB/octave High Cut: 62 Hz, Slope 80 dB/octave Notch: Out
Recording Gain	Instantaneous Floating Point Gain Constant 24 dB
Sample Rate (milliseconds)	4
Record Length (seconds)	5
Tape Format	SEG-B 1600 BPI-9 track
Energy Source	21 Air Gun Tuned Array 2183 CU. IN. 1800-2000 PSI
Source Depth (m)	8
Shotpoint Interval (m)	50
Cable Type	Century DSS V Streamer (SECo)
Cable Length (km)	3.2
Average Depth of Hydrophones (m)	10
Antenna to Source (m)	Max. 67 m from towing arm
Near Offset Distance (m)	188
Near Offset Trace/Group	64
Far Offset Distance (m)	3338
Far Offset Trace/Group	1
Number of Channels	64
Group Interval (m)	50
CDP Interval (m) from SEG-Y Header	65
Multiplicity (CDP Fold)	16

USGS E06-79 MAP AND TABLE OF FIELD PARAMETERS

Oil and Gas Readiness Study
Offshore Virginia

PLATE A-3

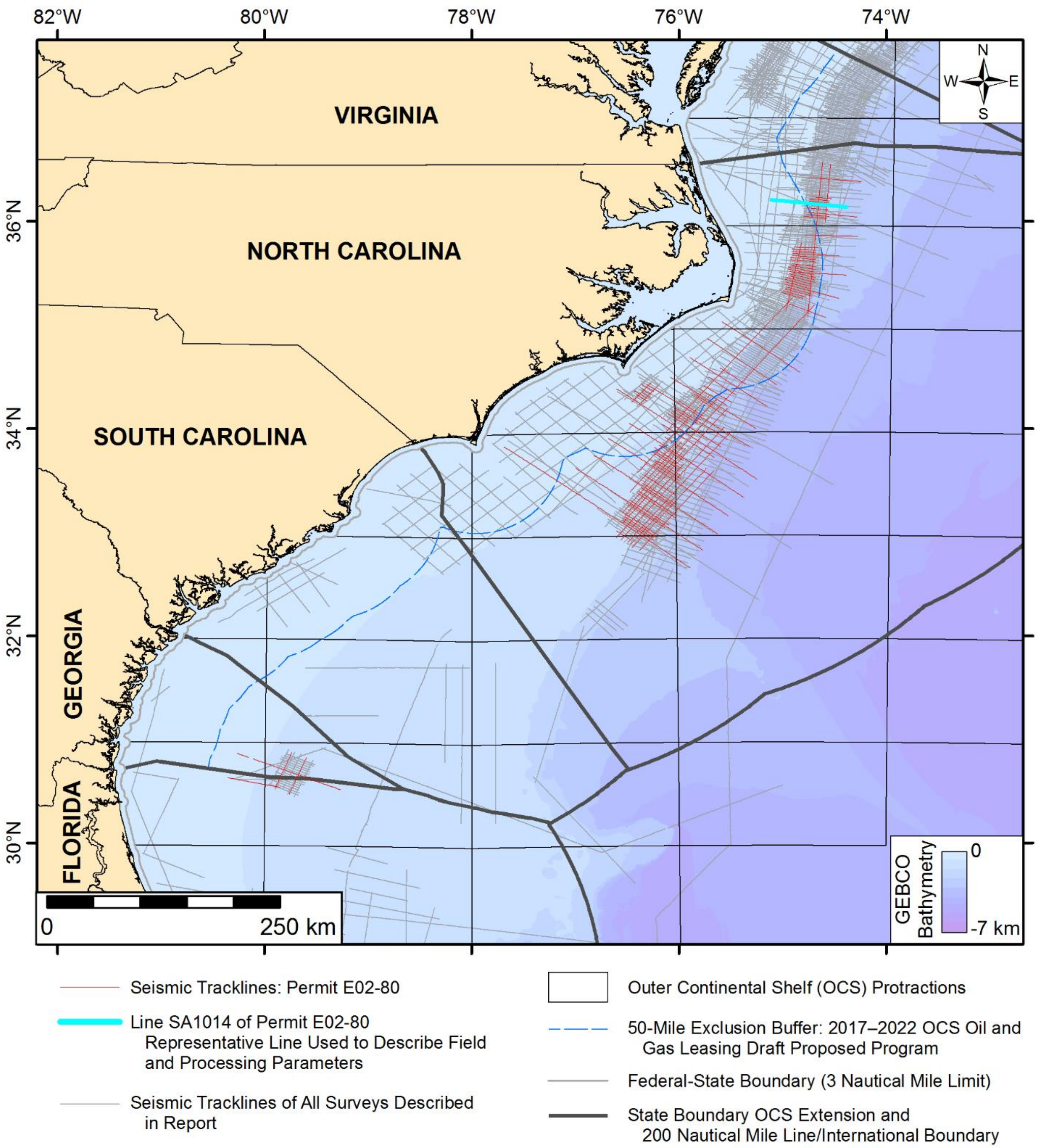


Permit E01-80	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	South Atlantic Group
Acquisition Company	Geosource Inc.
Year Acquired	1980
Processed by	Geosource (Petty-Ray Division)
Year Processed	1980
Vessel	M/V *Geomar I*
Total Number of Lines Collected	159
Kilometers Shot (Approximate)	6625 (4117 line-miles)
Navigation System	ARGO and LORAN C for auxiliary surveying
Recording Instruments	MDS-10
Recording Filter	Low Cut: 9 Hz, Slope: 18 dB/octave High Cut: 172 Hz
Recording Gain	Instantaneous Floating Point (IFP) Gain
Sample Rate (milliseconds)	2
Record Length (seconds)	8
Tape Format	SEG-B
Energy Source	14 Air Guns 2682 CU. IN. 1850 PSI
Source Depth (m)	5
Shotpoint Interval (m)	37
Cable Type	48 Trace Streamer
Cable Length (km)	3.5
Average Depth of Hydrophones (m)	10
Antenna to Source (m)	63
Near Offset Distance (m)	223
Near Offset Trace/Group	48
Far Offset Distance (m)	3747
Far Offset Trace/Group	1
Number of Channels	48
Group Interval (m)	75
Hydrophones	6 in line
Multiplicity (CDP Fold)	48

SAG E01-80 MAP AND TABLE OF FIELD PARAMETERS

Oil and Gas Readiness Study
Offshore Virginia

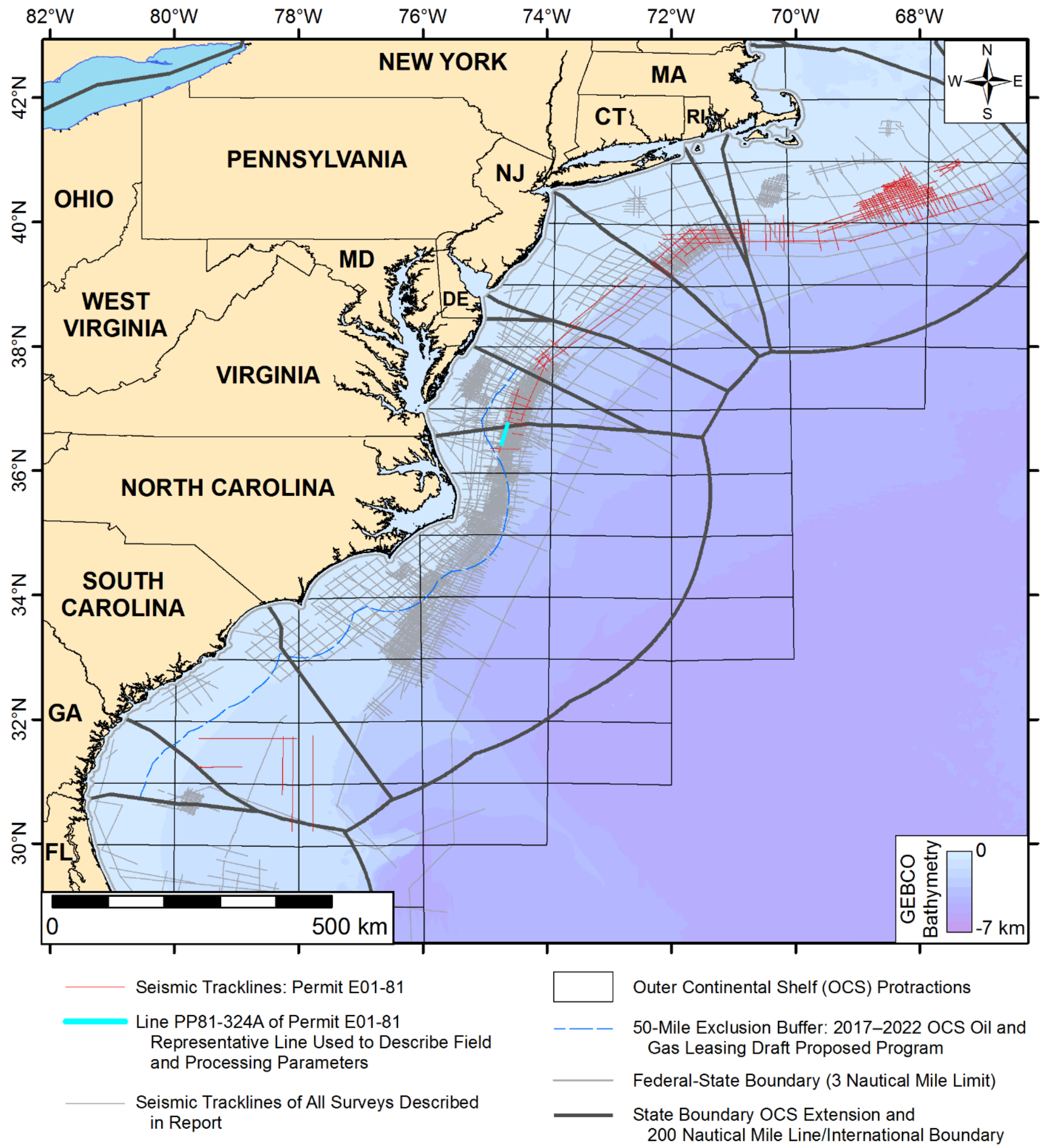
PLATE A-4



Permit E02-80	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	South Atlantic Group
Acquisition Company	Digicon
Year Acquired	1980
Processed by	Digicon
Year Processed	1981
Vessel	M/V *Gulf Seal*
Total Number of Lines Collected	106
Kilometers Shot (Approximate)	5899 (3665 line-miles)
Recording Instruments	DFS V
Recording Filter	Low Cut: 8 Hz, Slope: 18 dB/octave High Cut: 128 Hz, Slope: 70 dB/octave
Recording Gain	Instantaneous Floating Point (IFP) Gain
Sample Rate (milliseconds)	2
Record Length (seconds)	7
Tape Format	SEG-B
Energy Source	25 Air Guns 2220 CU. IN. 1700-1800 PSI
Shotpoint Interval (m)	50
Cable Type	Non-linear Streamer
Cable Length (km)	3.6
Near Offset Distance (m)	244
Near Offset Trace/Group	96
Far Offset Distance (m)	3562
Far Offset Trace/Group	1
Number of Channels	96
Group Interval (m)	channels: 96 to 49 = 50 m channels: 48 to 1 = 25 m
Multiplicity (CDP Fold)	36

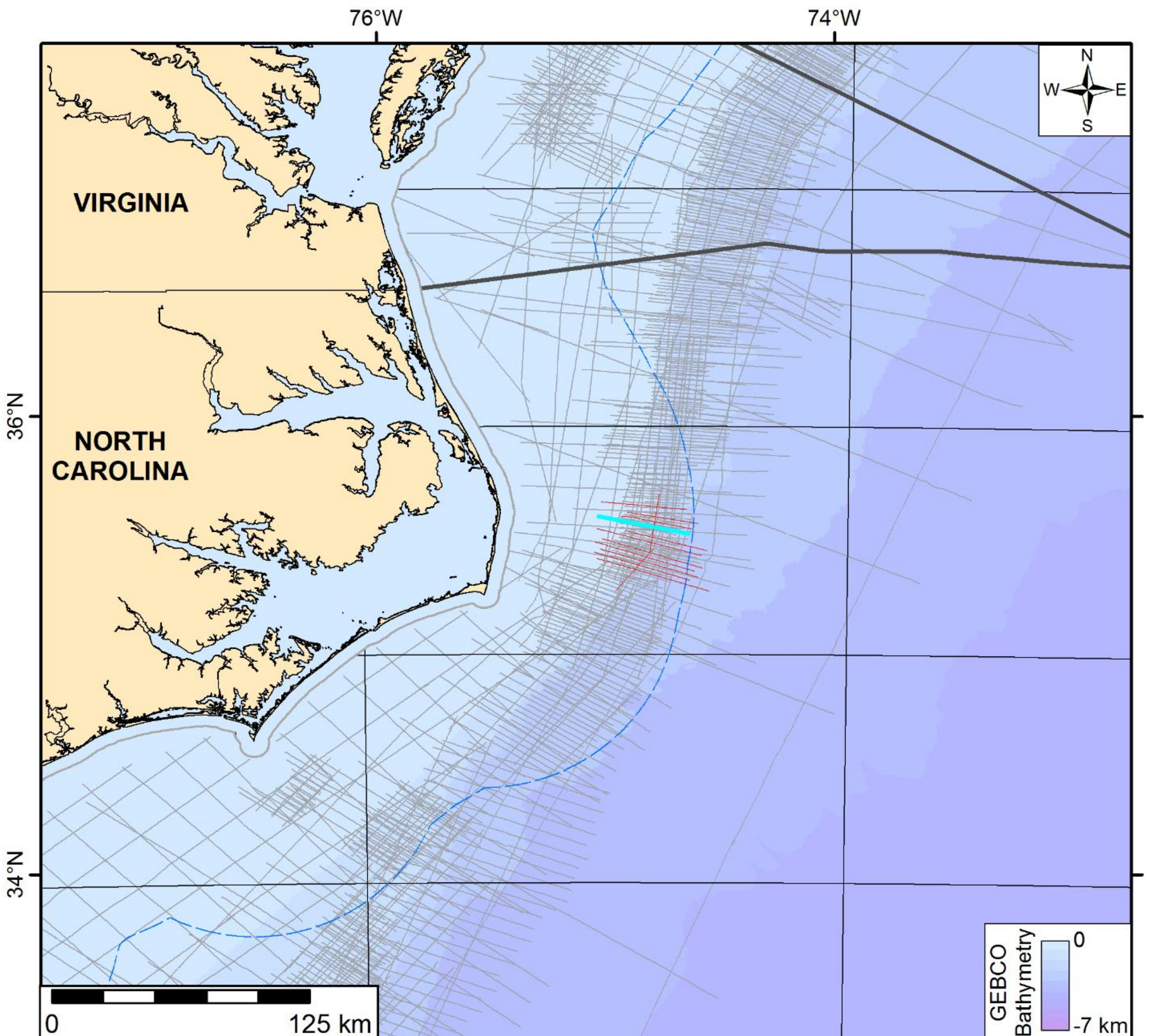
SAG E02-80 MAP AND TABLE OF FIELD PARAMETERS

Oil and Gas Readiness Study
Offshore Virginia



Permit E01-81	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Exxon Exploration
Acquisition Company	Geosource Inc.
Year Acquired	1981
Processed by	Exxon Exploration Data Processing Center
Year Processed	1982
Vessel	M/V *Rob Ray I*
Total Number of Lines Collected	107
Kilometers Shot (Approximate)	7184 (4464 line-miles)
Number of Lines Collected in Virginia Waters	7
Kilometers Shot in Virginia Waters (Approximate)	306 (190 line-miles)
Navigation System	ARGO
Recording Instruments	DFS V
Recording Filter	Low Cut: 5.3 Hz, Slope: 18 dB/octave High Cut: 90 Hz, Slope 70 dB/octave
Recording Gain	Binary Gain
Sample Rate (milliseconds)	4
Record Length (seconds)	8
Tape Format	SEG-B
Energy Source	14 Air Guns 2511 CU. IN.
Source Depth (m)	9
Shotpoint Interval (m)	22.5
Cable Type	Geophones: MD-5 Array: PB=93
Cable Length (km)	2.9
Average Depth of Hydrophones (m)	11
Near Offset Distance (m)	217
Near Offset Trace/Group	75
Far Offset Distance (m)	3157
Far Offset Trace/Group	1
Number of Channels	120
Group Interval (m)	Listed as 15m on data label
Hydrophones/Group	17
CDP Interval (m) from SEG-Y Header	25
Multiplicity (CDP Fold)	40 to 75

EXXON E01-81 MAP AND TABLE OF FIELD PARAMETERS
Oil and Gas Readiness Study
Offshore Virginia



Seismic Tracklines: Permit E07-81

Line CSA-81-8 of Permit E07-81 Representative Line Used to Describe Field and Processing Parameters

Seismic Tracklines of All Surveys Described in Report

Outer Continental Shelf (OCS) Protractions

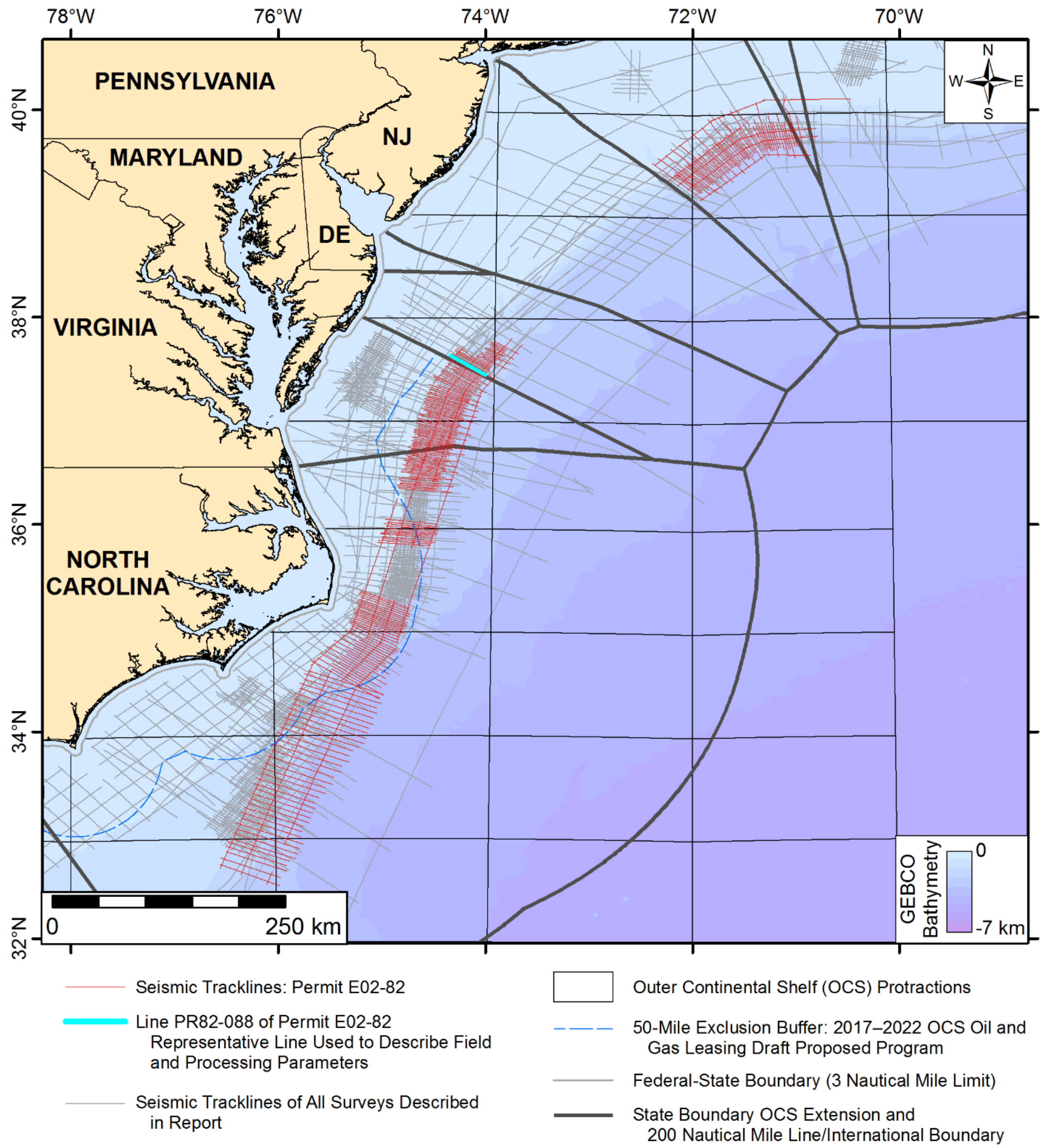
50-Mile Exclusion Buffer: 2017–2022 OCS Oil and Gas Leasing Draft Proposed Program

Federal-State Boundary (3 Nautical Mile Limit)

State Boundary OCS Extension and 200 Nautical Mile Line/International Boundary

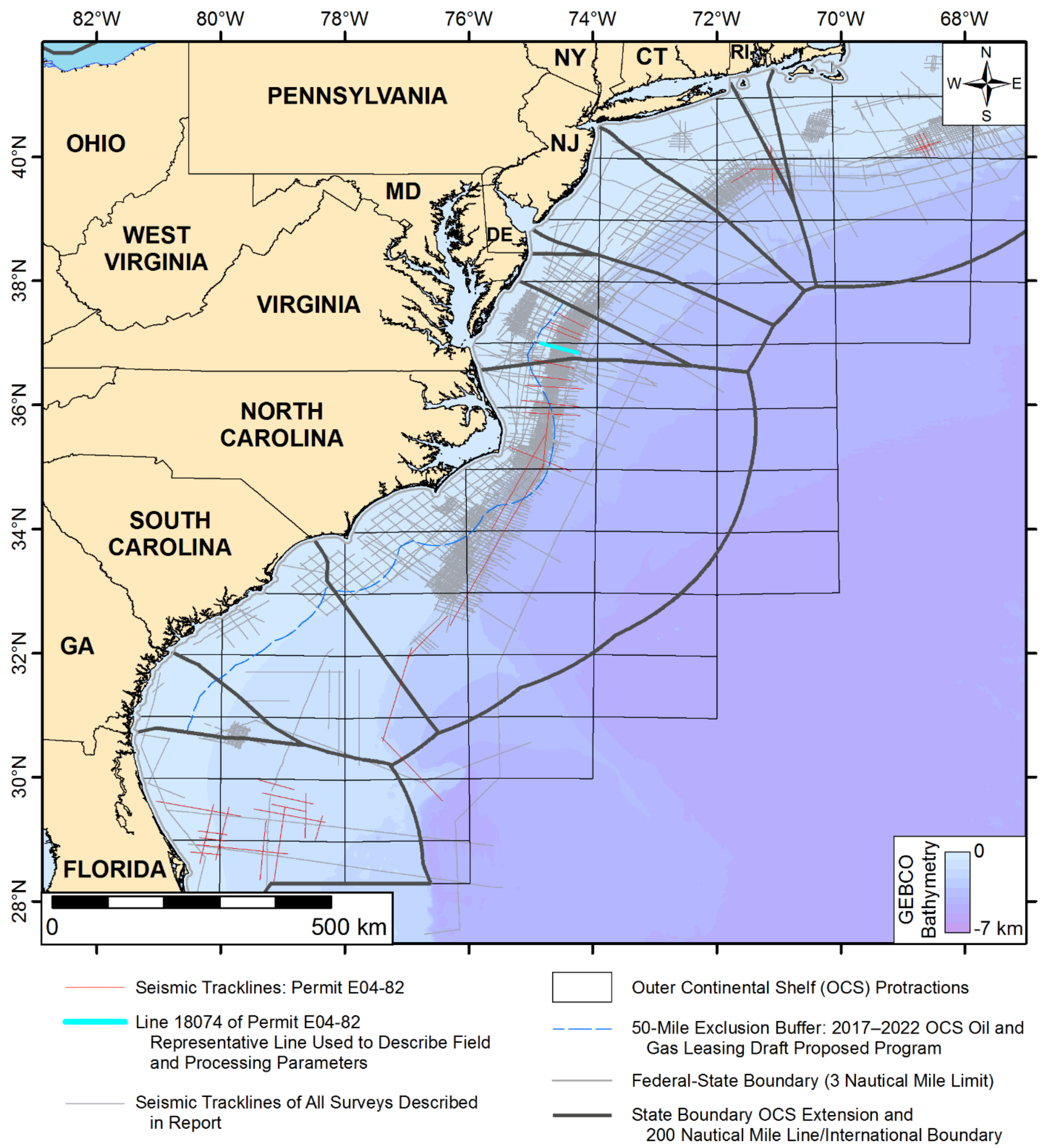
Permit E07-81	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Chevron
Acquisition Company	Digicon
Year Acquired	1981
Processed by	Chevron Geosciences Company
Year Processed	1981 - Assumed
Total Number of Lines Collected	12
Kilometers Shot (Approximate)	473 (294 line-miles)
Recording Instruments	DFS V
Recording Filter	Low Cut: 8 Hz, Slope: 18 dB/octave High Cut: 128 Hz, Slope: 72 dB/octave
Recording Gain	Binary Gain
Sample Rate (milliseconds)	2
Record Length (seconds)	7.4
Energy Source	25 Air Guns 1800 PSI
Shotpoint Interval (m)	50
Cable Type	Non-linear Streamer
Cable Length (km)	3.6
Near Offset Distance (m)	270
Near Offset Trace/Group	96
Far Offset Distance (m)	3575
Far Offset Trace/Group	1
Number of Channels	96
Group Interval (m)	channels: 96 to 49 = 50 m channels: 48 to 1 = 25 m
Multiplicity (CDP Fold)	36

CHEVRON E07-81 MAP AND TABLE OF FIELD PARAMETERS
Oil and Gas Readiness Study
Offshore Virginia



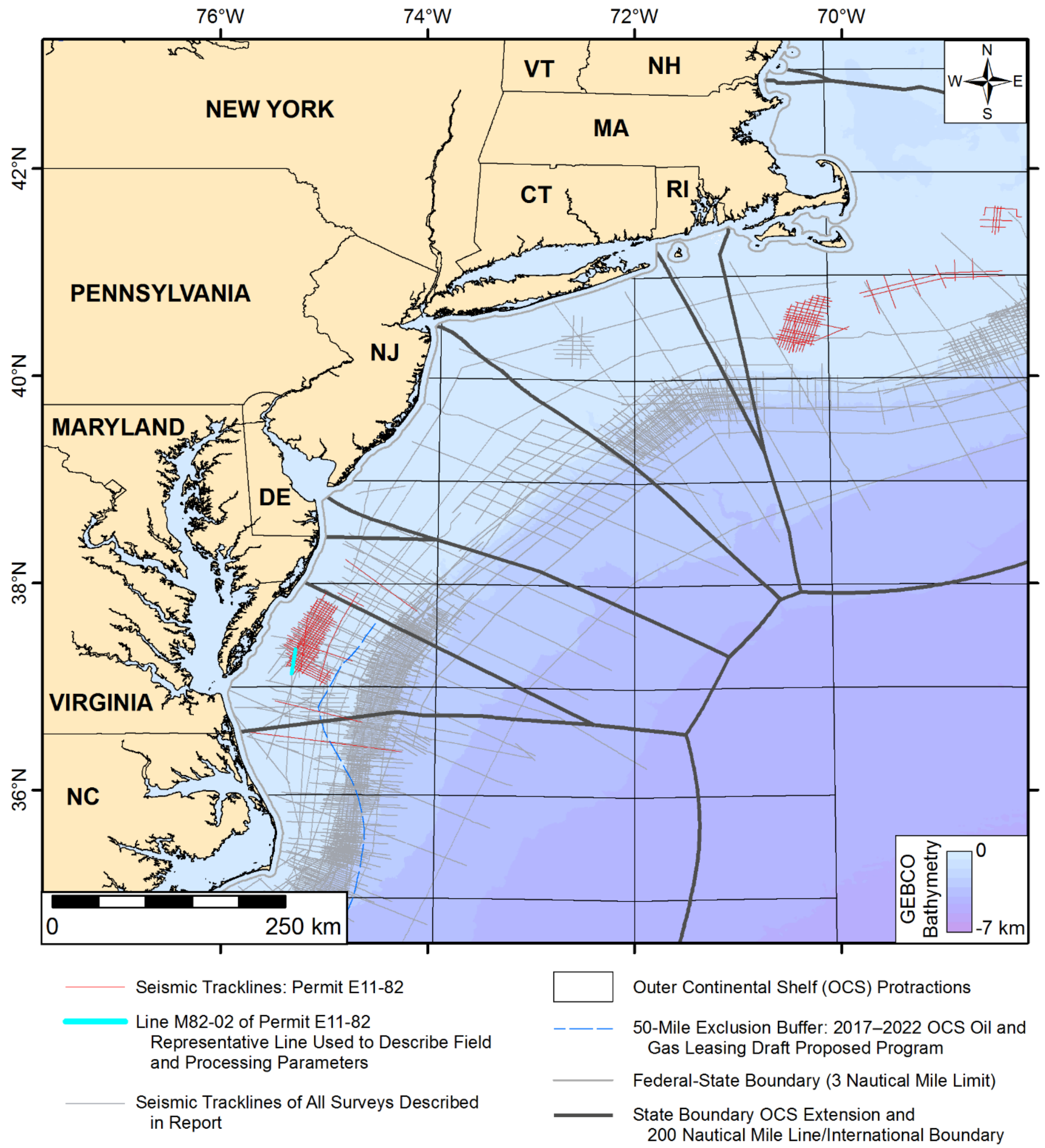
Permit E02-82	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Mid-South Atlantic Group
Acquisition Company	Geosource Inc.
Year Acquired	1982
Processed by	Geosource Inc.
Year Processed	1982 (Assumed)
Vessel	M/V *Geomar II*
Total Number of Lines Collected	274
Kilometers Shot (Approximate)	13835 (8597 line-miles)
Number of Lines Collected in Virginia Waters	63
Kilometers Shot in Virginia Waters (Approximate)	2324 (1444 line-miles)
Recording Instruments	DFS V
Recording Filter	Low Cut: 8 Hz, Slope: 18 dB/octave High Cut: 128 Hz
Recording Gain	Fixed Gain (derived from SEG-Y Header)
Sample Rate (milliseconds)	2
Record Length (seconds)	8
Tape Format	SEG-B
Energy Source	14 Air Guns 3060 CU. IN. 1800-2000 PSI
Source Depth (m)	9
Shotpoint Interval (m)	37.5
Cable Length (km)	3.6
Average Depth of Hydrophones (m)	13
Near Offset Distance (m)	225
Near Offset Trace/Group	96
Far Offset Distance (m)	3787
Far Offset Trace/Group	1
Group Interval (m)	37.5
Hydrophones/Group	36
CDP Interval (m) from SEG-Y Header	37.5
Multiplicity (CDP Fold)	48

MSAG E02-82 MAP AND TABLE OF FIELD PARAMETERS
Oil and Gas Readiness Study
Offshore Virginia



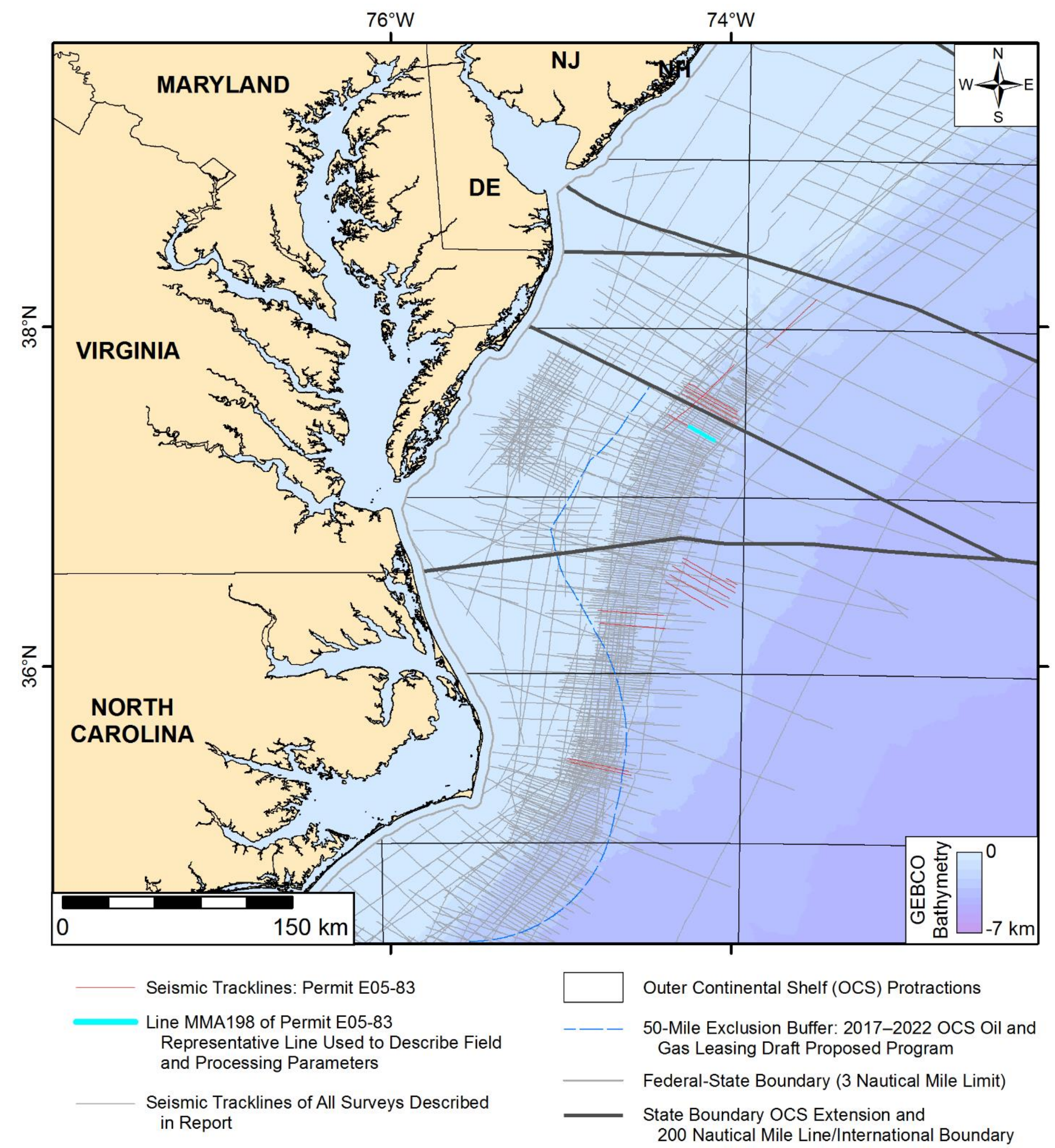
Permit E04-82	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Shell
Acquisition Company	Shell (Assumed)
Year Acquired	1982
Processed by	Shell (Assumed)
Year Processed	1982 (Assumed)
Total Number of Lines Collected	40
Kilometers Shot (Approximate)	3233 (2009 line-miles)
Number of Lines Collected in Virginia Waters	5
Kilometers Shot in Virginia Waters (Approximate)	242 (150 line-miles)
Recording Gain	Binary Gain and Fixed Gain (derived from SEG-Y Header)
Sample Rate (milliseconds)	4
Record Length (seconds)	9
Shotpoint Interval (m)	30.5
CDP Interval (m) from SEG-Y Header	30.5

SHELL E04-82 MAP AND TABLE OF FIELD PARAMETERS
Oil and Gas Readiness Study
Offshore Virginia



Permit E11-82	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	ARCO Exploration
Acquisition Company	ARCO Resolution
Year Acquired	1982
Processed by	ARCO Exploration Resources Department Geophysical Data Processing
Year Processed	1982
Vessel	ARCO Resolution
Total Number of Lines Collected	92
Kilometers Shot (Approximate)	3855 (2395 line-miles)
Number of Lines Collected in Virginia Waters	45
Kilometers Shot in Virginia Waters (Approximate)	1872 (1163 line-miles)
Recording Filter	Low Cut: 8 Hz High Cut: 160 Hz
Recording Gain	Fixed Gain (derived from SEG-Y Header)
Sample Rate (milliseconds)	2
Record Length (seconds)	8
Tape Format	SEG-Y
Energy Source	Air Guns 5600 CU. IN.
Shotpoint Interval (m)	25
Cable Type	Inline
Cable Length (km)	3.0
Near Offset Distance (m)	329
Far Offset Distance (m)	3316
CDP Interval (m) from SEG-Y Header	50
Multiplicity (CDP Fold)	240 (many SEG-Y Headers list 144 fold for migrated data)

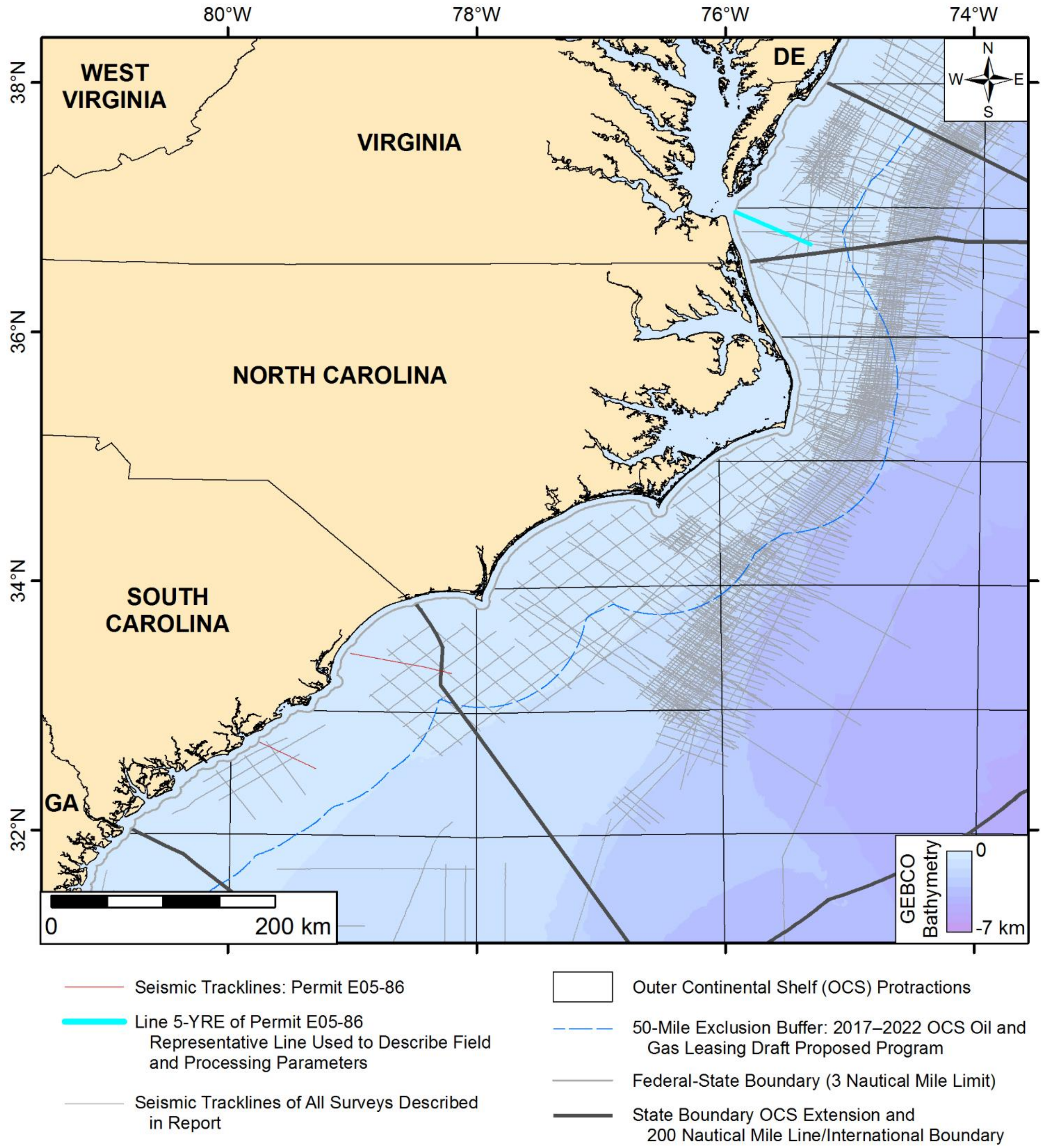
ARCO EXPLORATION E11-82 MAP AND TABLE OF FIELD PARAMETERS
Oil and Gas Readiness Study
Offshore Virginia



Permit E05-83	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Amoco
Acquisition Company	Norpac
Year Acquired	1983
Processed by	Amoco Tulsa Processing Group
Year Processed	1983 (Assumed)
Total Number of Lines Collected	23
Kilometers Shot (Approximate)	962 (598 line-miles)
Number of Lines Collected in Virginia Waters	2
Kilometers Shot in Virginia Waters (Approximate)	77 (48 line-miles)
Recording Instruments	DFS V
Recording Filter	Low Cut: 8 Hz, Slope: 18 dB/octave High Cut: 128 Hz
Recording Gain	Fixed Gain (derived from SEG-Y Header)
Sample Rate (milliseconds)	2
Record Length (seconds)	9
Tape Format	SEG-B
Energy Source	18 Air Guns 2000 PSI
Shotpoint Interval (m)	25
Cable Length (km)	3.0
Near Offset Distance (m)	250
Near Offset Trace/Group	120
Far Offset Distance (m)	3224
Far Offset Trace/Group	1
Number of Channels	120
Group Interval (m)	25
CDP Interval (m) from SEG-Y Header	12.5
Multiplicity (CDP Fold)	60

AMOCO E05-83 MAP AND TABLE OF FIELD PARAMETERS

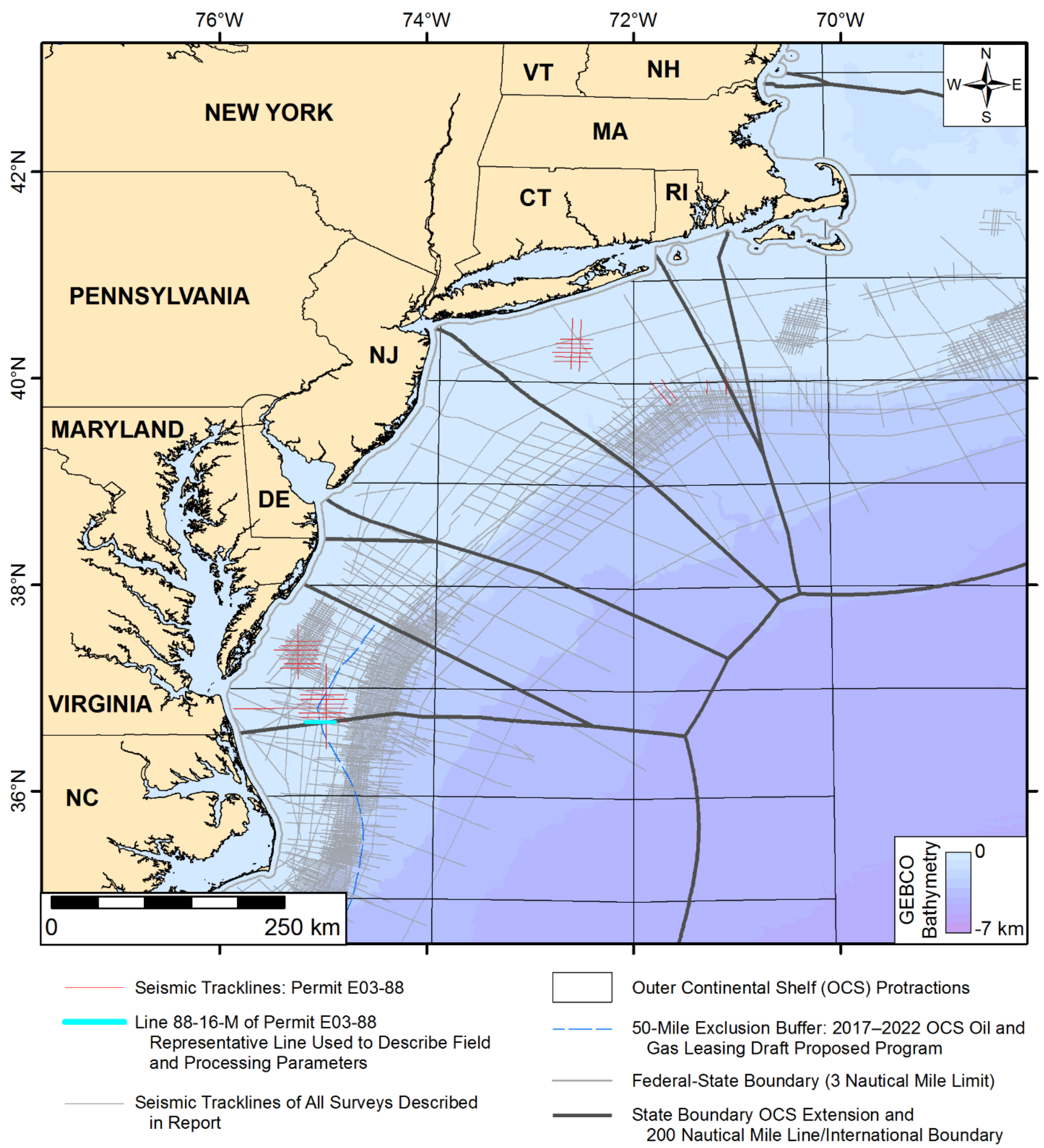
Oil and Gas Readiness Study
Offshore Virginia



Permit E05-86	
Source of Field Parameter	Scanned seismic sections obtained from BOEM/BSEE's online data center.
Client	Spectrum Resources/Texaco
Acquisition Company	Teledyne Exploration
Year Acquired	1986
Processed by	Teledyne Exploration
Year Processed	1986
Total Number of Lines Collected	3
Kilometers Shot (Approximate)	207 (129 line-miles)
Number of Lines Collected in Virginia Waters	1
Kilometers Shot in Virginia Waters (Approximate)	62 (38 line-miles)
Recording Instruments	DFS IV
Recording Filter	Low Cut: 8 Hz High Cut: 128 Hz
Recording Gain	Binary Gain
Sample Rate (milliseconds)	2
Record Length (seconds)	6
Energy Source	6 Air Guns 984 CU. IN. 2000 PSI
Shotpoint Interval (m)	25
Cable Length (km)	1.2
Near Offset Distance (m)	125
Far Offset Distance (m)	1312
Number of Channels	96
Group Interval (m)	12.5
CDP Interval (m) from SEG-Y Header	12.5
Multiplicity (CDP Fold)	48

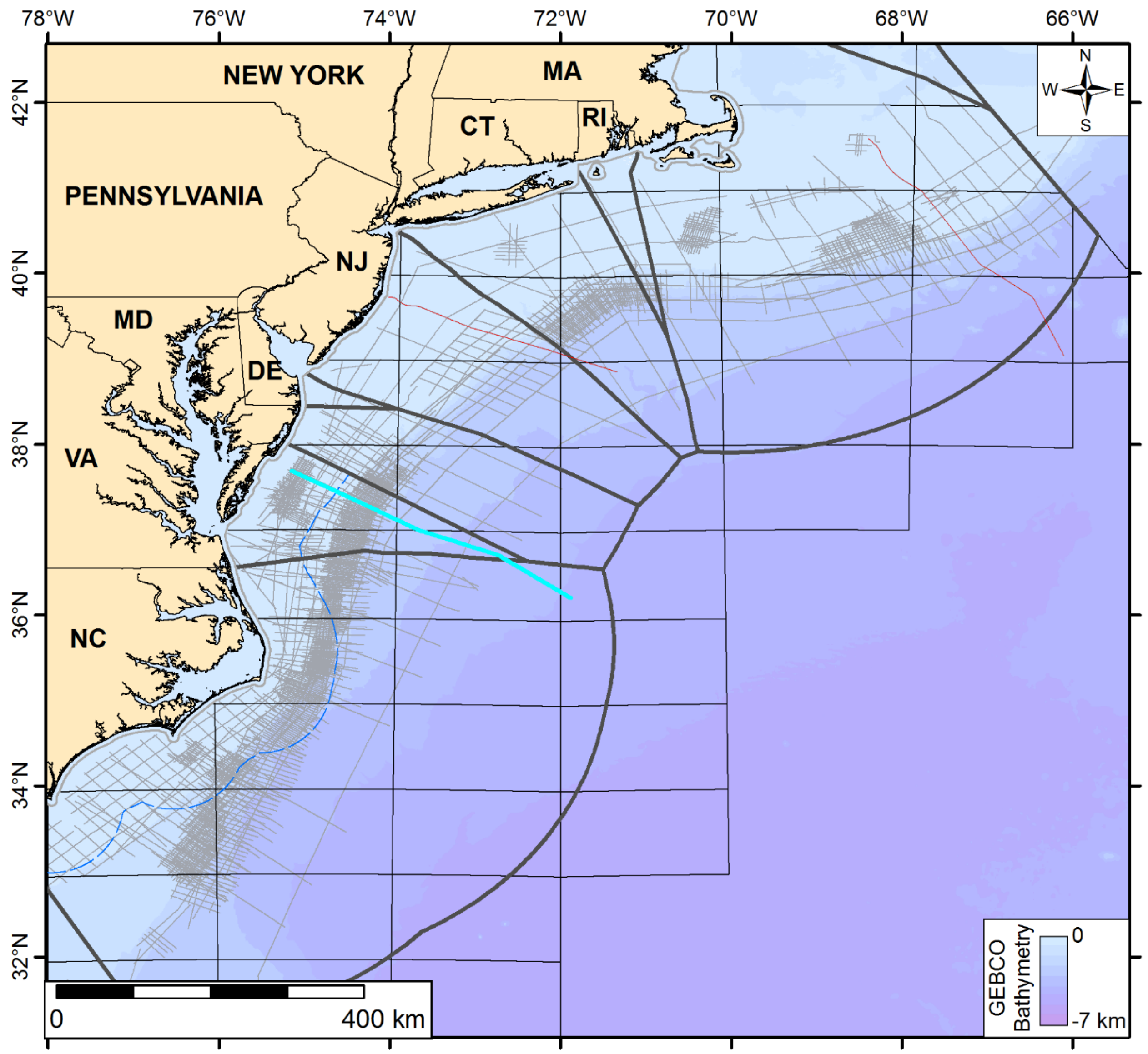
SPECTRUM/TEXACO E05-86 MAP AND TABLE OF FIELD PARAMETERS

Oil and Gas Readiness Study
Offshore Virginia



Permit E03-88	
Source of Field Parameter	Scanned seismic permit label obtained from BOEM/BSEE's online data center.
Client	Texaco
Acquisition Company	GECO
Year Acquired	1988
Processed by	CGG Data Processing Services
Year Processed	1988
Vessel	*M/V GECO My*
Total Number of Lines Collected	29
Kilometers Shot (Approximate)	1176 (731 line-miles)
Number of Lines Collected in Virginia Waters	17
Kilometers Shot in Virginia Waters (Approximate)	701 (436 line-miles)
Recording Instruments	DSS/DFS V
Recording Filter	Low Cut: 5.3 Hz, Slope: 18 dB/octave High Cut: 128 Hz, Slope 72 dB/octave
Recording Gain	Binary Gain
Sample Rate (milliseconds)	2
Record Length (seconds)	8
Tape Format	SEG-D
Energy Source	24 Air Guns 6324 CU. IN.
Source Depth (m)	8
Shotpoint Interval (m)	25
Cable Type	Streamer GX 600
Cable Length (km)	6.0
Average Depth of Hydrophones (m)	10
Antenna to Source (m)	145
Near Offset Distance (m)	281
Near Offset Trace/Group	1
Far Offset Distance (m)	6256
Far Offset Trace/Group	240
Group Interval (m)	25
CDP Interval (m) from SEG-Y Header	25
Multiplicity (CDP Fold)	70

TEXACO E03-88 MAP AND TABLE OF FIELD PARAMETERS
Oil and Gas Readiness Study
Offshore Virginia



Seismic Tracklines: USGS Survey S-1-73

Line 3 of USGS Survey S-1-73 Representative Line Used to Describe Field and Processing Parameters

Seismic Tracklines of All Surveys Described in Report

Outer Continental Shelf (OCS) Protractions

50-Mile Exclusion Buffer: 2017–2022 OCS Oil and Gas Leasing Draft Proposed Program

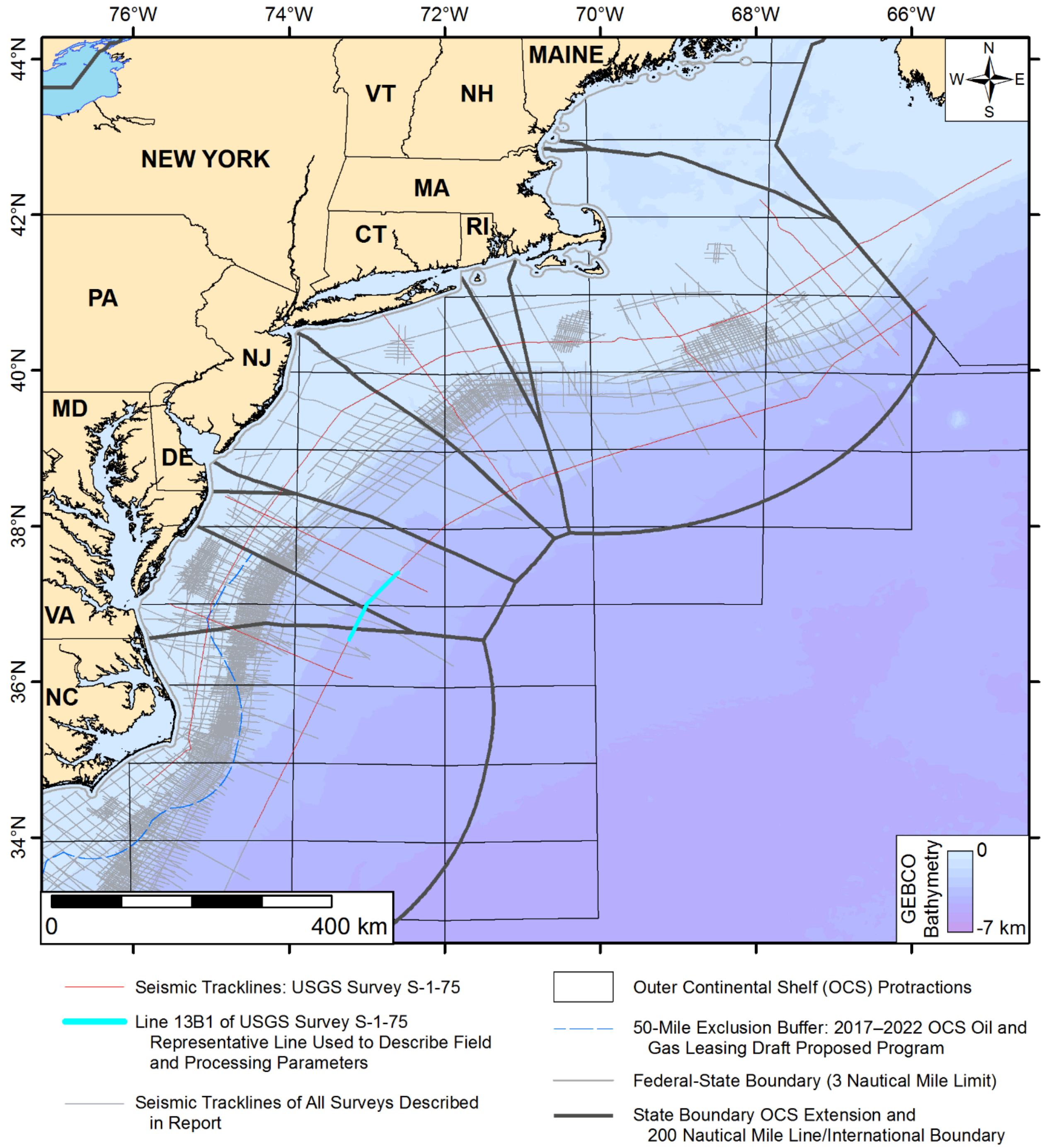
Federal-State Boundary (3 Nautical Mile Limit)

State Boundary OCS Extension and 200 Nautical Mile Line/International Boundary

USGS Survey S-1-73	
Source of Field Parameters	Scanned seismic section from NOAA's NGDC website and Schlee et al., 1976.
Client	USGS
Acquisition Company	Digicon Geophysical Corporation
Year Acquired	1973
Processed by	Digicon Geophysical Corporation
Year Processed	1973
Vessel	*M/V Gulf Seal*
Total Number of Lines Collected	3
Kilometers Shot (Approximate)	949 (589 line-miles)
Number of Lines Collected in Virginia Waters	1
Kilometers Shot in Virginia Waters (Approximate)	258 (161 line-miles)
Recording Instruments	DFS III
Recording Filter	Low Cut: 8 Hz, Slope: 16 dB/octave High Cut: 62 Hz
Recording Gain	Binary Gain
Sample Rate (milliseconds)	4
Record Length (seconds)	10
Energy Source	20 Air Guns 1260 CU. IN. 1800-2000 PSI
Source Depth (m)	9
Shotpoint Interval (m)	100
Cable Type	Linear Streamer
Cable Length (km)	2.3
Average Depth of Hydrophones (m)	12
Antenna to Source (m)	52.4 (shotpoints are ship antenna locations)
Near Offset Distance (m)	339
Near Offset Trace/Group	24
Far Offset Distance (m)	2666
Far Offset Trace/Group	1
Number of Channels	24
Group Interval (m)	100
Multiplicity (CDP Fold)	6-, 12- or 24-fold

USGS S-1-73 MAP AND TABLE OF FIELD PARAMETERS

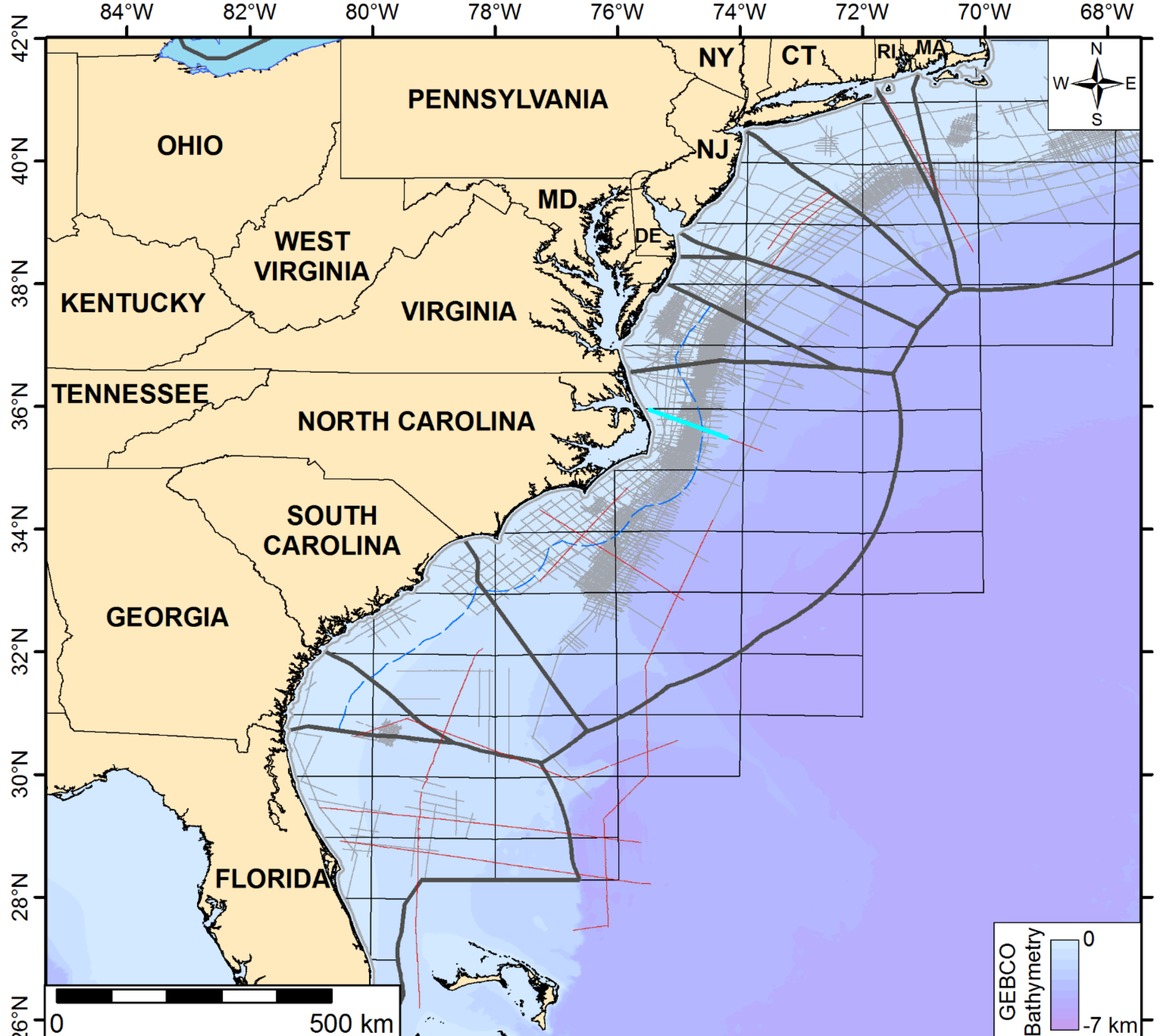
Oil and Gas Readiness Study
Offshore Virginia



USGS Survey S-1-75	
Source of Field Parameters	Wise and Oliver, 1988 & Wise and Oliver, 1989
Client	USGS
Acquisition Company	Digicon Geophysical Corporation
Year Acquired	1975
Processed by	Digicon Geophysical Corporation
Year Processed	1977 (reprocessed in the late 1980's by USGS)
Vessel	*M/V Gulf Seal*
Total Number of Lines Collected	7
Kilometers Shot (Approximate)	3873 (2406 line-miles)
Number of Lines Collected in Virginia Waters	3
Kilometers Shot in Virginia Waters (Approximate)	235 (146 line-miles)
Navigation System	Satellite-Loran-C Satellite/Sonar for Cable Positioning
Recording Instruments	DFS III
Recording Filter	Low Cut: 8 Hz, Slope: 18 dB/octave High Cut: 124 Hz, Slope 72 dB/octave 60 Hz Notch: Out
Recording Gain	Binary Gain
Sample Rate (milliseconds)	2
Record Length (seconds)	10
Tape Format	SEG-A 800 BPI
Energy Source	Air Guns 1700 CU. IN.
Source Depth (m)	9
Shotpoint Interval (m)	100
Cable Type	48T COLD Non-linear Streamer
Cable Length (km)	3.5
Average Depth of Hydrophones (m)	15
Antenna to Source (m)	52.4
Near Offset Distance (m)	348
Near Offset Trace/Group	48
Far Offset Distance (m)	3848
Far Offset Trace/Group	1
Number of Channels	48
Group Interval (m)	traces: 48 to 25 = 100 m traces: 25 to 24 = 75 m traces: 23 to 1 = 50 m
Multiplicity (CDP Fold)	36

USGS S-1-75 MAP AND TABLE OF FIELD PARAMETERS

Oil and Gas Readiness Study
Offshore Virginia



Seismic Tracklines: USGS Survey S-1-77

Line 17 of USGS Survey S-1-77 Representative Line Used to Describe Field and Processing Parameters

Seismic Tracklines of All Surveys Described in Report

Outer Continental Shelf (OCS) Protractions

50-Mile Exclusion Buffer: 2017–2022 OCS Oil and Gas Leasing Draft Proposed Program

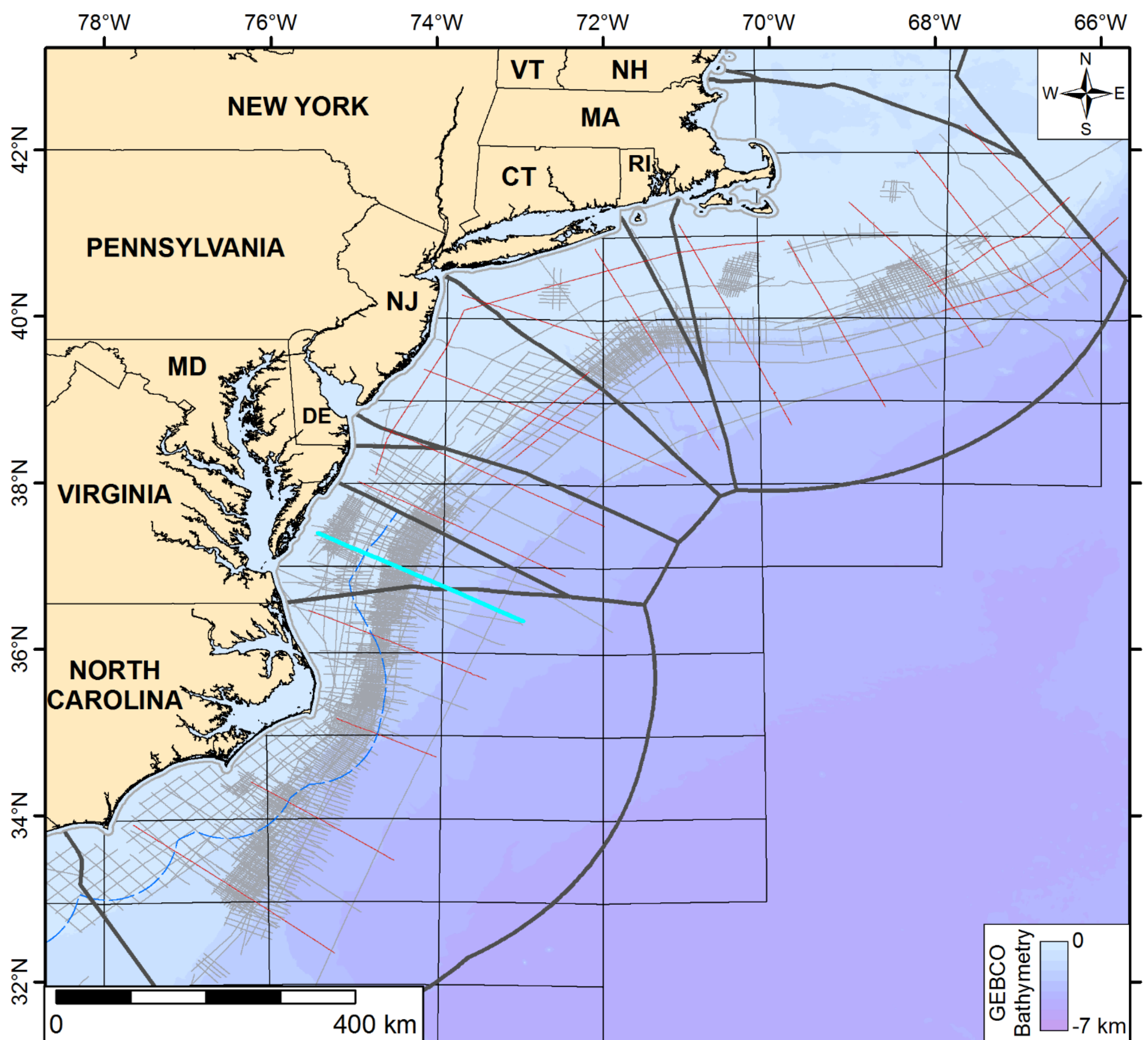
Federal-State Boundary (3 Nautical Mile Limit)

State Boundary OCS Extension and 200 Nautical Mile Line/International Boundary

USGS Survey S-1-77	
Source of Field Parameter	Scanned seismic section from NOAA's NGDC Gilbert and Dillon, 1981
Client	USGS
Acquisition Company	Teledyne Exploration
Year Acquired	1977
Processed by	Teledyne: Lines 15, 16, TD-1, TD-3, TD-4, TD-5 and part of TD-2 USGS: Lines 14, 17, TD-6 and part of TD-2
Year Processed	1979
Vessel	M/V *Coral Sea*
Total Number of Lines Collected	10
Kilometers Shot (Approximate)	4451 (2766 line-miles)
Navigation System	Satellite Navigation/LORAN C
Recording Instruments	DFS IV
Recording Filter	Low Cut: 8 Hz, Slope: Out High Cut: 124 Hz
Recording Gain	Instantaneous Floating Point (IFP) Gain
Sample Rate (milliseconds)	2
Record Length (seconds)	12
Energy Source	4 Air Guns towed abreast 4 m apart 2160 CU. IN. 2000 PSI
Source Depth (m)	8
Shotpoint Interval (m)	50 (100 m in deep water or in strong currents)
Cable Type	TEC 48 Trace
Cable Length (km)	3.6
Average Depth of Hydrophones (m)	10
Antenna to Source (m)	62
Near Offset Distance (m)	300
Near Offset Trace/Group	48
Far Offset Distance (m)	3300
Far Offset Trace/Group	1
Number of Channels	48
Group Interval (m)	traces: 48 to 25 = 50 m traces: 24 to 1 = 100 m
Hydrophones/Group	30
Multiplicity (CDP Fold)	48

USGS S-1-77 MAP AND TABLE OF FIELD PARAMETERS

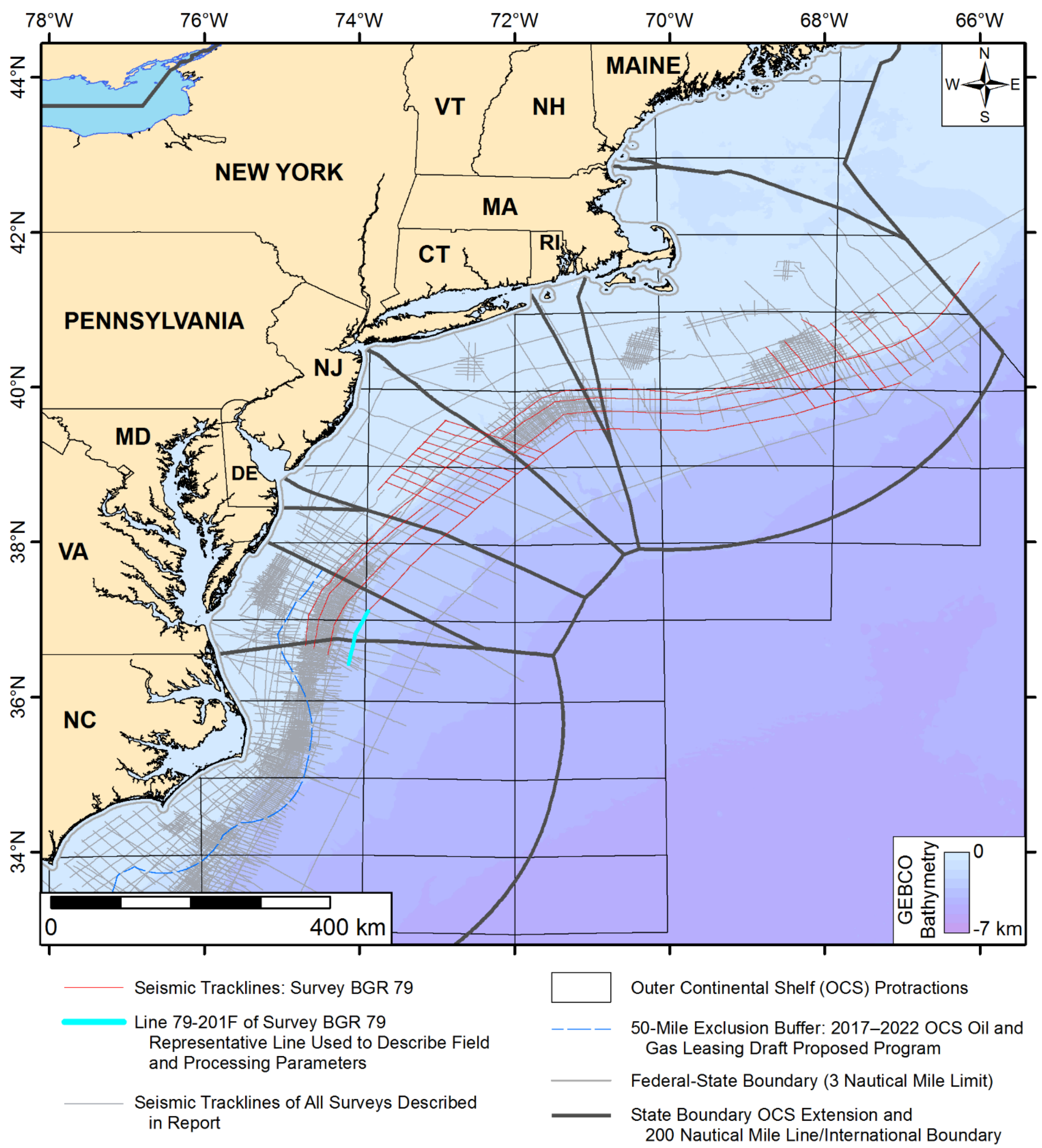
Oil and Gas Readiness Study
Offshore Virginia



USGS Survey C-1-78	
Source of Field Parameter	Twichell and Polloni, 1993 and Grow et al., 1980
Client	USGS
Acquisition Company	Geophysical Services, Inc. (GSI)
Year Acquired	1978
Processed by	Geophysical Services, Inc. (GSI)
Year Processed	1978 (Assumed)
Vessel	*M/V Carino* and *M/V Cecil Green*
Total Number of Lines Collected	21
Kilometers Shot (Approximate)	4866 (3024 line-miles)
Number of Lines Collected in Virginia Waters	1
Kilometers Shot in Virginia Waters (Approximate)	160 (99 line-miles)
Recording Instruments	DFS IV
Recording Filter	Low Cut: 8 Hz, Slope: 18 dB/octave High Cut: 62 Hz, Slope: 72 dB/octave
Recording Gain	Instantaneous Floating Point (IFP) Gain
Sample Rate (milliseconds)	4
Record Length (seconds)	12
Tape Format	SEG-B 1600 BPI - 9 track
Energy Source	Air Guns 1450 CU. IN. 2000 PSI
Source Depth (m)	6
Shotpoint Interval (m)	50
Cable Type	Non-linear Streamer
Cable Length (km)	3.6
Average Depth of Hydrophones (m)	13
Antenna to Source (m)	57
Near Offset Distance (m)	335
Near Offset Trace/Group	48
Far Offset Distance (m)	3938
Far Offset Trace/Group	1
Number of Channels	48
Group Interval (m)	traces:48 to 25 = 100 m traces: 25 to 24 = 75 m traces: 23 to 1 = 50 m
Multiplicity (CDP Fold)	48

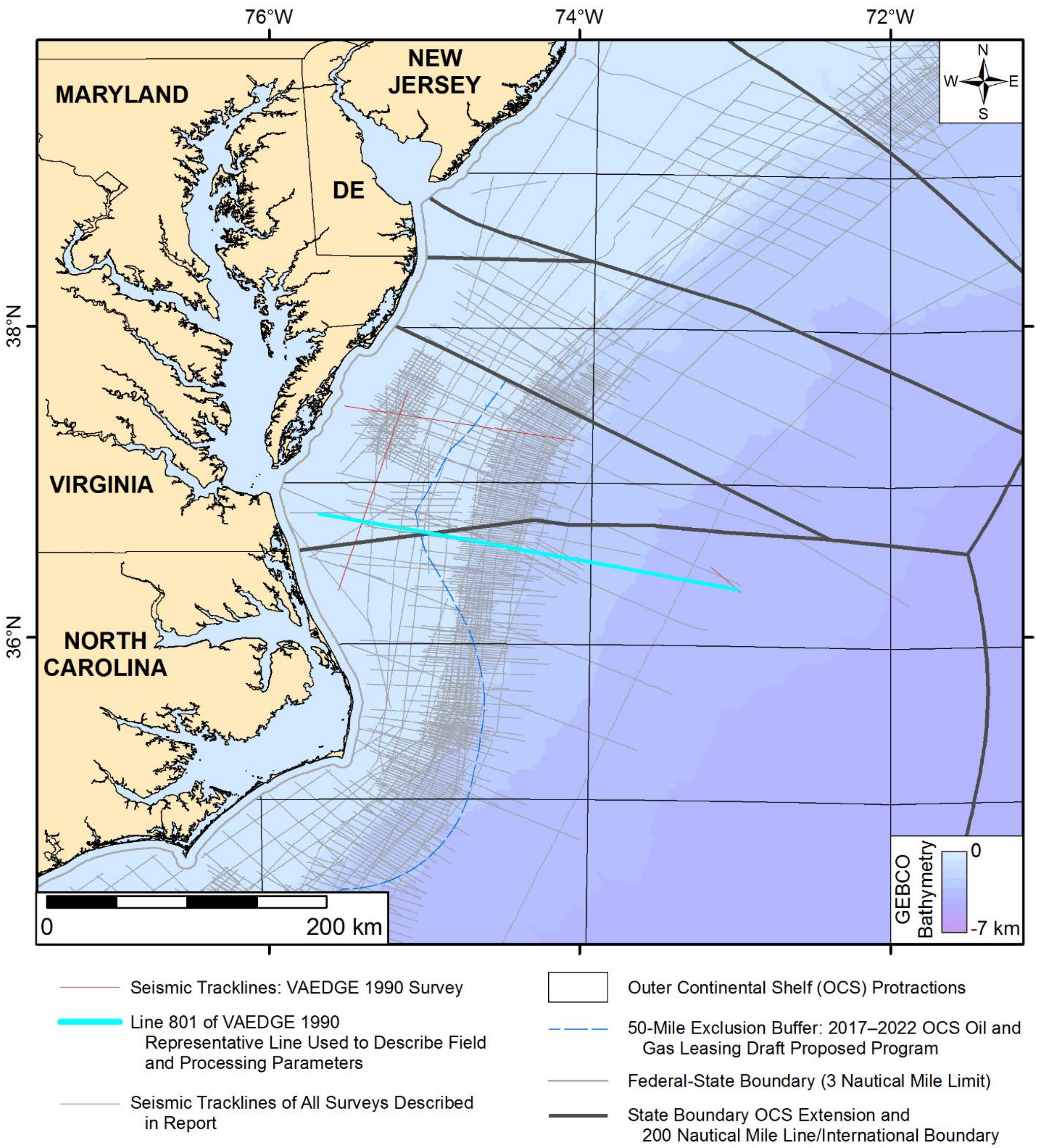
USGS C-1-78 MAP AND TABLE OF FIELD PARAMETERS

Oil and Gas Readiness Study
Offshore Virginia



Survey BGR 79	
Source of Field Parameter	Scanned seismic sections obtained from BOEM
Client	Bundesanstalt für Geowissenschaften und Rohstoffe (The Federal Institute for Geosciences and Natural Resources)
Acquisition Company	Prakla-Seismos
Year Acquired	1979
Processed by	Prakla-Seismos
Year Processed	1979 (Assumed)
Vessel	R/V *Explora*
Total Number of Lines Collected	21
Kilometers Shot (Approximate)	4763 (2959 line-miles)
Number of Lines Collected in Virginia Waters	4
Kilometers Shot in Virginia Waters (Approximate)	360 (224 line-miles)
Recording Instruments	DFS V
Recording Filter	Low Cut: 8 Hz, Slope 18 dB/ocatve High Cut: 62 Hz, Slope 18 dB/ocatve
Recording Gain	Quaternary Instantaneous Floating Point (QIFP)
Sample Rate (milliseconds)	4
Record Length (seconds)	10
Tape Format	SEG-B 800 BPI - 9 track
Energy Source	Air Gun "U-Type" 1430 CU. IN.
Source Depth (m)	8
Shotpoint Interval (m)	50
Cable Type	Prakla-Seismos HSSG
Cable Length (km)	2.4
Average Depth of Hydrophones (m)	15
Near Offset Distance (m)	300
Near Offset Trace/Group	48
Far Offset Distance (m)	2650
Far Offset Trace/Group	1
Number of Channels	48
Group Interval (m)	50
Hydrophones/Group	32
Multiplicity (CDP Fold)	24

BGR 79 SURVEY MAP AND TABLE OF FIELD PARAMETERS
Oil and Gas Readiness Study
Offshore Virginia



Virginia 1990 EDGE Experiment (VAEDGE)	
Source of Field Parameter	Sheridan et al., 1993 and Holbrook et al., 1994
Client	USGS/Various Academic Institutions
Acquisition Company	GECO, WHOI, University of Wyoming, and University of Georgia
Year Acquired	1990
Processed by	Houston Advanced Research Center
Year Processed	1990 (Assumed)
Vessel	*M/V GECO Searcher (MCS)* *R/V Endeavor (OBS and OBH)*
Total Number of Lines Collected	4
Kilometers Shot (Approximate)	554 (344 line-miles)
Number of Lines Collected in Virginia Waters	3
Kilometers Shot in Virginia Waters (Approximate)	311 (193 line-miles)
Navigation System	StarFix
Sample Rate (milliseconds)	2
Record Length (seconds)	16
Energy Source	36 Air Guns (60-meter wide array) 10,800 CU. IN. 2000 PSI
Shotpoint Interval (m)	50
Cable Length (km)	6.0
Number of Channels	240
Group Interval (m)	25
Multiplicity (CDP Fold)	60

VAEDGE SURVEY MAP AND TABLE OF FIELD PARAMETERS

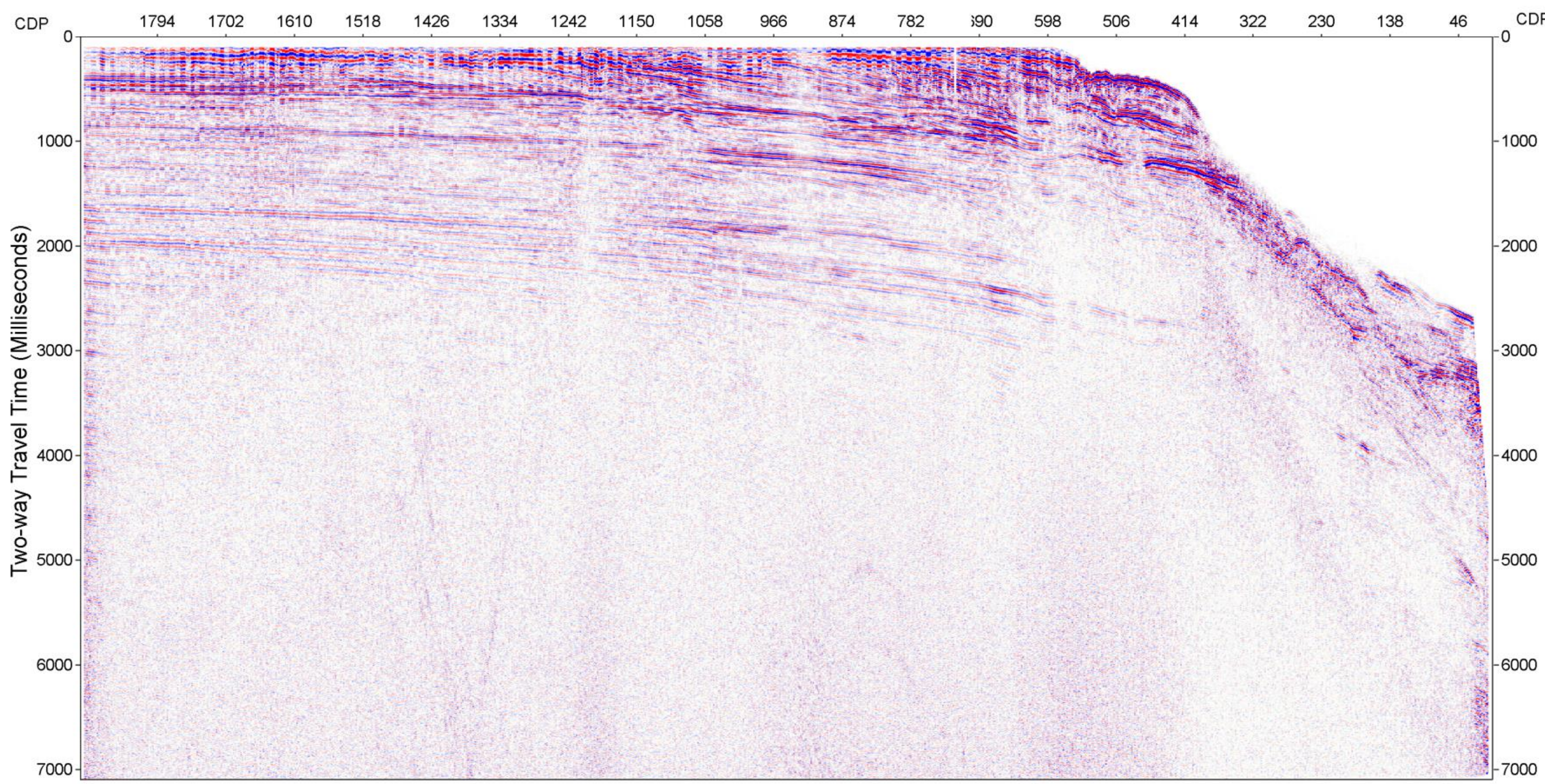
Oil and Gas Readiness Study
Offshore Virginia

APPENDIX B – PROCESSING PARAMETERS

CONTENTS

Stacked Section and Possible Processing Sequence,
Line WE-2 (Permit E14-75) .... Plate B-1
Stacked Section and Processing Sequence,
Line MA-003-2 (Permit E16-76) .... Plate B-2A
Migrated Section and Processing Sequence,
Line MA-003-2 (Permit E16-76) .... Plate B-2B
Scanned Stacked Section and Processing Sequence,
Line V-104RS (Permit E06-79) .... Plate B-3
Stacked Section and Processing Sequence,
Line 56-062 (Permit E01-80) .... Plate B-4A
Migrated Section and Processing Sequence,
Line 56-062 (Permit E01-80) .... Plate B-4B
Stacked Section and Processing Sequence,
Line SA1014 (Permit E02-80) .... Plate B-5A
Migrated Section and Processing Sequence,
Line SA1014 (Permit E02-80) .... Plate B-5B
Depth Migrated Section and Processing Sequence,
Line SA1014 (Permit E02-80) .... Plate B-5C
Stacked Section and Processing Sequence,
Line PP81-324A (Permit E01-81) .... Plate B-6A
Migrated Section and Processing Sequence,
Line PP81-324A (Permit E01-81) .... Plate B-6B
Migrated Section and Processing Sequence,
Line CSA-81-8 (Permit E07-81) .... Plate B-7A
Depth Migrated Section and Processing Sequence,
Line CSA-81-8 (Permit E07-81) .... Plate B-7B
Stacked Section and Processing Sequence,
Line PR82-088 (Permit E02-82) .... Plate B-8A
Migrated Section and Processing Sequence,
Line PR82-088 (Permit E02-82) .... Plate B-8B
Depth Section and Processing Sequence,
Line PR82-088 (Permit E02-82) .... Plate B-8C
Migrated Section and Processing Sequence,
Line 18074 (Permit E04-82) .... Plate B-9A
Depth Section and Processing Sequence,
Line 18074 (Permit E04-82) .... Plate B-9B
Migrated Section and Processing Sequence,
Line M82-02 (Permit E11-82) .... Plate B-10
Migrated Section and Processing Sequence,
Line MMA-198 (Permit E05-83) .... Plate B-11A
Depth Section and Processing Sequence,
Line MMA-198 (Permit E05-83) .... Plate B-11B
Stacked Section and Processing Sequence,
Line 5-YRE (Permit E05-86) .... Plate B-12

Migrated Section and Processing Sequence,
Line 8879916-M (E03-88) .... Plate B-13
Digitized Stacked Section and Processing Sequence,
Line 3 (USGS S-1-73) .... Plate B-14A
Digitized Stacked Section and Processing Sequence,
Line 3A (USGS S-1-73) .... Plate B-14B
Stacked Section and Processing Sequence,
Line 13-B1S (USGS S-1-75) .... Plate B-15
Stacked Section and Processing Sequence,
Line 17 (USGS S-1-77) .... Plate B-16
Stacked Section and Processing Sequence,
Line 28 (USGS C-1-78) .... Plate B-17
Stacked Section and Processing Sequence,
Line 79-201F (BGR 1979) .... Plate B-18A
Migrated Section and Processing Sequence,
Line 79-201F (BGR 1979) .... Plate B-18B
Migrated Section and Processing Sequence,
Line 801(VAEDGE) .... Plate B-19



Permit E14-75

Source of processing information: Scanned seismic section data label of Line WE-1 from BOEM/BSEE's online data center.**

Client: Western Geophysical
Acquisition Company: Western Geophysical
Year Acquired: 1975
Processed by: Western Geophysical
Year Processed: 1975

Stacked Section (Line WE-2)

Sample rate: 4 msec.
Sum 2 records
Digital deconvolution before stack with time variant filter
- Time variant minimum phase inverse filter
  - Autocorrelation interval: 2 equal zones
  - Search zone: 36 msec.
  - Operator length: 140 msec.
  - Time zone: 0.0-5.3 sec.
- Time variant filter

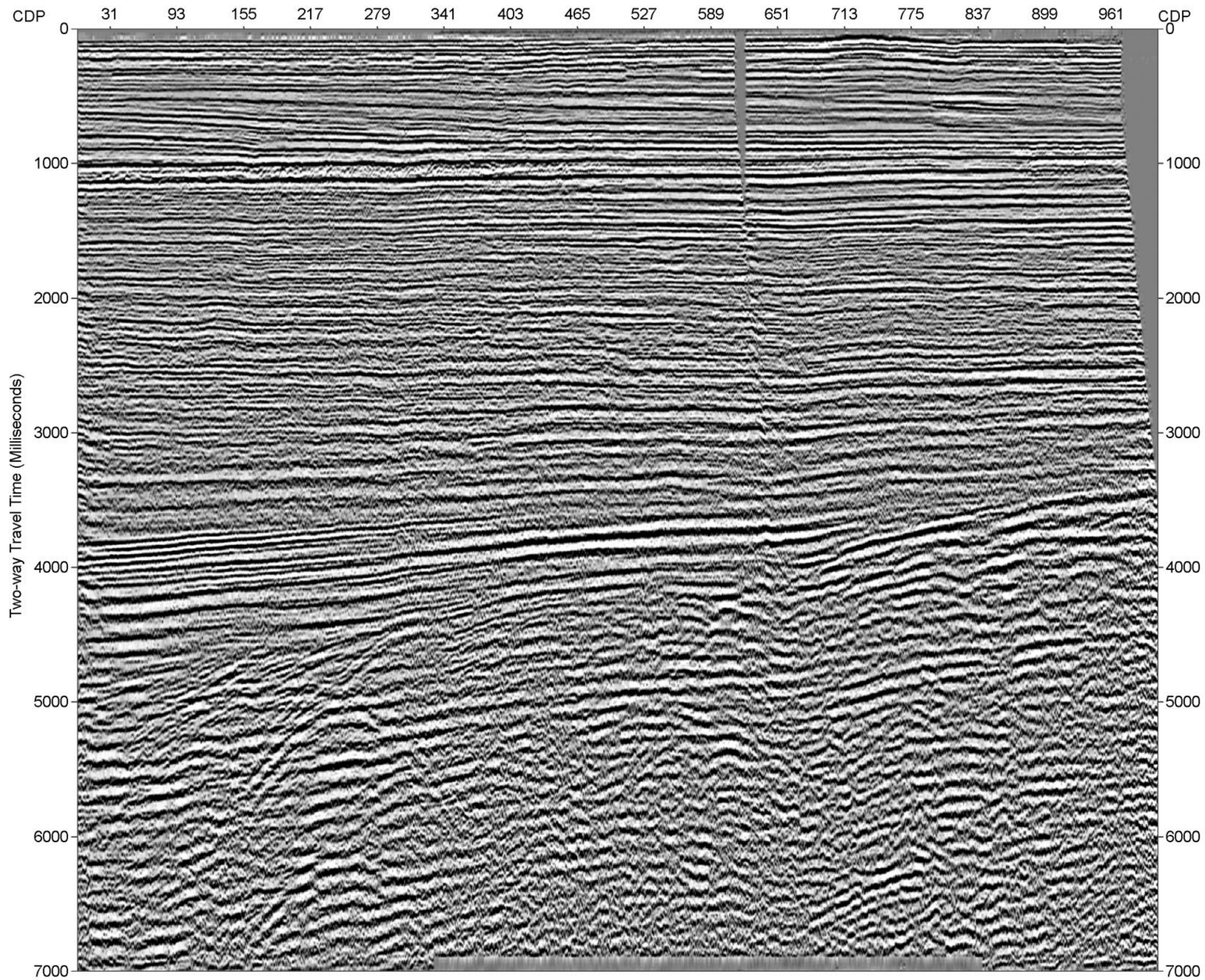
Time	Low cut	High cut
0.0-0.5 sec.	15 Hz	45 Hz
0.5-1.6 sec.	10 Hz	40 Hz
1.6-3.0 sec.	8 Hz	30 Hz
3.0-5.3 sec.	7 Hz	25 Hz

Velocity analysis made every 5280 feet
Stack 24 fold
Digital deconvolution after stack with time variant filter
- Time variant minimum phase inverse filter
  - Autocorrelation interval: 3 equal zones
  - Search zone: 2nd zero crossing
  - Operator length: 240 msec.
  - Time zone: 0.0-5.3 sec.
- Time variant filter

Time	Low cut	High cut
0.0-0.5 sec.	15 Hz	45 Hz
0.5-1.6 sec.	10 Hz	40 Hz
1.6-3.0 sec.	8 Hz	30 Hz
3.0-5.3 sec.	7 Hz	25 Hz

****Note:** While most, if not all of the seismic lines that were acquired as part of permit E14-75 are available as image files and in SEG-Y format, only one scanned seismic data label from line WE-1, collected in South Carolina waters, is available to determine the acquisition parameters and processing sequence for this survey. We have included the information for Line WE-1 here, although the seismic data example comes from Line WE-2, which is located in our study area. The exact ordering of the processing sequence was not indicated on the data label so we have attempted to order the processing steps in an order that is common to surveys of this vintage.

STACKED SECTION AND POSSIBLE PROCESSING SEQUENCE
LINE WE-2 (PERMIT E14-75)
Oil and Gas Readiness Study
Offshore Virginia



Permit E16-76

Source of processing information: Scanned seismic section of Line MA-003-2 from BOEM/BSEE's online data center.

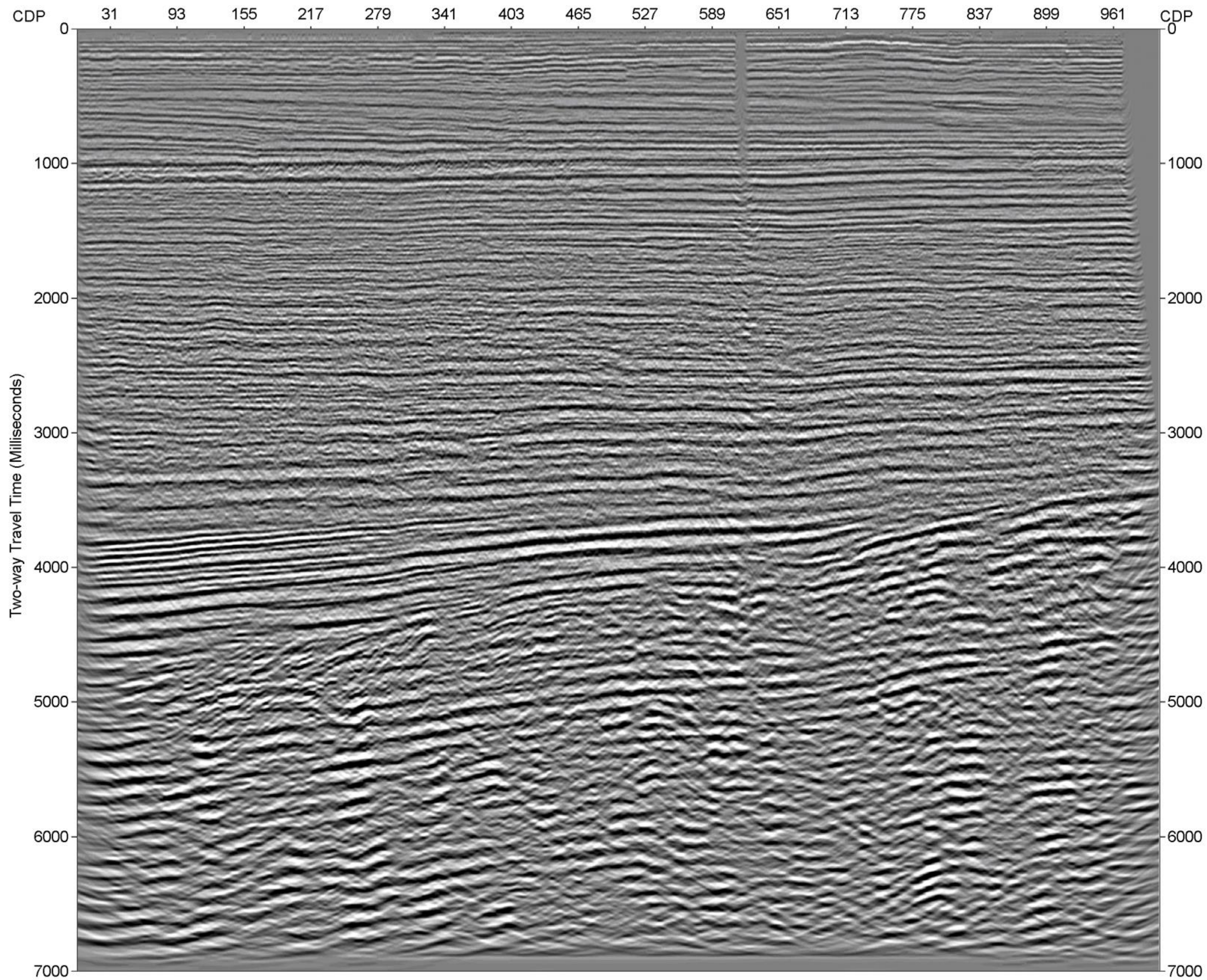
Client: Offshore Atlantic Group
Acquisition Company: Digicon Geophysical Corporation
Year Acquired: 1976
Processed by: Digicon Geophysical Corporation
Year Processed: 1976

Stacked Section (Line MA-003-2)

1. Gain: Exponential Rate: 3 dB/sec Gate: 0-3.0 sec
2. System Delay Static: 40 msec
3. CDP Gather
4. Velocity Analysis
5. Time Variant Deconvolution
   - Number of filters: 3
   - White Noise: 1%
   - Filter Length: 120 MS
   - Design Gates Near Offset: 0.2-2.0 1.5-2.7 2.2-3.4 sec
   - Design Gates Far Offset: 3.4-4.6 4.1-5.3 4.8-6.0 sec
6. NMO
7. Stack: 36 Fold CDP
8. Digital Filter: Number of filters (2)
   - Band Pass: 10-35 Hz TIME: 0.0-1.6 sec
   - Band Pass: 5-25 Hz TIME: 4.0-7.0 sec
9. Trace Amplitude Equalization

STACKED SECTION AND PROCESSING SEQUENCE
LINE MA-003-2 (PERMIT E16-76)
Oil and Gas Readiness Study
Offshore Virginia

PLATE B-2A



Permit E16-76

Source of processing information: Scanned seismic section of Line MA-003-2 from BOEM/BSEE's online data center and SEG-Y header from MA-003-2_migr.

Client: Offshore Atlantic Group
Acquisition Company: Digicon Geophysical Corporation
Year Acquired: 1976
Processed by: Digicon Geophysical Corporation
Year Processed: 1976

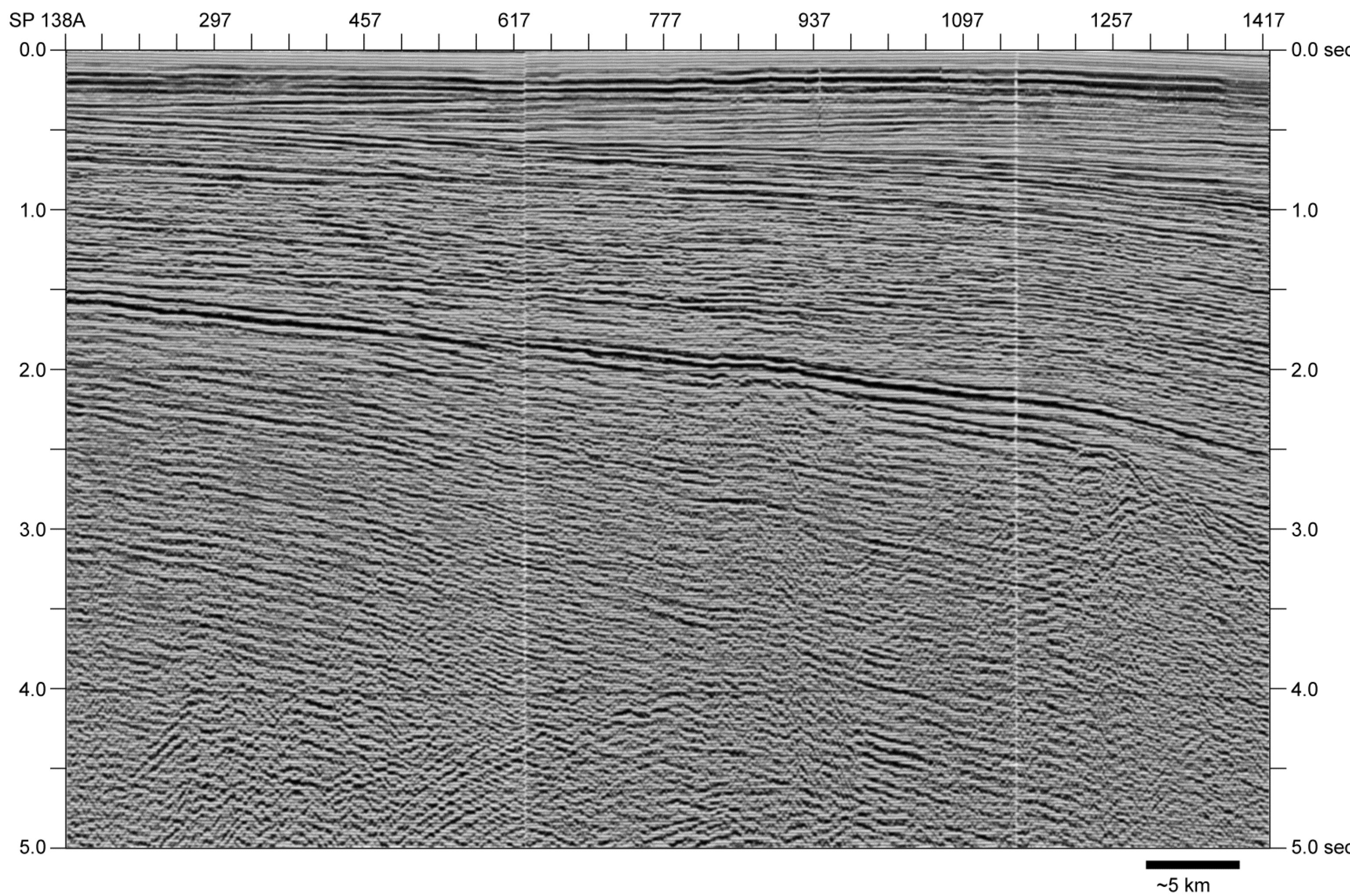
Migrated Section (Line MA-003-2)

1. Gain: Exponential Rate: 3 dB/sec Gate: 0-3.0 sec
2. System Delay Static: 40 msec
3. CDP Gather
4. Velocity Analysis
5. Time Variant Deconvolution
   - Number of filters: 3
   - White Noise: 1%
   - Filter Length: 120 MS
   - Design Gates Near Offset: 0.2-2.0 1.5-2.7 2.2-3.4 sec
   - Design Gates Far Offset: 3.4-4.6 4.1-5.3 4.8-6.0 sec
6. NMO
7. Stack: 36 Fold CDP
8. Digital Filter: Number of filters (2)
   - Band Pass: 10-35 Hz TIME: 0.0-1.6 sec
   - Band Pass: 5-25 Hz TIME: 4.0-7.0 sec
9. Trace Amplitude Equalization

Migrated Section:
Trace Interval: 164 FT
DataQuest Processing Flow:
1) SEGY to ProMax
2) Muting
3) Kirchhoff Time Migration
   Half-aperture: 15000 ft
   Max Dip: 70 degrees
   Frequency cutoff: 55 Hz
   110% RMS Velocity
4) ProMax to SEGY

Note: No scanned sections are available for the migrated sections but the header information from the SEG-Y file may indicate the process sequence that took place directly after the stack processing sequence.

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE MA-003-2 (PERMIT E16-76)
Oil and Gas Readiness Study
Offshore Virginia



Permit E06-79 (ECOAST79)

Source of processing information: Scanned seismic stacked section of Line V-104 obtained from BOEM after inquiring about the availability of the data from this survey.

Client: USGS Conservation Division, Eastern Region
Acquisition Company: Whitehall Corporation (Seismic Explorations International, S.A.)
Year Acquired: 1979
Processed by: Whitehall Corporation (Geophysical Data Processing Center, Inc.)
Year Processed: 1979 (Assumed)

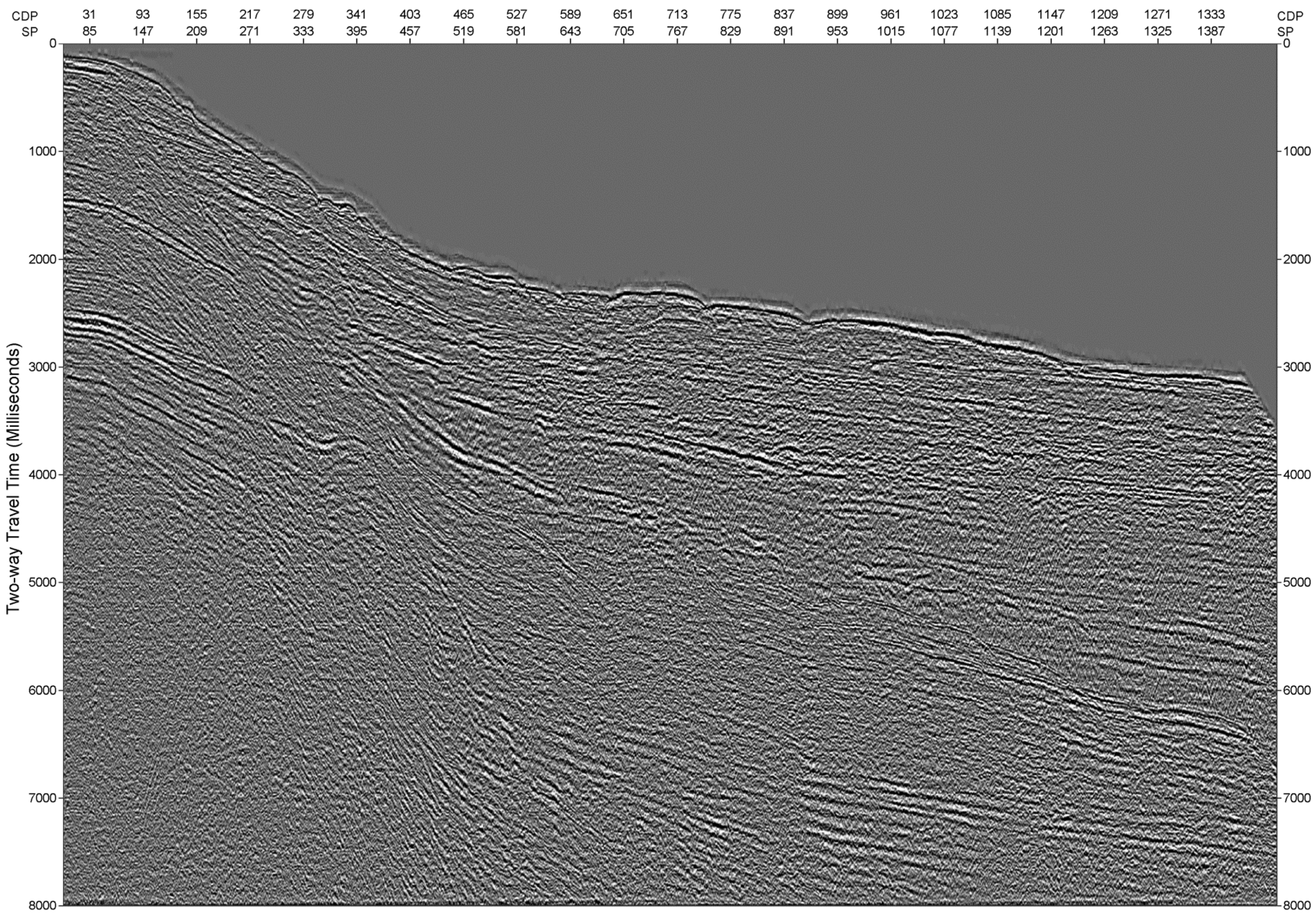
Stacked Section (V-104RS)

1. Reformat Sample rate: 4 msec
2. Vertical sum 2 records
3. Deconvolution Operator Length: 120 msec Predictive distance = 2^{nd} zero crossing
   Design Window: Near Trace: 0.4 to 3.0 sec
   Far Trace: 2.2 to 3.5 sec
4. Velocity Analysis
5. NMO Correction
6. Mute
7. Stack 16 Fold
8. Deconvolution Operator Length: 120 msec. Predictive distance = 2^{nd} zero crossing
   Design Window: 0.4 to 3.0 sec
9. Filter: 0 to 5 sec 12 to 40 Hz
10. Scale

Note:

The seismic section displayed to the left is an edited tif image of line V-104RS obtained from BOEM after first learning of the survey's existence from NOAA's National Geophysical Data Center where the survey is known as ECOAST79. The seismic data collected for Permit E06-79 is not available for download at any online websites that we know of and must be specially requested from BOEM as it is not part of any of their previous data releases. Only two lines in Delaware/New Jersey waters, D100 and D102, are available in SEG-Y format. Only scanned images, like the one shown to the left, are available for the rest of the seismic profiles.

SCANNED STACKED SECTION AND PROCESSING SEQUENCE
LINE V-104RS (PERMIT E06-79)
Oil and Gas Readiness Study
Offshore Virginia



Permit E01-80

Source of processing information: Scanned seismic section of Line 56-062 from BOEM/BSEE's online data center.

Client: South Atlantic Group
Acquisition Company: Geosource Inc.
Year Acquired: 1980
Processed by: Geosource, Inc. (Petty-Ray Division)
Year Processed: 1980

Stacked Section (Line 56-062)

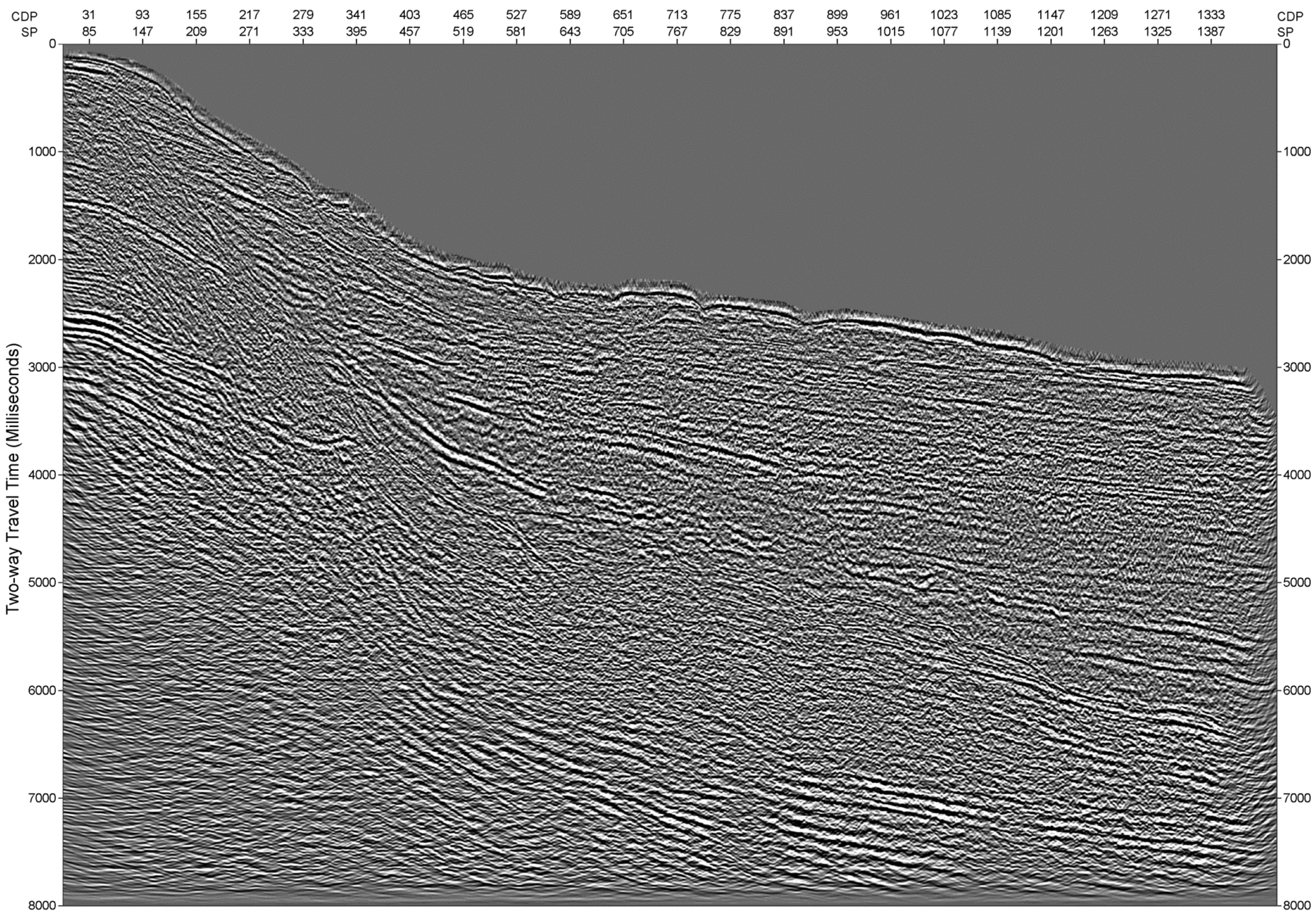
1. Edit Demultiplex Resample to 4 msec.
   Gain Recovery A=4 B=1 C=20 Gain End 8 4 sec.
2. 1x48 Fold Sort with 32 msec. Lag Predictive Time-Variant Deconvolution
   Operator Length: 240 msec. Window: 2 sec. Overlap: 500 msec.
   1st Window Start Trace 1: 2400 msec. Trace 48: 500 msec.
   1st Window End Trace 1: 4400 msec. Trace 48: 2500 msec.
   2nd Window Start Trace 1: 3900 msec. Trace 48: 2000 msec.
   2nd Window End Trace 1: 5900 msec. Trace 48: 4000 msec.
3. Velocity Analysis
   Contour Plot Velstack Every Mile
4. Normal Moveout Corrections
   12 msec. Sea Level Datum Correction Applied
5. Stack 48 Fold
6. Spike Deconvolution
   Operator length: 240 msec. Window: 4 sec.
   Time Variant Filter - Balance
   500 msec. Balance Window 5000-4000 RMS Decay

Time	F1	F2	F3	F4
0.0	4	10	45	55
1.0	4	8	35	45
2.0	4	8	35	45

7. Photodot: Film Presentation

Digital Processing Remarks: Shotpoints are referenced to antenna location. Window start time and mute times and filters vary with water depth.

STACKED SECTION AND PROCESSING SEQUENCE
LINE 56-062 (PERMIT E01-80)
Oil and Gas Readiness Study
Offshore Virginia



Permit E01-80

Source of processing information: Migrated SEG-Y text header for Line 56-062 from BOEM/BSEE's online data center.

Client: South Atlantic Group
Acquisition Company: Geosource Inc.
Year Acquired: 1980
Processed by: Geosource, Inc. (Petty-Ray Division)
Year Processed: 1980

Migrated Section (Line 56-062)

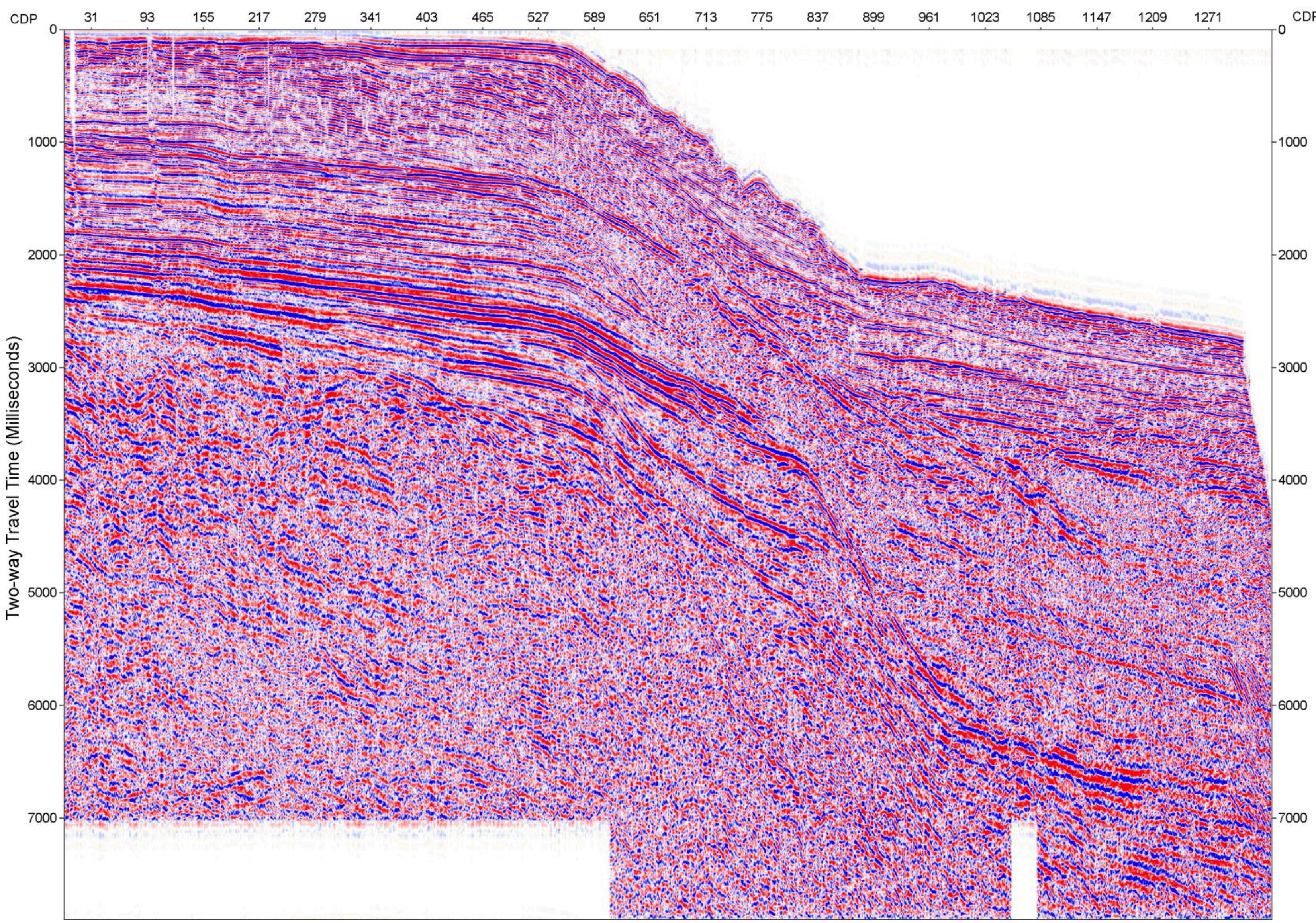
DataQuest Processing Flow:

1. SEGY to ProMax
2. Muting
3. Kirchhoff Time Migration
   Half-aperature: 15000 Feet
   Max Dip: 70 degrees
   Frequency cutoff: 55Hz
   110% RMS Velocity
4. ProMax to SEGY

Note: No scanned sections are available for the migrated sections but the header information from the SEG-Y file may indicate the process sequence that took place directly after the stack processing sequence (see Plate B-4A).

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE 56-062 (PERMIT E01-80)
Oil and Gas Readiness Study
Offshore Virginia

PLATE B-4B



Permit E02-80

Source of processing information: Scanned seismic section of Line SA1014 from BOEM/BSEE's online data center.

Client: South Atlantic Group
Acquisition Company: Digicon, Inc.
Year Acquired: 1980
Processed by: Digicon, Inc.

Stacked Section (Line SA1014)

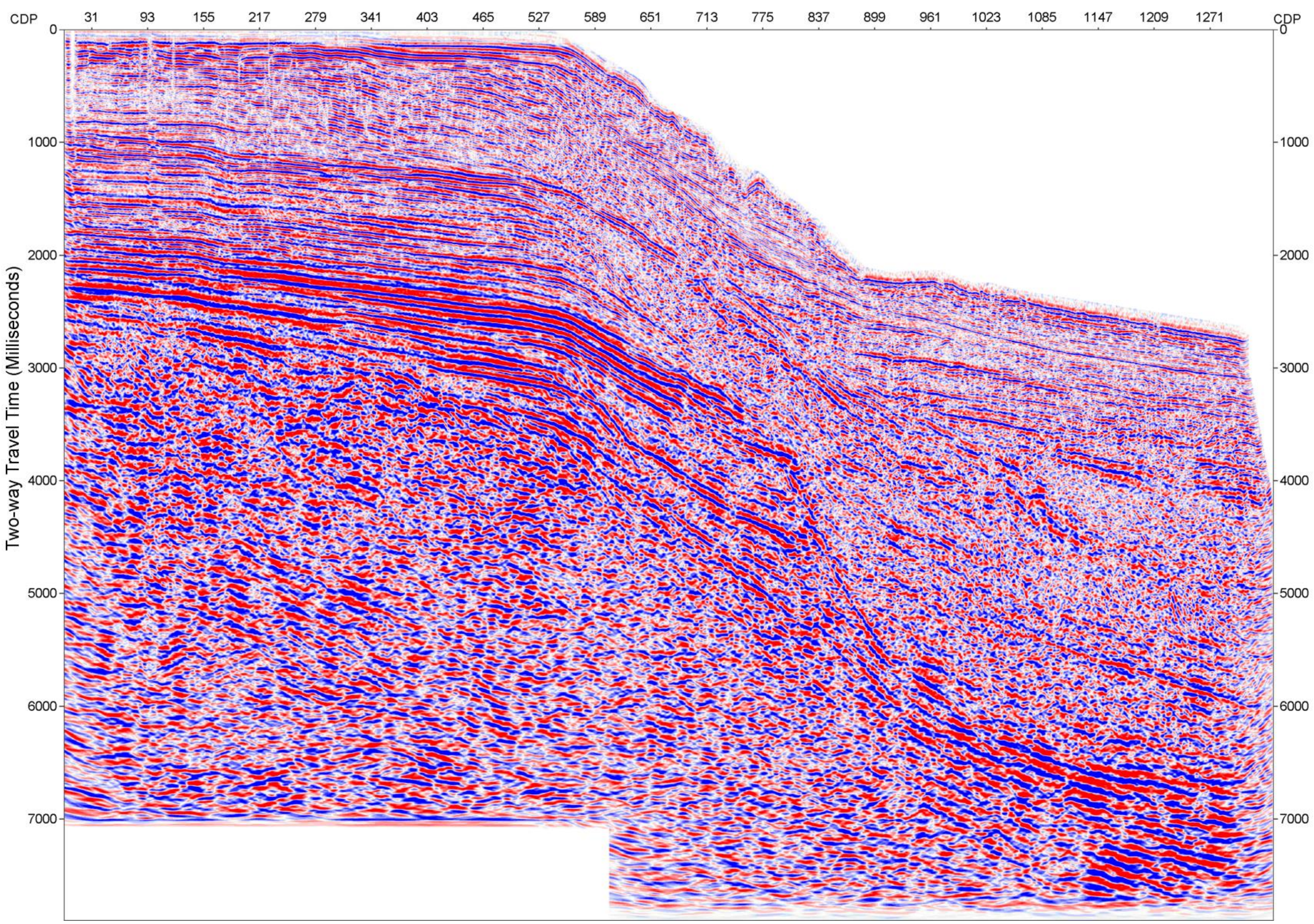
1. Demultiplex   Resample to 4 msec.
2. Gain Recovery – Spherical Divergence Correction
   Exponential Gain Rate: 4 dB/sec.
   Gate: 0.0 - 4.0 sec.
3. 2-in-1 Sum of adjacent traces for 82 ft. groups [Far trace] to simulate 164 ft. groups
4. An additional 2-in-1 sum of all groups to simulate 328 ft.
5. Signature Deconvolution [Spiking]
   White noise: 0.001 Length 200 msec.
6. CDP Gather 36 Fold
7. Reveal
8. Velocity Analysis (Every Mile)
9. Deconvolution [Spiking]
   White noise: 0.01 Length 216 msec.
10. Normal Moveout
11. CDP Sum 36 Fold [Non-weighted]
12. Digital Filter   Number of Filters: 4

Band Pass (Hz/DB/Hz)	Time (sec.)	
15/3-50/2	WB*	0.50
10/3-45/2	WB*	1.00
8/3-35/2	WB*	2.00
5/3-20/2	WB*	3.50

13. Time Variant Equalization

Notes: Shotpoints are antenna locations.

STACKED SECTION AND PROCESSING SEQUENCE
LINE SA1014 (PERMIT E02-80)
Oil and Gas Readiness Study
Offshore Virginia



Permit E02-80

Source of processing information: Migrated SEG-Y text header for Line SA1014 from BOEM/BSEE's online data center.

Client: South Atlantic Group
Acquisition Company: Digicon, Inc.
Year Acquired: 1980
Processed by: Digicon, Inc.
Year Processed: 1981

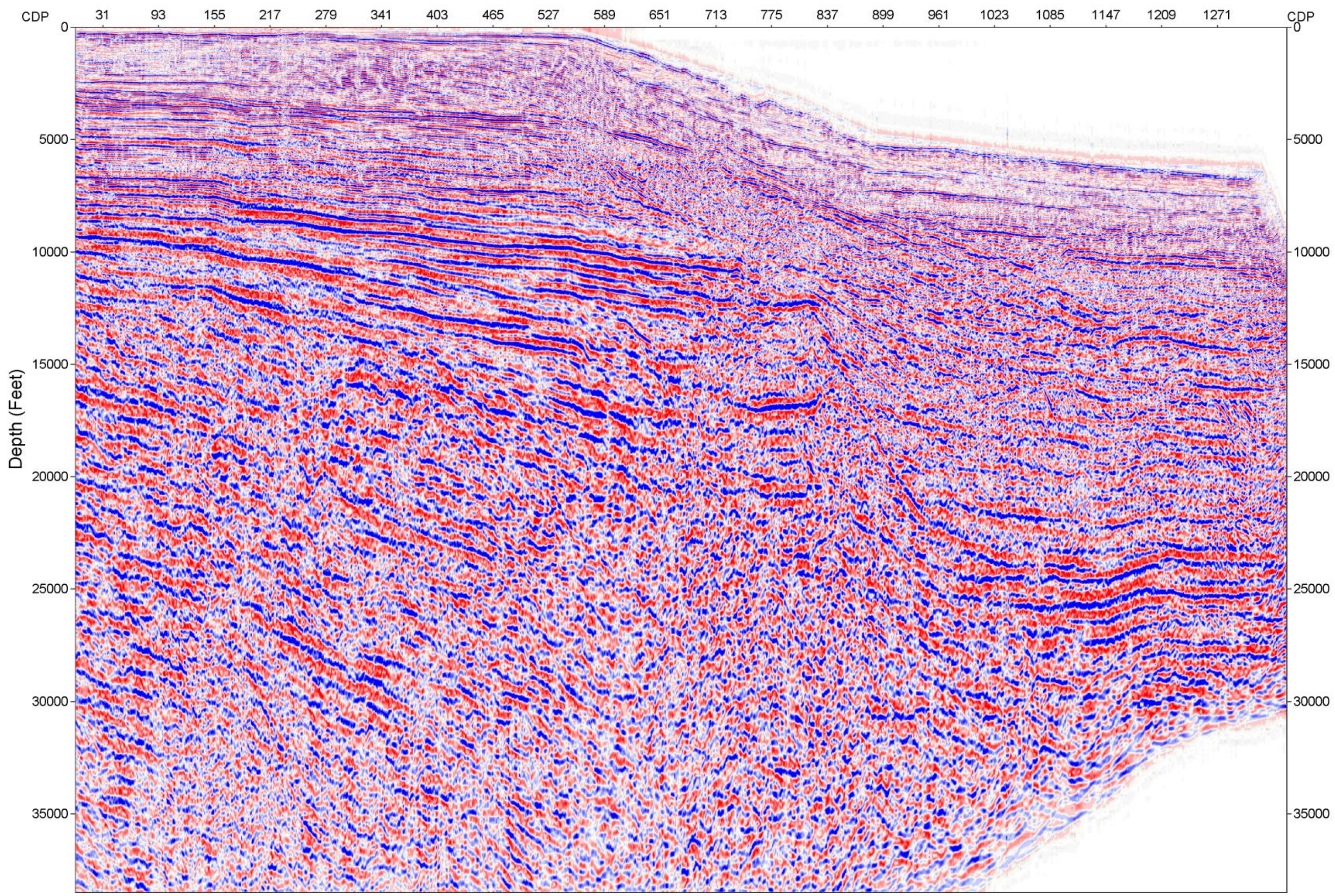
Migrated Section (Line SA1014)

DataQuest Processing Flow:

1) SEGY to ProMax
2) Muting: Top/Bottom
3) Kirchhoff Time Migration
   Half-aperature: 15000 Feet
   Max Dip: 70 degrees
   Frequency cutoff: 60Hz
   110% RMS Velocity
4) ProMax to SEGY

Note: No scanned sections are available for the migrated sections but the header information from the SEG-Y file may indicate the process sequence that took place directly after the stack processing sequence (see Plate B-XA).

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE SA1014 (PERMIT E02-80)
Oil and Gas Readiness Study
Offshore Virginia



Permit E02-80

Source of processing information: Scanned seismic stacked section of Lines SA1014 and SA1024 and the depth migrated scanned seismic section of Line SA1024 from BOEM/BSEE's online data center.**

Client: South Atlantic Group
Acquisition Company: Digicon, Inc.
Year Acquired: 1980
Processed by: Digicon, Inc.
Year Processed: 1981

Depth Migrated Section (Line SA1014)

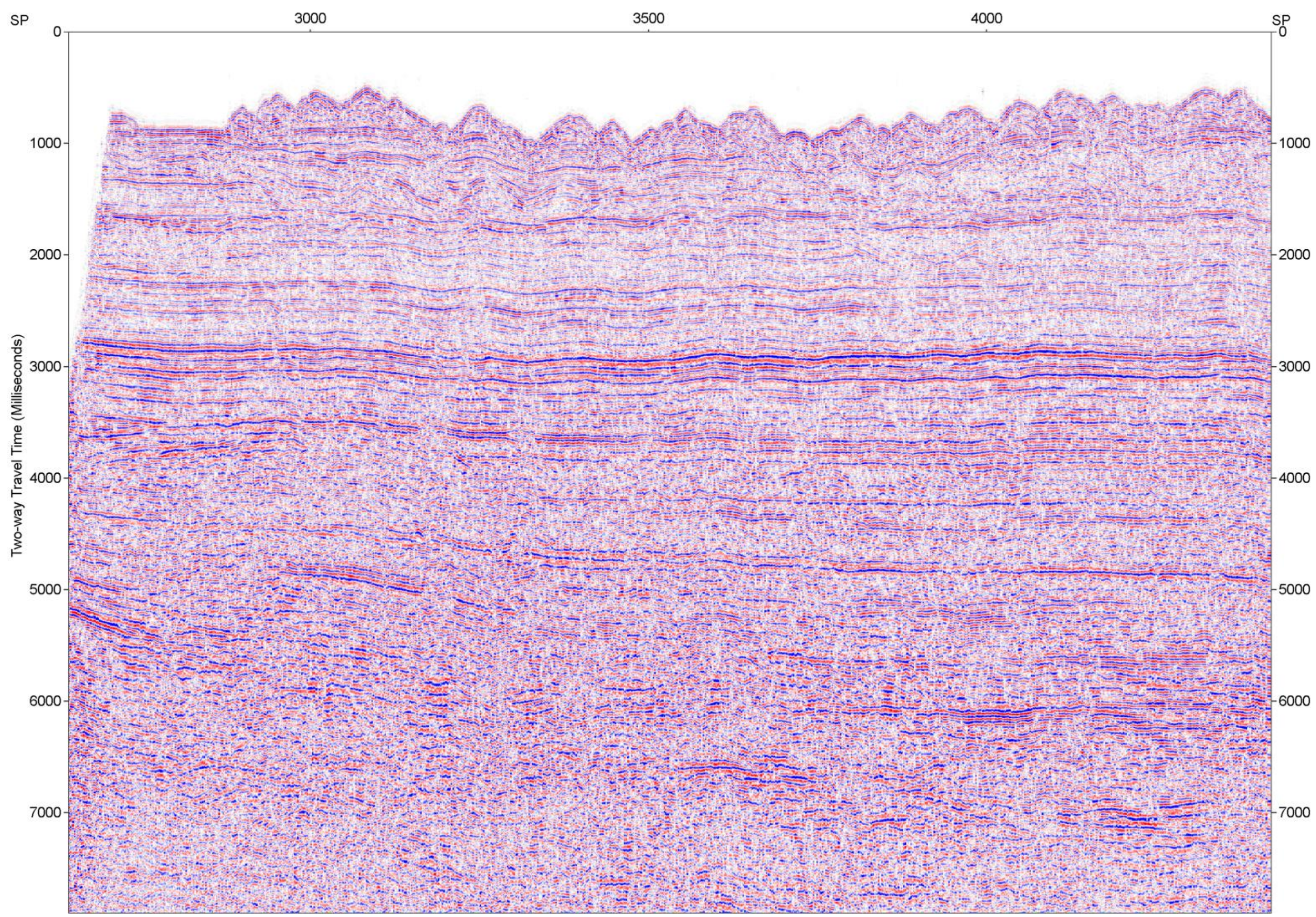
1. Demultiplex Resample to 4 msec.
2. Gain Recovery – Spherical Divergence Correction
   Exponential Gain Rate: 4 dB/sec.
   Gate: 0.0 - 4.0 sec.
3. 2-in-1 Sum of adjacent traces for 82 ft. groups [Far trace] to simulate 164 ft. groups
4. An additional 2-in-1 sum of all groups to simulate 328 ft.
5. Signature Deconvolution [Spiking]
   White noise: 0.001 Length 200 msec.
6. CDP Gather 36 Fold
7. Velocity Analysis (Every Mile)
8. Deconvolution [Spiking]
   White noise: 0.01 Length 216 msec.
9. Normal Moveout
10. CDP Sum 36 Fold [Weighted]
11. Digital Filter Number of Filters: 4

Band Pass (Hz/DB/Hz)	Time (sec.)	
15/3-50/2	WB*	0.50
10/3-45/2	WB*	1.00
8/3-35/2	WB*	2.00
5/3-20/2	WB*	3.50

12. Time Variant Equalization
13. Depth Migration

<u>**Notes:**</u> Shotpoints are antenna locations.
**No scanned paper copy of the depth migrated section is available for Line SA1014, so we determined the changes in the processing sequence applied to the stacked and depth-migrated sections of Line SA1024 (no "Reveal" step, applying a weighted stack in step 10 and the depth migration step) and applied them to the stacked processing scheme for Line SA1014

DEPTH MIGRATED SECTION AND PROCESSING SEQUENCE
LINE SA1014 (PERMIT E02-80)
Oil and Gas Readiness Study
Offshore Virginia



Permit E01-81

Source of processing information: Scanned seismic section of Line PP81-324A_stk from BOEM/BSEE's online data center.

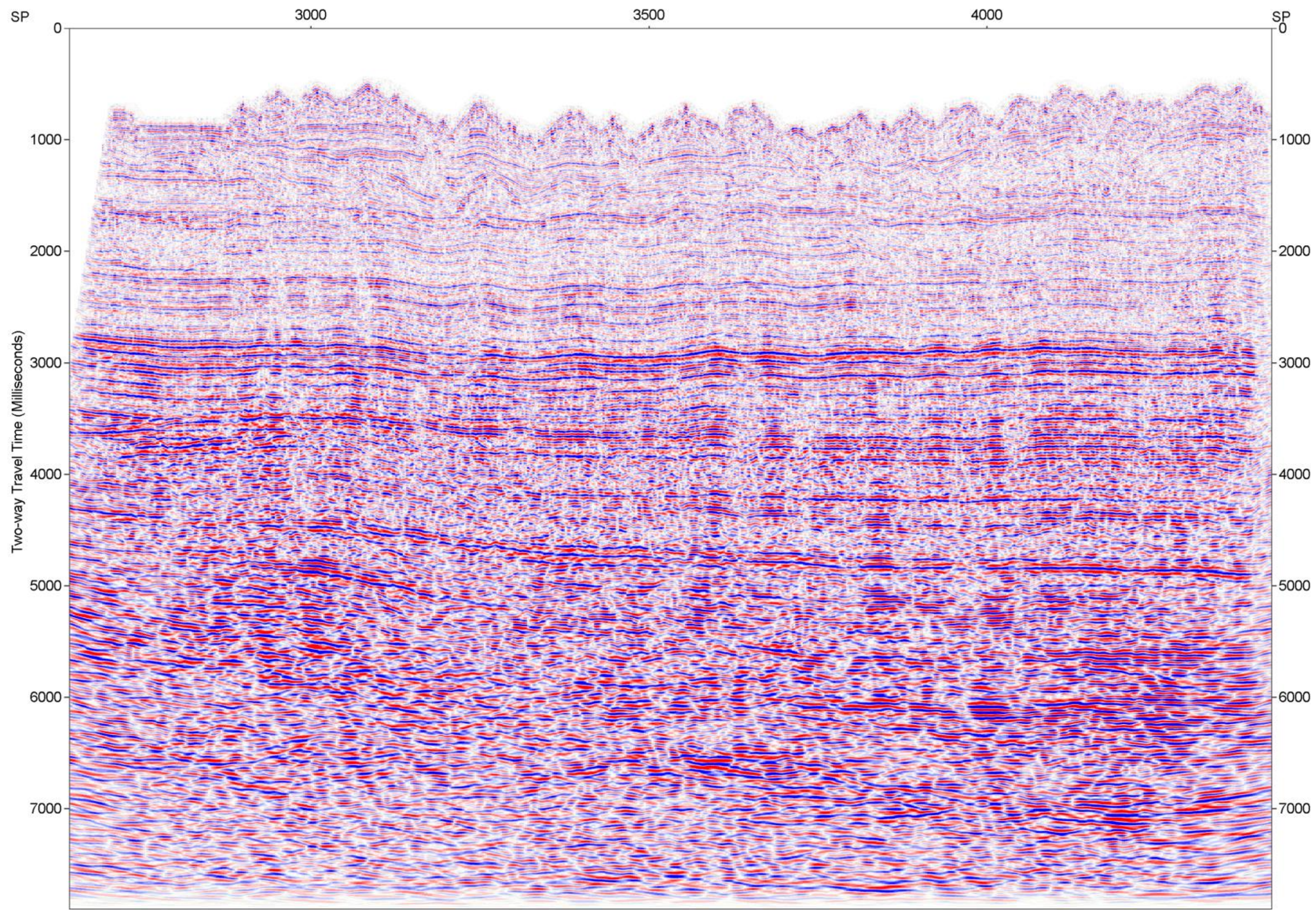
Client: Exxon Exploration
Acquisition Company: Geosource Inc.
Year Acquired: 1981
Processed by: Exxon Exploration Data Processing Center
Year Processed: 1982

Stacked Section (Line PP81-324A_stk)

1. Demultiplex: Geosource
2. Gain: Exponential
3. Velocity Analysis: CONVEL-HIREZ
   Constant velocity stacks – high-resolution variation
4. Stack: 75-40 Fold; SB Interval: 73.8
5. FLINTOR to remove field phase
6. TVSCAL
   Time Variant Scaling
7. SHAPECON 11-42 Hz, OP=70
   Spectral Balancing or Cascading Deconvolution
   Bandpass filter: 11-42 Hz; Operator Length = 70 msec
8. PRECON ALPHA=70, OP=100
   Predictive Deconvolution
   Predictive distance, alpha = 70
   Operator Length = 100 msec
9. FD TVFIL: 12-50 @0.0, 12-45 @0.8; 10-40 @ 1.6, 8-28 @ 2.5
   Time Variant Filter
10. TV SCALE
   Time Variant Scaling
11. AGC: 2000 MS

Note: We have attempted to interpret the processing sequence on the data label for this line (shown in bold and italicized font) because we believe that it could be of value to further processing efforts. Please realize that this interpretation could contain errors and if one wishes to determine the exact processing steps taken, it would be necessary to contact someone with existing documentation or great familiarity of old processing methods used by the Exxon Exploration Data Processing Center Group.

STACKED SECTION AND POSSIBLE PROCESSING SEQUENCE
LINE PP81-324A (PERMIT E01-81)
Oil and Gas Readiness Study
Offshore Virginia



Permit E01-81

Source of processing information: Scanned seismic section of Line PP81-324A_stk and header information from PP-81-324A_migr from BOEM/BSEE's online data center.

Client: Exxon Exploration
Acquisition Company: Geosource Inc.
Year Acquired: 1981
Processed by: Exxon Exploration Data Processing Center
Year Processed: 1982

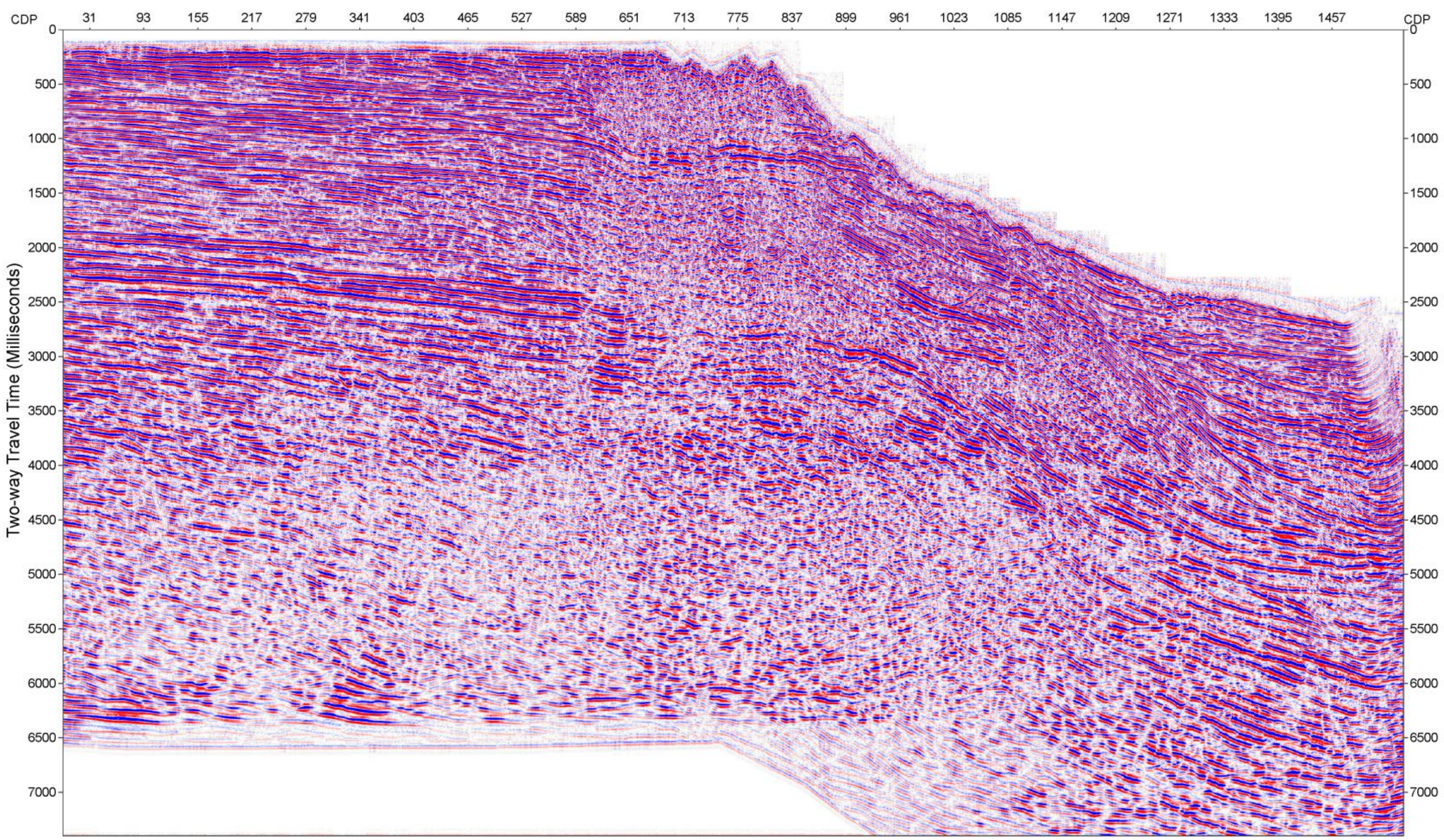
Migrated Section (Line PP81-324A_migr)

DataQuest Processing Flow:
1) SEGY to ProMax
2) Muting
3) Kirchhoff Time Migration
   Half-aperture: 15000 ft
   Max Dip: 70 degrees
   Frequency cutoff: 55 Hz
   110% RMS Velocity
4) ProMax to SEGY

Note: No scanned sections are available for the migrated sections but the header information from the SEG-Y file may indicate the process sequence that took place directly after the stack processing sequence (see Plate B-7A).

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE PP81-324A (PERMIT E01-81)
Oil and Gas Readiness Study
Offshore Virginia

PLATE B-6B



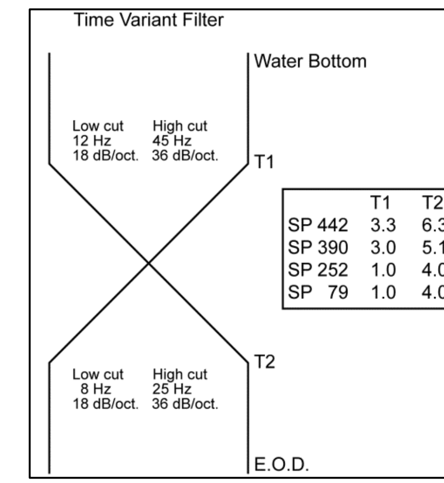
Note: The processing steps shown in the scanned seismic sections for all lines collected as part of permit E07-81 are very difficult to read and therefore the processing information listed to the right (especially the numerical information) may contain errors. The data label for the time migrated section of Line CSA-81-8 is near impossible to read, so we have included the processing information from the depth migrated section excluding only the two lines related specifically to time-to-depth conversion.

Permit E07-81

Source of processing information: Scanned seismic time migrated section of Line CSA-81-8 from BOEM/BSEE's online data center.

Client: Chevron
Acquisition Company: Digicon, Inc.
Year Acquired: 1981
Processed by: Chevron Geosciences Company
Year Processed: 1981 - Assumed

Migrated Section (Line CSA-81-8)



EDITED
MMEDER
Antialias filter applied
Data resampled to 4 msec.
Spherical Divergence Removed - Attenuation Applied
Constant static of 12 msec. applied to all traces
DECON Deconvolution with filter
Operator = 216 msec
Lo cut: 8 Hz Slope: 18dB/octave
Hi cut: 45 Hz Slope: 72 dB/octave
Zero phase
Autocorrelation gate varies with offset
AVC Time constant = 200 msec.
MSTACK SETSSI= 4381139 Time: 07.52.08 Date: 8.180
FILTER Time and/or space variant - 2 time variant filters
AVC Time constant = 800 msec.
CREAM 14081138 82.180 11.32.41
Apply water bottom mute
CWEAVR Migrated stacked time section Date: 06/30/81 Time: 06:14:49
TMIN=0.0 TMAX=7.9 YMIN=-6265.0 YMAX=19769.0 Sample rate=4.0
Stacked midpoint interval = 82.0 Downward Continuation Step Size: 250 Max # of steps: 268
22 velocity function model Units are English Angle=60 Decmat=0 NMOR=1

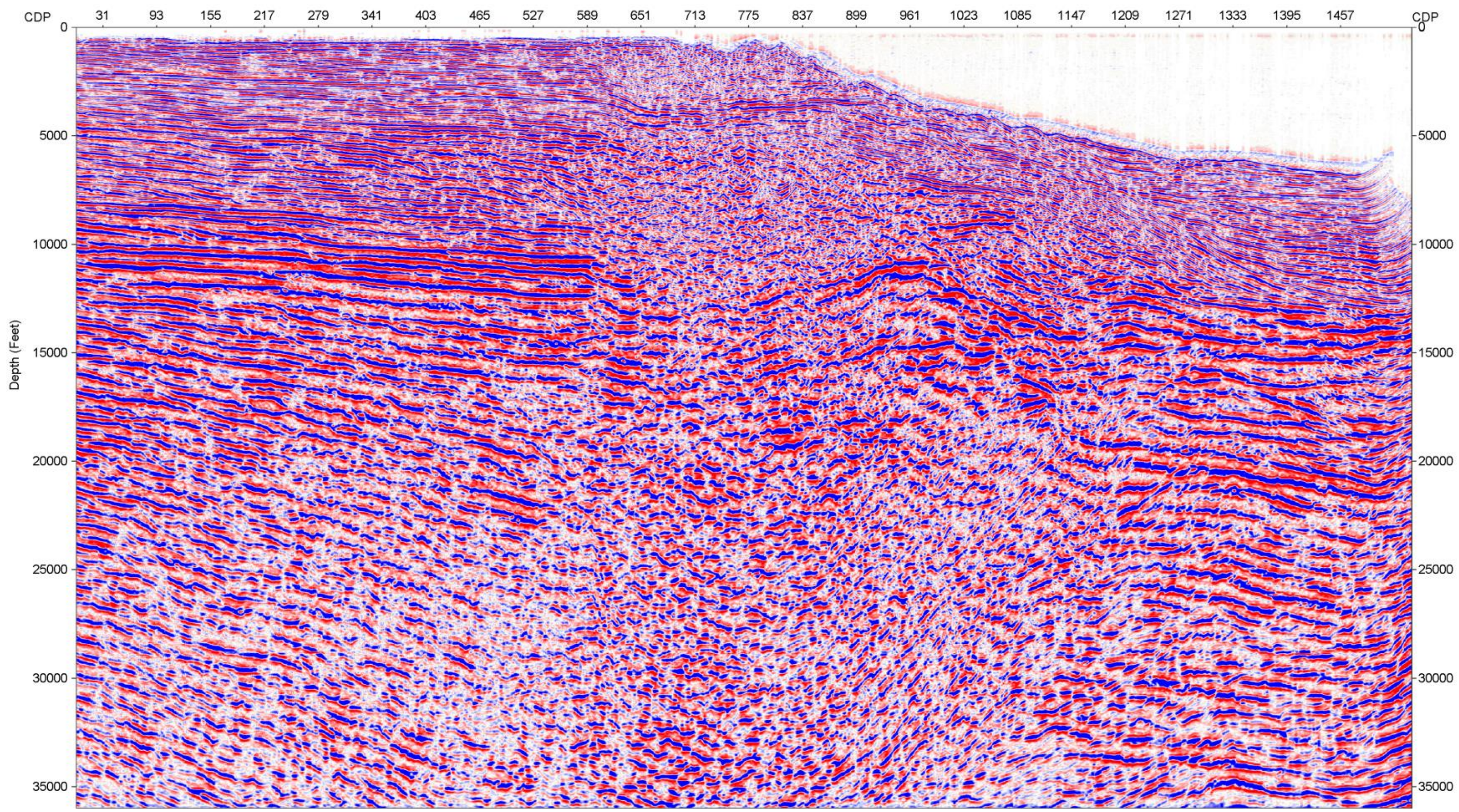
<u>Velocity at depth point 1484</u>	<u>Velocity at depth point 5732</u>
V = 4850 to 6304.992 ft	V = 4850 to 6062.500 ft
V = 8017 to 11118.934 ft	V = 8589 to 11169.086 ft
V = 11055 to 14991.770 ft	V = 9429 to 13276.242 ft
V = 19676 to 16951.254 ft	V = 13192 to 15255.090 ft
V = 13631 to 21348.977 ft	V = 17360 to 17425.055 ft
V = 12380 to 25062.887 ft	V = 18446 to 21794.919 ft
V = 14833 to 99999.000 ft	V = 24238 to 33308.035 ft
	V = 18121 to 99999.000 ft

Plot 81.202 15.20.21 13481082
Floating point data trace equalized

Final annotation shifted to Antenna

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE CSA-81-8 (PERMIT E07-81)
Oil and Gas Readiness Study
Offshore Virginia

PLATE B-7A



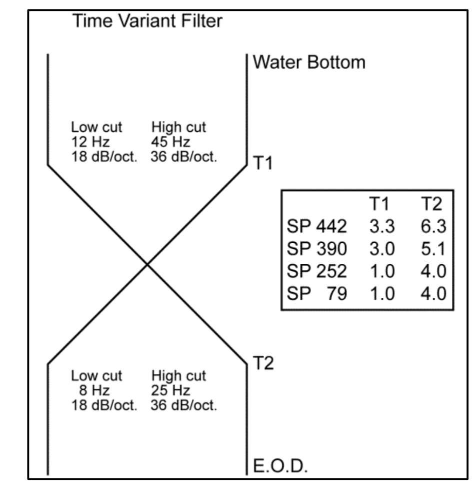
Note: The processing steps shown in the scanned seismic sections for all lines collected as part of permit E07-81 are very difficult to read and therefore the processing information listed to the right (especially the numerical information) may contain errors.

Permit E07-81

Source of processing information: Scanned seismic depth migrated section of Line CSA-81-8 from BOEM/BSEE's online data center.

Client: Chevron
Acquisition Company: Digicon, Inc.
Year Acquired: 1981
Processed by: Chevron Geosciences Company
Year Processed: 1981 - Assumed

Depth Migrated Section (Line CSA-81-8)



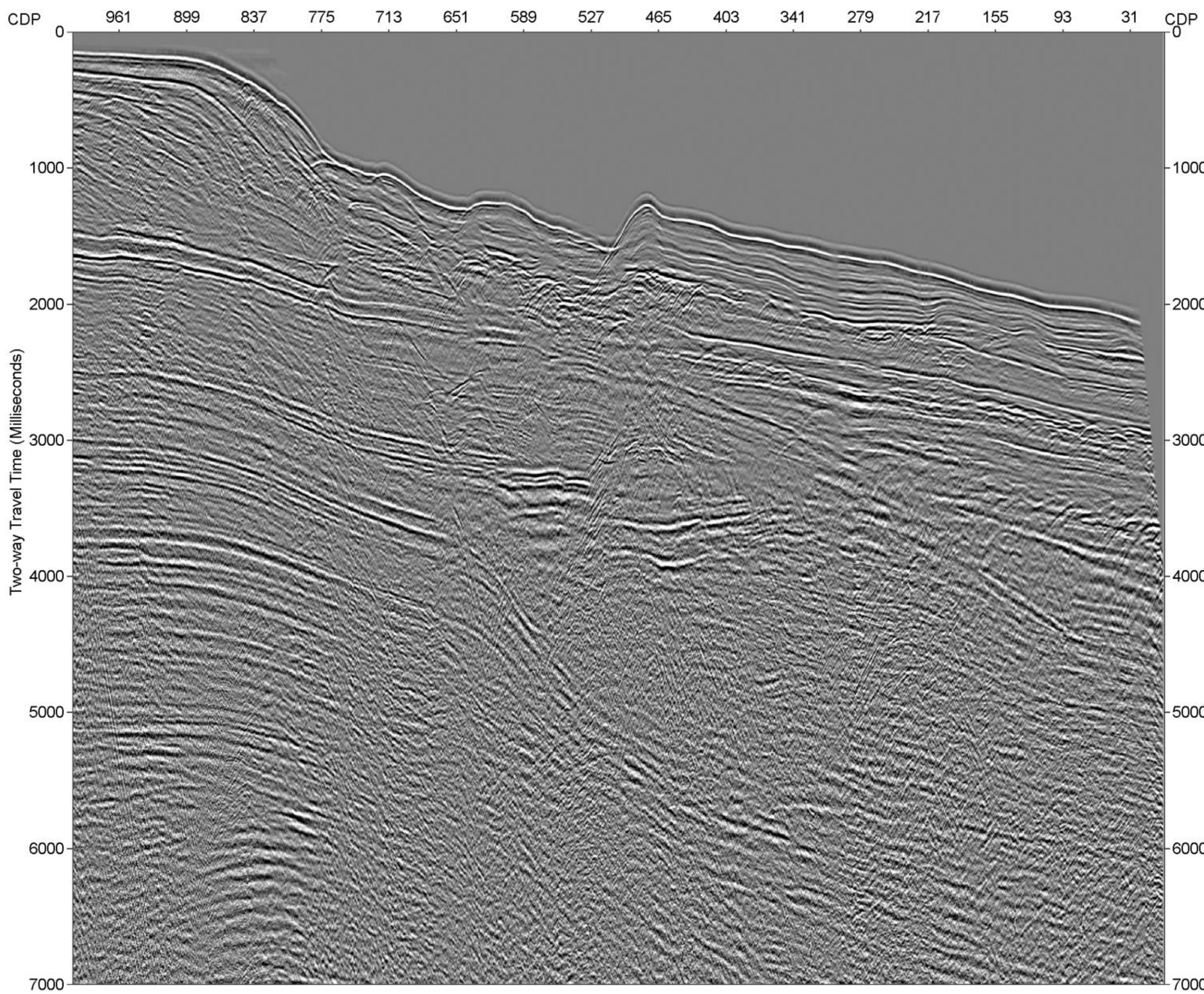
EDITED
MMEDER
Antialias filter applied
Data resampled to 4 msec.
Spherical Divergence Removed - Attenuation Applied
Constant static of 12 msec. applied to all traces
DECON Deconvolution with filter
Operator = 216 msec
Lo cut: 8 Hz Slope: 18dB/octave
Hi cut: 45 Hz Slope: 72 dB/octave
Zero phase
Autocorrelation gate varies with offset
AVC Time constant = 200 msec.
MSTACK SETSSI= 4381139 Time: 07.52.08 Date: 8.180
FILTER Time and/or space variant - 2 time variant filters
AVC Time constant = 800 msec.
CREAM 14081138 82.180 11.32.41
Apply water bottom mute
CWEAVR Migrated stacked time section Date: 06/30/81 Time: 06:14:49
TMIN=0.0 TMAX=7.9 YMIN=-6265.0 YMAX=19769.0 Sample rate=4.0
Stacked midpoint interval = 82.0 Downward Continuation Step Size: 250 Max # of steps: 268
22 velocity function model Units are English Angle=60 Decmat=0 NMOR=1

Velocity at depth point 1484	Velocity at depth point 5732
V = 4850 to 6304.992 ft	V = 4850 to 6062.500 ft
V = 8017 to 11118.934 ft	V = 8589 to 11169.086 ft
V = 11055 to 14991.770 ft	V = 9429 to 13276.242 ft
V = 19676 to 16951.254 ft	V = 13192 to 15255.090 ft
V = 13631 to 21348.977 ft	V = 17360 to 17425.055 ft
V = 12380 to 25062.887 ft	V = 18446 to 21794.919 ft
V = 14833 to 99999.000 ft	V = 24238 to 33308.035 ft
	V = 18121 to 99999.000 ft

Stretch direct time-to-depth data conversion using 15 velocity functions
SSINT = 82.00 FKMIG = 0.
Plot 81.202 15.20.21 13481082
Floating point data trace equalized

Final annotation shifted to antenna

DEPTH MIGRATED SECTION AND PROCESSING SEQUENCE
LINE CSA-81-8 (PERMIT E07-81)
Oil and Gas Readiness Study
Offshore Virginia



Note: Of the 737 SEG-Y files available for this permit from BOEM/BSEE, there is only one available stacked SEG-Y file for Line PR82-X266 in southern North Carolina waters. No scanned image is available for this stacked seismic section. Since there is limited information available in the SEG-Y header file for the stacked seismic section of Line PR82-088, we list the pre-migration seismic processing sequence to the right which is taken from the scanned migrated section of Line PR82-088.

Permit E02-82

Source of processing information: Scanned seismic section of Line PR82-088 from BOEM/BSEE's online data center and SEG-Y header from pr82_88 for the stacked section. Stacked section downloaded from the USGS NAMSS website where it is listed as the WesternGeco Middle Atlantic survey (W-4-82-NA).

Client: Mid-South Atlantic Group
Acquisition Company: Geosource Inc.
Year Acquired: 1982
Processed by: Geosource, Inc. (Petty-Ray Crew 37)
Year Processed: 1982 (Assumed)

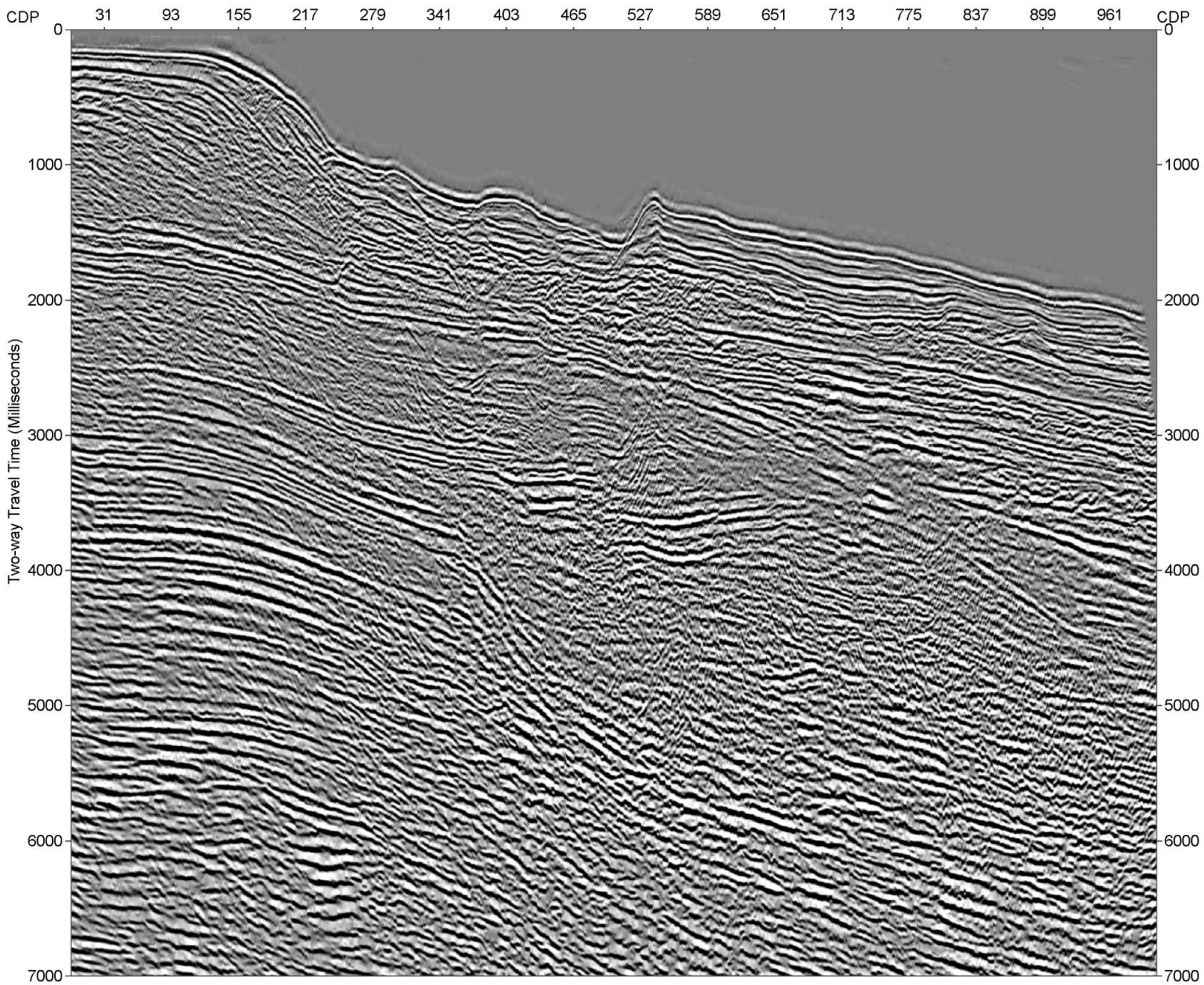
Stacked Section (Line PR82-88)

1. Edit Demultiplex
   Resample to 4 MS
   Sum adjacent trace with differential NMO
2. Signature Wavelet Filter Application
3. 48 Trace sort with Predictive Deconvolution
   Gain Recovery A=8.0 B=0.4 C=20
   200 MS Operator 40 MS Lag
4. Velocity Analysis
   Contour Plot VELSTACK every 1.1 miles
5. NMO Corrections
   16 MS sea level datum correction applied
6. Notch Mute Stack
   Trace 48-25 Notched
7. Time Variant Filter - Balance
   500 MS Balance Window 5000-4000 RMS

Time	F1	F2	F3	F4
0.0	5	10	45	55
1.0	4	8	35	45
2.0	4	8	30	38
3.0	0	3	20	30
8.0	0	3	20	30

Digital Processing Remarks: Shotpoints are referenced to antenna location. Window start time and mute times and filters vary with water depth.

STACKED SECTION AND PROCESSING SEQUENCE
LINE PR82-088 (PERMIT E02-82)
Oil and Gas Readiness Study
Offshore Virginia



Permit E02-82

Source of processing information: Scanned seismic section of Lines PR82-088 from BOEM/BSEE's online data center.

Client: Mid-South Atlantic Group
Acquisition Company: Geosource Inc.
Year Acquired: 1982
Processed by: Geosource, Inc. (Petty-Ray Crew 37)
Year Processed: 1982 (Assumed)

Migrated Section (Line PR82-088)

1. Edit Demultiplex
   Resample to 4 MS
   Sum adjacent trace with differential NMO
2. Signature Wavelet Filter Application
3. 48 Trace sort with Predictive Deconvolution
   Gain Recovery A=8.0 B=0.4 C=20
   200 MS Operator 40 MS Lag
4. Velocity Analysis
   Contour Plot VELSTACK every 1.1 miles
5. NMO Corrections
   16 MS sea level datum correction applied
6. Notch Mute Stack
   Trace 48-25 Notched
7. Time Variant Filter - Balance
   500 MS Balance Window 5000-4000 RMS

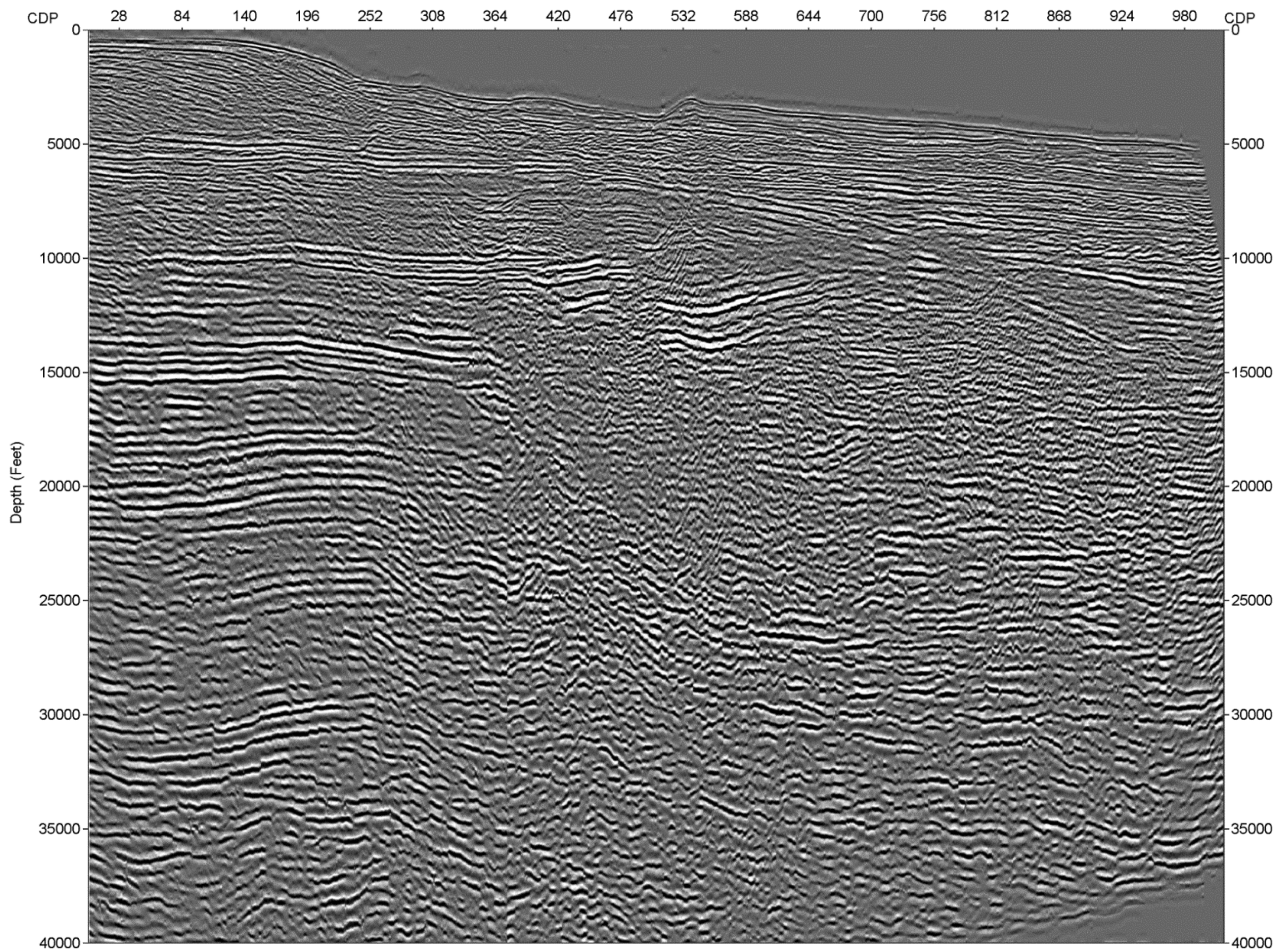
Time	F1	F2	F3	F4
0.0	5	10	45	55
1.0	4	8	35	45
2.0	4	8	30	38
3.0	0	3	20	30
8.0	0	3	20	30

8. Frequency Migration
   1000 MS Balance Window 5000-4000 RMS
9. Photodot Input Reel = 06286

Digital Processing Remarks: Shotpoints are referenced to antenna location. Window start time and mute times and filters vary with water depth.

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE PR82-088 (PERMIT E02-82)
Oil and Gas Readiness Study
Offshore Virginia

PLATE B-8B



Permit E02-82

Source of processing information: Scanned seismic section of Line PR82-088-D from BOEM/BSEE's online data center.

Client: Mid-South Atlantic Group
Acquisition Company: Geosource Inc.
Year Acquired: 1982
Processed by: Geosource, Inc. (Petty-Ray Crew 37)
Year Processed: 1982 (Assumed)

Depth-Converted Section (Line PR82-088-D)

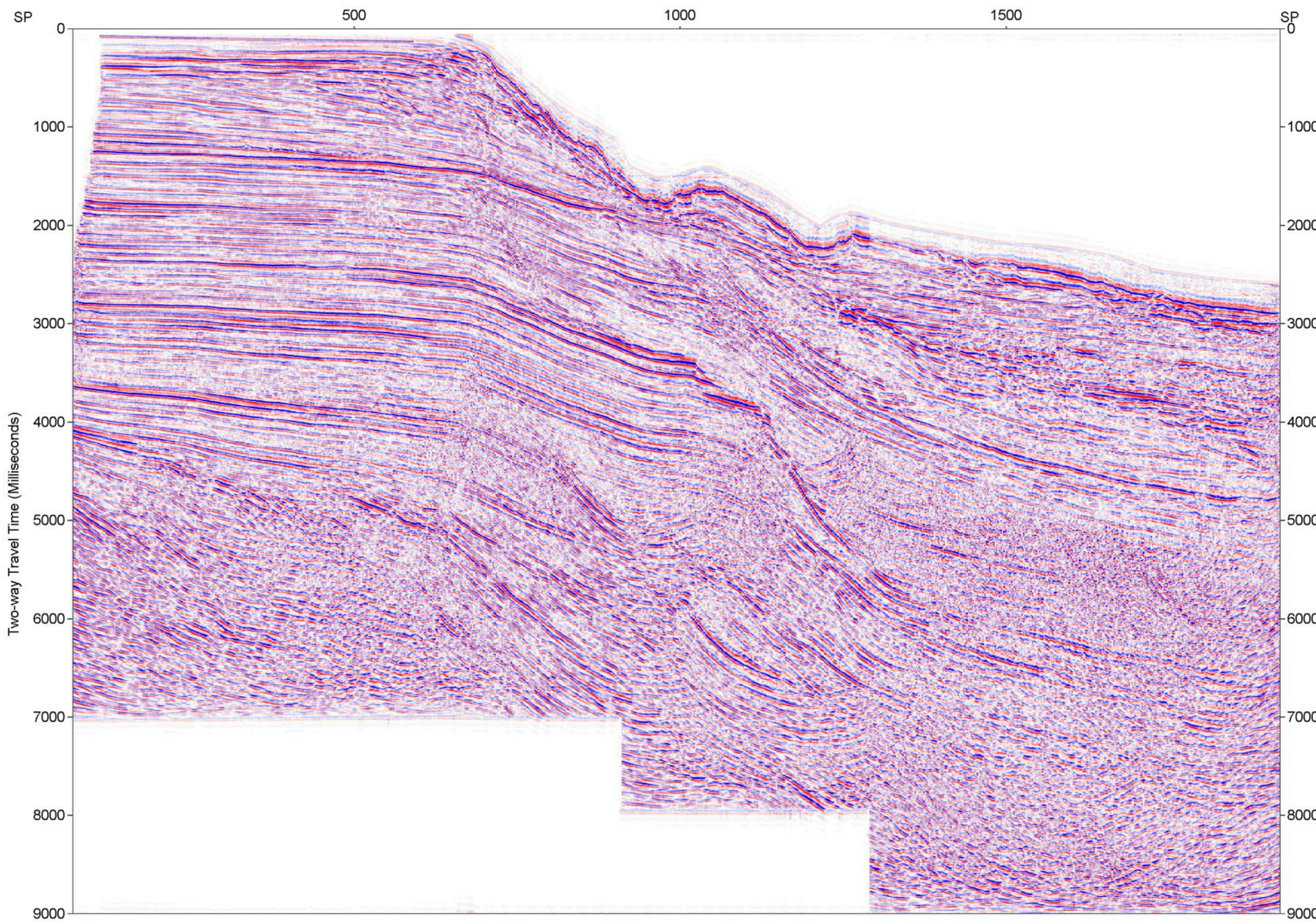
1. Edit Demultiplex
   Resample to 4 MS
   Sum adjacent trace with differential NMO
2. Signature Wavelet Filter Application
3. 48 Trace sort with Predictive Deconvolution
   Gain Recovery A=8.0 B=0.4 C=20
   200 MS Operator 40 MS Lag
4. Velocity Analysis
   Contour Plot VELSTACK every 1.1 miles
5. NMO Corrections
   16 MS sea level datum correction applied
6. Notch Mute Stack
   Trace 48-25 Notched
7. Time Variant Filter - Balance
   500 MS Balance Window 5000-4000 RMS

Time	F1	F2	F3	F4
0.0	5	10	45	55
1.0	4	8	35	45
2.0	4	8	30	38
3.0	0	3	20	30
8.0	0	3	20	30

8. Frequency Migration
   1000 MS Balance Window 5000-4000 RMS
9. Depth
10. Photodot Input Reel = 06286

Digital Processing Remarks: Water depth specified in feet. Shotpoints are referenced to antenna location. Window start time and mute times and filters vary with water depth.

DEPTH SECTION AND PROCESSING SEQUENCE
LINE PR82-088 (PERMIT E02-82)
Oil and Gas Readiness Study
Offshore Virginia



Permit E04-82

Source of processing information: Scanned seismic section of Line 18074 from BOEM/BSEE's online data center.

Client: Shell
Acquisition Company: Shell (Assumed)
Year Acquired: 1982
Processed by: Shell (Assumed)
Year Processed: 1982 (Assumed)

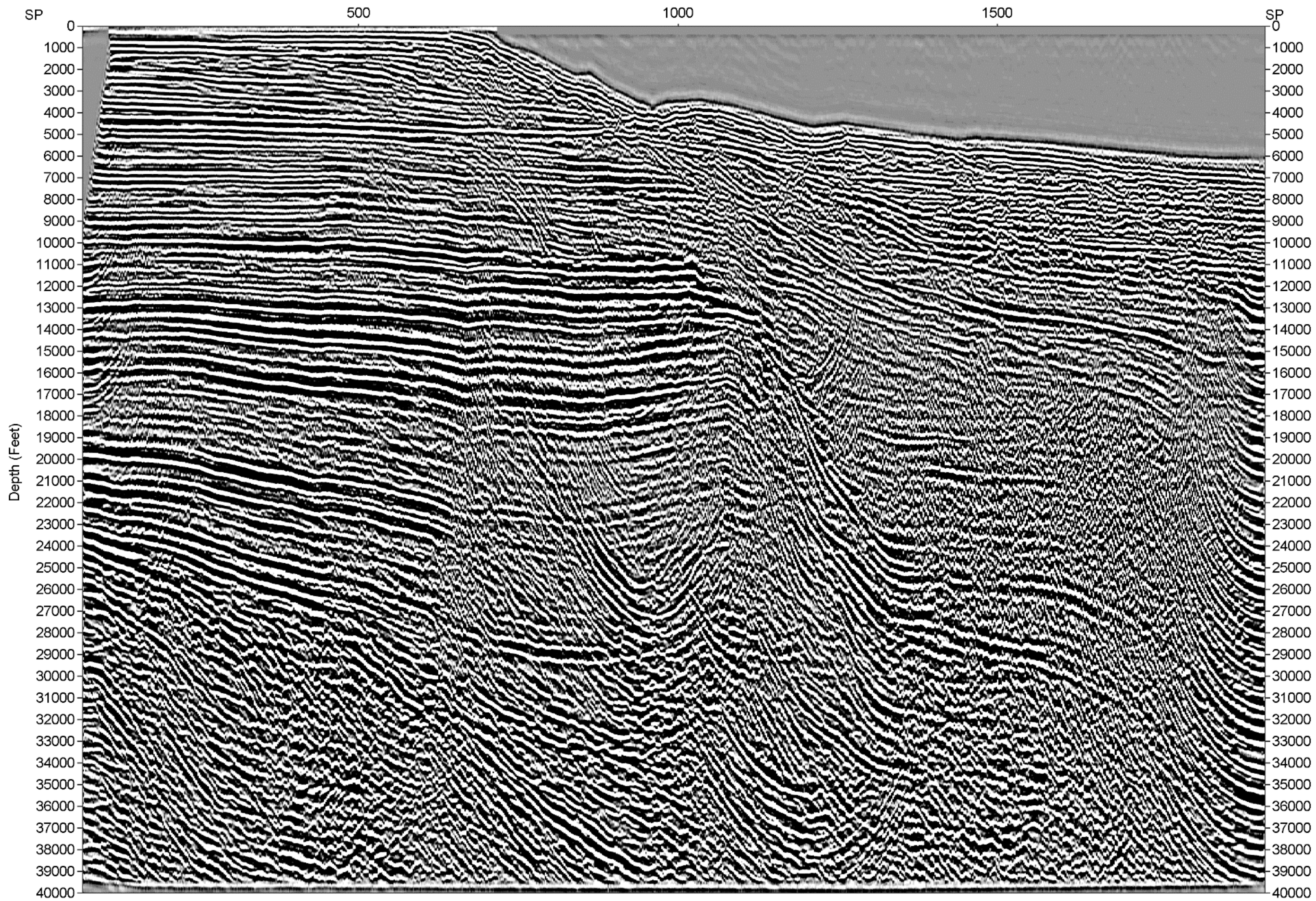
Migrated Section (Line 18074)

Program History

USIP	
BLANK3	
SEAMOR	
CHAMP	
VELGAN	
MIDAS	
DYNOMX	
DEPULS	***Depulse Filter***
COMUS	
DECON	***Deconvolution***
JASON	
HSTK	***Horizontal Stack***
DRISTK	***Stack***
RUNSUM	
CHAMP	
PROGAN	
CHAMP	
NORM5	***Normalize Amplitude***

Note: We have attempted to interpret the processing sequence on the data label for this line (shown in bold and italicized font) because we believe that it could be of value to further processing efforts. Please realize that this interpretation could contain errors and if one wishes to determine the exact processing steps taken, it would be necessary to contact someone with existing documentation or great familiarity of old processing methods used by the appropriate processing group.

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE 18074 (PERMIT E04-82)
Oil and Gas Readiness Study
Offshore Virginia



<u>Permit E04-82</u>

Source of processing information: Scanned seismic section of Lines 18074 and 18074_D from BOEM/BSEE.

Client: Shell
Acquisition Company: Shell (Assumed)
Year Acquired: 1982
Processed by: Shell (Assumed)
Year Processed: 1982 (Assumed)

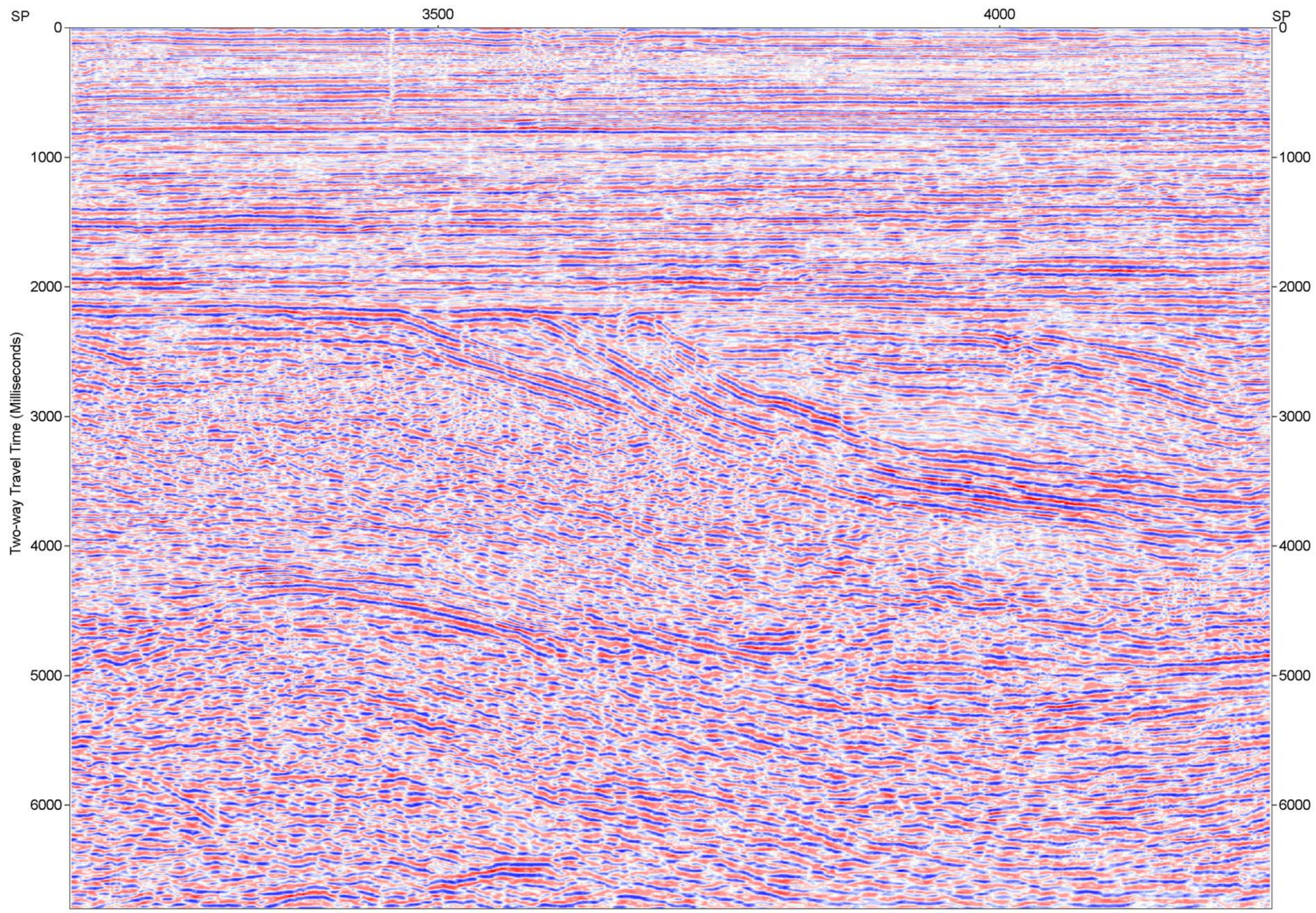
Depth Section in Feet (Line 18074)

<u>Program History</u>

BLANK3	
SEAMOR	
CHAMP	
VELGAN	
MIDAS	
DYNOMX	
DEPULS	***Depulse Filter***
COMUS	
DECON	***Deconvolution***
JASON	
HSTK	***Horizontal Stack***
TVBAND	***Time Variant Bandpass Filter***
MYTMAC	***Part of Depth Conversion ?***
IMPA5	***Part of Depth Conversion ?***
RUNSUM	
CHAMP	
PROGAN	
MYTMAC	***Part of Depth Conversion ?***

Note: We have attempted to interpret the processing sequence on the data label for this line (shown in bold and italicized font) because we believe that it could be of value to further processing efforts. Please realize that this interpretation could contain errors and if one wishes to determine the exact processing steps taken, it would be necessary to contact someone with existing documentation or great familiarity of old processing methods used by the appropriate processing group.

DEPTH SECTION AND PROCESSING SEQUENCE
LINE 18074 (PERMIT E04-82)
Oil and Gas Readiness Study
Offshore Virginia



Permit E11-82

Source of processing information: Scanned seismic section of Line M82-02 obtained from BOEM/BSEE's online data center.

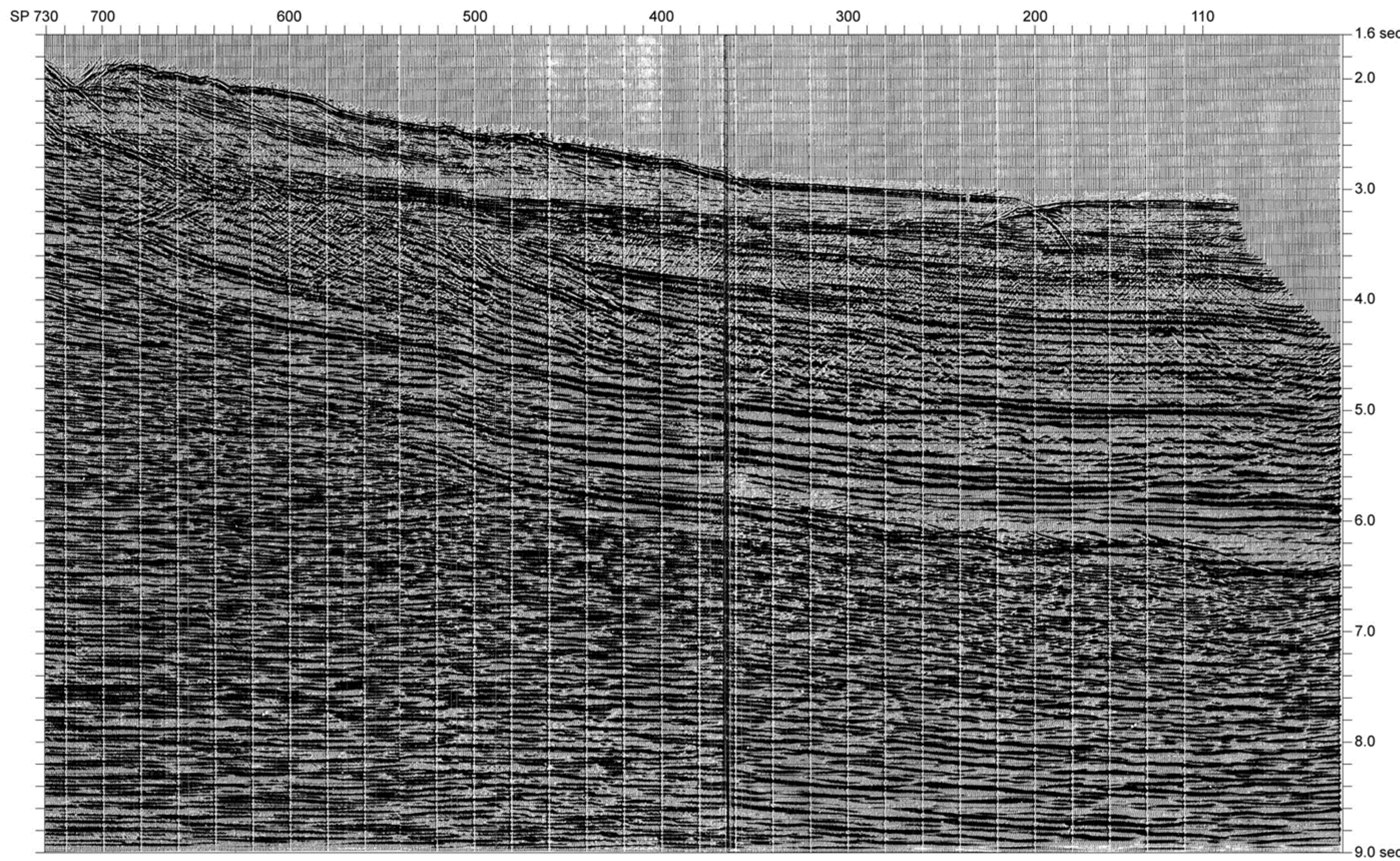
Client: ARCO Exploration
Acquisition Company: ARCO Resolution
Year Acquired: 1982
Processed by: ARCO Exploration Resources Department Geophysical Data Processing
Year Processed: 1982

Migrated Section (M82-02)

Gain Recovery Scaling: Exponential
Trace Mute
  Type: Front End   Pattern: Linear
  Distance: 1570 1730 10875
  Time: 0.00 0.40 2.60
Deconvolution
  Type: Time Domain Minimum Phase
  Design Window: 0.3-2.3   2.1-4.1
  Operator Length: 0.20   0.20
  Prediction Time: Spiking   Spiking
NMO
  Mute Reapplied
  Interpolation: Iso-time
Time Variant Scaling
  User Specified Information
Stack: Maximum CDP Fold 240
Vertical Sum
Data resampled from 2 msec to 4 msec
Filter
  Time-domain Zero Phase
  Band Pass: 14-56 12-48 10-40 8-32
  Window: 0.0-0.6 0.6-1.7 1.7-4.5 4.5-8.0
Time Variant Scaling
  Window Length: Begin 0.050   Max 0.600   Multiplier 1.8
Record Modification
  Process: Set
Migration
  Type: Finite Difference
  Step Size: 0.020 sec
  CDP Interval 164
Filter
  Time-domain Zero Phase
  Band Pass: 14-56 12-48 10-40 8-32
  Window: 0.0-0.6 0.6-1.7 1.7-4.5 4.5-8.0
Time Variant Scaling
  Window Length: Begin 0.050   Max 0.600   Multiplier 1.8
Record Modification Process: Set

Notes: All scanned seismic sections and SEG-Y files are migrated sections.

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE M82-02 (E11-82)
Oil and Gas Readiness Study
Offshore Virginia



Note: We have attempted to interpret the processing modules listed in the processing sequence on the data label for this line because we believe that it could be of value to further processing efforts. Please realize that this interpretation could contain errors and if one wishes to determine the exact processing steps taken, it would be necessary to contact someone with documentation or great familiarity of old processing methods used by the Amoco Tulsa Processing Group.

No SEG-Y files were available for the two lines from this survey that extend into Virginia waters, so we present the scanned paper copy of one of the lines.

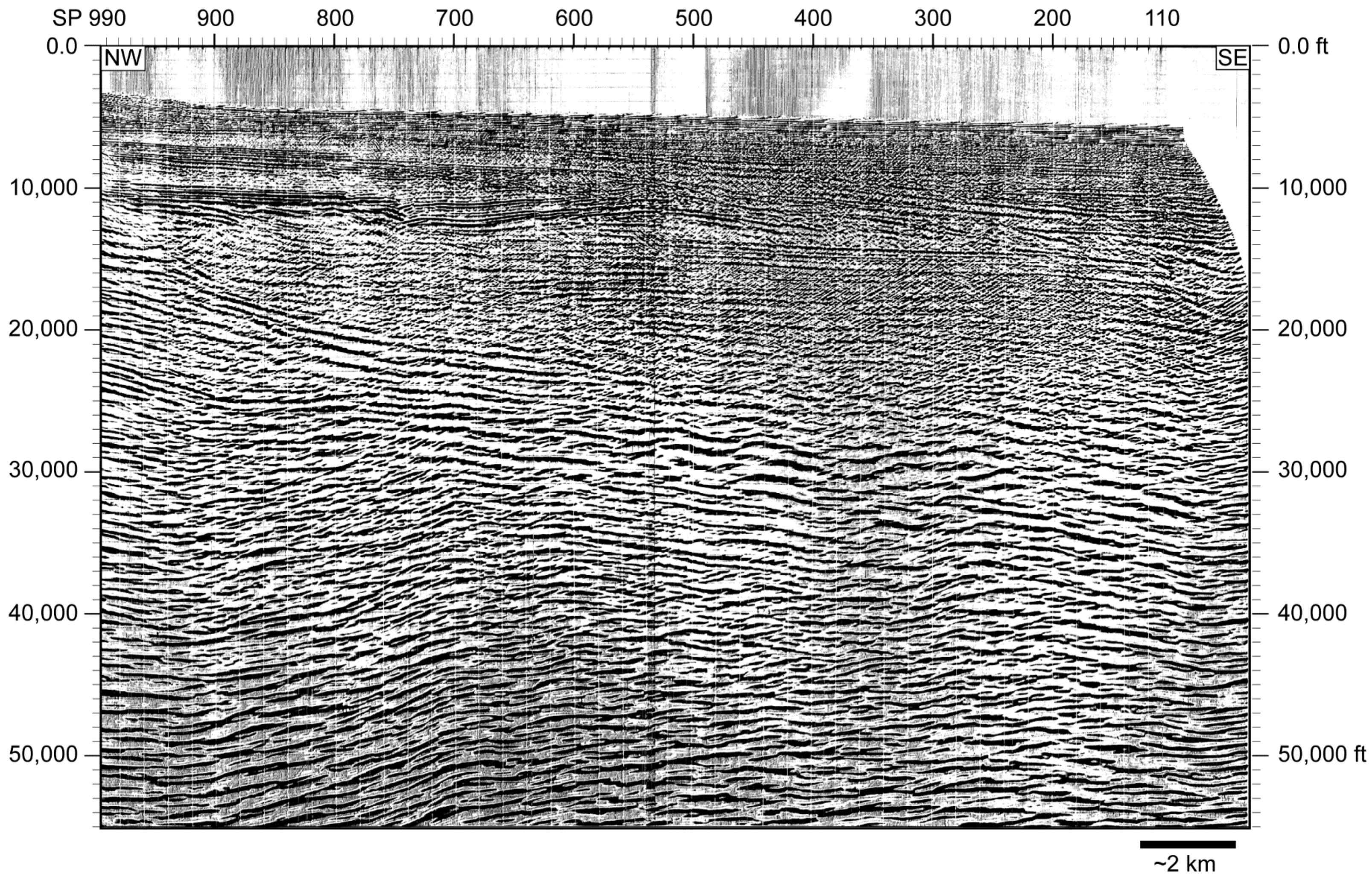
Permit E05-83

Source of processing information: Scanned migrated section of Line MMA-198 obtained from BSEE's online data center (www.data.bsee.gov).

Client: Amoco
Acquisition Company: Norpac
Year Acquired: 1983
Processed by: Amoco Tulsa Processing Group
Year Processed: 1983 (Assumed)

Migrated Section (Line MMA-198)	Interpretation of Processing Sequence
FIXT	Trace Edit?
CODE <INPUT DATA SETS-MERG>	Merge data sets
REDT	Trace Edit?
WRDT	Wiener inverse filter-deconvolution Edit?
REIN <2 To 4>	Resample and Interpolate – 2 to 4 msec?
DAVC <1000 MS AGC WINDOW 72%>	Digital Volume Control: 1.0 sec AGC window
MUDS	Mute or statics?
SORT	CDP sort 60 fold
FOLD = 60 SORT TYPE = 1	
TRACE OMIT CARDS ENTERED	
ANMO<STAT-NMO>	Normal moveout (NMO)
MUDS	Mute or statics?
MUDS	Mute or statics?
STAK<60 FOLD, VM=0, TO=0, EXP=0.7>	Stack 60 fold
CTVF--	Linear Time-Variable (TV) Filter
MODE 3/LINEAR	Time: 0.0 sec Filter: 4/9/55/60 Hz
TIME = FILTER	Time: 5.3 sec Filter: 4/9/55/60 Hz
0.0 SEC 4/9/55/60	Time: 6.8 sec Filter: 4/9/45/50 Hz
5.3 SEC 4/9/55/60	Time: 8.8 sec Filter: 4/9/36/40 Hz
6.8 SEC 4/9/45/50	Time: 9.0 sec Filter: 4/9/36/40 Hz
8.8 SEC 4/9/36/40	Rejection level: 60 dB
9.0 SEC 4/9/36/40	
REJECT LEVEL 60 DB	
ZERO	Zero Phase Filter?
DAVC<1000 MS AGC WINDOW 15%>	Digital Volume Control: 1.0 sec AGC window
REIN< 4 TO 8>	
KMIG <CDP INTERVAL = 41>	Kirchhoff Migration, Half aperture = 41 CDP
MAX DIP = 20 MS	Maximum dip: 20 msec
VEL PERCENT = 90	Velocity field: 90% stacking/RMS vel.
REIN< 8 TO 4>	Resample and Interpolate – 4 to 8 msec?
DAVC<500 MS AGC WINDOW 15%>	Digital Volume Control: 0.5 sec AGC window
PLOT<TSS756>X	Plot section

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE MMA-198 (E05-83)
Oil and Gas Readiness Study
Offshore Virginia



Note: We have attempted to interpret the processing modules listed in the processing sequence on the data label for this line because we believe that it could be of value to further processing efforts. Please realize that this interpretation could contain errors and if one wishes to determine the exact processing steps taken, it would be necessary to contact someone with documentation or great familiarity of old processing methods used by the Amoco Tulsa Processing Group.

No SEG-Y files were available for the two lines from this survey that extend into Virginia waters, so we present the scanned paper copy of one of the lines.

Permit E05-83

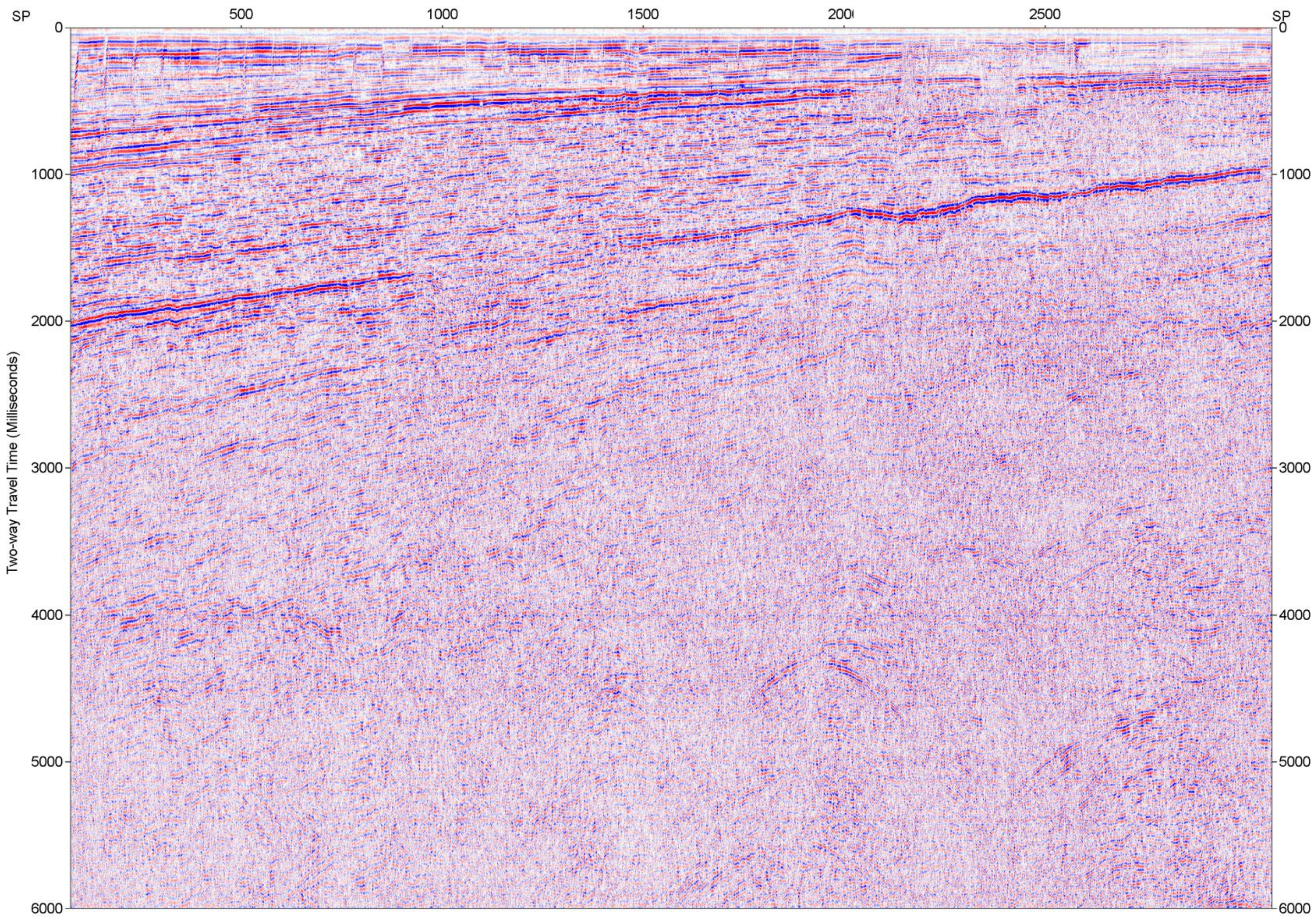
Source of processing information: Scanned migrated section of Line MMA-198-D obtained from BOEM/BSEE’s online data center.

Client: Amoco
Acquisition Company: Norpac
Year Acquired: 1983
Processed by: Amoco Tulsa Processing Group
Year Processed: 1983 (Assumed)

Depth-Converted Section (MMA-198-D)	Interpretation of Processing Sequence
SIAM	?
FIELD TAPE DEMUX B1200FS SAM	Demultiplex Field Tape
DEMUX AND GAIN REMOVAL TYPE 1	Gain Removal
AMOCO FORMAT 3 OUTPUT 9.0 SEC	Output Amoco Format
CODE <INPUT DATA SETS-MERG>	Merge data sets
REDT	Trace Edit?
WRDT	Trace Edit?
REIN <2 To 4>	Resample 2 to 4 ms?
DAVC <1000 MS AGC WINDOW 72%>	Digital Volume Control: 1.0 sec AGC window
MUDS	Mute?
SORT	CDP sort 60 fold
FOLD = 60 SORT TYPE = 1	
TRACE OMIT CARDS ENTERED	
ANMO<STAT-NMO>	Normal moveout (NMO)
MUDS	Mute?
MUDS	Mute?
STAK<60 FOLD, VM=0, TO=0, EXP=0.7>	Stack 60 fold
CTVF	Linear Time-Variable (TV) Filter
MODE 3/LINEAR	Time: 0.0 sec Filter: 4/9/55/60 Hz
TIME = FILTER	Time: 5.3 sec Filter: 4/9/55/60 Hz
0.0 SEC 4/9/55/60	Time: 6.8 sec Filter: 4/9/45/50 Hz
5.3 SEC 4/9/55/60	Time: 8.8 sec Filter: 4/9/36/40 Hz
6.8 SEC 4/9/45/50	Time: 9.0 sec Filter: 4/9/36/40 Hz
8.8 SEC 4/9/36/40	Rejection level: 60 dB
9.0 SEC 4/9/36/40	
REJECT LEVEL 60 DB	
DAVC<1000 MS AGC WINDOW 15%>	Digital Volume Control: 1.0 sec AGC window
REIN< 4 TO 8>	Resample 4 to 8 ms?
KMIG <CDP INTERVAL = 41>	Kirchhoff Migration, Half aperture = 41 CDP
MAX DIP = 20 MS>	Maximum dip = 20 msec
VEL PERCENT = 90>	Velocity field = 90% of stacking/RMS velocity
REIN< 8 TO 4>	Resample 8 to 4 ms?
FRED	Frequency/Wavenumber– depth conversion?
TIME TO NORMAL DEPTH CONVERSION	Depth Conversion
DECAY = 0 0 X SMTH = 400 VEL % = 100	Smooth the velocity before depth conversion?
DAVC<500 MS AGC WINDOW 15%>	Digital Volume Control: 0.5 sec AGC window
PLOT<TSS756>X	Plot section

SCANNED DEPTH SECTION AND PROCESSING SEQUENCE
LINE MMA-198 (E05-83)
Oil and Gas Readiness Study
Offshore Virginia

PLATE B-11B



Permit E05-86

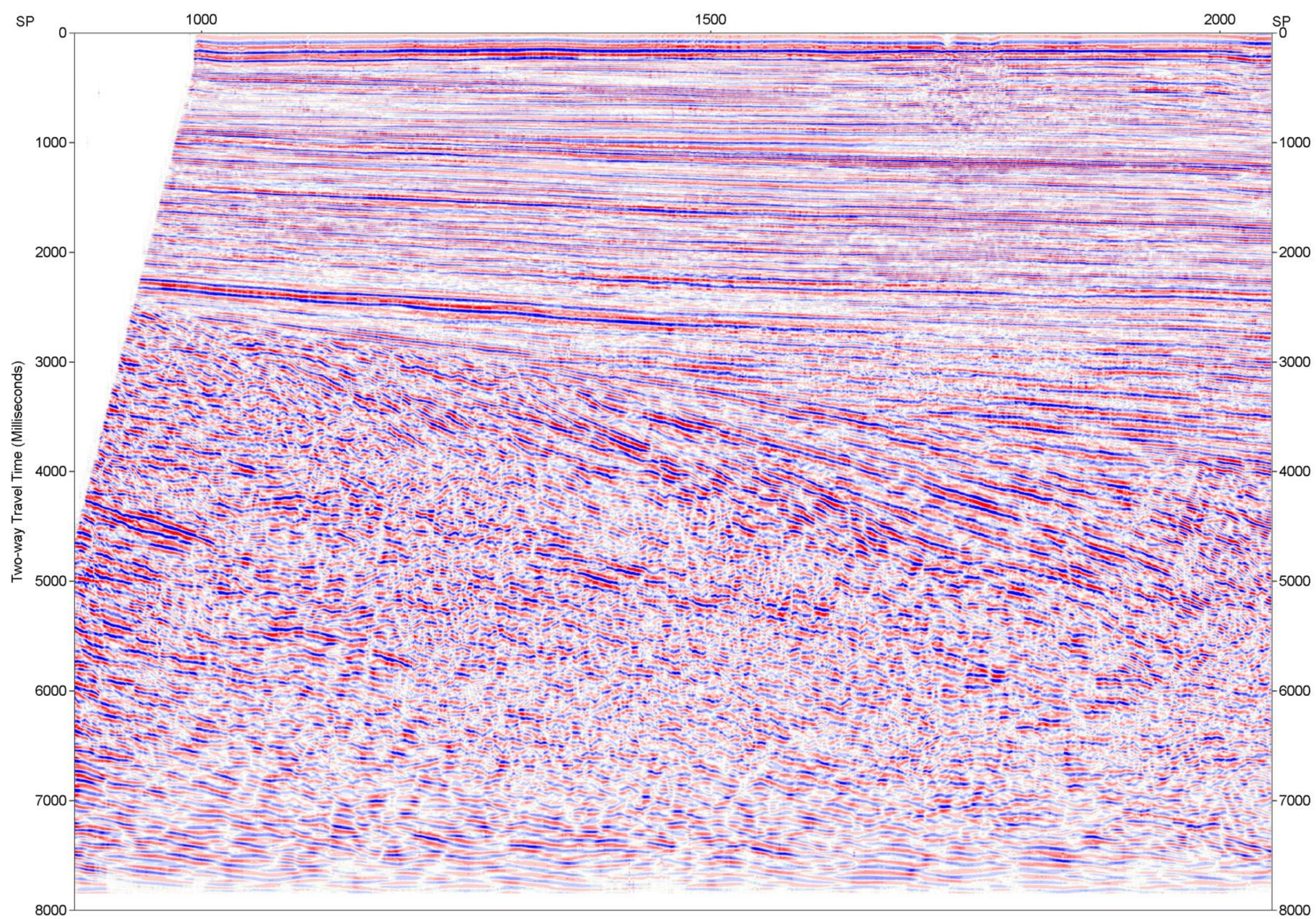
Source of processing information: Scanned seismic section of line 5-YRE obtained from BOEM/BSEE's online data center.

Clients: Spectrum Resources & Texaco
Acquisition Company: Teledyne Exploration
Year Acquired: 1986
Processed by: Teledyne Exploration
Year Processed: 1986

Stacked Section (5-YRE)

1. Gain Recovery
2. Two Trace Composite
3. Divergence Correction
4. Deconvolution
   - Operator Length (1): 256 msec
   - Prediction Length (1): 4 msec
   - Correlation Gate (1): 0.5-2.5 sec DISTANCE: 431 ft
   - Correlation Gate (1): 1.0-2.8 sec DISTANCE: 4285 ft
   - Band Limit (1): OUT-OUT TIME: Correlation Gates
   - Operator Length (2): 256 msec
   - Prediction Length (2): 4 msec
   - Correlation Gate (2): 2.0-4.0 sec; DISTANCE: 431 ft
   - Correlation Gate (2): 2.3-4.3 sec; DISTANCE: 4285 ft
   - Band Limit (2): OUT-OUT TIME: Correlation Gates
5. Velocity Analysis
6. NMO
7. Stack: 48 Fold CDP
   - Stack Mutes:
   - TIME: 0.05 sec DISTANCE: 431 FT
   - TIME: 0.05 sec DISTANCE: 595 FT
   - TIME: 0.70 sec DISTANCE: 4285 FT
8. Predictive Deconvolution
9. Digital Filter
   - Band Limit: 15-60 Hz TIME: 0.0-6.0 sec
10. Program Gain

STACKED SECTION AND PROCESSING SEQUENCE
LINE 5-YRE (E05-86)
Oil and Gas Readiness Study
Offshore Virginia



Permit E03-88

Source of processing information: Seismic permit label for migrated stack section of Line 88-16-M obtained from BSEE's online data center.

Client: Texaco
Acquisition Company: GECO
Year Acquired: 1988
Processed by: CGG Data Processing Services
Year Processed: 1988

Migrated Section (88-16-M)

Reformatting
Anti-Alias Filter
Resample to 4 msec
Source Designature
Spherical Divergence Correction
Trace Editing
Common Depth Point Gather
Predictive Deconvolution: Operator Length: 216 msec
Gap: 32 msec
First Gate: 300 to 1900 msec
Second Gate: 2100 to 3700 msec
Velocity Spectrum: Every 4 kilometers
Single Gate Equalization
Partial Stack (4/1) with Residual NMO Correction
Dip Moveout (Offset Domain: 30 Offsets)
Velocity Spectrum: Every kilometer
Normal Moveout (NMO)
Mutes (Internal and External)
Stack (Maximum Fold: 95)
Merge
Cascaded Migration:
FK (1900 m/sec) + Residual Finite
Difference Wave Equation Migration
(95 % Stacking Velocities)
Two in One Trace Sum

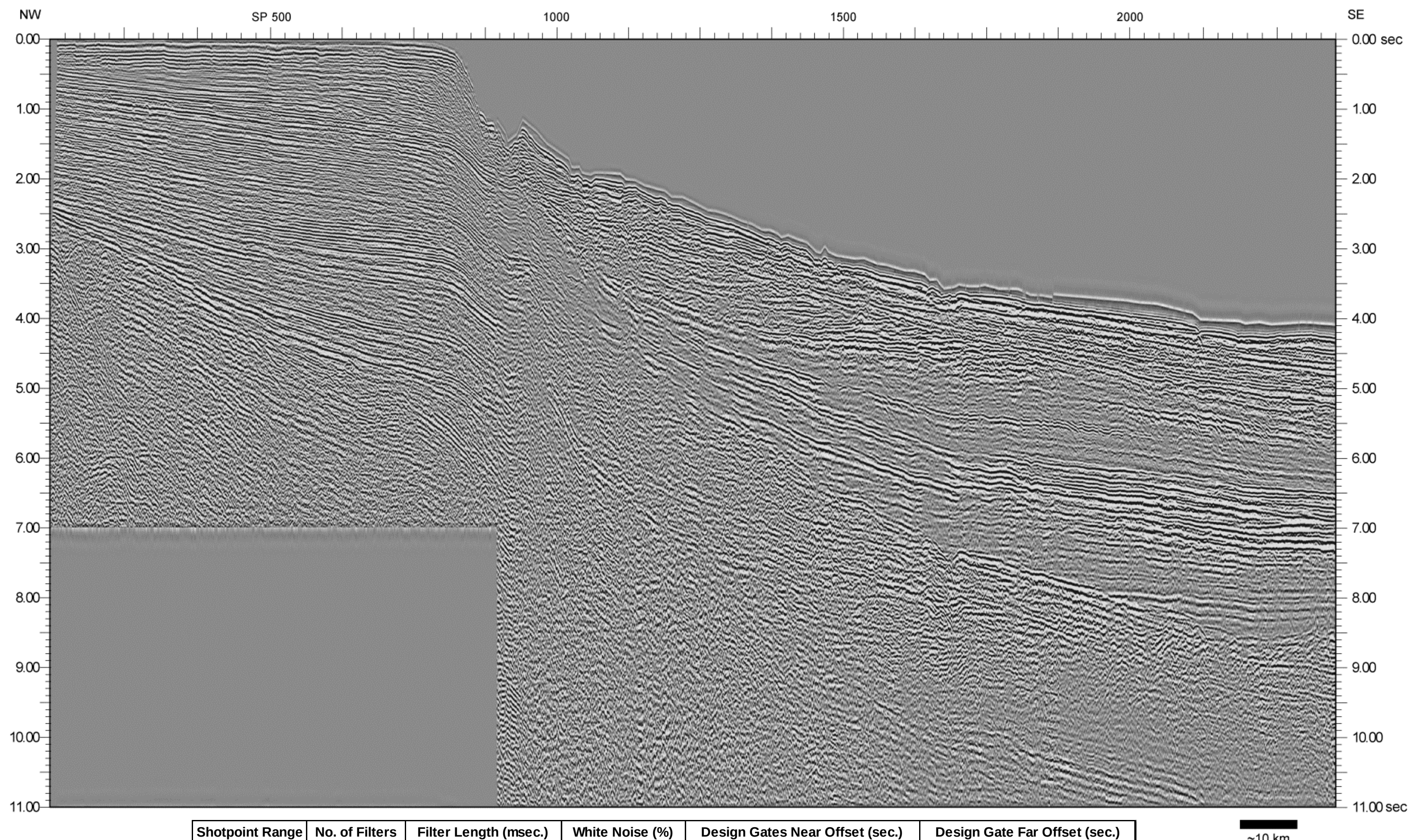
Time Variant Filter:	5/9/45/67 Hz	0.0 to 2.0 sec
	5/9/30/45 Hz	2.0 to 4.0 sec
	5/9/20/30 Hz	4.0 to 8.0 sec

Dynamic Equalization: (Times from Water Bottom)

Operator Length: 500 msec	0.0 to 4.0 sec
Operator Length: 1000 msec	4.0 to 8.0 sec

Datum Correction for Source and Receiver: 12 msec
Final Gain: 2 dB
Film Display

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE 88-16-M (PERMIT E03-88)
Oil and Gas Readiness Study
Offshore Virginia



Shotpoint Range	No. of Filters	Filter Length (msec.)	White Noise (%)	Design Gates Near Offset (sec.)	Design Gate Far Offset (sec.)
130-560	3	120	1	0.6 to 4.8	3.6 to 4.8
				4.3 to 5.5	4.3 to 5.5
				5.0 to 6.2	5.0 to 6.2
561-760	2	160	1	0.6 to 5.2	3.6 to 6.2
				4.7 to 6.3	4.7 to 6.3
761-795	2	200	1	0.6 to 5.6	3.6 to 5.6
				5.0 to 7.0	5.0 to 7.0
796-820	1	280	1	0.6 to 6.4	3.6 to 6.4
821-904	1	320	1	0.6 to 6.4	3.6 to 6.8
890-974	1	320	1	1.5 to 4.0	1.5 to 4.0
975-1305	1	320	1	2.0 to 4.5	2.0 to 4.5
1275-1324	1	320	1	3.0 to 6.0	4.0 to 7.5
1325-1550	1	320	1	3.5 to 7.0	3.5 to 7.0
1551-1873	1	320	1	4.0 to 7.5	4.0 to 7.5
1863-2350	1	320	1	4.5 to 6.0	4.5 to 6.5

USGS Survey S-1-73

Source of processing information: Scanned seismic section of Line 3 from NOAA's NGDC website.

Client: USGS
Acquisition Company: Digicon Geophysical Corporation
Year Acquired: 1973
Processed by: Digicon Geophysical Corporation
Dates Processed:
Line3: 10/9/1973 (SP 130-904); April, 1974 (SP 890-1305, 1275A-1305A & 1306-1873, 1863-2350)

Stacked Section (Line 3)

LINE 3 (SP 130-2350):
1. Exponential Gain Rate: 3dB/sec Gate: 0.0-3.0 sec
2. System Delay Static: 40 msec
3. Vertical Stack: 2 on 1
4. CDP Gather
5. Velocity Analysis
6. Normal moveout (NMO)
7. TV (Time Variant) Deconvolution[1]
8. CDP Stack 12 Fold
9. Digital Filter[2]
   Time: 0.0-1.6 sec Bandpass: 10 – 35 Hz
   Time: 4.0-11.0 sec Bandpass: 5 – 25 Hz
10. Trace Amplitude Equalization

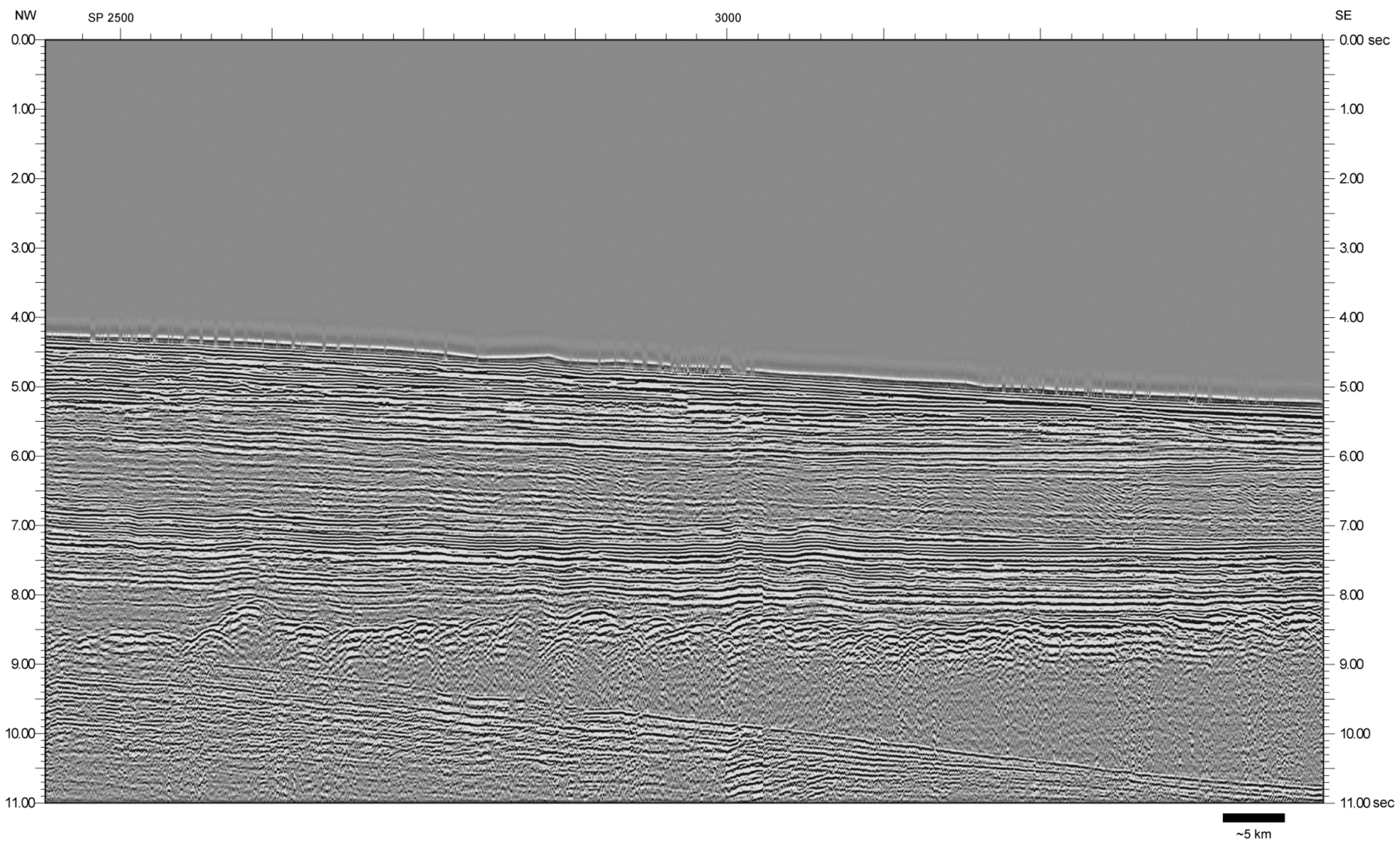
Notes:
Both lines 3 and 3A are shown in Appendix B to show variations in the processing steps used in shallow water (Line 3 with 12 fold coverage) and deep water (Line 3A with 6 fold coverage)

[1]For specific processing parameters for shotpoint ranges see table (left)

[2]Digital filter parameters listed above are for all shotpoints with the exception of a second bandpass filter from 5 to 25 Hz over a time window of 4.0 to 7.0 seconds being applied to shotpoints 130 to 904.

DIGITIZED STACKED SECTION AND PROCESSING SEQUENCE
LINE 3 (USGS S-1-73)
Oil and Gas Readiness Study
Offshore Virginia

PLATE B-14A



USGS Survey S-1-73

Source of processing information: Scanned seismic section of Line 3A from NOAA's NGDC.

Client: USGS
Acquisition Company: Digicon Geophysical Corporation
Year Acquired: 1973
Processed by: Digicon Geophysical Corporation
Dates Processed:
Line 3A: October, 1973 (SP 2451-3493)

Stacked Section (Line 3A)

LINE 3A (SP 2451-3493):

1. Exponential Gain Rate: 3dB/sec Gate: 0.0-3.0 sec
2. System Delay Static: 40 msec
3. Vertical Stack: 2 on 1
4. CDP Gather
5. Velocity Analysis
6. Normal moveout (NMO)
7. TV Deconvolution
   - Shotpoints: 2451 to 3051
   - No. Filters: 1
   - White Noise: 1%
   - Filter Length: 320 msec.
   - Design Gates Near Offset: 5.1 to 8.3 sec
   - Design Gates Far Offset: 5.1 to 8.3 sec.

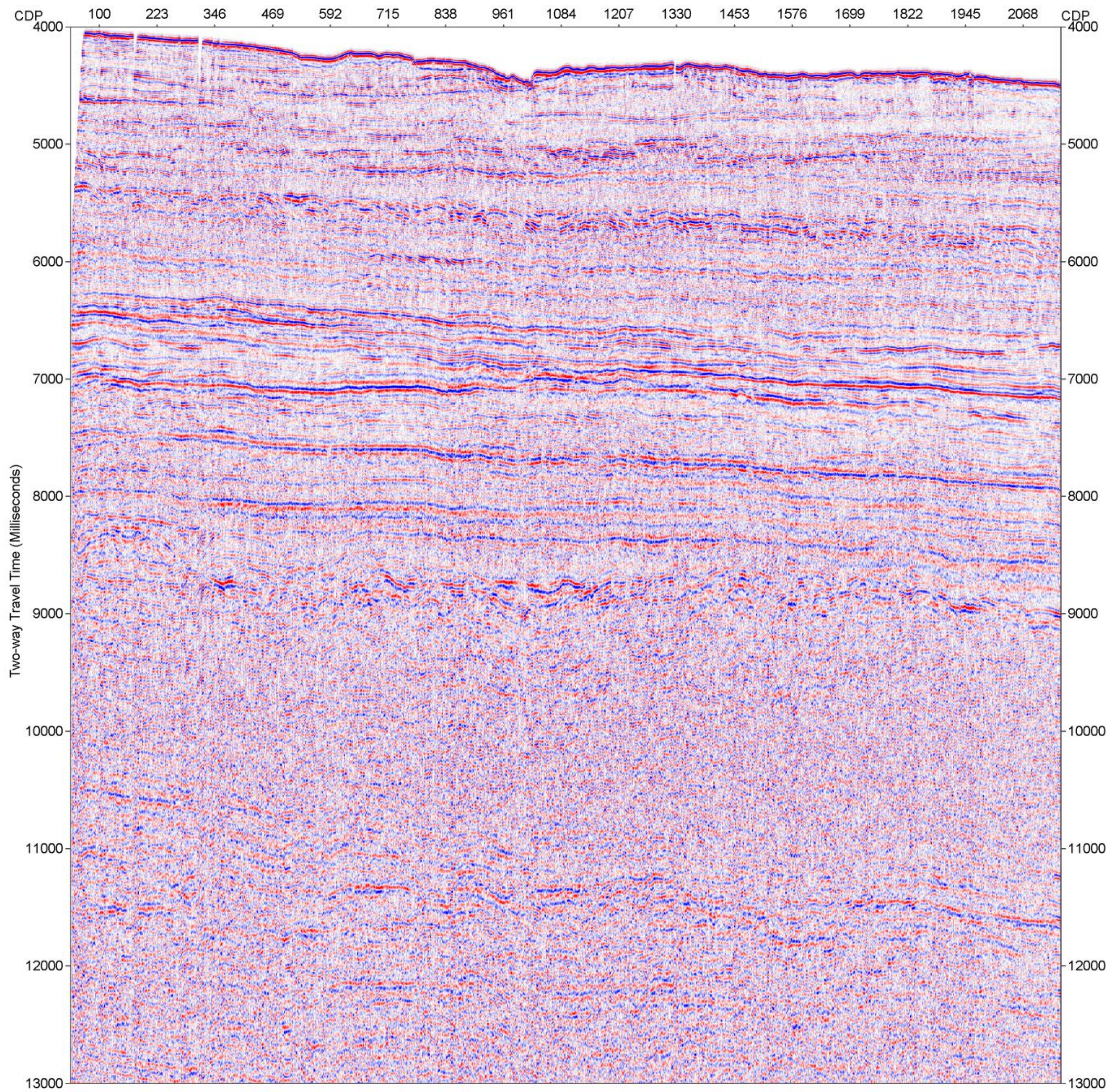
   - Shotpoints: 3039 to 3493
   - No. Filters: 1
   - White Noise: 1%
   - Filter Length: 320 msec.
   - Design Gates Near Offset: 5.3 to 9.3 sec
   - Design Gates Far Offset: 5.3 to 9.3 sec.
8. Stack 6 Fold
9. Digital Filter

Time: 0.0-1.6 sec Bandpass: 10 – 35 Hz
Time: 4.0-11.0 sec Bandpass: 5 – 25 Hz

10. Trace Amplitude Equalization

Note:
Both lines 3 and 3A are shown in Appendix B to show variations in the processing steps used in shallow water (Line 3 with 12 fold coverage) and deep water (Line 3A with 6 fold coverage)

DIGITIZED STACKED SECTION AND PROCESSING SEQUENCE
LINE 3A (USGS S-1-73)
Oil and Gas Readiness Study
Offshore Virginia



Note: The image above is a portion of Line 13 (Line 13 B1S) where it crosses into Virginia waters. It is uncertain whether the image above, created from a SEG-Y stacked section downloaded from the USGS NAMSS website is a copy of the data subjected to the original processing sequence shown on the right or whether it is a copy of the data reprocessed by Wise and Oliver (1989).

USGS Survey S-1-75

Source of processing information: Wise and Oliver, 1989

Client: USGS
Acquisition Company: Digicon Geophysical Corporation
Year Acquired: 1975
Processed by: Digicon Geophysical Corporation
Year Processed: 1977
Reprocessed by: USGS on VAX-II-780 computer using "Disco" software
Year Reprocessed: Late 1980's

Original Processing:
1. Demultiplex-Edit-Sum
2. Velocity Analysis
3. Normal moveout (NMO)
4. Trace Equalization
5. Filter
6. Distance Height
7. Stack 36 fold
8. Post-stack deconvolution
   Operator Length: 240 msec
   Time Window: 4.0-7.0 sec
   Prediction: 50 msec
9. TV Filter
   Time:0.0-5.0 sec
   Bandpass: 15 – 55 Hz
   Overlap: 0.3 sec

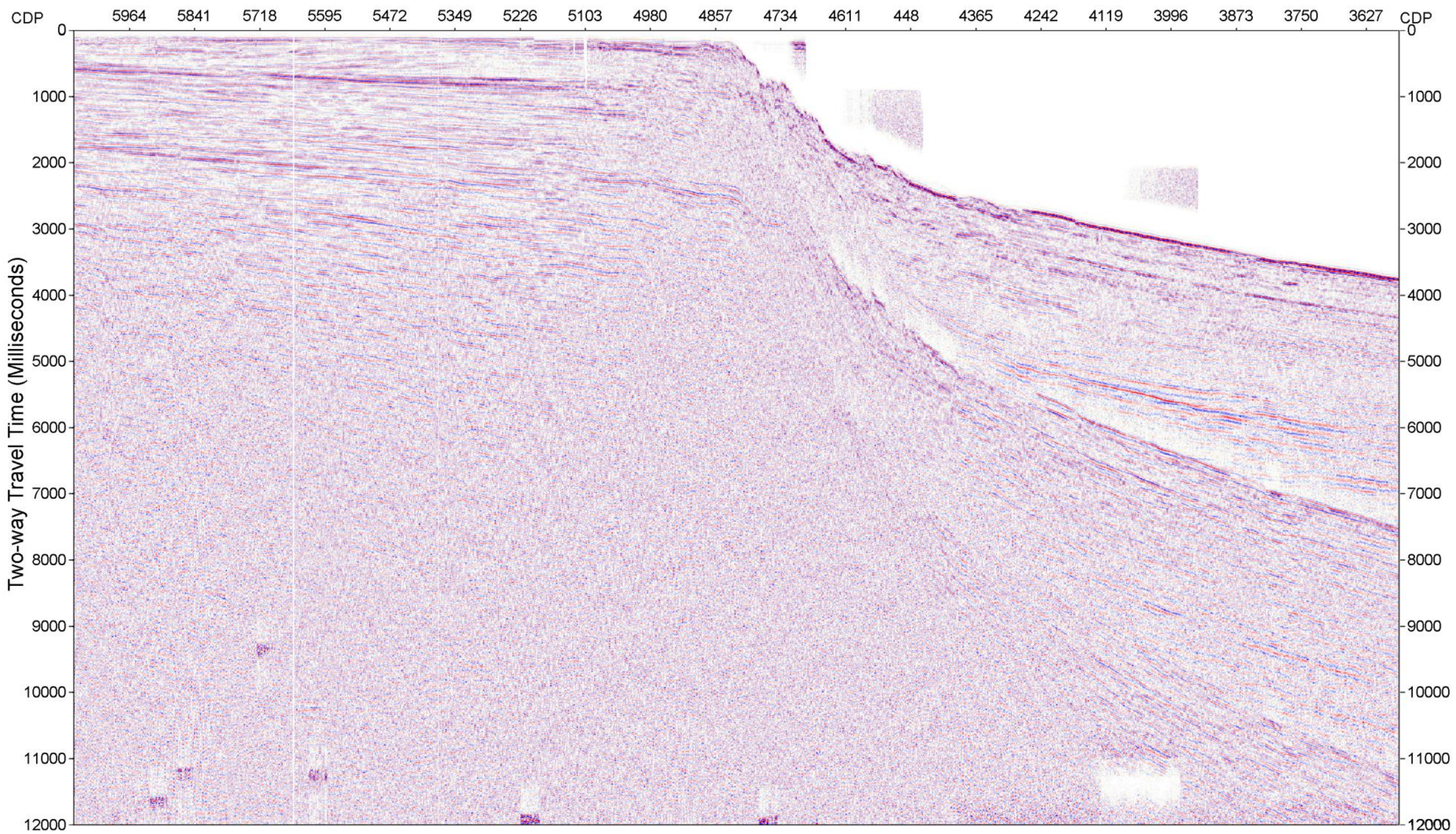
   Time:5.0-6.0 sec
   Bandpass: 10 – 40 Hz
   Overlap: 0.3 sec

   Time:6.0-14.0 sec
   Bandpass: 6 – 25 Hz
10. AGC 11 sec

Reprocessing:
1. Demultiplex
2. Recording Gain Removal
3. Geometry Definition
4. Trace Editing
5. Resample to 4 msec
6. Compress to 36 trace 100 meter records
7. CDP sort 36 fold
8. Velocity Analysis
9. Automatic Gain Control (AGC)
   Gate Length: 1000 msec
10. Pre-stack deconvolution
   Type: Spiking
   Operator Length: 81 Points (324 msec.)
   Time Window: 4.6-8.0 sec
   Type: Spiking
   Operator Length: 81 Points (324 msec.)
   Time Window: 7.0-14.0 sec
11. Normal moveout (NMO) Correction
12. First Break Noise Suppression (Mute)
13. Stack 36 Fold
14. Post-stack deconvolution
   Type: 2nd zero crossing
   Operator Length: 41 Points (164 msec)
   Time Window: 4.275-6.0 sec
   Type: 2nd zero crossing
   Operator Length: 41 Points (164 msec)
   Time Window: 5.5-8.5 sec
   Type: 2nd zero crossing
   Operator Length: 41 Points (164 msec)
   Time Window: 8.5-12.0 sec
15. Bandpass Filter
   Time: 4.0-5.5 sec Bandpass: 8:10 – 40:45
   Time: 6.5-7.5 sec Bandpass: 4:8 – 30:40
   Time: 8.5-14.0 sec Bandpass: 3:5 – 20:30
16. Mute along water bottom
17. Display

Notes: Shot points adjusted to actual antenna position.

STACKED SECTION AND PROCESSING SEQUENCE
LINE 13-B1S (USGS S-1-75)
Oil and Gas Readiness Study
Offshore Virginia



USGS Survey S-1-77

Source of processing information: Gilbert and Dillon, 1981 and a scanned section of Line 17 downloaded from NOAA's NGDC website.

Client: USGS
Acquisition Company: Teledyne Exploration
Year Acquired: 1977
Processed by: USGS on the Phoenix "I" computer (Lines 14, 17, TD-6 and part of TD-2) and Teledyne Exploration (Lines 15, 16, TD-1, TD-3, TD-4, TD-5 and parts of TD-2)
Year Processed: 1979

Stacked Section (Line 17)

1. Demultiplex edit sum
2. Velocity analysis
   5 adjacent CDP's were summed at 2.5 km intervals.
   Velocity sampling over range of 1400 to 3150 m/sec. at 50 m/sec. increments.
3. Bandpass filter

Interval (sec.)	Filter (Hz)
Variable	10-60
Variable	6-45
Variable	3-35

4. Constant scale
5. Mute
6. Normal moveout
7. Bandpass filter

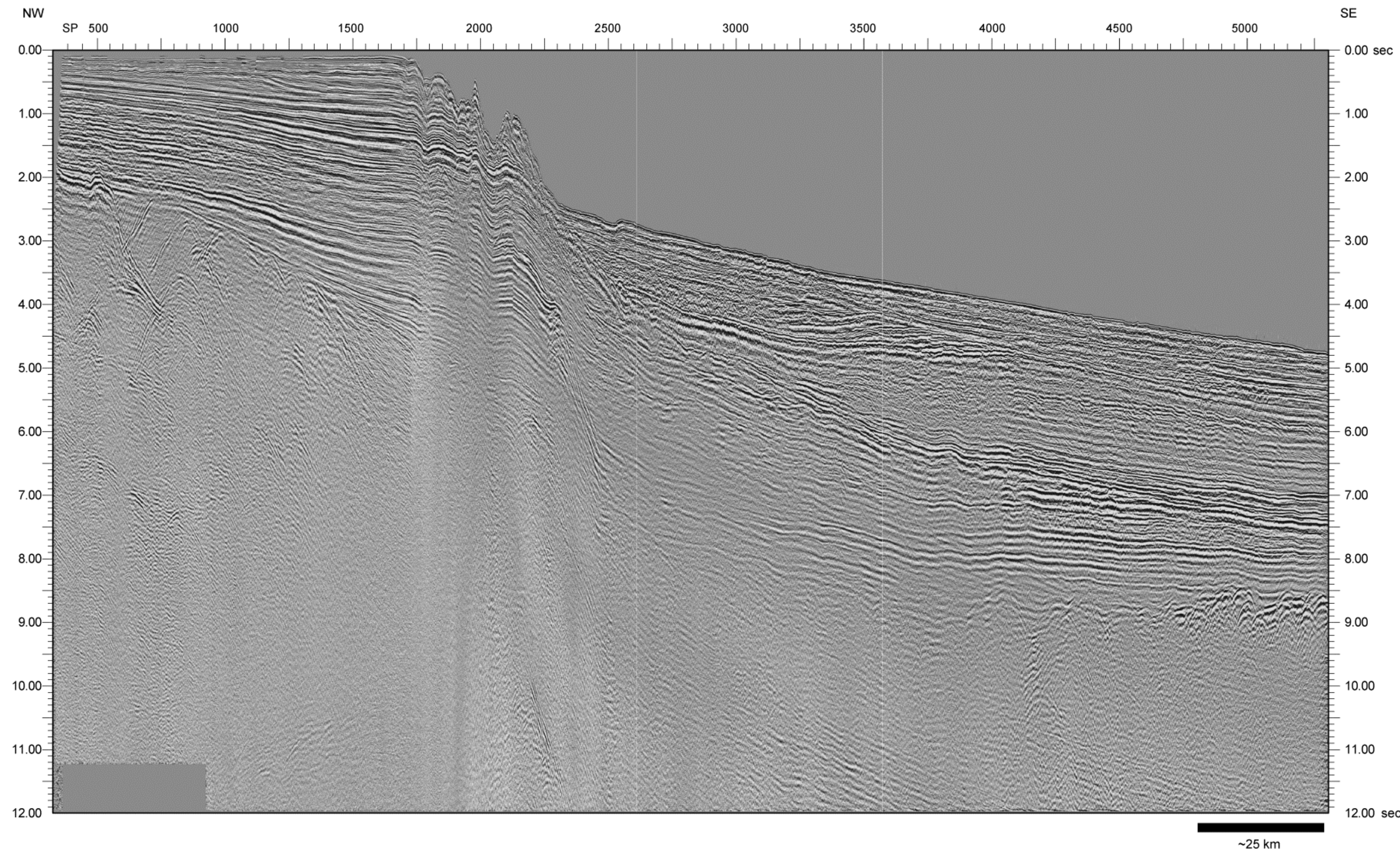
Interval (sec.)	Filter (Hz)
Variable	10-60
Variable	6-45
Variable	3-35

8. CDP Stack
   SP interval resulted in 1 trace per SP
9. AGC Scale
   AGC gain based on 1000 msec. sliding windows
10. Deconvolution

Operator	Predictive distance	Interval (sec.)
256 msec.	36 msec.	3.7 to 6.7
256 msec.	36 msec.	2.1 to 5.1
256 msec.	36 msec.	0.1 to 3.1
256 msec.	36 msec.	0.1 to 3.1

11. Trace equalization

STACKED SECTION AND PROCESSING SEQUENCE
LINE 17 (USGS S-1-77)
Oil and Gas Readiness Study
Offshore Virginia



USGS Survey C-1-78

Source of processing information: ATLAN_28.SPN text file from Twichell and Polloni, 1993.

Client: USGS
Acquisition Company: Geophysical Services, Inc. (GSI)
Year Acquired: 1978
Processed by: Geophysical Services, Inc. (GSI)
Year Processed: 1978 (Assumed)

Stacked Section (Line 28)

TRUE AMPLITUDE RECOVERY: GAIN REMOVAL
ALPHA = 5.0 dB/SEC
T1 = 0
T2 = 4.5 SEC

TIME VARIANT DECONVOLUTION:

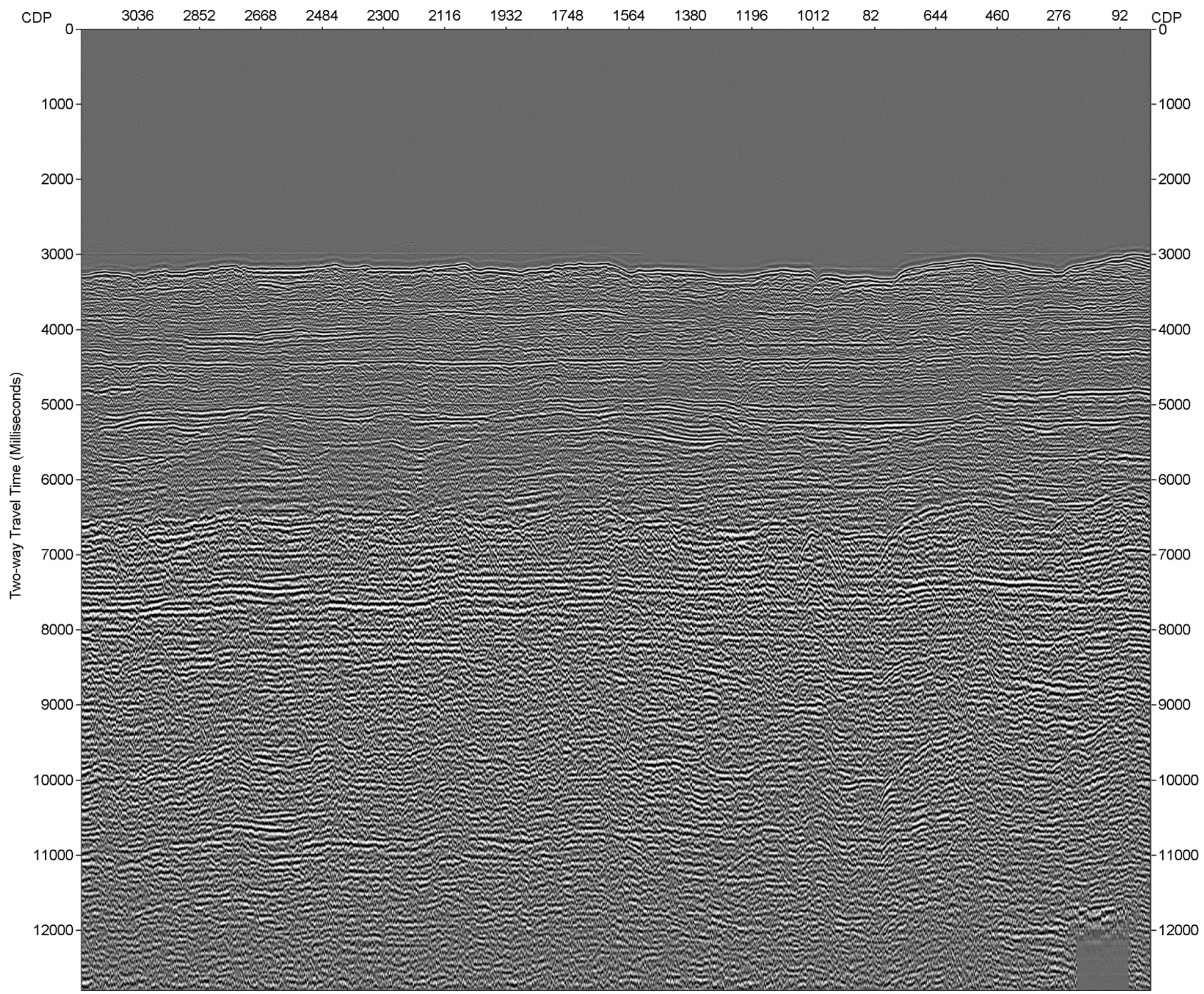
DEPTHS: 0-137 M	NUMBER OF FILTERS: 3	Filter Length: 400 MSEC
DEPTHS: 138-244 M	NUMBER OF FILTERS: 2	Filter Length: 400 MSEC
DEPTHS: > 244 M	NUMBER OF FILTERS: 3	Filter Length: 200 MSEC

TIME VARIANT SCALING:
GATE LENGTH 500 MSEC. UNITY AND
2 TO 1 FAR TO NEAR OFFSET SCALERS
START TIME = WB
VELOCITY ANALYSIS: VELSCAN VELOCITY ANALYSIS
SCATTERGRAMS AT 3 KM. INTERVALS
NORMAL MOVEOUT CORRECTIONS:
VELOCITY ANNOTATION ON SECTION HEADING
OPTIMUM TRACE MUTING
FIRST BREAK SUPPRESSION: VARIABLE
COMMON DEPTH POINT STACK: 48 FOLD
TIME VARIANT FILTERING:

TIME (MS+WB)	FILTER (HZ)
0	15 - 45
3000	12 - 30
5000	8 - 25

TIME VARIANT SCALING:
GATE LENGTH = 200 MSEC
START TIME = WB
UNITY SCALERS

STACKED SECTION AND PROCESSING SEQUENCE
LINE 28 (USGS C-1-78)
Oil and Gas Readiness Study
Offshore Virginia



BGR 79 Survey

Source of processing information: Scanned seismic section of Line 79-201F obtained from BOEM.

Client: Bundesanstalt für Geowissenschaften und Rohstoffe (BGR): The Federal Institute for Geosciences and Natural Resources
Acquisition Company: Prakla-Seismos
Year Acquired: 1979
Processed by: Prakla-Seismos
Year Processed: 1979 (Assumed)

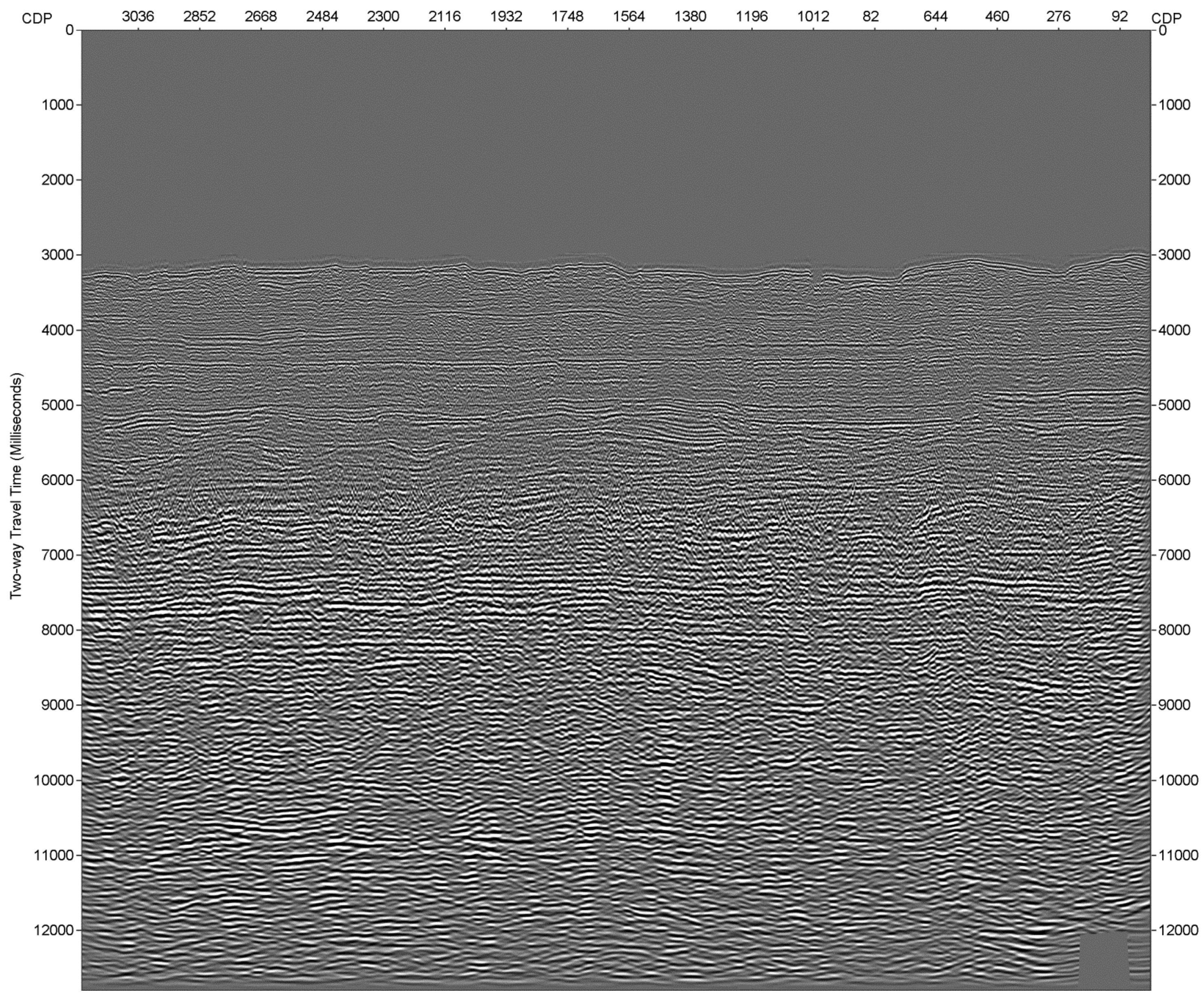
Stacked Section (BGR 79-201F)

1. Input: Tape format SEG-B 9-track, 800 BPI
   Sampling rate: 4 msec. 48 traces
2. Gain removal
3. Amplitude corrections
4. Predictive deconvolution
   1 Gate Gate length: 3000 msec.
   On shot near trace: Variable with water depth
   On shot far trace: Variable with water depth
   Operator length: 144 msec.
   Prediction interval: 36 msec.
5. Dynamic corrections derived from: Velocity analyses "GERA" 3 per 10 km
6. Normalization
7. Multiple suppression: MUKO
8. Horizontal stacking: 24-fold
9. Predictive time variant deconvolution
   7 gates Gate length: 2000 msec.
   Gates: Variable with water depth
   Operator length: 200 msec.
   Prediction interval: 60 msec.
10. Frequency filter: Linearly interpolated SP: 15253

Travel time	Low cut	High cut
0.0-3.7 sec.	12 Hz,15 dB/octave	45 Hz, 25 dB/octave
5.8 sec.	8 Hz,15 dB/octave	30 Hz, 25 dB/octave
6.4 sec.	5 Hz,15 dB/octave	20 Hz, 25 dB/octave
7.0 sec.- End	5 Hz,15 dB/octave	15 Hz, 25 dB/octave

11. Normalization
12. Display

STACKED SECTION AND PROCESSING SEQUENCE
LINE 79-201F (BGR 79)
Oil and Gas Readiness Study
Offshore Virginia



BGR 79

Source of processing information: Scanned seismic section of Line 79-201F obtained from BOEM.

Client: Bundesanstalt für Geowissenschaften und Rohstoffe (BGR): The Federal Institute for Geosciences and Natural Resources
Acquisition Company: Prakla-Seismos
Year Acquired: 1979
Processed by: Prakla-Seismos
Year Processed: 1979 (Assumed)

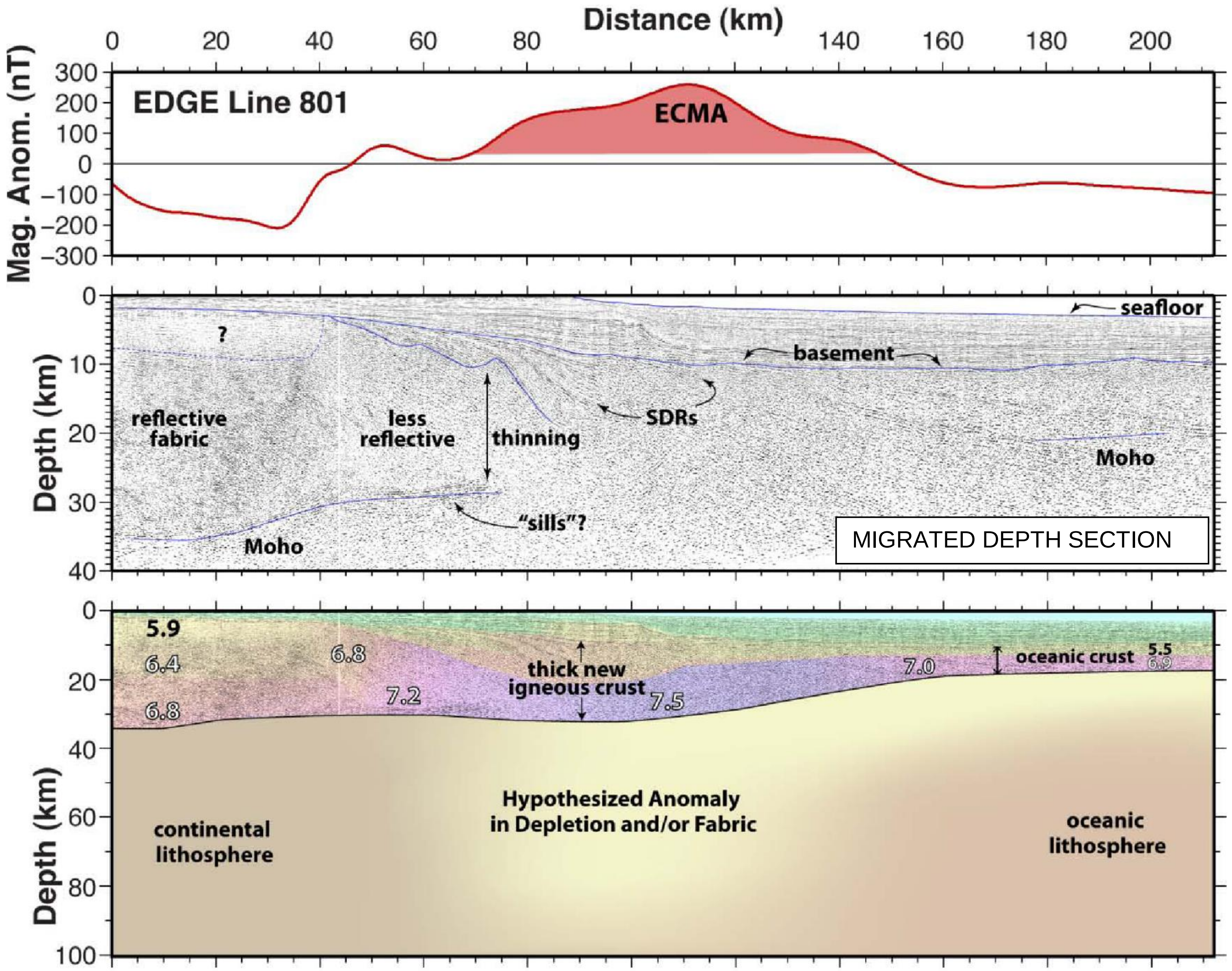
Migrated Section (BGR 79-201F)

1. Input: Tape format SEG-B 9-track, 800 BPI
   Sampling rate: 4 msec. 48 traces
2. Gain removal
3. Amplitude corrections
4. Predictive deconvolution
   1 Gate Gate length: 3000 msec.
   On shot near trace: Variable with water depth
   On shot far trace: Variable with water depth
   Operator length: 280 msec.
   Prediction interval: 36 msec.
5. Dynamic corrections derived from: Velocity analyses "GERA" 3 per 10 km
6. Normalization
7. Multiple suppression: MUKO
8. Horizontal stacking: 24-fold
9. Predictive time variant deconvolution
   7 gates Gate length: 2000 msec.
   Gates: Variable with water depth
   Operator length: 200 msec.
   Prediction interval: 60 msec.
10. Normalization
11. Wave equation migration
    ΔZ = 20 msec., Operator = 45 degrees
12. Frequency filter: Linearly interpolated SP: 1

Travel time	Low cut	High cut
0.0-0.6 sec.	12 Hz,15 dB/octave	45 Hz, 25 dB/octave
2.6 sec.	8 Hz,15 dB/octave	30 Hz, 25 dB/octave
3.2 sec.	5 Hz,15 dB/octave	20 Hz, 25 dB/octave
3.8 sec.- End	5 Hz,15 dB/octave	15 Hz, 25 dB/octave

13. Normalization
14. Display

MIGRATED SECTION AND PROCESSING SEQUENCE
LINE 79-201F (BGR 79)
Oil and Gas Readiness Study
Offshore Virginia



The above set of images came from a proposal submitted by various researchers (Van Avendonk et al., 2012) proposing to collect a suite of seismic data along the mid-Atlantic coast of the Eastern North America Margin (ENAM). The migrated depth section (middle image) is from Lizarralde and Holbrook, 1997 while the magnetic anomaly and bottom image of the velocity structure within the crust originate from Holbrook et al., 1994. Attempts to locate and download the MCS data as part of the VAEDGE project were unsuccessful.

Virginia 1990 EDGE Experiment (VAEDGE)

Source of processing information: Purdy and Holbrook, 1990, Sheridan et al., 1993 and Holbrook et al., 1994.

Client: Cooperative project between USGS and various academic institutions (Funded by NSF and Texaco Oil Company)
Acquisition Company: GECO (MCS Data)
WHOI, USGS Woods Hole & URI (Ocean Bottom Seismometer & Ocean Bottom Hydrophone data)
University of Wyoming (Land-based recording: 16 PASSCAL REFTEK instruments)
University of Georgia (Land-based recording: 20 EDA instruments at one station)
Year Acquired: 1990
Processed by: Houston Advanced Research Center
Year Processed: 1990 (Assumed)

Processing Steps from Sheridan et al., 1993

1. Decimation to 8 msec
2. CDP gathering
3. Deconvolution
4. F-k filtering to suppress coherent noise and multiples
5. Low-velocity multiple suppression (Z mult)
6. Muting
7. Constant-velocity stacking at 1 km spacing
8. NMO corrections
9. Dip-moveout (DMO) stacking
10. Summing adjacent 12.5 CDPs
11. Finite difference wave-equation migration
12. Time-variable filter
13. Automatic Gain Control (AGC)
14. A velocity model was constructed by inversion of wide-angle and vertical-incidence travel times.

Notes: Southeast end of line MA801 & MA804 were not processed routinely due to Gulf Stream velocities of 4 knots degrading the data so that only the near 40 traces were useful.

MCS data was collected in conjunction with OBS/OBH data and recordings at land-based seismometers. Only information pertaining to the processing of the MCS data is listed here.

More detailed information regarding the inversion of the seismic data can be found in Holbrook et al., 1994 & Lizzarralde and Holbrook, 1997.

MIGRATED DEPTH SECTION AND PROCESSING SEQUENCE
LINE 801 (VAEDGE)
Oil and Gas Readiness Study
Offshore Virginia

APPENDIX C- SUMMARY OF KEY DATA PROCESSING CONSIDERATIONS AND LIMITATIONS

APPENDIX C

The ultimate objectives of seismic data processing are to preserve the signal and attenuate the noise. Unfortunately, many noise attenuation procedures also tend to attenuate portions of the primary reflection signal energy. Improving the signal-to-noise ratio to enable more accurate geological interpretation of the recorded seismic wave-fields requires carefully designed procedures to avoid significant loss of geophysical data. The following sections describe many important topics that need to be considered when processing seismic data, although, acquisition of high quality data in the field is a pre-requisite for successful seismic imaging.

1.0 ALIASING (TEMPORAL AND SPATIAL)

The ultimate control on resolution in seismic data processing is aliasing – an effect of digital sampling which creates ambiguity in the frequency content of the digital time series. It is necessary to have two samples per wavelength to define the corresponding frequency. Higher frequencies will appear lower due to this sampling effect and, during data processing such as stacking, aliased data appearing at low frequencies will obscure the real signal at higher frequencies. The maximum frequency that can be accurately represented is called the Nyquist Frequency.

For typical digital sample rates in exploration seismology, two samples per wavelength represents the following Nyquist frequencies:

Sampling Interval	Nyquist Frequency
1 ms	500 Hz
2 ms	250 Hz
4 ms	125 Hz
8 ms	62.5 Hz

Anti-alias filters are applied to the analog hydrophone signal during acquisition (before digitizing) typically using one-half the Nyquist frequency to avoid any possible aliasing of the digital signal.

Elements of the receiver (and source) arrays also represent digital (discrete) sampling, so there is a spatial Nyquist frequency to be considered. The spatial Nyquist frequency is usually the ultimate control on resolution in seismic reflection data. If there is coherent noise, the velocity appropriate for computing the spatial Nyquist frequency is the slowest velocity of the noise (or signal – for dipping events, normal moveout, etc.). Use of the common depth point (CDP) method for data acquisition and processing places some special constraints, which are often overlooked, on the potential for aliasing. The group interval in the hydrophone streamer defines the spatial Nyquist frequency for attenuating backscatter and source-generated noise in shot gathers. However for the stack array, which is the CDP gather, the relevant sampling interval is 2 x group interval. For migration, the CDP bin interval is the relevant sample interval (trace distance) used for migration. The lowest spatial Nyquist frequency arises from the stack array – for some typical group intervals the spatial Nyquist frequencies (using 1500 m/s acoustic velocity) are:

Group Interval	Nyquist Frequency
100 m	7.5 Hz
50 m	15 Hz
25 m	30 Hz

“Noise-free” areas may use a higher frequency bandwidth, but the processor should be aware of spatial aliasing that creeps in during any stacking process. Most coherent noise is source-generated, and shallow water enhances the propagation of coherent noise in the water column waveguide.

2.0 SPECTRAL WHITENING

Deconvolution is used to produce a more impulsive waveform with zero phase, so that the arrival time of the reflection corresponds to the peak of the waveform rather than at a zero-crossing. Some of the early seismic data did not apply deconvolution until after stacking the data. More recent wavelet processing schemes equalize the wavelet so that through summation in the stacking process, noise is attenuated through destructive interference (cancellation) and the signal is enhanced (which has a similar waveform).

Signature Deconvolution uses the known (measured) source signature to design an inverse filter that will convert the raw wavelet into a well-defined symmetrical wavelet – the ideal wavelet would be a signal spike, but finite frequency bandwidth produces a central peak with side lobes. A waveform with a narrow peak and few low-amplitude side lobes is desired to produce the best resolution. Spectral whitening is a procedure similar to deconvolution that is used to broaden the bandwidth of the seismic data by enhancing higher frequencies in the spectrum to account for source character, receiver array filtering, reverberation and subsurface attenuation of higher frequency wave energy. Spiking deconvolution, which sets the prediction distance to zero in order to create a true spike waveform is applied before stack to “equalize” the wavelet.

Time-Varying Deconvolution, where parameters are varied over different two-way travel time windows, is commonly applied in the vintage data to produce better waveforms at depth. The long record length includes data that suffers greater reduction in bandwidth with depth due to attenuation of high-frequency signal.

Predictive Deconvolution after stack is applied to remove reverberations and preserve higher frequencies that may be attenuated by the stack after normal move-out (NMO) correction. Stretch of the shallow reflection energy smears out the reflections at longer offsets which attenuates higher frequencies. Also, slight differences in arrival times of the primary reflection signal, due to variations in streamer depth (ocean waves), small-scale velocity variations, and other effects also smear the reflection signal after stacking. The prediction length should be appropriate for attenuating reverberation observed in the stacked data, and a zero phase operator should be used if a spiking deconvolution or other filter was applied to convert the raw data from minimum-phase into zero-phase (symmetrical wavelet) character.

3.0 CONFLICTING DIPS

Stacking requires consideration of variable dips because the NMO correction may misalign important features like diffractions needed for migration or events with opposing dips located at different positions along the profile. Dip Moveout (DMO) may be necessary to properly account for these effects, although pre-stack migration is a more accurate, but time-consuming procedure for accommodating these events.

4.0 NEAR TRACE OFFSET (SHALLOW WATER IMAGING)

Deep seismic imaging surveys use longer offsets than high-resolution (hazard) surveys, resulting in shallow water reflections that are wide-angle reflections or refractions (first breaks) on the near traces. Stretch produced by the NMO correction smears these events and the CDP stacking process is unable to image water bottom and shallow subsurface features. Deep imaging of reflections is satisfactory in most cases provided that the offset range is adequate to capture normal-incidence reflection energy from the seafloor and subsurface features.

5.0 MULTIPLES (SURFACE-REFLECTED AND INTERBED)

Seismic wave energy that is reflected multiple times between the seafloor and sea surface (surface reflected multiples) or between different layers in the subsurface (interbed multiples) are the most severe form of coherent noise in marine seismic reflection profiles. In single-channel data, where only one trace is recorded from the hydrophone streamer for each shot point, it is usually impossible to identify any subsurface primary reflections below the arrival time of the first water-bottom multiple. Multichannel seismic reflection profiling uses the relative differences in travel time between adjacent traces for each group in the shot records to attenuate both surface-reflected and interbed multiples. Interbed multiples are sometimes referred to as friendly multiples because the reverberation produced by the multiple reflections within a layer create lower frequency signal energy that may actually help in imaging and interpreting deeper structures. Resolution is progressively lower at depth because high frequency wave energy dissipates whereas the low frequency energy persists to greater depths.

Normal Moveout differences are used to attenuate multiples, which travel at water velocity which is almost always slower than the seismic velocity within primary reflection layers. Differential moveout between receiver groups is used to attenuate the multiples, and the far offset groups show greater differential moveout than the near traces. Consequently, the far trace offset and fold determine success of multiple attenuation during CDP stacking. Careful velocity analysis is required to achieve success using the stacking process for attacking multiples, and use of frequency-wavenumber (f-k) filters may be used to attenuate multiples, too.

Surface-Reflected Multiple Elimination (SRME) – Procedures to eliminate surface-reflected multiples by subtraction of the predicted multiple require good acquisition geometry and accurate measurement of sea floor elevation (depth). SRME was probably not used on the vintage data. It is a labor-intensive process that requires careful testing and selection of parameters to successfully attenuate the multiples. It is less damaging to the primary signal wave energy than radon transform or f-k filtering methods of attenuating multiples. SRME may be used with the other methods, but always must be performed first, without other filtering effects in order to predict the multiples accurately.

Radon Demultiple Processing requires dense sampling to avoid spatial aliasing at high frequencies. Radon transform methods may be used in conjunction with SRME and the CDP stack to improve multiple suppression where deep water multiples are severe.

6.0 SEISMIC VELOCITY DATA

Accurate seismic velocities are necessary for stacking, migration (imaging), time-to-depth conversion, and lithology. Velocity analysis is performed on multichannel seismic data by using the moveout variations along the receiver array to compute subsurface velocity structure.

The hydrophone streamer must be long enough to provide adequate NMO differences to provide separation of reflection events at depth. The group interval must be short enough to avoid spatial aliasing at far offsets. Thus, hybrid streamers with shorter group intervals at far offsets were frequently used in vintage surveys.

Fold (number of channels, group interval and shot interval) must be sufficient for resolution of velocities, i.e., there must be enough traces to compute the hyperbolic moveout at various subsurface depths. Also, the CDP hyperbolic moveout approximations (Dix equation) are valid only for the shorter offsets. Many state-of-the-art seismic processing systems can compute non-hyperbolic moveout for long offset data.

Dipping Events have apparent velocities that are higher than flat (horizontal) surfaces. Dipping seafloor or subsurface structure may produce multiples that are difficult to separate from primary reflections at greater depths because the moveout resembles higher velocities of deep layers.

Side-Swipe from shallow structure off-line may obscure deeper primary reflections. 3-D effects like side-swipe are more severe in shallow water for deep targets because water-layer trapped energy is readily backscattered from seafloor irregularities and may be recorded at times similar to primary reflections from target depths. The high-frequency character of the backscatter helps to identify these problems, and low-pass filtering may attenuate the coherent noise.

Stacking Velocities are faster than Migration Velocities due to effects of dip. Consequently, additional effort is necessary to define the migration velocity structure. Separate velocity analysis may be necessary to determine appropriate migration velocities. Alternatively, simple f-k migration at water velocity (1500 m/s) would provide significant sharpening of the subsurface image for a “quick-and-dirty” reprocessing strategy for existing stacked data.

7.0 NOISE – COHERENT AND AMBIENT (RANDOM)

Most severe coherent noise is source-generated. The same acoustic source used to produce the seismic reflections from the subsurface also creates coherent acoustic noise in the water column that may “stack-in” during CDP processing. Dense sampling of the seismic wavefield is needed to attack coherent noise and avoid aliasing (spatial in particular).

Ambient (random) noise is usually attenuated by averaging (destructive interference) during the stacking process. Attenuation is proportional to $1/\sqrt{N}$ (where N is the fold or the number of traces summed in the stacking process), so that higher fold is important in the data acquisition and processing.

8.0 STATICS

Time shifts in data due to elevation differences (variable source and receiver depths), shallow velocity structure, and swell (ocean waves) are called statics. Stacking seismic reflection traces with variable time-shifts smears the primary events and reduces image resolution. Source and receiver elevation time shifts can be computed from data provided in the acquisition observer’s notes (if available) and the statics may be removed during data processing. With increased effort, more refined statics analysis and corrections may be applied to improve the resolution and coherency of the seismic image.

Tidal correction may be required for high-resolution data where tidal variations are significant (mis-ties on cross-lines acquired at different tide levels) but are not normally required on open ocean surveys. Tidal corrections are probably not significant at relative low-frequencies of deep imaging data where 3-D effects like cross-dip are more likely to produce mis-ties at line intersections.

APPENDIX D – DESCRIPTION OF PROPOSED METHODOLOGY AND EQUIPMENT FOR POTENTIAL FUTURE 2-D SEISMIC SURVEY

APPENDIX D

Appendix D presents a description of the methodology and equipment for a potential future 2D survey as proposed in Section 5 of this report. The intent is to propose a survey that provides regional coverage of the anticipated Mid-Atlantic OCS that may be put up for lease during the upcoming BOEM 2017-2022 Oil and Gas Leasing Program sale. The survey is intended to include coverage (both strike and dip lines) over each of the BOEM recognized geologic plays (Figure 5.3-1) but small enough so that the survey could be permitted, contracted, performed and interpreted in time for the results to be included within the Lease Block documents which will be required by early 2016.

1.0 SUGGESTED SURVEY METHODOLOGY

The challenges the offshore O&G industry faces in the new millennium are far more complex than in the 1970's and 1980's when a large portion of conventional hydrocarbon resources had yet to be discovered through the use of 3-D seismic technology. The search for offshore oil and gas has moved from the more accessible and less expensive near-shore environment into ecologically sensitive and/or extremely harsh deepwater environments into regions where seismic imaging is difficult due to reservoirs being located beneath large-scale salt structures (i.e., sub-salt plays) and within structurally complex (i.e., heavily folded and faulted) areas. Field development in these environments often requires substantially larger accumulations of hydrocarbons (compared to the near-shore environment) to be of economic interest to developers.

Presently, the discovery of new offshore oil fields is not keeping pace with the decline of known, proven offshore reserves. According to the US Energy Information Administration (EIA), energy consumption is projected to increase by 50% from 2015 to 2030. To successfully meet such demands, future exploration surveys need to be carefully planned and implemented to ensure successful identification of potential hydrocarbon targets. The oil and gas production from numerous reservoirs located in the frontier Atlantic Margin OCS are anticipated to be of sufficient size and pressure to be commercially exploited for the coming decades.

Seismic acquisition companies strive to provide their clients with the best possible product by utilizing the most dependable, state-of-the-art equipment to properly image the target(s) of interest in the subsurface. After receiving details of the geographical area of interest, the depth of the target, the resolution (both horizontal and lateral) needed by the client and its intended use (e.g., a regional 2-D study, 4-D reservoir monitoring, sub-salt imaging, amplitude versus offset analysis), the seismic acquisition contractor will determine the specific design of the survey (e.g., 2-D or 3-D acquisition, source-receiver offsets, group intervals, shotpoint intervals) and the optimal equipment to employ.

In this appendix, equipment typically specified to acquire a 2-D survey similar in scale to the one proposed in Section 5.3 ("Acquisition of New Seismic Data") of this report are presented along with an estimated schedule to complete such a survey. In order to acquire high quality seismic data it is necessary to use reliable equipment that meets the specifications of the seismic survey's design.

Commonly, equipment specified to conduct a seismic survey can be divided into five primary categories:

1) Navigation/Positioning
2) Seismic Recording System
3) Seismic Energy Source
4) Streamer Design
5) Onboard Processing System

1.1 NAVIGATION/POSITIONING

Marine positioning is more difficult than on land because the survey vessel (and all of the necessary towed equipment) is continuously in motion. Nevertheless, the precise locations of the energy source(s) and the streamer(s) relative to each other, and their actual position over the seabed, must be known at all times. In such a dynamic environment, real-time positioning is extremely complex. During acquisition, the survey company should utilize an integrated combination of multiple reference site Differential Global Positioning System (DGPS), Relative GPS, laser measurements of ranges and angles, underwater acoustic ranging and digital compasses along the streamer(s).

The accuracy of GPS is limited by how well the different positioning error sources can be determined. Conventional DGPS techniques typically calculate for all sources of errors (orbit, ionosphere, troposphere, clock, multi-path) into range (Prc) and range rate (Rrc) correction components. Providing the impact of these errors is the same at both reference station and user location, the user position will be accurate. However, as the distance between the user and reference station increases, the effects of error de-correlation become more and more significant, thereby increasing the potential for error in the user's observed position.

Literally hundreds of complex mathematical position calculations are carried out every few seconds, enabling the precise positions of the vessel, the seismic source(s) and the individual hydrophone groups in the streamer(s) to be calculated in real-time as the vessel continuously moves along. Traditional DGPS services use the fixed location of a single reference station to measure the ranges to all GPS satellites in view. These measurements are then compared to the computed ranges at that location and the resulting differences in the observations are transmitted as pseudo range corrections. This technique introduces some inaccuracies as the distance from the reference station grows.

In the more modern surveys being carried out today, a positioning system such as Starfix-HP, a state-of-the art positioning system, is required to provide highly reliable corrections for any location, regardless of distance to a reference station. Starfix-HP, the latest innovation in DGPS technology by Fugro, removes the range limitation of traditional DGPS by using ionosphere corrected measurements in combination with the observed signal carrier phase, to produce a wide area positioning solution with decimeter accuracy at ranges greater than any other operational system.

The accurate positioning of air guns and streamers towed behind the survey vessel are in turn determined by a combination of GPS sensors mounted on the streamer floats, tailbuoys, and range finding techniques using Ultra Short Baseline (USBL), or equivalent, from the survey vessel, or from a second following vessel called the Slave Ship.

1.2 SEISMIC RECORDING SYSTEM

In the 1970's and 1980's the amount of data that could be recorded and processed was highly dependent on the capabilities of the seismic recording system employed. The number of channels recorded varied over this time period from 24 in the early 1970's to well over 200 at the end of the 1980's. Today, systems such as the Input/Output MSX allow the recording of up to 7,680 channels at a 2 millisecond sampling rate with up to 16 streamers. Additionally, this system creates automatic observer and tape cartridge logs and comes with a Quality Control system for instantaneous detection of errors. There are a variety of low cut and high cut filter designs to suit each survey's needs and the data is recorded in SEG-D format using IBM Magstar 3590 tape drives.

1.3 SEISMIC ENERGY SOURCE

Seismic energy sources are devices that generate controlled seismic energy used to provide the acoustic source for seismic surveys. A seismic source can be a low technology explosive such as dynamite, but for modern marine seismic surveys, more sophisticated technology, such as an air gun array specially designed for the survey target types and depths. Seismic sources can provide single pulses or continuous sweeps of energy. Both types of seismic sources generate seismic waves, which travel down through the water column into the subsurface stratigraphy, and reflect back a portion of the signal at each density contrast to be recorded by hydrophone receivers within the streamers.

The typical seismic energy sources utilized in modern surveys are air guns. Within the air gun there are one or more pneumatic chambers that are pressurized with compressed air from 2,000 to 3,000 pounds per square inch (psi). When the air gun is fired every few seconds, a solenoid is triggered, releasing air into a fire chamber which, in turn, causes a piston to advance, allowing the air to escape the main chamber through portholes to produce a controlled pulse of acoustic energy. Seismic energy is generated by the rapid, explosive release of compressed air through the air gun's ports. This produces a primary energy pulse and oscillating bubble.

An example of a typical air gun used for modern survey is the G. Gun by Seismic Solutions, Inc. This is a lightweight air gun that is small, powerful, and most important for seismic surveying fires with a consistent, repeatable acoustic pulse. This air gun can be repeated up to 250,000 time at 3,000 psi, which is on the higher end of most seismic survey requirements for air gun pressures.

Typically, multiple air guns are towed behind the vessel, several meters below the sea surface in a pre-determined combination, or 'array' of different chamber volumes designed to generate an optimally tuned energy output of desirable sound frequencies. Air gun arrays can be built up of up to 48 individual air guns with different size chambers, the aim being to create the optimum initial shock wave with minimum reverberation of the bubble after the first shot. Gun arrays can be fired in a single combined shot mode or be selected and fired alternately. Large chambers (i.e., greater than 1.15 liters or 70 cubic inches) tend to give low frequency signals, whereas small chambers (less than 70 cubic inches) give higher frequency signals.

1.4 STREAMER DESIGN

As discussed in the main report, streamers consist of a flexible hose filled with hydrophones, electronics, flotation, and other electrical components. A group of individual hydrophones are wired together to record the acoustic wave energy along sections of the streamer at specific intervals, known as the group interval. This array of hydrophones acts as a spatial filter for the acoustic waves, so that vertical wave energy is enhanced by constructive interference and horizontal energy is attenuated by destructive interference. Steel or Kevlar support allow the streamers to hold together despite weights of several tons each including the drag forces induced by being dragged through the water.

Modern streamer construction includes a wide range of innovations that were not available in legacy surveys. These include the ability to query in real time the feathering effect of the streamer behind the vessel, the hydrophone group array for data quality, the ability to turn on and off hydrophones in case of faulty data recording, and the ability to control in real time the tow depth and alienation of the streamers relative to the air gun sources.

Streamers are most commonly towed at a uniform depth. Birds are used to adjust the streamer during the survey. The wings on the birds are hydrostatically controlled to adjust based on the pressure, temperature and salinity variations. The birds are frequently spaced at 250 to 300 m intervals along the streamer.

1.5 ONBOARD PROCESSING SYSTEM

In order to have enough computational processing speed and memory onboard the survey ship to record and collect all of the data from the array of hydrophones and other data sources, it is imperative that high quality and robust computer equipment is readily available. In addition, several key processing software packages must be available onboard the vessel. The goal of onboard processing is to ensure that the acquired data is properly recorded and of sufficient depth and resolution, for the survey goals.

1.6 SUGGESTED SURVEY PARAMETERS

The following parameters are suggested for the regional survey as described in Section 5 of the main report.

Survey Size:	8,100 kilometers
Number of Lines:	14 lines (Average lengths of approximately 600 km)
Streamer Length:	8 kilometers
Single Source:	5,860 cubic inches
	138.3 bar-meter peak-to-peak amplitude
	Pulse to bubble ratio (P/B) = 18.0:1
Shot Point Interval:	25 meters
Record Length:	12 seconds
	Deepwater delay available for increased recording length

2.0 SUGGESTED SEISMIC EQUIPMENT SPECIFICATIONS

2.1 Navigation/Positioning System

On-line Navigation System:	Spectra, Concept Systems

Primary Navigation:	Starfix HP, Differential GPS
GPS Receiver:	Ashtech, Z-Eurocard
Secondary Navigation:	Starfix L1, Differential GPS. Fugro
Demodulator:	Fugro 3000LR
GPS Receiver:	Trimble 4000DS 9 channels nav ver. 7.28
Tail Buoy Tracking	Seatrack 220 RGPS (Fugro) and radar.
Gun Array Tracking:	Nominal offset rotated by near compass. Optional RGPS
Laser:	Optional - MDL Fanbeam
VRU:	Seatex MRU-5
Navigation Processing:	Sirius v2001, ECL / Concept Sprint
Echosounder:	Simrad EA500
Echosounder Transducer:	Simrad 27-26/21 (Frequency = 27 kHz) Simrad 12-16/60 (Frequency = 12 kHz, Narrow beam = 16 degrees, Wide beam = 60 degrees) Maximum range 3,000/11,000 meters
Streamer Control	Digicourse DigiBIRD 5010 / 5011 Compass birds
Speed log:	Simrad Skipper EML 224

2.2 Seismic Recording System

Type	Input/Output, MSX, 24 bit system
Number of Channels	960 channels @ 1 millisecond sample rate
Number of waterbreaks	4 channels
Number of auxiliary	48 channels
Sample Rate	1, 2 and 4 ms
Filters	
Low Cut	Out, 2 Hz, 6dB/octave 2 Hz, 12 dB/octave 4 Hz, 12 dB/octave 6 Hz, 12 dB/octave 8 Hz, 18 dB/octave
High Cut	1 millisecond: 412 Hz, 264 dB/octave 2 milliseconds: 206 Hz, 264 dB/octave 4 milliseconds: 103 Hz, 264 dB/octave
Recording Format	SEG-D
Recording Medium	6 x IBM Magstar 3590

QC System	All QC data, QC plots - AGC or fixed gain; harmonic distortion analyses; noise analyses; spectral analysis;
On-line Display	Oyo GS 624-2
Single channel recorder	Ultra 200

2.3 Acoustic Energy Source

Type	Sodera G-gun
Size of guns:	40, 70, 100, 150, and 250 Cubic Inches
Maximum Volume:	5860 Cu. Inch
Maximum Output: (Depth: 5 m; 0-128 Hz)	138.3 bar-meter peak-to-peak amplitude Pulse to bubble ratio (P/B) = 18.,0:1
Number of Subarrays:	4
Configuration:	Single or dual source 2 x 2930 Cubic Inches
Tow Width:	30 or 50 m dual source
Firing Control/QC:	Seamap Gunlink 2000
Depth transducers:	4 x 3
Tow system:	Norwegian buoys
Offset:	144 m with a 6,000 m streamer 250 m with a 12,000 m streamer
Compressor	2 x LMF, each 1100 SCFM 4 x EKA, each 390 SCFM
Compressor capacity	3760 SCFM
Pressure:	2000 PSI

2.4 Streamer Design

Type	Input/Output, MSX or Solid digital
Maximum length	12 kilometers
Available group interval	12.5/25 meters
Section length	99.5 meters
Groups per section	8
Hydrophone type	Input/Output, Preseis 2517
Hydrophones per group	14 hydrophones (2.5 m), tapered array, center weighted. 29 % overlap, total group length 17.55 m
Streamer diameter	63.5 mm
Streamer sensitivity	14 V/Bar
Fault locator	Input/Output

Depth Controller	Digicourse System 3. DMU
Depth Control / Compass	Digicourse DigiBIRD 5010/5011
Cable oil superclean	3000 ltr.
Cable oil clean:	2250 + 960 ltr.
Cable oil dirty:	1.920 ltr.

2.5 Onboard Processing Equipment

Hardware:	SGI Origin 200. 4 X R10000 CPU's at 250 Mhz 2 SGI O2 workstations Total disk space: 4 TB Total RAM: 4 GB SeisNet Real-time QC system from SSI inc. Oyo 36" thermal plotter
Software:	Paradigm Focus v. 5.1 SeisPact data compression v. 3.4 from Aware Inc.
Capability:	Full 2D QC processing Real time 2D QC Full onboard final processing Short offset high resolution processing
Tape drives:	3 x IBM 3590 Magstar 1 x 8 mm Exabyte drive

2.6 Estimated Duration for Survey

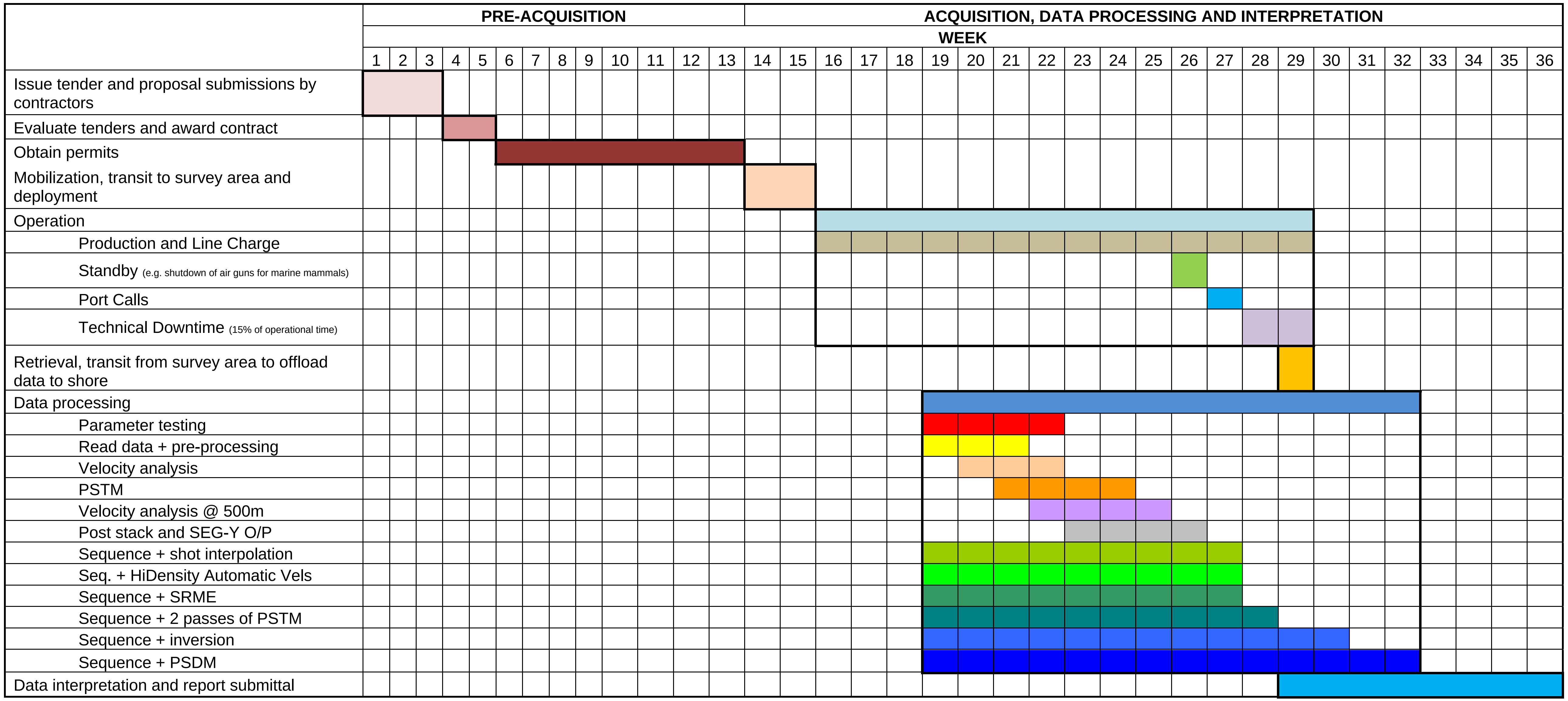
Estimates for the durations of the survey are as follows:

- Mobilization from the Gulf of Mexico — 15 days
- Operational (Production and Line change) — 67 days
  - *Standby for third party factors; fishing activity or identified presence of marine mammals (Estimated at 8% of Operational Time)* — *5 days*
  - *Port Calls (Assumed 1 port call during survey)* — *5 days*
  - *Technical Downtime (Estimated at 15% of Operational Time)* — *10 days*
- Retrieval, transit from survey area and demobilization — 2 days
- Processing of seismic data — 28 days
- Interpretation of seismic data and report writing — 28 days

Total Survey Duration — ***160 days***

The total time frame for the bidding process is listed below.

- 3 weeks to issue tender and have contractors submit proposals
- 2 weeks to evaluate tenders and award
- 6 to 8 weeks to get permit



PROCESSING TIMELINE FOR POTENTIAL FUTURE 2-D SEISMIC SURVEY
Oil and Gas Readiness Study
Offshore Virginia

FIGURE D-1

APPENDIX E – EXAMPLE LEASE STIPULATIONS

APPENDIX E - EXAMPLE LEASE STIPULATIONS[1]

A. HOLD AND SAVE HARMLESS

Whether compensation for such damage or injury might be due under a theory of strict or absolute liability or otherwise, the lessee assumes all risks of damage or injury to persons or property that occur in, on, or above the OCS, and to any persons or to any property of any person or persons who are agents, employees, or invitees of the lessee, its agents, independent contractors, or subcontractors doing business with the lessee in connection with any activities being performed by the lessee in, on, or above the OCS, if such injury or damage to such person or property occurs by reason of the activities of any agency of the United States (U.S.) Government, its contractors or subcontractors, or any of its officers, agents, or employees, being conducted as a part of, or in connection with, the programs and activities of the command headquarters listed in the following table.

Notwithstanding any limitation of the lessee's liability in Section 14 of the lease, the lessee assumes this risk whether such injury or damage is caused in whole or in part by any act or omission, regardless of negligence or fault, of the U.S. Government, its contractors or subcontractors, or any of its officers, agents, or employees. The lessee further agrees to indemnify and save harmless the U.S. Government against all claims for loss, damage, or injury sustained by the lessee, or to indemnify and save harmless the U.S. Government against all claims for loss, damage, or injury sustained by the agents, employees, or invitees of the lessee, its agents, or any independent contractors or subcontractors doing business with the lessee in connection with the programs and activities of the aforementioned military installation, whether the same be caused in whole or in part by the negligence or fault of the U.S. Government, its contractors or subcontractors, or any of its officers, agents, or employees and whether such claims might be sustained under a theory of strict or absolute liability or otherwise.

B. ELECTROMAGNETIC EMISSIONS

The lessee agrees to control its own electromagnetic emissions and those of its agents, employees, invitees, independent contractors, or subcontractors emanating from individual designated defense warning areas in accordance with requirements specified by the commander of the command headquarters listed in the following table to the degree necessary to prevent damage to, or unacceptable interference with, Department of Defense flight, testing, or operational activities conducted within individual designated warning areas. Necessary monitoring control and coordination with the lessee, its agents, employees, invitees, independent contractors, or subcontractors will be effected by the commander of the appropriate onshore military installation conducting operations in the particular warning area provided, however, that control of such electromagnetic emissions shall in no instance prohibit all manner of electromagnetic communication during any period of time between a lessee, its agents, employees, invitees, independent contractors, or subcontractors, and onshore facilities.

C. EVACUATION

A. The lessee, recognizing that oil and gas resource exploration, exploitation, development, production, abandonment, and site cleanup operations on the leased

[1] These example stipulations can be found in Department of Defense (DoD), 2010, Report on the Compatibility of Department of Defense Activities with Oil and Gas Resources Development on the Outer Continental Shelf, 15 February.

area of submerged lands may occasionally interfere with tactical military operations, hereby recognizes and agrees that the United States reserves and has the right to temporarily suspend operations and/or require evacuation on this lease in the interest of national security. Such suspensions are considered unlikely in this area. Every effort will be made by the appropriate military agency to provide as much advance notice as possible of the need to suspend operations and/or evacuate. Advance notice of fourteen (14) days shall normally be given before requiring a suspension or evacuation, but in no event will the notice be less than four (4) days. Temporary suspension of operations may include the evacuation of personnel, and appropriate sheltering of personnel not evacuated. Appropriate shelter shall mean the protection of all lessee personnel for the entire duration of any Department of Defense activity from flying or falling objects or substances and will be implemented by a written order from the MMS Regional Supervisor for Field Operations (RS-FO), after consultation with the appropriate command headquarters or other appropriate military agency, or higher authority. The appropriate command headquarters, military agency, or higher authority shall provide information to allow the lessee to assess the degree of risk to, and provide sufficient protection for, lessee's personnel and property. Such suspensions or evacuations for national security reasons will not normally exceed seventy-two (72) hours; however, any such suspension may be extended by order of the RS-FO. During such periods, equipment may remain in place, but all production, if any, shall cease for the duration of the temporary suspension if so directed by the RS-FO. Upon cessation of any temporary suspension, the RS-FO will immediately notify the lessee such suspension has terminated and operations on the leased area can resume.

B. The lessee shall inform the MMS [*now BOEM*] of the persons/offices to be notified to implement the terms of this stipulation.

C. The lessee is encouraged to establish and maintain early contact and coordination with the appropriate command headquarters in order to avoid or minimize the effects of conflicts with potentially hazardous military operations.

D. The lessee shall not be entitled to reimbursement for any costs or expenses associated with the suspension of operations or activities or the evacuation of property or personnel in fulfillment of the military mission in accordance with subsections A through C above.

E. Notwithstanding subsection D, the lessee reserves the right to seek reimbursement from appropriate parties for the suspension of operations or activities or the evacuation of property or personnel associated with conflicting commercial operations.

D. COORDINATION

A. The placement, location, and planned periods of operation of surface structures on this lease during the exploration stage are subject to approval by the MMS Regional Director (RD) after the review of an operator's exploration plan (EP). Prior to approval of the EP, the lessee shall consult with the appropriate command headquarters regarding the location, density, and the planned periods of operation of such structures, and to maximize exploration while minimizing conflicts with Department of Defense activities. When determined necessary by the appropriate command headquarters, the lessee will enter a formal Operating Agreement with such command headquarters, that delineates the specific requirements and operating parameters for the lessee's final activities in accordance with the military stipulation clauses contained herein. If it is determined that the final operations will result in interference with scheduled military missions in such a manner as to possibly jeopardize the national defense or to pose unacceptable risks to life and property, then the RD may approve the EP with conditions, disapprove it, or require modification in accordance with 30 CFR Part 250. The RD will notify the lessee in writing of the conditions associated with plan approval, or the reason(s) for disapproval or required modifications. Moreover, if there is a serious threat of harm or damage to life or property, or if it is in the interest of national security or defense, pending or approved operations may be suspended in accordance with 30 CFR Part 250. Such a suspension will extend the term of a lease by an amount equal to the length of the suspension, except as provided in 30 CFR 250.169(b). The RD will attempt to minimize such suspensions within the confine of related military requirements. It is recognized that the issuance of a lease conveys the right to the lessee, as provided in section 8(b)(4) of the OCS Lands Act, to engage in exploration, development, and production activities conditioned upon other statutory and regulatory requirements.

B. The lessee is encouraged to establish and maintain early contact and coordination with the appropriate command headquarters in order to avoid or minimize the effects of conflicts with potentially hazardous military operations.

C. If national security interests are likely to be in continuing conflict with an existing operating agreement, the RD will direct the lessee to modify any existing operating agreement or to enter into a new operating agreement to implement measures to avoid or minimize the identified potential conflicts, subject to the terms and conditions and obligations of the legal requirements of the lease.