1.0 INTRODUCTION

Shell Canada Limited (Shell) is proposing to conduct an exploratory drilling program within the area of its offshore Exploration Licences (EL) 2423, 2424, 2425, 2426, 2429 and 2430 (the Licences) (refer to Figure 1.1.1). These activities will be conducted pursuant to the six year exploration periods that commenced on March 1, 2012 for ELs 2423, 2424, 2425 and 2426 and January 15, 2013 for ELs 2429 and 2430. Shell maintains a 50% working interest and is the operator of the ELs, with a 30% non-operating interest held by ConocoPhillips and a 20% non-operating interest held by Suncor.

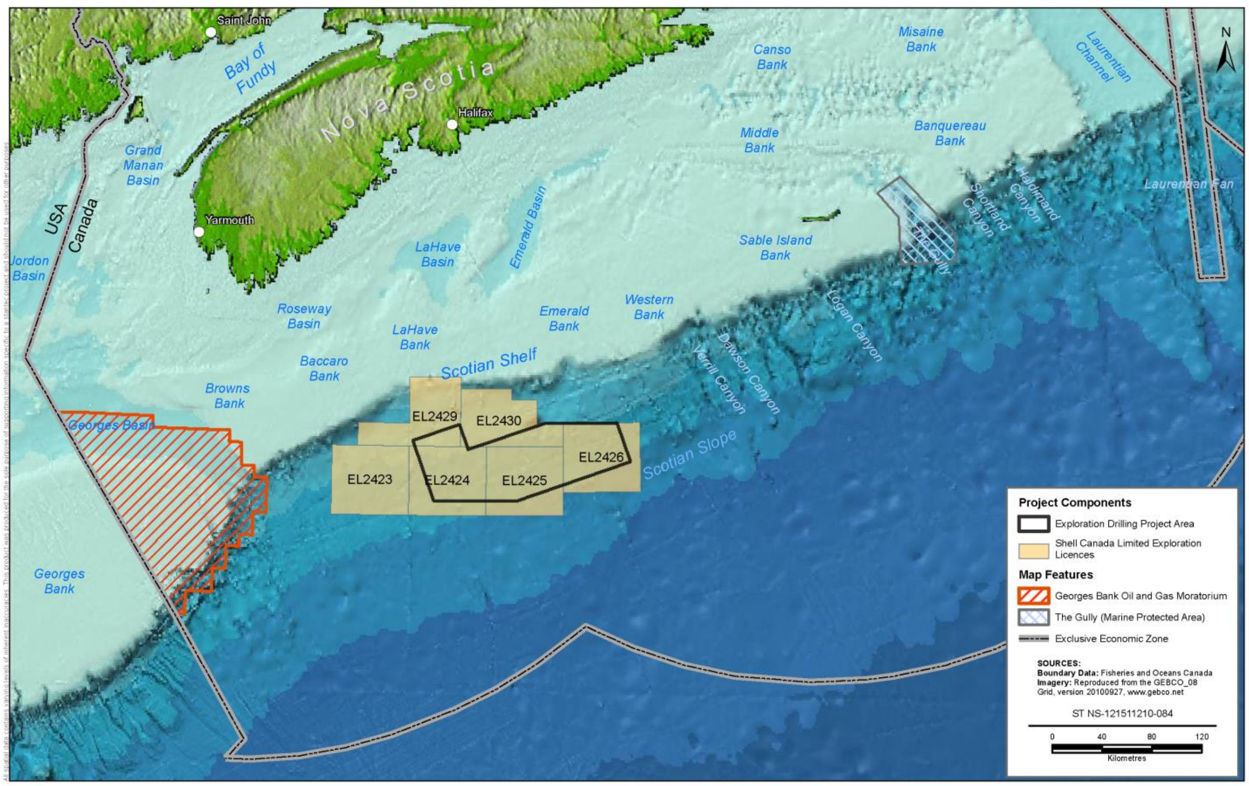

Figure 1.1.1 Proposed Exploration Drilling Project Area

This document is intended to fulfill requirements for an environmental assessment (EA) pursuant to the *Canadian Environmental Assessment Act, 2012* (CEAA, 2012) as well as EA requirements of the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) pursuant to the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act* (the Accord Acts). This Environmental Impact Statement (EIS) has been prepared to respond to Project-specific *Guidelines for the Preparation of an Environmental Impact Statement Pursuant to CEAA, 2012* (EIS Guidelines) (Appendix A) which were developed for the Project by the Canadian Environmental Assessment Agency (CEA Agency) with input from other government departments and agencies and the public and were issued as final on February 28, 2014 (CEA Agency 2014).

1.1 PROJECT OVERVIEW

The Shelburne Basin Venture Exploration Drilling Project (the Project) will consist of up to seven exploration wells drilled over a four-year period from 2015 to 2019 in association with the exploration periods of the Licences. The Project will be divided into two separate drilling campaigns, further outlined in Section 2.6. Each phase of drilling will be contingent upon the results from Shell's Shelburne Basin 3D Seismic Survey conducted in summer 2013, as well as the results of the previous phases of drilling conducted in association with the Project. Specific drilling locations have not yet been identified and will be determined using seismic data gathered as part of the 2013 Shelburne Basin 3D Seismic Survey. Further details associated with Project activities and components are provided in Section 2.

1.2 PROPONENT INFORMATION

Royal Dutch Shell (RDS) is active in more than 70 countries and employs approximately 87 000 full-time employees worldwide. Shell is currently one of the country's largest oil and gas companies operating in Canada, and has been active in the country since 1911. Headquartered in Calgary, Alberta, Shell employs more than 8000 people across Canada. Shell's Upstream business explores for and produces oil and natural gas using a variety of technologies, and includes business streams such as deep water, heavy oil and unconventional developments. Shell's Downstream business manufactures, refines, distributes and sells oil, fuels, lubricants, petrochemicals and bitumen worldwide.

1.2.1 Offshore Experience

Shell's experience operating offshore Nova Scotia dates back more than 50 years. Since the company acquired its first offshore leases in 1963 (~80 000 km^2), Shell has participated in 77 of the nearly 200 wells drilled offshore Nova Scotia to date inclusive of the first offshore gas discovery well, Onondaga B-84 in 1969. The first Nova Scotia offshore rig made at the Halifax shipyards, the semi-submersible Sedco H, was built and put into service by Shell in 1970. Shell drilled 24 wells in the 1970s and had an active exploration program through the 1980s, which involved drilling the first deepwater well (Shubenacadie H-100) and significant new gas discoveries (Glenelg, Alma, North Triumph). These discoveries resulted in the development of the Sable Offshore Energy Project, of which Shell has a 31.3% interest. As a result of Shell's activities, the company holds 28 Significant Discovery Licences (SDLs) in the Nova Scotia offshore, including the Primrose, Onondaga, Intrepid, Chebucto and Uniacke discoveries near Sable Island. The company's last 100% interest well was drilled in 2002 on the Onondaga B-84 discovery.

RDS has a number of existing international offshore exploration and production plays and significant experience in deepwater drilling. This deepwater drilling experience includes projects in the United States, Nigeria, Brazil, Malaysia, Brunei, French Guiana, and Norway. RDS also has experience developing and operating in northern offshore environments including the Sea of Okhotsk, the Beaufort Sea and the North Sea. As a result, RDS is a recognized global leader in deepwater exploration, with the following industry milestones (see also Figure 1.2.1):

- 2013 – announcement that RDS will design and build the world's deepest production facility at a water depth of 2900 m at their Stones discovery in the Gulf of Mexico. This facility will also include the deepest gas export pipeline in the world
- 2013 – RDS' largest tension leg platform (TLP), Olympus, is completed and deployed to the Mars B field in the Gulf of Mexico where it will be moored in a water depth of 910 m
- 2006 – announcement that three fields will be developed through the use of the Perdido Regional Host development spar; moored in a water depth of 2400 m. This spar is the deepest production facility in the world
- 2003 – installation of the Na Kika floating development and production system in 1920 m of water in the Gulf of Mexico
- 2001 – Brutus TLP installed in the Gulf of Mexico in 910 m of water
- 1998 – Ursa TLP installed in a water depth of 1160 m in the Gulf of Mexico
- 1997 – Ram Powell TLP installed in the Gulf of Mexico at a water depth of 980 m
- 1996 – Mars TLP installed in 900 m of water in the Gulf of Mexico, setting a water depth record at the time
- 1993 – Auger TLP installed in 870 m of water in the Gulf of Mexico establishing a water depth record at the time of its installation
- 1988 – deployment of the Bullwinkle platform in the Gulf of Mexico, the world's tallest conventional (pile-supported) fixed steel platform in 410 m of water (NRI 2012)

Future drilling locations in association with the Project are anticipated to be in depths less than 2700 m.

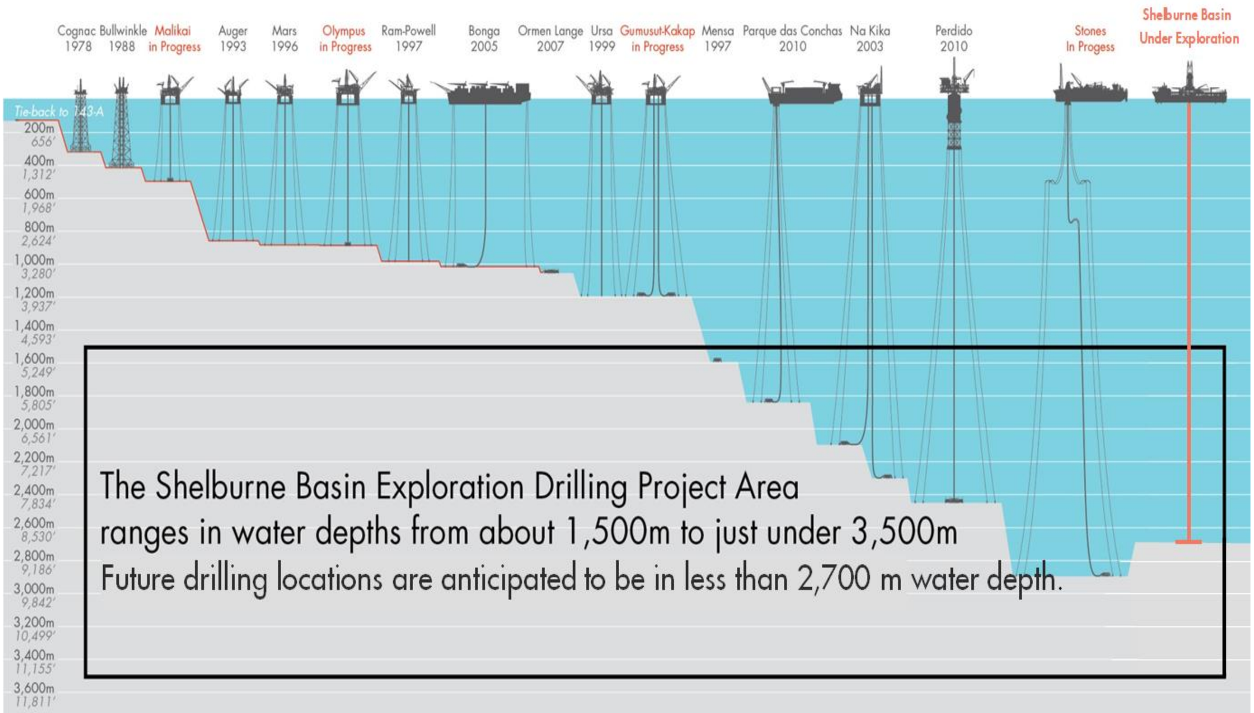

Figure 1.2.1 Shell's Global Offshore Experience

1.2.2 Commitment to Health, Safety and the Environment

Shell is committed to protecting the environment and actively managing its environmental performance. This is reflected in Shell's Business Principles and Health, Safety, Security, Environment and Social Performance (HSSE & SP) framework. Design features and mitigation measures have been incorporated into the Project to prevent or reduce potential environmental effects.

Shell's general operating principles are underpinned by a deliberate focus on safety and environmental protection. Shell meets or exceeds regulatory requirements applicable to its operations, which are designed to reduce risks to the environment and keep people safe. Shell's safety record is built on strict company standards, multiple safety barriers to prevent incidents from occurring, and ongoing attention to being able to mobilize a quick and effective response should it be required. Shell's safety standards also include extensive competence assurance, and a culture that requires workers, contractors and visitors to stop any unsafe activities. As a result of these safety standards and practices, Shell is recognized internationally as a responsible operator. Such recognition was clearly demonstrated when Shell became the first offshore operator in the Gulf of Mexico to receive an approval for a new deepwater exploration plan and drilling permit following the Deepwater Horizon Oil Spill. As part of this commitment to safe operations, spill prevention and response are of critical importance in Shell's project planning and operations.

All operations relating to the Project will be required to comply with Shell standards and regulatory standards as a minimum. Shell and its Contractors will institute appropriate health and safety programs to provide a safe working environment for all personnel and to conduct operations in a responsible manner in compliance with corporate standards and regulatory requirements.

Shell requirements for health, safety and environment apply to all persons conducting work for Shell irrespective of whether they are Operator Employees, Contract Staff, Third Parties or occasional visitors. They also apply whether or not the individual is under the direct or indirect responsibility of Shell as the Operator.

The Shell HSSE & SP Commitment and Policy (see Figure 1.2.2) provides the foundation for a systematic approach to HSSE & SP Management and outlines specific commitments regarding objectives and performance expectations. The HSSE & SP Commitment and Policy is communicated to employees and contractors, as well as being displayed in office and work locations and underpins Shell's HSSE & SP Management System.

SHELL COMMITMENT AND POLICY ON HEALTH, SECURITY, SAFETY, THE ENVIRONMENT AND SOCIAL PERFORMANCE

COMMITMENT

In Shell we are all committed to:

- Pursue the goal of no harm to people;
- Protect the environment;
- Use material and energy efficiently to provide our products and services;
- Respect our neighbours and contribute to the societies in which we operate;
- Develop energy resources, products and services consistent with these aims;
- Publicly report on our performance;
- Play a leading role in promoting best practice in our industries;
- Manage HSSE & SP matters as any other critical business activity; and
- Promote a culture in which all Shell employees share this commitment.

In this way we aim to have an HSSE & SP performance we can be proud of, to earn the confidence of customers, shareholders and society at large, to be a good neighbour and to contribute to sustainable development.

POLICY

Every Shell Company:

- Has a systematic approach to HSSE & SP management designed to ensure compliance with the law and to achieve continuous performance improvement;
- Sets targets for improvement and measures, appraises and reports performance;
- Requires contractors to manage HSSE & SP in line with this policy;
- Requires joint ventures under its operational control to apply this policy, and uses its influence to promote it in its other ventures;
- Engages effectively with neighbours and impacted communities; and
- Includes HSSE & SP performance in the appraisal of staff and rewards accordingly.

Ben van Beurden
Chief Executive Officer

Lorraine Mitchelmore
President and Canada Country Chair

Originally published in March 1997 and updated by the Executive Committee December 2009.

General Disclaimer: The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate entities. In this Policy the expression "Shell" is sometimes used for convenience where references are made to companies within the Shell group or to the group in general. Likewise, the words "we", "us" and "our" are also used to refer to Shell companies in general or those who work for them. These expressions are also used where no useful purpose is served by identifying specific companies.

Figure 1.2.2 The Shell HSSE & SP Commitment and Policy

HSSE & SP Management System

Shell's HSSE & SP Management System requires that all parts of the organization are established to meet the requirements outlined in the HSSE & SP Control Framework. The HSSE & SP Control Framework defines and communicates the HSSE & SP requirements established to support the objectives and commitments outlined under the HSSE & SP Commitment and Policy Document and manage HSSE & SP risks associated with business activities. Some of these specific requirements include:

- Establishment of a governance structure for HSSE & SP roles and responsibilities
- Identification and maintenance of the resources required to implement the HSSE & SP Control Framework and to comply with regulatory requirements
- Establishment of a process for the identification, management and mitigation of HSSE & SP risks

In addition to these requirements, the HSSE & SP Control Framework contains requirements for competence assurance. These requirements are established to manage the competence of people who manage HSSE & SP risk and people who fill other HSSE & SP critical positions to ensure that these individuals can carry out their work safely and effectively in their area of responsibility.

Shell's organization for the Shelburne Basin Venture Exploration Drilling Project is a function-based organization drawn primarily from its Upstream Americas (UA) organization, which includes all upstream operations in North and South America. The UA organization provides the majority of technical and managerial support to field operations in the Shelburne Basin through a matrix style organization. This organization contains expertise in Safety, Environmental Protection, Health Management and Emergency Response.

Operations are coordinated on behalf of Shell UA by a Venture Leadership Team (VLT). The VLT consists of the managers who oversee the functional work processes on behalf of Upstream America and Shell Exploration and Production Company (SEPCO) for whom the work is being executed. The VLT sets policies, establishes the plans for safe operation of the Venture (including an HSSE & SP Plan), and has ultimate accountability for performance and achieving plans including HSSE & SP objectives and targets.

Reporting to the VLT are all of the various functions (with their associated contractors) within each of the departments. These functions ensure that the correct processes are in place to achieve the Venture plans. There are multiple interfaces between Shell Businesses, Functions, Departments and Contractors and it is the role of the VLT to ensure all those interfaces are managed, including those necessary for HSSE & SP.

All Shell employees and Contractors are responsible, accountable and have the necessary authority for conducting their work in such a manner which reduces risk to themselves, fellow workers, the environment, Operator assets, communities potentially affected by operations, and Operator reputation as low as reasonably practicable (ALARP). Additionally, every Shell and contract employee has the authority and responsibility to intervene and stop any activity believed harmful to individuals or the environment.

In addition to personal safety considerations, Shell's business operations include a number of critical process safety elements that are integrated into all phases of development from Project planning (well design) to operations (well drilling and testing). These process safety elements include physical controls and barriers as well as operational processes and procedures established to reduce the likelihood of accidental events. In addition to preventative measures, response plans will be established and tested to ensure effective preparedness and response in the unlikely event that an accidental event should occur. For more information on Shell's process safety, refer to Section 8.1.

1.2.3 Proponent Contacts

A Halifax Regional Office has been opened in support of the Shelburne Basin Venture Exploration Drilling Project and key technical staff will be located in Halifax for the duration of the Project. Support for the Project will also be provided by staff at the Calgary Head Office and will draw upon Shell's deepwater expertise from Houston, New Orleans, and other global deepwater operations. The associated addresses for these office locations are:

Calgary Head Office	Halifax Regional Office
400 4th Avenue SW	9th Floor Founders Square
Calgary, Alberta	1701 Hollis Street
T2P 2H5	Halifax, Nova Scotia, B3J 3M8

All communications regarding the EA for this Project should be sent to the following:

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Christine Pagan, Atlantic Canada Venture Manager
Upstream Americas Exploration
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Email: christine.pagan@shell.com

1.2.4 Environmental Assessment Study Team

This EIS was prepared by Shell and a consulting team led by Stantec Consulting Ltd. (Stantec). Stantec is a consulting firm with extensive experience conducting environmental assessments in Nova Scotia, Canada and internationally.

In addition to Stantec as EIS lead, the following consultants (presented in alphabetical order) provided key expertise and services in support of EIS preparation:

- Environmental Research Consulting conducted the spill probability analysis
- HDR provided input with respect to dispersant use
- Membertou Geomatics Solutions (MGS) and Unama'ki Institute of Natural Resources (UINR) completed the Traditional Use Study
- RPS ASA conducted sediment dispersion and spill trajectory modelling
- SayleHSE Inc. provided specialist input regarding spill prevention and response

1.3 REGULATORY FRAMEWORK AND THE ROLE OF GOVERNMENT

1.3.1 Offshore Petroleum Regulatory Regime

Petroleum activities in the Nova Scotia offshore are regulated by the CNSOPB, a joint federal-provincial agency reporting to the federal Minister of Natural Resources Canada and the provincial Minister of Energy. In 1986, the Government of Canada and the Province of Nova Scotia signed the *Canada-Nova Scotia Offshore Petroleum Resource Accord* which proclaimed that oil and gas in the offshore area must be developed in a manner that harmonizes the interest of all Canadians with the interests of those living in Nova Scotia to maximize social and economic benefits associated with exploitation of the resource. The Accord outlines the management, division of powers, and the fiscal regime (royalties, fees, taxes) associated with management of petroleum resources offshore Nova Scotia.

Pursuant to the Accord, the federal and provincial governments established mirror legislation to implement the Accord. The *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act* and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act,* collectively referred to as the Accord Acts, are based on the *Canadian Oil and Gas Operations Act* (COGOA) and the *Canadian Petroleum Resources Act*

(*CPRA*). The Accord Acts outline the shared management of oil and gas resources in the offshore, revenue sharing and establish the offshore regulatory board (CNSOPB).

Under the Accord Acts, the CNSOPB is responsible for the issuance of licences for offshore exploration and development, the management and conservation of Nova Scotia's offshore petroleum resources, and protection of the environment as well as the health and safety of offshore workers, while maximizing employment and industrial benefits for Nova Scotians and Canadians.

Offshore petroleum activities and the CNSOPB's decision-making processes are governed by a variety of legislation, regulations, guidelines and memoranda of understanding. Exploration drilling projects require an Operations Authorization (OA) under the Accord Acts. Prior to issuing an OA, the CNSOPB requires the following to be submitted in satisfactory form:

- an Environmental Assessment report
- a Canada – Nova Scotia Benefits Plan
- a Safety Plan
- an Environmental Protection Plan (including a waste management plan)
- Emergency Response and Spill Contingency Plans
- appropriate financial security
- appropriate certificates of fitness for the equipment proposed for use in the activities

For each well in the drilling program, a separate Approval to Drill a Well (ADW) is required. This authorization process involves specific details about the drilling program and well design.

There are several regulations under the Accord Acts which govern specific exploration or development activities. There are also various guidelines, some of which have been jointly developed with the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) and National Energy Board (NEB) which are intended to address environmental, health, safety and economical aspects of offshore petroleum exploration and development activities. Relevant regulations and guidelines that fall under the jurisdiction of the CNSOPB are summarized in Table 1.3.1.

Table 1.3.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and the *Canada-Nova Scotia Offshore Petroleum Resource Accord Implementation (Nova Scotia) Act* (Accord Acts)	Natural Resources Canada (NRCan)/Nova Scotia Department of Energy (NSDOE)	The Accord Acts give the CNSOPB the authority and responsibility for the management and conservation of the petroleum resources offshore Nova Scotia in a manner that protects health, safety and the environment while maximizing economic benefits. The Accord Acts are the governing legislation under which various regulations are established to govern specific petroleum exploration and development activities.	The regulatory approvals identified below may be required pursuant to section 142 of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*, section 135 of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation* (Nova Scotia) *Act,* and the regulations made under the Accord Acts.
Nova Scotia Offshore Area Petroleum Geophysical Operations Regulations (and associated Guidelines)	CNSOPB	These regulations pertain to the geophysical operations in relation to exploration for petroleum in the Nova Scotia Offshore area and outline specific requirements for authorization applications and operations.	A Geotechnical/ Geological/ Engineering/ Environmental Program Authorization is being obtained in support of seabed surveys conducted outside the scope of this EIS (refer to Section 2.4). A Geophysical Operations Authorization may be required in support of the Project if walkaway vertical seismic profiling methods are employed in support of exploratory drilling activities (refer to Section 2.4.2).
Nova Scotia Offshore Petroleum Drilling and Production Regulations (and associated Guidelines)	CNSOPB	These regulations outline the various requirements that must be adhered to when conducting exploratory and or production drilling for petroleum.	The primary regulatory approvals necessary to conduct an offshore drilling program are an Operations Authorization (Drilling) and a Well Approval (Approval to Drill a Well) pursuant to the Accord Acts and these regulations.
Nova Scotia Offshore Certificate of Fitness Regulations	CNSOPB	Pursuant to subsection 136(b) of the *Canada-Nova Scotia Offshore Petroleum Resources Implementation Act*, these regulations outline the associated requirements for the issuance of a Certificate of Fitness to support an	A Certificate of Fitness will be required in support of the Project.

Table 1.3.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		authorization for petroleum exploration and or production drilling in the Nova Scotia Offshore Area.	
Offshore Waste Treatment Guidelines (OWTG)	NEB/CNSOPB/C-NLOPB	These guidelines outline recommended practices for the management of waste materials from oil and gas drilling and production facilities operating in offshore areas regulated by the Boards. The OWTG were prepared in consideration of the offshore waste/effluent management approaches of other jurisdictions, as well as available waste treatment technologies, environmental compliance requirements, and the results of environmental effects monitoring programs in Canada and internationally. The OWTG specify performance expectations for the following types of discharges (NEB *et al*. 2010): • emissions to air • produced water and sand • drilling muds and solids • storage displacement water • bilge water, ballast water and deck drainage • well treatment fluids • cooling water • desalination brine • sewage and food wastes • water for testing of fire control systems • discharges associated with subsea systems • naturally occurring radioactive material	Compliance with OWTG

Table 1.3.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Offshore Chemical Selection Guidelines (OCSG)	NEB/CNSOPB/ C-NLOPB	These guidelines provide a framework for chemical selection that minimizes the potential for environmental effects from the discharge of chemicals used in offshore drilling and production operations. The framework incorporates criteria for environmental acceptability that were originally developed by the Oslo and Paris Commissions (OSPAR) for the North Sea. An operator must meet the minimum expectations outlined in the OCSG as part of the authorization for any work or activity related to offshore oil and gas exploration and production. The OCSG includes the following requirements (NEB *et al*. 2009): • the quantity of each chemical used, its hazard rating, and its ultimate fate (*e.g.*, storage, discharge, onshore disposal, downhole injection, abandonment in the well, or consumption by chemical reaction) must be tracked and reported • all products to be used as biocides must be registered under the *Pest Control Products Act* (PCPA) and used in accordance with label instructions • all chemicals other than those with small quantity exemptions must be on the Domestic Substances List (DSL) of approved substances pursuant to the *Canadian Environmental Protection Act, 1999* (CEPA, 1999), or must be assessed under the New Substances Notification process to identify	Compliance with OCSG

Table 1.3.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		any restrictions, controls, or prohibitions • any chemicals included on the List of Toxic Substances under Schedule 1 of CEPA, 1999 must be used in accordance with CEPA, 1999 risk management strategies for the substance and alternatives must be considered for any substances on the CEPA, 1999 Virtual Elimination List • any chemicals intended for discharge to the marine environment must o be included on the OSPAR Pose Little or No Risk to the Environment (PLONOR) List o meet certain requirements for hazard classification under the Offshore Chemical Notification Scheme (OCNS) o pass a Microtox test (*i.e.*, toxicity bioassay) o undergo a chemical-specific hazard assessment in accordance with UK OCNS models o and/or have the risk of its use justified through demonstration to the Board that discharge of the chemical will meet OCSG objectives	
Compensation Guidelines Respecting Damage Relating to Offshore Petroleum Activity (Compensation Guidelines)	CNSOPB/C-NLOPB	Guidelines describing the various compensation sources available to potential claimants for loss or damage related to petroleum activity offshore Nova Scotia and Newfoundland and Labrador; and outline the regulatory and administrative roles which the Boards exercise respecting compensation payments for actual loss or damage directly attributable to offshore operators.	Compliance with Compensation Guidelines

Table 1.3.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Environmental Protection Plan Guidelines (EPP Guidelines)	CNSOPB	Guidelines to assist an operator in the development of an environmental protection plan (EPP) that meets the requirements of the Accord Acts and associated regulations and the objective of protection of the environment from its proposed work or activity.	Compliance with EPP Guidelines
Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment (SOCP)	DFO/EC/CNSOPB/ C-NLOPB	Specifies the minimum mitigation requirements that must be met during the planning and conduct of marine seismic surveys, in order to minimize impacts on life in the oceans. Required mitigation measures include, but are not limited to (DFO 2007a): • planning seismic surveys to use the lowest amount of energy necessary to achieve operational objectives, as well as to control horizontal energy propagation and minimize unnecessarily high energy frequencies • planning seismic surveys to avoid potential interactions with certain biologically important behaviours (*i.e.*, breeding/spawning, nursing, feeding, and migration) of marine species, as well as to avoid significant adverse effects on any individual marine mammal or sea turtle of a species at risk or the population of any marine species • establishing a safety zone with a radius of at least 500 m from the centre of the air source array(s) that is continuously monitored by a qualified Marine Mammal Observer (MMO) for at least 30 minutes prior to the start-up of the air source array(s)	Compliance with SOCP

Table 1.3.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		• not starting or restarting any air source array(s) that have been shut down for more than 30 minutes unless the full extent of the safety zone is visible and the MMO has not observed any of the following within the safety zone for at least 30 minutes: a cetacean or sea turtle, a marine mammal species at risk, or any other marine mammal that has been identified in an EA process as a species for which there could be significant adverse effects • if the conditions above are met, gradually ramping up the air source array(s) over a minimum of a 20 minute period when starting or restarting any air source array(s) that have been shut down for more than 30 minutes • immediately shutting down the air source array(s) if the MMO observes any of the following in the safety zone: a marine mammal or sea turtle species at risk or any other marine mammal or sea turtle that has been identified in an EA process as a species for which there could be significant adverse effects	

1.3.2 Environmental Assessment Requirements

In addition to CNSOPB requirements, the Project requires environmental assessment under the CEAA, 2012.

The *Regulations Designating Physical Activities* (amended October 24, 2013) specify the physical activities to which CEAA, 2012 applies. Based on the activities and location of the Project, it is a "designated project" under section 10 of the amended regulations.

Section 10 of the amended *Regulations Designating Physical Activities* states:

> The drilling, testing and abandonment of offshore exploratory wells in the first drilling program in an area set out in one or more exploration licences issued in accordance with the *Canada-Newfoundland Atlantic Accord Implementation Act* or the *Canada-Nova Scotia Petroleum Resources Accord Implementation Act*.

The Project consists of the drilling, testing and abandonment of offshore exploratory wells within the ELs issued to Shell by the CNSOPB. These proposed wells constitute the first drilling program in the licensed areas.

In association with this requirement, Shell filed a Project Description with the CEA Agency on November 26, 2013 (Shell and Stantec 2013). Following a public review and comment period on the Project Description, the CEA Agency determined that an EA under CEAA, 2012 would be required for the Project and subsequently issued a Notice of Commencement on January 17, 2014 to mark the beginning of the federal EA process. Draft EIS Guidelines were issued by the CEA Agency for public review and comment on the same date, and the final EIS Guidelines were issued to Shell on February 28, 2014.

Following submission of this EIS to the CEA Agency, another public comment period will occur in conjunction with government review. The CEA Agency will prepare a draft EA Report which will take into consideration public and government comments and detail the CEA Agency's conclusions regarding the potential for environmental effects from the Project. The EA Report will be subject to public review and comment before being finalized. Following finalization, the Minister of the Environment will review the EA Report and issue an EA decision, which will include a determination of significance of environmental effects.

It is expected that the EIS completed to satisfy the CEAA, 2012 requirements will also satisfy the CNSOPB requirements for an EA as part of the OA review process under the Accord Acts.

A provincial EA under the Nova Scotia *Environment Act* is not required based on the proposed Project scope.

1.3.3 Other Applicable Requirements and Resources

Other applicable requirements and resources include federal legislation, guidelines, and studies as well as Aboriginal policies and guidelines. Project activities and components will be located in areas of the marine environment that are under federal jurisdiction and are not subject to provincial or municipal regulatory requirements.

1.3.3.1 Federal Legislation, Guidelines and Government Studies

Project activities and components in the nearshore and offshore marine environment will take place within federal waters (*i.e.*, Canada's Exclusive Economic Zone (EEZ)) and are therefore subject to various federal legislative and regulatory requirements, including those summarized in Table 1.3.2.

Table 1.3.2 Summary of Key Relevant Federal Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Canadian Environmental Assessment Act, 2012 (CEAA, 2012)	Canadian Environmental Assessment Agency (CEA Agency)	"The drilling, testing and abandonment of offshore exploratory wells in the first drilling program in an area set out in one or more exploration licences" has been recently added to the list of designated activities under CEAA, 2012. The CEA Agency determined that exploratory drilling for the Project requires an EA under CEAA, 2012.	The Project is contingent upon EA approval (*i.e.*, an EA Decision Statement that allows the Project to proceed).
Fisheries Act	Fisheries and Oceans Canada (DFO) Environment Canada (EC) (administers Section 36, specifically)	The *Fisheries Act* contains provisions for the protection of fish, shellfish, crustaceans, marine mammals and their habitats. Under the *Fisheries Act*, no person shall carry on any work, undertaking, or activity that results in serious harm to fish that are part of a commercial, recreational, or Aboriginal fishery, or to fish that support such a fishery, unless this activity has been authorized by the Minister of Fisheries and Oceans. Section 36 of the *Fisheries Act* pertains to the prohibition of the deposition of a deleterious substance into waters	Authorization from the Minister of Fisheries and Oceans under section 35(2) of the *Fisheries Act* has not been required in the past for offshore exploration drilling projects. Therefore, such an authorization is not anticipated to be required in support of the Project.

Table 1.3.2 Summary of Key Relevant Federal Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		frequented by fish.	
Canadian Environmental Protection Act, 1999 (CEPA, 1999)	EC	CEPA, 1999 pertains to pollution prevention and the protection of the environment and human health in order to contribute to sustainable development. Among other items, CEPA, 1999 provides a wide range of tools to manage toxic substances, and other pollution and wastes, including disposal at sea.	Disposal at Sea Permits (under the *Disposal at Sea Regulations* pursuant to CEPA, 1999) have not been required in the past for operational discharges of drill muds or cuttings. Therefore, such a permit is not anticipated to be required in support of the Project.
Migratory Birds Convention Act, 1994 (MBCA)	EC	Under the MBCA, it is illegal to kill migratory bird species not listed as game birds or destroy their eggs or young. The Act also prohibits the deposit of oil, oil wastes or any other substance harmful to migratory birds in any waters or any area frequented by migratory birds.	The salvage of stranded birds during offshore Project operations would require a handling permit under section 4(1) of the *Migratory Birds Regulations* pursuant to the MBCA.
Species at Risk Act (SARA)	DFO/EC/Parks Canada	SARA is intended to protect species at risk in Canada and their "critical habitat" (as defined by SARA). The main provisions of the Act are scientific assessment and listing of species, species recovery, protection of critical habitat, compensation, permits and enforcement. The Act also provides for development of official recovery plans for species found to be most at risk, and management plans for species of special concern. Under the Act, proponents are required to complete an	Under certain circumstances, the Minister of Fisheries and Oceans may issue a permit under section 73 of SARA authorizing an activity that has potential to affect a listed aquatic species, any part of its critical habitat, or the residences of its individuals. However, such a permit is not anticipated to be required in support of the Project.

Table 1.3.2 Summary of Key Relevant Federal Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		assessment of the environment and demonstrate that no harm will occur to listed species, their residences or critical habitat or identify adverse effects on specific listed wildlife species and their critical habitat, followed by the identification of mitigation measures to avoid or minimize effects. All activities must be in compliance with SARA. Section 32 of the Act provides a complete list of prohibitions.	
Oceans Act	DFO	The *Oceans Act* provides for the integrated planning and management of ocean activities and legislates the marine protected areas (MPA) program, integrated management program, and marine ecosystem health program. MPAs are designated under the authority of the *Oceans Act*.	No applicable permitting requirements under the *Oceans Act* have been identified for the Project.
Navigation Protection Act (NPA)	Transport Canada (TC)	The NPA came into force in April 2014 and replaced the former *Navigable Waters Protection Act* (NWPA). The NPA is intended to protect specific inland and nearshore navigable waters (as identified on the list of "Scheduled Waters" under the NPA) by regulating the construction of works on those waters and by providing the Minister of Transport with the power to remove obstructions to navigation.	No applicable permitting requirements under the NPA have been identified for the Project, as the Project Area is located offshore, outside of the Scheduled Waters specified in the NPA.

In addition to the EIS Guidelines (CEA Agency 2014) developed for the Project, other guidance developed by the CEA Agency has been consulted during the preparation of the EIS.

- The Reference Guide for the Canadian Environmental Assessment Act: Determining whether a Project is Likely to Cause Significant Environmental Effects from the CEA Agency (1994), was considered in defining criteria or established thresholds for determining the significance of residual adverse environmental effects.
- The Operational Policy Statement: Assessing Cumulative Environmental Effects Under the Canadian Environmental Assessment Act, 2012 (CEA Agency 2013b) was taken into consideration during the development of the cumulative effects assessment scope and methods.
- The Operational Policy Statement: Addressing "Purpose of" and "Alternative Means" under the Canadian Environmental Assessment Act, 2012 (CEA Agency 2013d) was consulted with respect the assessment of Project alternatives (refer to Section 2.8).

The government has conducted a number of environmental studies (inclusive of technical reports) regarding the Scotian Slope and Scotian Shelf marine region, including the following which are pertinent to the EA:

- Strategic Environmental Assessment for Offshore Petroleum Exploration Activities – Western Scotian Slope (Phase 3B) (Stantec 2014)
- Strategic Environmental Assessment: Petroleum Exploration Activities on the Southwestern Scotian Slope (Hurley 2011)
- The Scotian Shelf in Context: The State of the Scotian Shelf Report (ACSISC 2011)
- The Marine Environment and Fisheries of Georges Bank, Nova Scotia: Consideration of the Potential Interactions Associated with Offshore Petroleum Activities (DFO 2011a)
- Ocean Noise: The State of the Scotian Shelf Report (Walmsley and Theriault 2011)

The studies above have been considered as part of the EA process and have informed preparation of this EIS. In particular, the recent Strategic Environmental Assessments (SEAs) undertaken by the CNSOPB for the Scotian Shelf and Slope have been used extensively to characterize the Project Area and surrounding region (refer to Section 5).

This EIS also incorporates relevant data from various databases managed by DFO and Environment Canada including marine mammal observation data and fisheries licences and landings from DFO and meteorological data and avifauna observation data from Environment Canada's Canadian Wildlife Service (refer to Section 5).

In addition to the relevant studies that have already been published by the government, the Canadian Science Advisory Secretariat (CSAS) is coordinating a national peer review of mitigation and monitoring measures for seismic survey activities in and near habitat for cetacean species at risk (*e.g.*, Northern bottlenose whale, North Atlantic right whale, Atlantic blue whale), using the Maritimes Region as a case study. The CSAS review focuses on sound exposure criteria and additional mitigation and monitoring measures which should be considered to avoid or minimize adverse effects on cetacean species at risk. It is expected that results from this review will be available in the fall of 2014.

1.3.3.2 Aboriginal Policies and Guidelines

There are two key Mi'kmaq guidelines which have influenced the EA process for this Project:

- The *Proponents' Guide: The Role of Proponents in Crown Consultation with the Mi'kmaq of Nova Scotia* (NSOAA 2012) was used to inform engagement activities with Aboriginal groups (refer to Section 4)
- The *Mi'kmaq Ecological Knowledge Study Protocol* (Assembly of Nova Scotia Mi'kmaq Chiefs 2007) was adhered to in the preparation of a Traditional Use Study for the Project by MGS and UINR (refer to Appendix B)

In the absence of similar guidelines or an equivalent protocol for New Brunswick, these documents were also used to direct engagement and Traditional Use Study activities involving select Mi'kmaq and Maliseet Nations in that province. This approach was agreed upon by the relevant First Nations in New Brunswick (*i.e.*, Fort Folly, St. Mary's, and Woodstock).

Other pertinent guidelines which influenced the EA process with respect to Aboriginal engagement include:

- *Aboriginal Consultation and Accommodation - Updated Guidelines for Federal Officials to Fulfill the Duty to Consult* (AANDC 2011)
- *Reference Guide: Considering Aboriginal Traditional Knowledge in Environmental Assessments Conducted Under the Canadian Environmental Assessment Act, 2012* (CEA Agency 2013a)

2.0 PROJECT DESCRIPTION

2.1 PROJECT NEED AND JUSTIFICATION

In 2011, Shell participated in a Call for Bids issued by the CNSOPB for offshore Nova Scotia parcels in deep water. In March 2012, Shell was awarded four ELs covering 13 765 km^2 (ELs 2423, 2424, 2425 and 2426) with a Work Expenditure Bid of $970 million (CNSOPB 2012a). Four additional ELs (ELs 2427, 2428, 2429, 2430) were acquired in the 2012 Call for Bids, awarded in January 2013. ELs 2429 and 2430 have a Work Expenditure Bid of almost $28 million (CNSOPB 2012b), and with their addition to the four ELs awarded in 2012 (ELs 2423, 2424, 2425, 2426), Shell now holds six contiguous ELs (ELs 2423, 2424, 2425, 2426, 2429 and 2430) covering an area of 19 845 km^2. ELs 2427 and 2428 are not included as part of the Project. In acquiring the ELs, Shell holds the exclusive right to drill and test for potential hydrocarbons, and to obtain a production licence to develop these areas in order to produce hydrocarbons should the exploratory drilling prove successful.

Exploratory drilling is required to assess potential drilling targets that have been identified through the analysis of seismic data. The purpose of exploratory drilling is to determine the presence, nature and quantities of the potential hydrocarbon resource. The Project, as proposed, is also intended to meet the Work Expenditure Bid requirements that need to be fulfilled within the initial six year exploration period of the nine year EL.

2.2 PROJECT LOCATION

Offshore Nova Scotia is a lightly explored continental margin with water depths ranging from hundreds of metres to more than 4 km. Most of the hydrocarbon exploration to date has focused on the shallower-water Sable Basin. This gas development was discovered in 1969 with first production to Nova Scotia in 1999. In contrast, the Shelburne Basin is located further offshore in deep water, where Shell is exploring both similar age (Cretaceous) and younger deepwater deposits.

The focus of Shell's geologic work in the Shelburne Basin has been to delineate the most prospective parts of the basin for inclusion in the Project. The original six-block leasehold was 19 855 km^2 and covered most of the Shelburne Basin. Subsequent analysis of existing 2D seismic data refined the area to approximately 12 000 km^2, which was further reduced to 7870 km^2 with the preliminary analysis of 10 850 km^2 Wide Azimuth (WAZ) 3D seismic data that was acquired in the summer of 2013 during Shell's Shelburne Basin 3D Seismic Survey. Thus the Project Area now includes portions of five ELs (EL 2424, 2425, 2426, 2429 and 2430) and encompasses approximately 40% of the original leasehold. The Project Area is located approximately 250 km offshore from Halifax in a geographical offshore area known as the Southwest Scotian Slope with water depths ranging from 1500 to 3000 m depth (refer to Figure 2.2.1). The corner coordinates of Project Area are provided in Table 2.2.1.

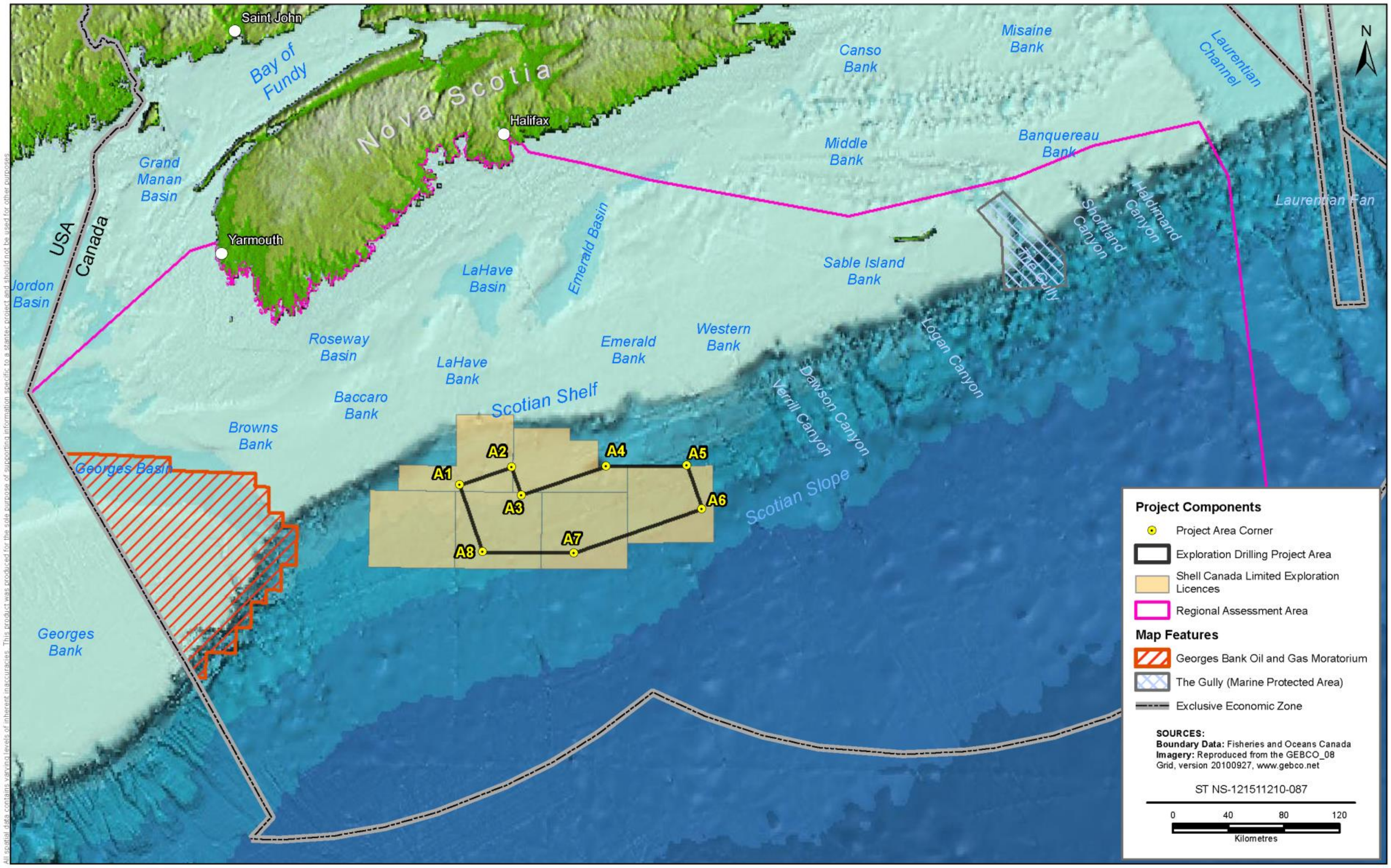


Figure 2.2.1 Project Area and Regional Assessment Area

Specific drill sites have not yet been determined and will be identified using the 3D WAZ seismic data collected in 2013, as well as a seabed and geotechnical survey (*i.e.*, the Shelburne Basin Venture Seabed Survey) to be conducted offshore in 2014 within the same area as the 2013 3D WAZ seismic survey. Shell expects that future exploration drilling activities associated with this Project will occur within the Exploration Drilling Project Area (Project Area), shown in Figure 2.2.1.

Table 2.2.1 Project Area Corner Coordinates

Project Area "Corner"	NAD27	
	Latitude DMS	Longitude DMS
A1	42° 22' 25.752" N	63° 57' 51.480" W
A2	42° 29' 35.232" N	63° 30' 44.640" W
A3	42° 18' 37.296" N	63° 25' 22.080" W
A4	42° 29' 58.668" N	62° 40' 56.640" W
A5	42° 29' 59.532" N	61° 58' 32.880" W
A6	42° 12' 58.788" N	61° 50' 58.560" W
A7	41° 56' 11.976" N	62° 57' 54.000" W
A8	41° 56' 34.080" N	63° 45' 29.880" W

For the purpose of environmental assessment, a regional assessment area (RAA) has been defined as the main study area boundary for describing existing baseline conditions and assessing direct and cumulative environmental effects of the Project (refer to Figure 2.2.1). The RAA is the area within which residual environmental effects from Project activities and components may interact cumulatively with the residual environmental effects of other past, present, and future (*i.e.*, certain and reasonably foreseeable) physical activities. The RAA is restricted to the 200 nautical mile limit of Canada's EEZ, including offshore marine waters of the Scotian Shelf and Slope within Canadian jurisdiction. The western extent of the RAA encompasses the Georges Bank Oil and Gas Moratorium Area and terminates at the international maritime boundary between Canada and the United States. The eastern extent of the RAA encompasses the Gully MPA and terminates at the eastern edge of Banquereau Bank. A portion of the Scotian Shelf and the Nova Scotia coastline to the Bay of Fundy is also included as part of the RAA boundary. The spatial boundaries of the assessment are discussed further in Section 6.

2.3 PROJECT COMPONENTS

The Project will consist of the following primary components:

- A mobile offshore drilling unit (MODU) designed for year-round operations in deep water will be used for the drilling activities
- Offshore exploration wells (up to seven) to be drilled over a four-year period from 2015 through 2019 in two separate drilling campaigns (up to three wells in first phase and up to four wells in second) in association with the exploration period of the ELs

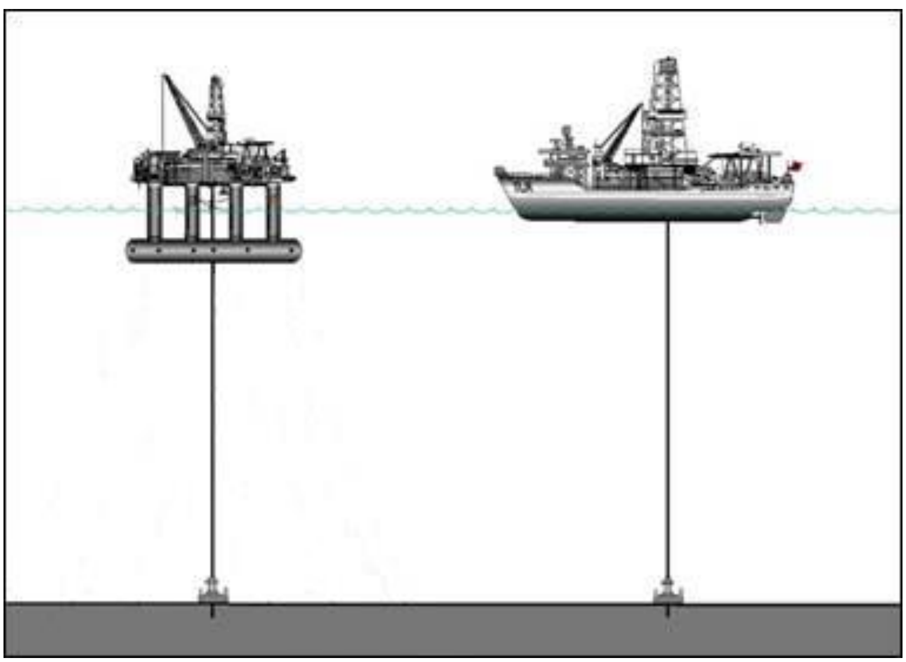
Logistical support will also be required to support the Project, consisting of:

- OSVs for re-supply and for on-site standby during drilling activities
- Helicopter support for crew transport as well as delivering light supplies and equipment

The only Project component to be newly developed as part of the Project will be the offshore exploration wells. All other primary Project components and logistical support (MODU, OSVs, helicopter support) will use existing sites, infrastructure and/or equipment. A description of supply and servicing is provided in Section 2.4.5.

2.3.1 Mobile Offshore Drilling Unit

Either a drill ship or a semi-submersible (Figure 2.3.1) will be used as the MODU for the Project. Both of these MODU options would use a dynamic positioning (DP) system to keep them on location and therefore have no requirement for subsea mooring (*e.g.*, anchors). The specific MODU to be used for the Project has not yet been chosen and will be dependent on suitability and availability. It is anticipated that the selected MODU will be capable of drilling year-round (*i.e.*, winterized) and be rated for ultra-deepwater drilling in order to support the potential needs of the Project. Pursuant to the Accord Acts, and requirements for an OA from the CNSOPB, a Certificate of Fitness for the MODU will be issued by a recognized certifying authority prior to approval for use.



Source: Adapted from MMS 2000

Figure 2.3.1 Schematic of Semi-Submersible (left) and Drill Ship (right)

Some of the key components of a MODU include:

- DP system to maintain position under various environmental conditions. Typically these systems are equipped with wind sensors, satellite global positioning system (GPS) and gyroscopes to monitor the environmental conditions as well as the MODU's position. Thrusters and propellers on the MODU are automatically controlled by the DP system to keep the MODU on position
- Drilling derrick, which contains and operates the drilling equipment
- Ballast control used to maintain stability during operations
- Diesel-generated power system to operate the ship and the associated drilling equipment
- Helicopter deck and refuelling equipment
- Existing storage space to house the associated drilling materials (fuel oil, drilling muds, cement, *etc*.) and equipment (casing) in advance of use for drilling activities. In particular, the MODU is expected to contain the following storage capacity for petroleum products on board:
  - Fuel oil tank (16 500m^3)
  - Base oil tank (500 m^3)
  - Diesel oil service tanks (x 2 – 126 m^3 each)
  - Lube oil storage tank (30 m^3)
  - Helifuel storage tanks (x 4 – 2500 L each)
- Subsea equipment inclusive of well control equipment and marine risers to be used for drilling operations
- Cranes for supply and equipment transfer as well as support for drilling activities
- Waste management facilities for offshore treatment or temporary storage prior to shipment to shore
- Emergency and life-saving equipment inclusive of fire-fighting equipment, lifeboats and rafts for emergency evacuation
- Accommodations for up to 200 persons on board (POB)

2.3.1.1 Drill Ship

Drill ships are equipped with an onboard drilling derrick and moon pool (opening in the base of the vessel hull providing direct access to the water for drilling operations). Drill ships are commonly used for drilling in deep and ultra-deepwater (up to 3500 m) and use a DP system to remain on location. Thrusters are located in the fore, aft and mid sections of the vessel and respond to the DP control system to mechanically maintain vessel position. Figure 2.3.2 illustrates a typical drill ship, including some of the main equipment found onboard.

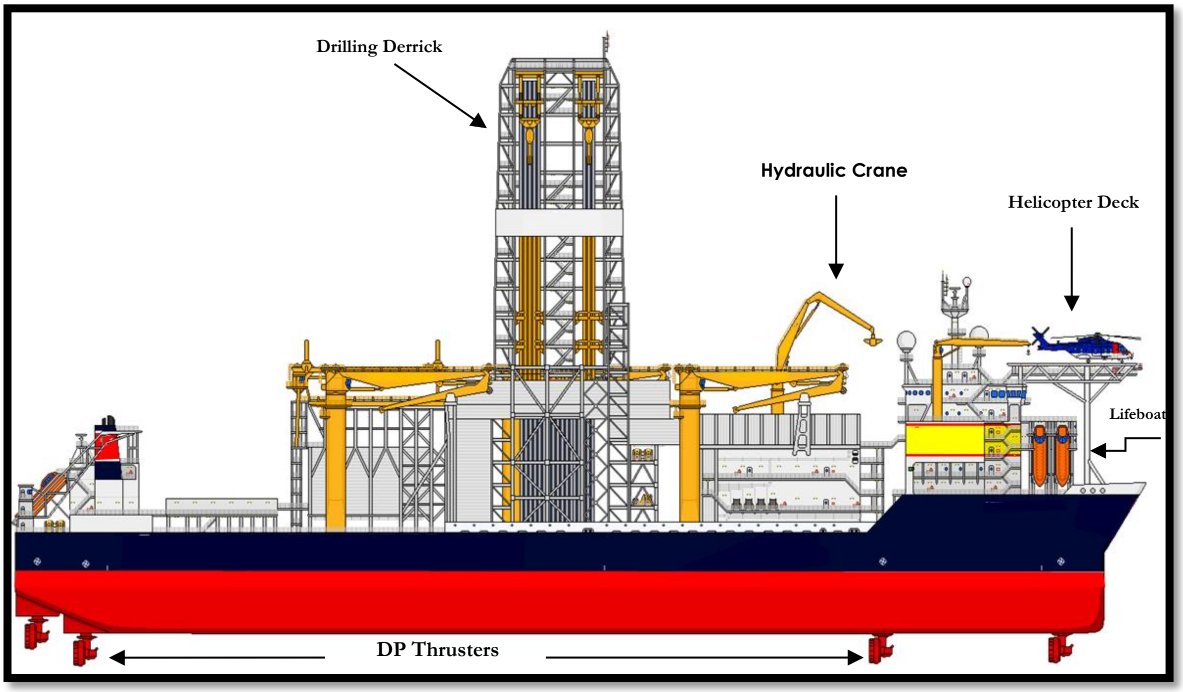


Figure 2.3.2 Typical Offshore Drill Ship

2.3.1.2 Semi-Submersible

A semi-submersible rig consists of two lower hulls that function to support several vertical columns, upon which sits the main deck of the rig. Both the submersed hulls and columns are ballasted with water so that the rig floats with the columns supporting the main deck and balancing it above the water. The hulls remain below the water surface once ballasted. Semi - submersibles provide a stable drilling platform as a result of much of the mass of the MODU being below the waterline. Semi-submersibles can be either towed by tug boat or moved under their own power to the chosen drill site. Once on-site and ballasted, a DP system is used to maintain position in deep waters and no bottom mooring is used. Figure 2.3.3 provides a schematic of a semi-submersible rig.

Source: Nelvik Norsk Hydro Ltd. 2010

Figure 2.3.3 Typical Semi-Submersible

2.3.2 Offshore Exploration Wells

Offshore exploration wells (up to seven) will be drilled over a four-year period (2015 through 2019). Figure 2.3.4 is a notional schematic of a typical well, showing the various sections. This schematic is subject to change as individual well design is completed. Table 2.3.1 presents a typical casing plan and drilled hole characteristics. Final well design for the initial wells is anticipated to be completed before the end of 2014. These technical details will be provided to the CNSOPB as part of the OA and ADW applications submitted in association with the Project and therefore require review and approval from the CNSOPB.

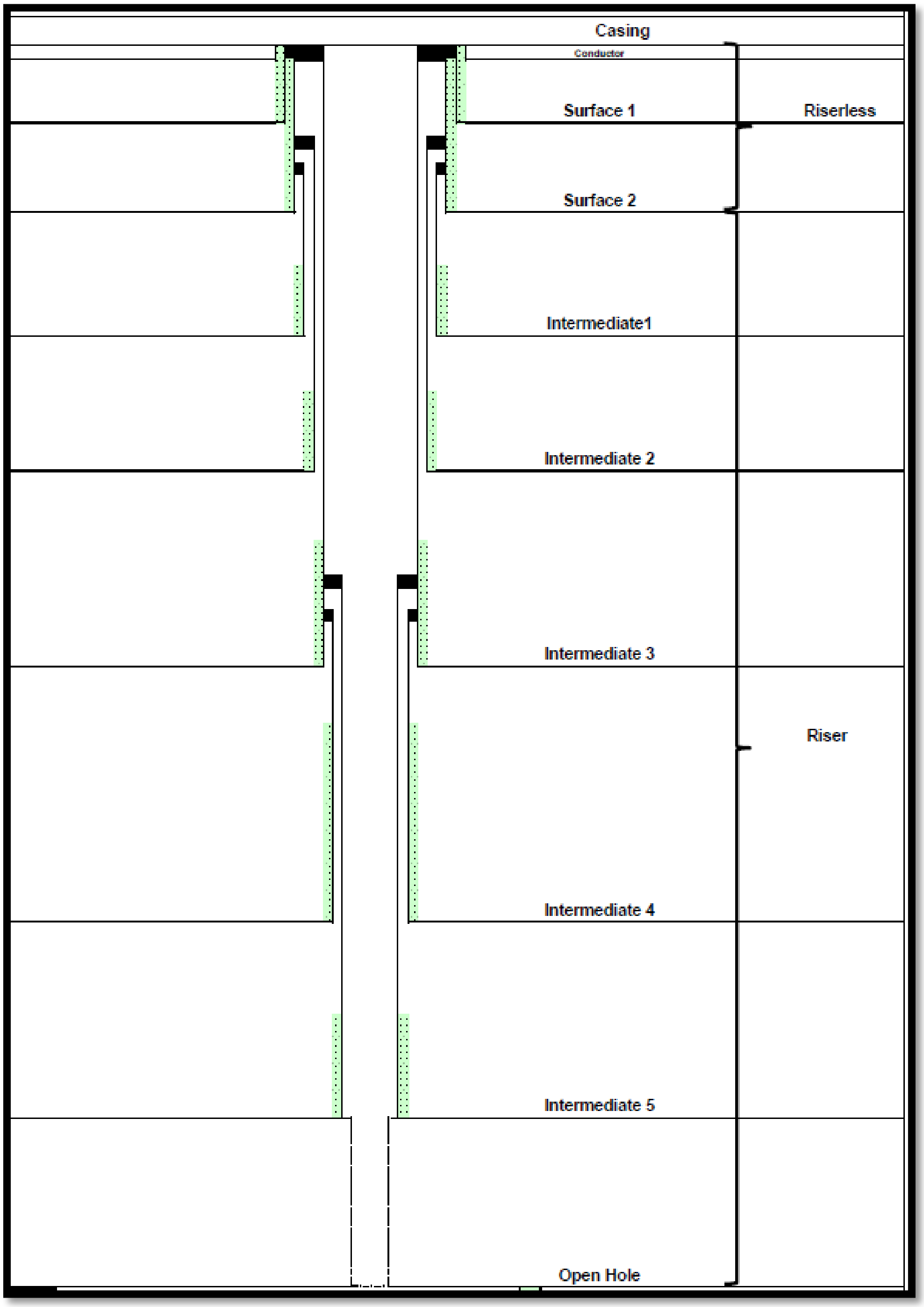


Figure 2.3.4 Notional Drilling Schematic

Table 2.3.1 Typical Casing Plan and Drilled Hole Characteristics for a Deepwater Well

Well Section	Hole Size	Casing Size	True Vertical Depth (TVD)	Drilling Fluid Type
Conductor	914 mm (36 in)	914 mm (36 in)	2419 m (7935 ft)	Seawater/Gel Sweeps
Surface	813 mm (32 in)	711 mm (28 in)	2888 m (9475 ft)	Seawater/WBM
Surface	660 mm (26 in)	559 mm (22 in)	3315 m (10 875 ft)	Seawater/WBM
Intermediate	559 mm (22 in)	457 mm (18 in)	3924 m (12 875 ft)	SBM
Intermediate	508 mm (20 in)	406 mm (16 in)	4290 m (14 075 ft)	SBM
Intermediate	444 mm (17.5 in)	356 mm (14 in)	5265 m (17 275 ft)	SBM
Intermediate	343 mm (13.5 in)	298 mm (11.75 in)	6089 m (19 977 ft)	SBM
Intermediate	298 mm (11.75 in)	238 mm (9.375 in)	6913 m (22 682 ft)	SBM

Further information regarding the offshore wells and drilling activity is provided in Section 2.4.

2.4 PROJECT ACTIVITIES

Offshore activities will commence with mobilization of the MODU at the pre-determined drill site. Prior to mobilization at the selected drilling site, the chosen MODU will undergo the required regulatory inspections to demonstrate that it meets Canadian and CNSOPB safety and technical specifications. Pursuant to the Accord Acts, and associated regulations, a Certificate of Fitness for the MODU must be issued by a recognized certifying authority. Upon receipt of the necessary regulatory approvals, authorizations and permits, the MODU will travel to the drilling site. Travel to the drilling site is anticipated to take between two to four days, dependent on where the inspections are conducted and the type of MODU that is selected. Following arrival on-site, mobilization activities will include the following:

- If a semi-submersible is used as the MODU, ballasting operations will take place following arrival on-site to provide suitable stability.
- The MODU will use its DP system to position above the drilling target. During drilling activities, the MODU will use computer-managed thrusters to maintain position. The DP system works to consistently monitor the environmental conditions on-site (*i.e.*, currents, wind, *etc.*) and adjust accordingly so that the MODU is always positioned above the drilling target.
- Once the MODU is in position, pre-drill site surveys will be conducted using a remotely operated underwater vehicle (ROV) deployed to the seabed. These surveys will be conducted to characterize the seabed and to confirm that no potential surface seabed

hazards or sensitivities are present at the drilling location. These site surveys will take approximately one day to conduct and will include the video inspection of the seabed to confirm that no surface impediments are present. There is no ground disturbance or seabed samples planned for this remote survey.

Prior to mobilization and drilling activities, a seabed and geotechnical survey (*i.e*., the Shelburne Basin Venture Seabed Survey) will be conducted in 2014 over potential drilling locations as determined from the results of Shell's Shelburne Basin 3D Seismic Survey conducted in 2013. The survey is not considered as part of this Project scope as it is being assessed as part of an update to a previously approved EA submitted to the CNSOPB in 2013. Additionally, the survey is not a designated project under the *Regulations Designating Physical Activities*.

Once the MODU has mobilized and ROV inspection of the seabed has been completed, drilling activities will commence. The actual well design inclusive of true vertical depth (TVD), drilling string depths and casing size is currently being developed, but a general overview of the associated steps for offshore drilling is provided in Section 2.4.1. These details are provided separately to the CNSOPB for review of the ADW applications.

2.4.1 Drilling

The drilling of each offshore well can be broken into two components, starting with riserless drilling (*i.e.*, an open system with no direct drill fluid return connection to the MODU) and continuing with riser drilling (*i.e.*, closed loop system with direct drill fluid return connection to the MODU). Each well is anticipated to take approximately 130 days to drill to TVD. The following details are provided to give a general overview of the activities associated with deepwater drilling.

During the drilling of the initial sections of the well, there is no close loop fluid (riser) system in place to return drilling fluid back to the MODU (*i.e.*, riserless drilling). As such, the associated drilling fluids, excess cement and cuttings are directed to the seabed and released directly to the seafloor. During this phase, the drilling fluid consists of seawater or water-based drilling mud (WBM) to cool the drill bit as well as transport the cuttings to the seabed. Riserless drilling will be used for the initial drill sections (conductor and surface strings) of each well, prior to connection of a riser system for drilling the additional sections to target depth. The following activities will occur during the riserless drilling portion of each exploration well:

- The drilling will commence with jetting the conductor section in place, which will be jetted to approximately 100 m below the sea floor (BSF).
- The drill string is then re-inserted into the conductor pipe and a surface hole section is drilled to approximately 1000 m BSF. The surface casing is then lowered into the wellbore to depth and cemented in place to surface. This process of drilling, casing and cementing is followed for all further drill sections.
- A blowout preventer (BOP) stack is then placed at the end of the drilling riser that is run down from surface to the well. The BOP is a critical piece of safety equipment, which is

connected to the wellhead, creating a connection between vessel and well via the riser system, and is put in place to protect both the crew and the environment against fluid releases from the well.

Following the installation of the BOP stack to the wellhead, the riser system creates a conduit to capture the associated drilling fluids and cuttings and transport them back to the MODU for further processing. During this phase of drilling, the remaining well sections are drilled to TVD using either a WBM or synthetic-based mud (SBM). At varying intervals determined from an assessment of geological and pore pressure parameters, intermediate casing is set at established depths to reinforce the wellbore. At each intermediate section, the casing is cemented in place.

The associated exploration wells are anticipated to require up to six intermediate strings. The specific depths of each section and the size of associated casing have not yet been determined and will require review and approval by the CNSOPB prior to drilling activities.

2.4.2 Vertical Seismic Profiling

Vertical Seismic Profiling (VSP) may be conducted in coordination with exploratory drilling activities. A VSP survey is used to calibrate surface seismic data, giving an accurate depth measure to geological features. By recording and analyzing the reflected seismic waves, the surface seismic data can be directly tied to the well.

VSP acquisition employs similar technology to that used during a seismic survey (source and receiver) and can employ a number of different configurations that vary based on the positioning of the associated source and receivers. VSP methods include Zero-offset VSP, Offset VSP and Walkaway VSP. In Zero-offset VSP, receivers (hydrophones) are placed in the wellbore and a source is deployed directly above the receivers off the MODU. Offset (or Walkaway) VSP involve similar placement of the receivers within the wellbore, but source deployment and activation is conducted at variable distances from the receivers. In Walkaway VSP, activation of the source is conducted at progressively farther offset distances from the receivers within the wellbore. In a Walkaway VSP scenario, the source would be deployed from a support vessel and activated at various distances from the receivers to a maximum distance of 10 km.

Shell would likely collect a Zero-offset VSP in the first exploration well in the Shelburne Basin. A vertical VSP deploys an array of geophones in the well bore at regular intervals and records seismic waves from a nearby, stationary seismic source into those geophones.

Although VSP uses a sound source similar to that used in seismic operations (*i.e.*, a source array), the associated size and volume of the array are much smaller than a traditional surface seismic survey. Additionally, as a result of the smaller spatial and temporal scale, sound effects from the VSP are considerably more localized and occur over a much shorter period than a seismic survey. A typical deepwater VSP survey would use a four-geophone array with an internal interval of 25 m and a stationary seismic source hung from a crane on the MODU. If determined to be required, a Zero-offset (MODU source) VSP would take place at the associated drill site and be conducted for approximately one day.

2.4.3 Well Testing

The testing of a hydrocarbon discovery is a regulatory requirement under the Accord Acts in order to convert an EL to a Significant Discovery Licence (SDL). Thus, as part of exploratory drilling activities, wells may be tested to gather further details regarding the potential reservoirs and to assess the associated commerciality of any potential discovery. The decision to test any of the associated exploration wells will be made following evaluation of the associated core samples and logs collected during drilling activities. As a result, well testing may not be conducted immediately following drilling activities and the associated exploration wells could be suspended immediately following drilling, with a MODU returning at a later date if well testing is determined to be necessary.

As the key objective of well testing is to collect a fluid sample, perforation of the respective reservoir(s) is necessary. Where well testing is determined to be necessary, casing will be set across the reservoir so that the well remains accessible and the borehole is protected. Additional well control tools are placed across the subsea BOP to maintain well control during testing activity. Once the well has been perforated, reservoir fluids are allowed to flow up the well to the deck of the MODU. In conjunction with this flow of reservoir fluids, the ship will have a temporary flow testing facility installed to handle the flow of any fluids from the wellbore. These reservoir fluids may contain hydrocarbons (oil and gas) and/or formation water (produced water).

The hydrocarbons are measured and separated from the produced water. Produced hydrocarbons and small amounts of produced water are flared using high-efficiency igniters for complete combustion and minimization of emissions. If produced water occurs, it will either be flared or treated in accordance with the latest version of the OWTG (NEB *et al.* 2010) prior to ocean discharge. Oil recovered during testing is stored onboard the MODU for future onshore disposal. Produced sand is not expected during well testing but if encountered, it will be stored onboard for onshore disposal.Once well testing is complete, the associated test string is removed from the well and the well is abandoned in accordance with the *Nova Scotia Offshore Petroleum Drilling and Production Regulations*.

2.4.4 Abandonment

Wells drilled during the first campaign that are required for testing in the second campaign will be suspended for potential future re-entry. Wells drilled in association with the Project cannot be used for production and, following testing, will be abandoned even in the event that hydrocarbons are discovered.

As a result, all wells drilled as part of the Project will be abandoned in accordance with CNSOPB regulatory requirements. Abandonment will take place immediately following drilling or well testing, if required.

Abandonment activities will include isolation of the wellbore using cement plugs. These plugs are placed at varying depths in the wellbore to separate and permanently isolate certain subsurface zones to prevent the escape of any subsurface fluids from the well. As part of well abandonment, approval may be sought to leave the wellhead in place. Where removal of the wellhead is required, the wellhead and associated equipment (casing) will be removed up to 1 m BSF through mechanical means (cutters).

Abandonment of individual exploration wells is anticipated to take approximately seven to ten days per well.

2.4.5 Supply and Servicing

OSVs will be used for the transport of supplies from the supply base to the MODU and returning waste material for appropriate disposal onshore, as well as providing standby assistance during drilling activities.

OSVs will undergo Shell's internal audit process as well as additional external inspections/audits inclusive of the CNSOPB pre-authorization inspection process during Q4 of 2014 or Q1 of 2015 in preparation for the Project. These audits will take place to ensure compliance with both Shell internal as well as external regulatory requirements and standards prior to operational start-up of the support vessel activity (*i.e.*, supply transport to drilling location) to ensure that vessels are safe and fit for purpose for use on the program. OSV operations are scheduled to commence in Q2 of 2015. Transfer of supplies (drilling fluids, pipe, *etc.*) to the OSVs will occur a minimum of one week in advance of the anticipated spud date, pending regulatory approvals.

It is anticipated that two to three OSVs will be required for the transport of associated materials and equipment (drilling fluids, casing, water, cement, fuel, *etc.*) to the MODU. During drilling activities, it is anticipated that the OSVs responsible for transporting supplies will make between two to three round trips per week from the supply base to the MODU. Transit to the Project Area by sea takes approximately 12 hours from Halifax travelling at a speed of 22 km/hour (12 knots).

One OSV must also be present on-site at all times as a standby vessel as required by Shell's operating standards and under regulations pursuant to the Accord Acts. This standby vessel will remain with the MODU for the purposes of on-site support in the event that emergency response or operational assistance is needed.

OSVs will be compliant with the *Canada Shipping Act* and its regulations while at sea, *Eastern Canadian Vessel Traffic Services Zone Regulations* when operating in nearshore or harbour areas, and applicable Port Authority requirements when in a port. Although the exact routes for the OSVs have not yet been determined, they are expected to be consistent with the shipping traffic routes/lanes commonly used by other vessels. Once out in the open sea, the support vessel will select the most direct route for reaching the destination.

Project activities will require helicopter support for transfer of crew and light supply. During drilling activities, it is anticipated that an average of one trip per day from onshore Nova Scotia (Halifax

Stanfield International Airport) to the MODU will be required. Additionally, helicopter support will be used in the event that emergency medical evacuation from the MODU is necessary during drilling activities. The MODU will be equipped with a helicopter landing pad (including refuelling capabilities) to support this service. Transit to the Project Area by helicopter takes approximately 1.5 hours from Halifax. Figure 2.4.1 shows the planned helicopter routes between the airport and the Project Area. These routes take into account avoidance of a military "no-fly" zone which would prohibit flying a straight line to the centre of the Project Area and also avoid Roseway Basin and Sable Island. Both routes are approximately 180 nautical miles from shore to Project Area.

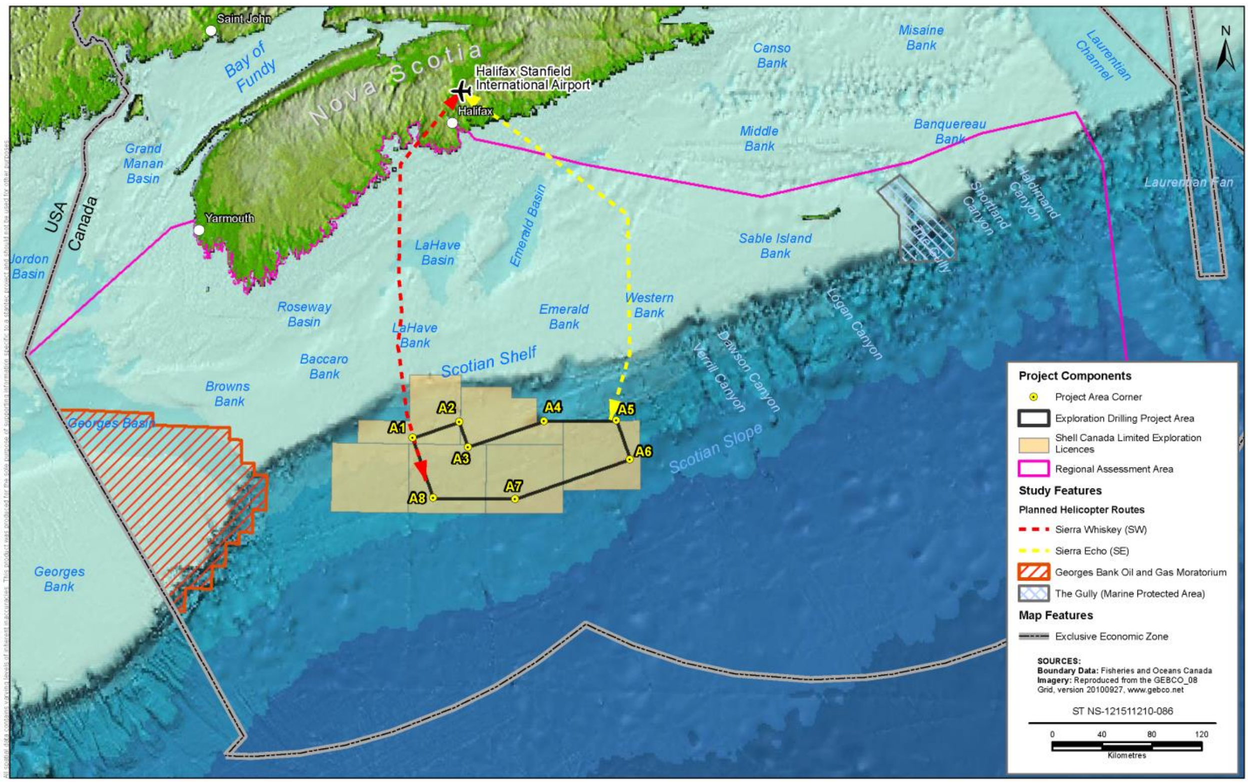


Figure 2.4.1 Helicopter Travel Routes between Halifax Stanfield International Airport (YHZ) and the Project Area

2.5 PROJECT PERSONNEL

The Project will be managed by Shell, which organizes its deepwater exploration ventures to include the disciplines and expertise required to deliver a project. During drilling, the two largest disciplinary teams will be the Well Delivery Team (approximately 25 persons) and the Subsurface Team (six to eight persons). Additional disciplinary support teams associated with the Shelburne Basin Venture include: Contracting and Procurement; Logistics; HSSE & SP; Environmental; Regulatory; Commercial; Social Performance; Stakeholder Consultation; Indigenous Relations; External Communications; Legal; and Finance. When the functions from these other disciplines are engaged, the total number of personnel involved on Shell's Project Team is approximately 50, not including the specific Shell and contractor roles associated with the management and implementation of the drilling program on the MODU. During the drilling program, it is expected that there could be up to 180 persons on board (POB) the MODU.

Figure 2.5.1 displays the management and communication structure for the drilling program. Shell and contractor roles are described in Table 2.5.1.

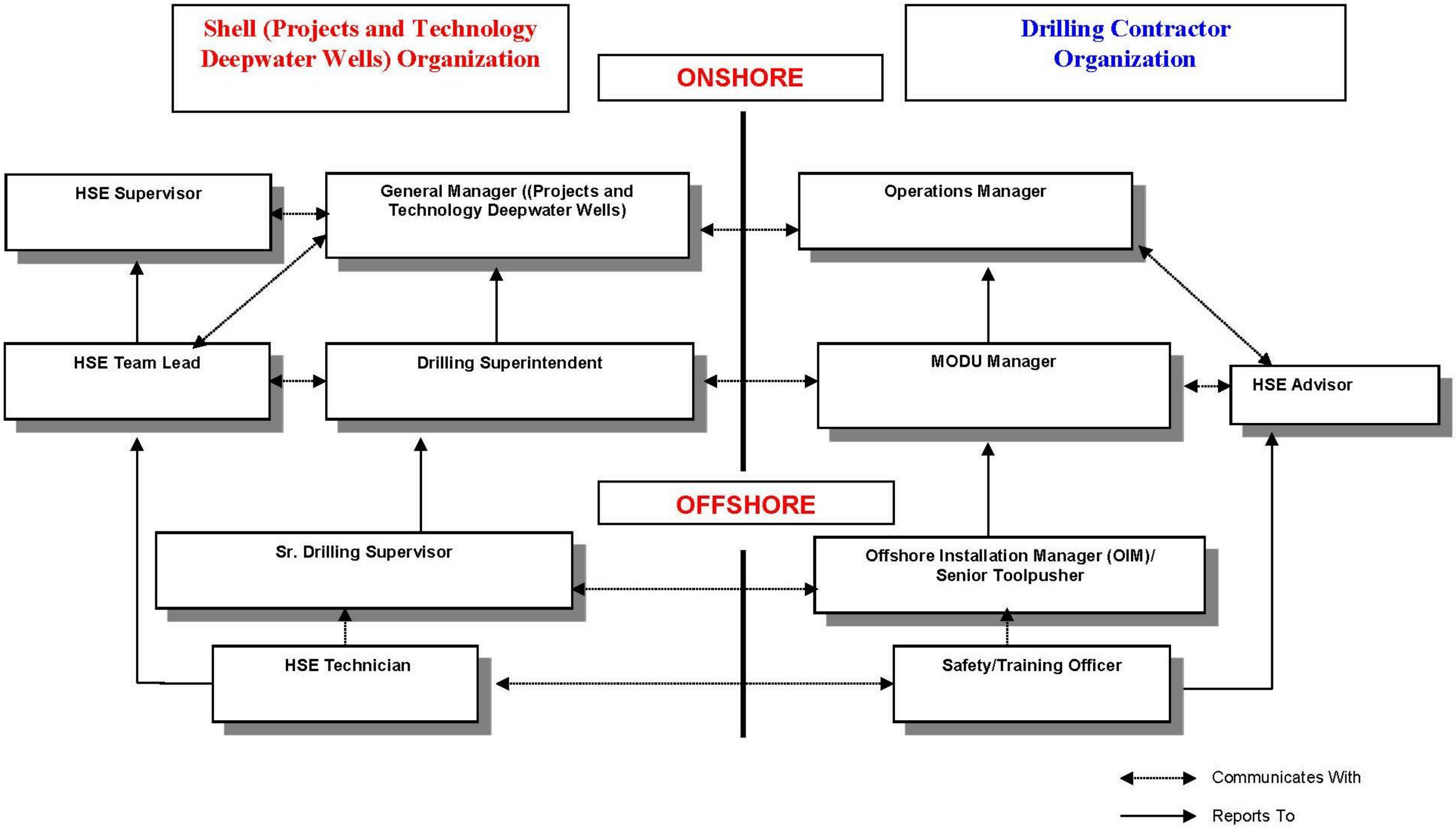


Figure 2.5.1 Organization of Key Roles and Responsibilities

Table 2.5.1 Description of Key Responsibilities

Role	Description of Key Responsibilities[1]
Shell Roles and Responsibilities	
General Manager (Projects and Technology Deepwater Wells)	The Shell General Manager (Projects and Technology Deepwater Wells) manages and oversees drilling and completion operations to achieve corporate performance results and communicates directly with the Drilling Superintendent. Other responsibilities include: • Coordinate the drilling program(s) and overall accountability for HSSE & SP. • Ensure well designs, programs and amendments are in compliance with Shell and statutory policies and procedures. • Ensure an effective Emergency Response Plan and Oil Spill Contingency Plan is understood and implemented. • Provide resources for Project Execution. • Management Focal Point for all Wells Contractors.
Drilling Superintendent	The Shell Drilling Superintendent directs and supervises the execution of approved drilling/completion programs. In addition, the Drilling Superintendent provides operational guidance and oversight for Engineering team(s) performing activities during planning and execution of the approved drilling & completion programs. This person reports to the Shell General Manager. Other responsibilities include: • Ensure all operations conform to the Shell HSSE & SP and operational requirements. • Approve design of drilling program. • Liaise with Contractor's management • Be the focal point of contact with the Shell Drilling Supervisor. • Supervise the safe and efficient implementation of Shell well program(s). • Monitor compliance with all local statutory as well as Shell policies and standards. • Ensure all required regulatory permits and approvals are obtained and onboard prior to spud. Ensure environmental mitigations and protection plans are fully implemented. • Be conversant with the local Emergency Response Plan and Oil Spill Contingency Plan. Ensure the MODU has its own Oil Spill Response Plan properly implemented. • Ensure that good and open communications are encouraged at the wellsite, promoting a culture of involvement and participation and safety. • Ensure that incidents are investigated and reported in compliance with regulatory as well as Shell requirements.
Sr. Drilling Supervisor	Shell Sr. Drilling Supervisor will be present offshore and will work on the drilling rig. This person is accountable to the Drilling Superintendent for the safety, environmental, and operational effectiveness of those rig and non-rig activities within his or her control. In addition, the Sr. Drilling Supervisor is expected to actively participate in the safety and environmental aspects or supporting activities occurring on the MODU. Other responsibilities include: • Coordinate the overall execution of the drilling program and oversee well related operations. • Communicate well plan through daily meetings. • Ensure drilling is implemented in a safe and efficient manner. • Ensure operations are managed in a manner that protects the environment, complies with all government regulations and follows Company policy. • Interface with the Offshore Installation Manager (OIM) to ensure that all safety precautions are taken. • Coordinate logistics, including standby helicopters and standby/supply vessels, with shore base.

Table 2.5.1 Description of Key Responsibilities

Role	Description of Key Responsibilities[1]
	• Hold safety meetings with the relevant personnel. • Review with key personnel contingency plans for potential emergencies. • Review weather forecasts to ensure conditions will allow conducting operations safely. • Act as the Shell On-scene Manager for all offshore incidents. • Assist the OIM to coordinate the actions to respond to any site emergencies. • Ensure HSSE & SP bridging and interface document requirements, including training and safety meetings, are fully implemented.
Sr. Drilling Engineer	The Shell Drilling Engineers have the following responsibilities: • Ensures casing design conforms to the latest Shell Casing, Tubing Design Manual. • Ensures well design conforms to Shell standards. • Ensures the appropriate volume of drilling fluids to overbalance expected formation pressures. • Issues a well-specific Well Control Plan. • Ensure proper drilling fluid properties and circulation details. • Provide well prognosis and offset history to the MODU. • Plan for required equipment for drilling operations. • Perform after action reviews for continuous learning and improvement.
Shell HSE Team Lead	The Shell HSE Team Lead is responsible to the General Manager and the Drilling Superintendent for the provision of Health, Safety and Environment (HSE) advice and assistance. The HSE Team Lead will assist offshore HSE representatives, providing immediate support to MODU operations. The Shell HSE Team Lead coordinates overall HSE support for the MODU Operations and owns and maintains the HSE documentation.
Shell HSE Technician	Shell HSE Technician provides support and oversight for HSE for rig operations and activities. These include but are not limited to: providing HSE leadership, safety inspections, meeting coordination, and reporting. They report to the HSE Team Lead, and support all Shell Drilling supervision.
Service Contractors	Shell Service contractors will perform contracted operations and work within their contract requirements, and in accordance with agreements in this document. Additional agreements by all Service contractors include: • All Shell third parties have agreed contractually to work according to policies, standards and practices that meet Shell's HSE requirements. • All Shell and third parties working on the MODU will follow and adhere to the MODU's HSE management system practices and procedures. Where service companies have more stringent HSE practices, specific to their activities and associated hazards, they will communicate these to the OIM, Toolpusher and Shell Drilling Supervisor, so that they can be adopted to supplement the Drilling Contractor's HSE procedures.
Drilling Contractor Roles and Responsibilities	
MODU Drilling Operations Manager	The Drilling Operations Manager is the executive accountable for overall operational and HSE performance. He ensures that a safe, efficient, and reliable drilling services are provided to the client in accordance with the Drilling Company's Values, Management System and contractual requirements including interfacing (bridging) documentation. The Operations Manager communicates directly with the MODU Manager and the Shell Wells General Manager.
MODU Manager (Onshore)	The MODU Manager is the shore-based manager for the MODU operations. The MODU Manager is responsible for liaising with the MODU's offshore leadership, the operator's onshore representative, and onshore support staff in the execution of contract

Table 2.5.1 Description of Key Responsibilities

Role	Description of Key Responsibilities[1]
	obligations on the daily basis.
Offshore Installation Manager (OIM)	The OIM has overall authority regarding the safety of personnel and the MODU. The OIM works directly with the Shell Drilling Supervisor and reports to the onshore MODU Manager. The OIM is responsible tocoordinate the implementation of the Oil Spill Contingency Plan on board the unit and act as the On Scene Commander for all site emergencies.
Senior Tool Pusher	The Senior Toolpusher assists the OIM to perform obligations to ensure the continuity of drilling operations. The Senior Toolpusher also ensures Well Control equipment is properly set-up and checked on a daily basis and that his crews are fully conversant with all well control aspects.
Safety and Training Officer	The Safety and Training Officer is responsible for assisting Supervisors, subcontractors and vendors with implementing the HSEE Management System.
[1] This is intended to be a characterization of key responsibilities and not an exhaustive description of all responsibilities for each role.	

2.6 PROJECT SCHEDULE

The tentative schedule outlined in Table 2.6.1 sets out the proposed timeline for the various Project activities. Project planning is currently underway. Aboriginal and stakeholder engagement as well as regulatory activities specific to the Project began in Q3 of 2013 and will continue throughout the life of the Project as required.

Table 2.6.1 Proposed Project Schedule

Task	2013				2014				2015				2016				2017				2018				2019			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Project Planning	■	■	■	■	■	■	■	■	■																			
Stakeholder Engagement			■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Regulatory Approvals			■	■	■	■	■	■	■				■	■	■	■					■	■	■					
First Drilling Campaign (2 to 3 wells)										■	■	■	■	■														
Assessment of First Program Results													■	■	■	■	■	■										
Well Testing *(dependent on assessment results)*																	■	■	■									
Potential Second Drilling Campaign (3 to 4 wells)																		■	■	■	■	■	■					
Abandonment																				■	■	■	■	■	■	■		

Exploration drilling activities are anticipated to commence in 2015, with the potential to continue into 2019. Offshore drilling activities will be initiated with mobilization of the OSVs and the MODU in Q2 2015 (pending regulatory approval). Drilling activities will not be continuous and instead will be divided into two separate drilling campaigns, with a number of sequential wells drilled in each campaign. In addition, the second campaign will be dependent on results of the first campaign. The initial drilling campaign is currently planned to commence in Q2 2015 and include up to three exploration wells, with the third well drilled dependent on the results of the previous two wells. Each well will take approximately 130 days to drill. Preference is to initiate drilling during the spring and summer months (May to September), when weather is more likely to be favourable: however, drilling will take place in the fall and winter months (October to April) as well, in order to complete the proposed wells within the schedule timeline.

Following the first drilling campaign, it is expected that 15 to 18 months will be required to assess the results of the first series of exploration wells. Depending on the results, well testing on the existing exploration wells and a second drilling campaign may be conducted. If conducted, the second drilling campaign would commence in approximately 2017 and include up to four additional exploration wells.

Abandonment or suspension activities will be conducted either immediately following drilling and/or well testing activities.

2.7 WASTE DISCHARGES AND EMISSIONS

Waste discharges associated with the offshore drilling operations include wastes that will be disposed of offshore, wastes that will be disposed of onshore, and air and noise emissions. Wastes are divided into three categories based on management and treatment approaches, and are outlined in Table 2.7.1. A Project-specific Waste Management Plan (WMP) will be developed, which will address collection, segregation, handling, storage, labeling and manifesting of the wastes generated during the Project. The WMP will be submitted to the CNSOPB in association with the authorizations sought for the Project.

All offshore waste discharges associated with the Project will be managed in compliance with the International Convention for the Prevention of Pollution from Ships (MARPOL) of which Canada has incorporated provisions under various sections of the *Canada Shipping Act* and its regulations and treated in accordance with the OWTG.

Wastes destined for onshore treatment, recycling and/or disposal will be managed in accordance with the Nova Scotia *Solid Waste-Resource Management Regulations* and will comply with any applicable federal and provincial waste requirements as well as municipal by-laws. Shell will retain a third-party waste management contractor to manage and dispose of wastes transported onshore in existing approved disposal facilities.

Table 2.7.1 Waste Classification

Non-Hazardous Wastes Managed Onshore	Hazardous Wastes including Waste Dangerous Goods Managed Onshore	Wastes Managed On-Board
• Domestic waste • Scrap wood • Scrap metal • Recyclables (glass, paper, plastic, aluminum) • Miscellaneous non-hazardous wastes	• Oil/fuel filters • Waste oil • Oily rags/gloves • Oil-contaminated sludge • Batteries (standard household cells) • Medical waste • E-waste (phones, computers, monitors, uninterruptible power supply (batteries, toner cartridges) • Fluorescent tubes • Empty oil/chemical drums • Empty paint cans • Paints/thinners/spent chemicals • Waste chemicals • Spent SBM	• Grey/black water • Drill cuttings with SBM on cuttings • Drill fluids and cuttings with WBM on cuttings • Produced gas from well testing • Produced water from well testing • Bilge and deck drainage water • BOP fluids • Cooling water • Ballast water • Fire control system test water • Food waste

2.7.1 Drilling Waste

2.7.1.1 Drilling Mud and Cuttings

A combination of WBM and SBM will be used for drilling the well to TVD, as detailed in Section 2.4.1. The drilling process results in spent drilling mud (also known as drilling fluid) and cuttings.

WBM consists of a suspension of particulate minerals, dissolved salts and organic compounds in freshwater, seawater or concentrated brine. Other than water, the most abundant ingredients are barite (used as a weighting agent), salts and bentonite viscosifier (Neff 2005). Table 2.7.2 presents the functional categories of materials used in WBM and examples of typical chemicals.

Table 2.7.2 Functional Categories of Materials Used in WBM and Typical Chemicals

Functional Category	Function	Typical Chemicals
Weighting Materials	Increase density (weight) of mud, balancing formation pressure, preventing a blowout	Barite, hematite, calcite, ilmenite
Viscosifiers	Increase viscosity of mud to suspend cuttings and weighting agent in mud	Bentonite or attapulgite clay, carboxymethyl cellulose and other polymers
Thinners, dispersants and temperature stability agents	Deflocculate clays to optimize viscosity and gel strength of mud	Tannins, polyphosphates, lignite, ligrosulfonates
Flocculants	Increase viscosity and gel strength of clays or clarify or de-water low-solids muds	Inorganic salts, hydrated lime, gypsum, sodium carbonate and bicarbonate, sodium tetraphosphate, acrylamide-

Table 2.7.2 Functional Categories of Materials Used in WBM and Typical Chemicals

Functional Category	Function	Typical Chemicals
		based polymers
Filtrate reducers	Decrease fluid loss to the formation through the filter cake on the wellbore wall	Bentonite clay, lignite, sodium-carboxymethyl cellulose, polyacrylate, pregelatinized starch
Alkalinity, pH control additives	Optimize pH and alkalinity of mud, controlling mud properties	Lime, caustic soda, soda ash, sodium bicarbonate and other acids and bases
Lost circulation materials	Plug leaks in the wellbore wall, preventing loss of whole drilling mud to the formation	Nut shells, natural fibrous materials, inorganic solids and other inert insoluble solids
Lubricants	Reduce torque and drag on the drill string	Oils, synthetic liquids, graphite, surfactants, glycols, glycerin
Shale control materials	Control hydration of shales that causes swelling and dispersion of shale, collapsing the wellbore wall	Soluble calcium and potassium salts, other inorganic salts,
Emulsifiers and surfactants	Facilitate formation of stable dispersion of insoluble liquids in water phase of mud	Anionic, cationic, or nonionic detergents, soaps, organic acids, and water-based detergents
Bactericides	Prevent biodegradation of organic additives	Glutaraldehyde and other aldehydes
Defoamers	Reduce mud foaming	Alcohols, silicones, aluminum stearate, alkyl phosphates
Pipe-freeing agents	Prevent pipe from sticking to wellbore wall or free stuck pipe	Detergents, soaps, oils, surfactants

Source: Boehm *et al.* 2001

Barite (barium sulphate) is a natural mineral used as weighting agent in drilling muds of all types. The weight is used to counteract the pressure of the formation being drilled. More barite is required in drilling muds for deepwater wells as a result of the higher reservoir pressure (Neff 2005). Bentonite clay is usually the second most abundant ingredient in WBM and is used as a viscosifier to maintain the gel strength required to suspend and carry drill cuttings to the surface (Neff 2005). Several other additives are used to change the physical and/or chemical properties of a drilling mud so that it will function optimally during drilling. The primary additives to SBM are emulsifiers, wetting agents, thinners, weighting agents, and gelling agents (Neff *et al.* 2000), whereas WBM generally contains a wider variety of additives (Table 2.7.2). However, most of these additives are used in small amounts and are considered non-toxic (Neff 2005).

SBM is a water-in-oil emulsion comprising synthetic-based fluids such as organic ester, ether, acetyl, or olefin, which are water soluble and as such, do not disperse in water the same as WBM (Hurley and Ellis 2004; Neff 2005). The synthetic chemical in SBM typically represents approximately 20–40% of the mass of the mud (Kenny 1993, in Neff 2005). SBM also often contains many of the additives used in WBM (see Table 2.7.2), including barite, clays, emulsifiers, water, calcium chloride, lignite and lime (Neff 2005).

The specific chemicals for the WBM and SBM to be used for the Project have not yet been selected. The OCSG (NEB *et al.* 2009) will be applied in selecting chemicals for drilling, as well as to the proper treatment and disposal of chemicals selected.

During riserless drilling, cuttings and drilling mud (WBM) are transported to the seabed and disposed in place. In accordance with the OWTG, spent WBM and drilling cuttings associated with the use of WBM may be discharged at the drill site without treatment. Shell's plans to discharge WBM and management approaches to reduce the need for the bulk disposal of these materials will be described in the EPP for the Project.

During riser drilling, cuttings and drilling mud (SBM) are transported back to the MODU via the riser pipe. On the MODU, cuttings will be separated from the drilling mud (SBM) for management and disposal through the use of shale shakers, mud recovery units and centrifuges. The recovered drilling mud (SBM) is reconditioned and reused. In accordance with the OWTG, drilling cuttings associated with the use of SBM must be treated prior to marine disposal such that the "synthetic-on-cuttings" does not exceed 6.9 g/100 g oil on wet cutting. No whole SBM or any whole mud containing SBM as a base fluid will be discharged at sea. Spent drilling mud (SBM) that is returned to the MODU during riser drilling and cannot be reused will be transported to shore for disposal.

Table 2.7.3 summarizes typical cuttings volumes based on a well plan presented in Table 2.3.1.

Table 2.7.3 Drill Mud and Cuttings Discharge Volumes

Open Hole Size	Casing OD	Casing ID	Casing Shoe Depth	Cuttings Volume		
				bbls	ft^3	m^3
914 mm (36 in)	914 mm (36 in)	853 mm (34 in)	2419 m (7935 ft)	431	2417	68
813 mm (32 in)	711 mm (28 in)	660 mm (26 in)	2888 m (9475 ft)	3064	17 201	487
660 mm (26 in)	559 mm (22 in)	508 mm (20 in)	3315 m (10 875 ft)	1839	10 323	292
559 mm (22 in)	457 mm (18 in)	432 mm (17 in)	3924 m (12 875 ft)	1034	5807	164
508 mm (20 in)	406 mm (16 in)	381 mm (15 in)	4290 m (14 075 ft)	513	2880	82
444 mm (17.5 in)	356 mm (14 in)	312 mm (12.3 in)	5265 m (17 275 ft)	1047	5879	166
343 mm (13.5 in)	298 mm (11.75 in)	262 mm (10.3 in)	6089 m (19 977 ft)	526	2954	84
298 mm (11.75 in)	238 mm (9.375 in)	218 mm (8.6 in)	6913 m (22 682 ft)	791	4440	126
WBM Cuttings Discharge				5333	2942	848
SBM Cuttings Discharge				3911	21 961	622

Table 2.7.3 Drill Mud and Cuttings Discharge Volumes

Open Hole Size	Casing OD	Casing ID	Casing Shoe Depth	Cuttings Volume		
				bbls	**ft^3**	**m^3**
WBM Cuttings Discharge Rate (per day)				667	3743	106
SBM Cuttings Discharge Rate (per day)				49	275	8
SBM Retained on cuttings				270	1515	43
TOTAL Cuttings Volume Discharge				**9244**	**51 903**	**1470**

2.7.1.2 Cement

Cement will be used to set the casing strings (conductor, surface and intermediate) in place. Any surplus cement used during riserless drilling will be disposed of on the seabed as is standard practice. Spent and surplus cement used during the riser drilling will be transported to shore for disposal in an approved facility.

2.7.1.3 Drill Waste Dispersion Modelling

Sediment dispersion modelling was conducted, based on the discharge volumes included in Table 2.7.3, for a representative well location in the Project Area (water depth of 2315 m) in order to predict the fate and behaviour of drilling discharges. A summary of the modelling process and results is provided below. For additional details, refer to *Sediment Dispersion Modelling in Support of the Shelburne Basin Exploration Drilling Program: Drilling Mud and Cuttings Operational Release and SBM Accidental Release* (RPS ASA 2014a) included as Appendix C to this EIS. Using the MUDMAP modelling system, and predicted drilling discharges based on Shell's proposed well design the transport of solid releases in the marine environment and the resulting seabed deposition was calculated.

As discussed in Section 2.7.1.1, the riserless sections of the well will be drilled using WBM, with cuttings to be released at the wellhead, approximately 5 m above the seafloor. Subsequent well sections drilled during riser drilling will use SBM, with treated cuttings discharged from the MODU, approximately 2 m below the sea surface at a continuous discharge rate. There is no planned bulk release of WBM or SBM. The total release is calculated to be 848 m^3 of WBM cuttings, and 622 m^3 of SBM cuttings per well.

Modelling was conducted for different seasons to reflect the varying oceanographic conditions in the Project Area. Drilling releases were simulated to begin on April 1 (spring), a period characterized by relatively weak and directionally variable surface currents, and October 1 (fall), a period characterized by slightly stronger currents in the upper water column. For both periods, subsurface currents (below 500 m) are consistently weak and directed west of the release site. For both scenarios, vertically and time varied currents derived from HYCOM for a representative period (2012-2013) were used as the primary environmental forcing.

As shown on Figures 22 and 23 in Appendix C, the extent of deposition between seasons is fairly similar, with both scenarios producing slightly elongated and westerly-oriented depositional footprints. In both seasonal scenarios, discharged SBM cuttings settle rapidly to the seabed, while the mud fraction of the discharge remains suspended in the upper water column (owing primarily to the small volumes and fine particle sizes associated with SBM that is adhered to drill cuttings) until eventually dispersing below levels detectible by the model. By contrast, both the cuttings and WBM discharged directly at the seabed (riserless sections) settle relatively quickly owing to: the release depth; the size distribution of the WBM; and the relatively weak currents near the seabed.

The majority of modelled drill mud and cuttings deposition is confined to an area within 100 m of the wellhead, although thicknesses of 0.1 mm extend up to 1380 m from the release site. Considering both spring and fall discharge scenarios, thicknesses at or above 1 mm extend up to 681 m from the discharge site and occupy a maximum areal extent of 71.18 ha; thicknesses greater than 10 mm extend up to 155 m, with a maximum footprint of 1.89 ha; and thickness at or above 100 mm is confined to a distance of 30 m from the wellhead, with a maximum footprint of 0.26 ha (Table 2.7.4).

Table 2.7.4 Modelled Spatial Extent of Seabed Deposition of Drill Mud and Cuttings (by Thickness Interval)

Deposition Thickness (mm)	Cumulative Area Exceeding (ha)	
	Scenario 1 (Spring)	Scenario 2 (Fall)
0.1	**284.703**	**302.676**
0.2	203.21	204.423
0.5	117.332	114.406
1	**71.178**	**68.244**
2	39.334	36.997
5	11.683	11.97
10	**1.887**	**2.506**
20	0.549	0.569
50	0.359	0.359
100	**0.26**	**0.25**
200	0.16	0.16
500	0.06	0.06

Source: RPS ASA 2014a

The environmental implications of these discharges as modelled are evaluated in Section 7 with respect to Valued Components.

2.7.2 Air and Noise Emissions

2.7.2.1 Air Emissions

Anticipated air emissions for the Project will include exhaust emissions from diesel engines powering the MODU and OSVs, plus potential flaring associated with produced gas that may be encountered during well testing. These emissions may include carbon monoxide (CO), sulphur oxides (SO_X), nitrogen oxides (NO_X), particulate matter, and carbon dioxide (CO_2). The air emissions from the Project will comply with the *Air Quality Regulations* under the Nova Scotia *Environment Act*, and meet the National Ambient Air Quality Objectives under the CEPA, 1999.

Potential routine flaring, an essential safety component of well drilling, would occur in accordance with the *CNSOPB Drilling and Production Guidelines*. In addition, non-routine emergency flaring may be necessitated by encounters with gas pockets and lesser levels of flaring may be required for solution or production gas. Exploration drilling will be conducted to restrict both routine and non-routine flaring to the amount necessary to characterize the well potential (refer to Section 2.4.3) and that which is necessary for the safety of the operation.

Marine engines are also subject to NO_X limits set by the International Maritime Organization (IMO) of the United Nations, with Tier II limits applicable in 2011 and Tier III limits to become applicable in 2016 in Emission Control Areas (ECA), which include the offshore waters of Nova Scotia to the 200 nautical mile (370 km) limit. In 2015, the sulphur limit in fuel in the ECAs in large marine diesel engines will drop from 1.0% to 0.1%, and the limit in non-large vessels (cylinder displacement < 30 litres) from 0.05% to 0.0015%, corresponding to a significant decrease in the sulphur dioxide emissions from these engines. The IMO is also responsible for development of efficiency measures that will involve mandatory measures to increase energy efficiency on ships, a process that will reduce the greenhouse gas emissions in the offshore.

Based on the emissions inventories of drill ships and OSVs employed by Shell in recent offshore drilling programs, it is assumed for the purpose of this assessment that the fuel consumption rate of the MODU will be approximately 74 616 gal/day, or 9.791 tonnes/hour. The fuel consumption by OSVs is estimated to be 39 089 gal/day, or 5.129 tonnes/hour. These totals do not include the negligible or zero contribution of emergency and minor sources, such as fire pump testing.

The US EPA AP-42 Emission Factor Inventory provides representative emissions factors for air contaminants released to the atmosphere by source type. In general, these emissions factors are understood to be representative of long-term averages for all facilities in the source category. For this assessment, AP-42, Fifth Edition, Volume 1, Chapter 3.4: Large Stationary Diesel and All Stationary Dual-fuel Engines was used, since the main domestic use of large stationary diesel engines (greater than 600 horsepower) is for the application of oil and gas exploration. As stated in the study, evaporative losses are very small in diesel engines due to low volatility of diesel fuel; therefore, only air contaminant emissions emitted through exhaust were considered.

The emissions factors as prescribed by AP-42 for large stationary diesel internal combustion sources are shown in Table 2.7.5.

Table 2.7.5 Gaseous Emissions Factors for Large Stationary Diesel Internal Combustion Sources

Air Contaminant	Emission Factor (fuel input) (lb/MMBtu)
NO_X	3.2
CO	0.85
SO_X[1]	$1.01S_1$
PM	0.1

[1]Assumes that all sulphur in the fuel is converted to SO_2. S_1 = % sulphur in fuel oil. Therefore, for this estimate, a sulphur fuel content of 0.05%, results in an emission factor of 0.0505.

Daily air contaminant emissions based on assumed fuel consumption rates were evaluated and are shown in Table 2.7.6.

Table 2.7.6 Daily Criteria Air Contaminant Emissions for the MODU and OSVs

Source	Air Contaminant	Diesel Fuel US gal/day	Energy Produced Per Day (MMBtu)	Emission Factors (fuel input) (lb/MMBtu)	Air Contaminant Emissions (tonnes/day)
MODU	NO_X	74616	9603	3.20	13.94
	CO	74616	9603	0.85	3.70
	SO_X*	74616	9603	0.05	0.22
	PM	74616	9603	0.10	0.44
OSVs	NO_X	39089	5031	3.20	7.30
	CO	39089	5031	0.85	1.94
	SO_X*	39089	5031	0.51	1.15
	PM	39089	5031	0.10	0.23

As the MODU will be more than 250 km from the nearest coastal community and there are strong average winds at the site, there will be no effect on the coastal communities from the Project.

The combusted fuel corresponds to greenhouse gas emissions of 0.741 and 0.389 kilotonnes CO_2e/day for the MODU and OSVs, respectively, or about 2% of Nova Scotia's average daily emission.

2.7.2.2 Noise Emissions

The energy from a single VSP shot is expected to create a sound pressure level (SPL) of 220–245 dB re 1 µPa @ 1 m (peak frequency of 5–300 Hz) (Lee *et al.* 2011). As indicated in Section 2.4.3, if required, VSP surveys are expected to take a day for each well and will occur at the associated drill sites.

Underwater noise will also be generated during operation of the OSVs and the MODU. The estimated SPL associated with OSV traffic is expected to be in the range of 170–180 dB_{RMS} re 1 μPa @ 1 m (peak frequency of 1–500 Hz) (Hurley and Ellis 2004; Richardson *et al.* 1995). SPLs produced by MODUs during operation are in the range of 130–190 dB re 1 μPa @ 1 m (peak frequency of 10–10 000 Hz) (Hildebrand 2005; Richardson *et al.* 1995). Drill ships are known to produce more noise than semi-submersibles or jack-up rigs because the hull containing the drilling machinery is further submerged in the water (NERI 2011; Richardson *et al.* 1995). Furthermore, drill ship noise emanates from both the drilling machinery and the propellers and thrusters for station-keeping (Hildebrand 2005). There are few specific studies that have considered noise associated with a drill ship. Measurement of drilling noise from the drill ship Stena Forth operating in Baffin Bay in 2010 revealed source levels of 184 dB_{RMS} re 1 μPa @ 1m, which corresponds to that of a large tanker (NERI 2011). Although SPLS associated with operation of the MODU are not as intense as SPLs associated with VSP surveys, they will be emitted continuously over a longer period of time (*i.e.*, due to constant use DP thrusters for station-keeping); the MODU is therefore considered the most substantial source of Project-related underwater noise emissions.

For information on ambient underwater noise refer to Section 5.1.3.6. Effects of Project-related underwater noise on the environment are discussed in Section 7.

2.7.3 Liquid Wastes

The following liquid waste streams are anticipated to be generated during Program activities:

- produced water
- grey/black water
- bilge and deck drainage water
- BOP fluids
- cooling water
- ballast water
- well treatment fluids
- fire control system test water

Liquid waste will be transported onshore for transport to an approved disposal facility via dedicated and appropriate containers/ containment that will comply with any applicable regulatory requirements. Once onshore, wastes will be collected and disposed of by a third-party waste contractor at an approved facility and in compliance with the associated regulations and requirements.

If hydrocarbons are encountered during well testing activities, small amounts of produced water may be flared. Surplus produced water will be treated onboard the MODU in accordance with

OWTG prior to ocean discharge. Oil that may be collected during testing will be stored onboard for onshore disposal.

The MODU includes living quarters and a galley, which will result in the production of grey and black water. Black water will be macerated to a maximum particle size of 6 mm and treated onboard. Following treatment it will be discharged to the ocean in accordance with the OTWG and MARPOL.

Bilge water and water drained through machinery spaces will be treated onboard the MODU and discharged in accordance with the OTWG (<15 mg/L). Any ballast water suspected to be contaminated by oil will be similarly treated and discharged.

BOP fluids are typically freshwater-based, with additives such as biocide, glycol and a lubricant. The biocide or lubricant additive is typically 2% by volume. The fluid is treated similarly to WBM, in that once spent, it will be discharged to sea in accordance with the OWTG.

Seawater is used for cooling purposes aboard the MODU. The volume of cooling water used will be minimal and therefore the area of thermal effects will be negligible. Following use, the water is treated through an oil-water separator and disposed of at sea. No additives are used in the cooling system.

Ballast water will be used in both the MODU and OSVs for stability. Ballast water is stored in dedicated tanks; therefore, typically, it does not contain any oil or other additives and can be taken on and disposed of as needed for vessel operational safety. Prior to transiting into Canadian waters, the MODU will undergo normal ballast tank flushing procedures, as required under IMO's *Ballast Water Management Requirements* and Transport Canada's *Ballast Water Control and Management Regulations*.

2.7.4 Hazardous Wastes and Waste Dangerous Goods

Hazardous wastes, including any waste dangerous goods, generated during the Project will be stored in the appropriate containers/containment and in designated areas on board the MODU for transportation to shore. Once on shore, it will be collected and disposed of by a third-party waste contractor at an approved facility and in compliance with the associated regulations and requirements.

The transportation of any dangerous goods, waste dangerous goods or hazardous substances will occur in compliance with the *Transportation of Dangerous Goods Act* and its associated regulations. Should any approvals be required for the transportation, handling, and any temporary storage of the dangerous goods, waste dangerous goods or hazardous substances, these will be acquired by the third-party waste contractor.

2.7.5 Non-Hazardous Wastes

Waste food will be macerated to maximum particle size (6 mm) and treated on board. Following treatment it will be discharged to the ocean in accordance with the OTWG and MARPOL.

Non-hazardous wastes generated during the Project will be stored in designated areas on board the MODU for transportation to shore, where it will be disposed of by a third-party waste management contractor at an approved facility.

2.8 ALTERNATIVE MEANS OF CARRYING OUT THE PROJECT

As required under Section 19(1)(g) of CEAA, 2012, every environmental assessment of a designated project must take into account the alternative means of carrying out the project that are technically and economically feasible and also consider the environmental effects of any such alternative means.

Consistent with the *Operational Policy Statement: Addressing "Purpose of" and "Alternative Means" under the Canadian Environmental Assessment Act, 2012* (CEA Agency 2013d), the process for consideration of alternative means of carrying out the Project included the following steps:

- Consideration of technical feasibility of alternative means of carrying out the Project
  - technical feasibility included consideration given to personal and process safety, additional infrastructural requirements, schedule delays as well as overall operational feasibility to meet the Project objectives
- Consideration of economic feasibility of alternative means of carrying out the Project
  - economic feasibility included considerations given to additional investment requirements or increased/reduced Project costs. Cost of alternatives was considered in the context of how the economic variation would affect operational costs and project success
- Description of each identified alternative to the extent needed to identify and compare potential environmental effects
- Consideration of the environmental and socio-economic effects of the identified technically and economically feasible alternatives of carrying out the Project; this includes potential adverse effects on potential or established Aboriginal and Treaty rights and related interests (where this information has been provided to the proponent)
- Selection of the preferred alternative means of carrying out the Project, based on the relative consideration of effects; and of technical and economic feasibility

The evaluated alternative means of carrying out the Project are discussed below; a summary table is provided in Table 2.8.1.

2.8.1 Identification of Alternatives

There are a limited number of viable alternative means for undertaking deepwater drilling. The alternative means of carrying out the Project identified for evaluation within this EIS are:

- type of mobile offshore drilling unit (MODU) (*e.g.*, drill ship or semi-submersible)
- selection and use of drilling fluids (*e.g.*, WBM or SBM)
- options for drilling waste management (*e.g.*, sea disposal, onshore disposal, or re-injection)
- MODU lighting alternatives (*e.g.*, reduced offshore lighting, spectral modified lighting, scheduled flaring)

Through the EIS Guidelines (CEA Agency 2014), Shell has also been asked to address the quantity and types of chemicals that may be used in support of the Project and chemical selection process to identify less toxic alternatives. The OCSG provide an accepted framework for the selection of chemicals in support of offshore operations (see Section 2.8.6).

2.8.2 Mobile Offshore Drilling Unit

A number of MODU options are available for the purposes of offshore exploratory drilling; these include drill ships, jack-up rigs and semi-submersibles. MODU selection criteria include: wellsite characteristics (water depth, physical environment, drilling depth); logistics (rig availability, mobility requirements); and safety and environmental considerations. The MODU for the Project is required to be rated for deepwater drilling (*i.e.*, those not requiring mooring or anchoring) and be winterized for year-round drilling. As a result, both a jack-up rig and an anchored semi-submersible would not be technically feasible for this Project.

The remaining two options, considered as alternative means of carrying out the Project, are a DP drill ship and a DP semi-submersible. Both of these MODU options are technically feasible to support the Project. Both are equipped with the same key components required on board as discussed in Section 2.3.1. Both options include a DP system for maintaining position on the drill site and therefore require no mooring or anchoring; they would be capable of operating in the varying water depths (1500 to 3000 m) in the Project Area. Operating costs during drilling are anticipated to be similar for both options.

Though both options are technically feasible, there are some operational differences. Drill ship typically travel at higher speeds (12 knots vs. 4 knots) than semi-submersibles; therefore mobilization and demobilization, as well as transit times would be shorter with a drill ship. All drill ship models are also capable of sailing to site without the assistance of other vessels; some semi-submersible models require additional vessel(s) to accompany and potentially tow to site.

Mobilization/demobilization time, as well as transit costs and fuel consumption, is therefore anticipated to be substantially higher with a semi-submersible. The global availability of winterized MODU options within the Shell Deepwater Fleet, as well as the currently proposed Project schedule, also aligns better with the drill ship option.

While there are differences between rig types with respect to capabilities, treatment facilities and effluent discharge depths, the characteristic volumes and types of waste streams are similar among drill units. There could be a slight reduction in emissions associated with the drill ship during mobilization/demobilization because the period of operation would be shorter.

Higher speeds associated with the drill ship could result in an increased risk of marine mammals strikes; however, lethal strikes to whales are infrequent at vessel speeds less than 25.9 km/hour (14 knots) and are rare at speeds less than 18.5 km/hour (10 knots) (Laist *et al.* 2001). Typical speeds of a drill ship (12 knots) are still low enough to reduce this risk.

A drill ship is known to produce more noise than semi-submersibles because the hull containing the drilling machinery is further submerged in the water (NERI 2011; Richardson *et al.* 1995). Noise levels from a moored drill ship is in the range of 174–185 dB re 1μPa and 154 dB re 1μPa from a moored semi-submersible (Richardson *et al.* 1995). However, as discussed in Section 7.1, the DP system that would be employed for either option could increase the underwater sound levels to 190 dB re 1μPa @ 1 m. The effects of noise on the various identified VCs are discussed in detail in the respective sections; however, even assuming the drill ship scenario, emissions would be geographically limited and would not result in population level effects for any of the identified VCs.

It is therefore predicted that there would be no substantive difference in potential environmental effects as a result of using one MODU over another. There is also not anticipated to be any substantive socio-economic differences as a result of choosing one option over the other. Both MODUs would require a 500-m radius safety zone (including fishing exclusion) and would therefore have similar effects on fishing activity in the Project Area. A more detailed assessment of the potential environmental and socio-economic effects of the presence and operation of the MODU on VCs is provided in Section 7.

Based on the technical and economic considerations and minimal differences in potential environmental and socio-economic effects between the two options, Shell's preferred option for the Project is a drill ship.

2.8.3 Drilling Fluids

Water-based mud (WBM) and synthetic-based mud (SBM) are two drilling fluid options for offshore Nova Scotia. It is technically feasible to drill the entire well using WBM, but because of borehole stability issues, a combination of WBM/SBM is preferred. If WBM were used for the entire well, there would be additional chemicals and a different composition of WBM used for the risered portion of the drill.

Both options are economically feasible. WBM is a less costly product, but borehole stability issues are more likely to occur with WBM, resulting in increased potential for downtime. Issues such as stuck drill strings, and problems getting casing to bottom, would result in longer drilling time and greater overall operational costs. This assessment is supported by analysis of the nine closest wells to the Project Area: four were drilled entirely with WBM and all four incurred hole instability and stuck pipe, indicating that these issues resulted from the exclusive use of WBM. When using WBM, there is free water available in the drilling fluid to interact with and hydrate shales. Once shales become hydrated, they become unstable and the wellbore can start to fall in. With SBM (which also contains some water) there is an emulsion created between the synthetic oil and water phase, meaning there is no free water available to interact with shale in the wellbore. The wellbore therefore maintains stability for much longer periods of time.

Comparison of the environmental effects of the use of SBM versus WBM does not clearly indicate a preferable option. WBM consists primarily of water and does not form sheens on the surface; SBM could potentially form sheens under certain operational and/or sea state conditions. SBM generally does not disperse as widely as WBM and, therefore, accumulates closer to the wellsite, limiting the zone of influence. Compared to SBM, WBM remains suspended in the water column longer and therefore has greater potential to affect filter feeding organisms (Cranford *et al.* 2005). WBM is also less stable than SBM (more susceptible to contaminants); consequently it is not uncommon for WBM to become unusable and require disposal and dilution with new WBM, thereby resulting in greater waste generation than with SBM. The OWTG contain guidance on allowable discharges of WBM and SBM on cuttings, which will be adhered to as part of the Project.

An SBM spill would result in the release of hydrocarbon; however, a whole spill of SBM is typically limited to within tens of metres of a wellsite. Predictive modelling of an accidental release of SBM is provided in Appendix C and indicates that sediment plumes could extend between 5 and 9.6 km from the release site and that concentrations of total suspended solids could exceed 1 mg/L for up to 30 hours. The effects of an accidental release of SBM are fully assessed in Section 8 and found to be not significant.

It is therefore predicted that there is no substantive difference in environmental effects between WBM and SBM assuming OWTG are followed with respect to SBM discharges. There is also not anticipated to be any substantive difference in socio-economic consequences as a result of choosing one option over the other. Biological effects on fish from either mud type will be in compliance with the OWTG, not cause serious harm to fish, and will not affect fisheries outside of the 500-m safety (fishing exclusion) zone surrounding the MODU. A more detailed assessment of the potential environmental and socio-economic effects of drilling muds on VCs is provided in Section 7.

Based on the technical and economic considerations discussed above, as well as lack of substantive difference in potential environmental and socio-economic effects between the two options, the preferred alternative for this Project is use of a combination of WBM and SBM.

2.8.4 Drill Waste Management

The types of drilling waste considered in this discussion are waste drilling muds (WBM and SBM) and cuttings produced during drilling activities. There are three options with respect to drill waste management: seabed/surface disposal, onshore disposal, and re-injection. Technically, both seabed/surface disposal and onshore disposal are feasible. Re-injection is not considered technically feasible for this Project. Re-injection involves grinding up cuttings, mixing them with a liquid (potentially waste drilling fluid) and sending to an injection well for disposal. This disposal method requires a specific injection well which is not planned for this Project.

Economically, the most feasible alternative is seabed/surface disposal. Onshore disposal is economically feasible, but would result in additional costs for transit times and disposal onshore. Re-injection is not considered economically feasible as it would result in increased costs associated with drilling of a secondary well specifically for re-injection.

Onshore disposal would eliminate the offshore environmental effects associated with discharge of drilling wastes to the marine environment; however, transport of drill wastes to shore results in additional transit emissions and safety exposure along with the potential effects of onshore waste disposal (*e.g*., terrestrial habitat and land use effects associated with the development and use of onshore disposal facilities). There is not predicted to be any substantive socio-economic differences between either disposal option except for the additional procurement required for handling and disposal of drill waste onshore.

Seabed/surface disposal is the preferred management method. The MODU is equipped with shale shakers and cuttings dryers to reduce the SBM remaining on cuttings below the level appropriate for ocean disposal (6.9% synthetic oil-on-cuttings in accordance with the OWTG). Biological effects on fish and marine benthos from drill waste discharge are not expected to affect fisheries in the area beyond the 500-m radius safety (fishing exclusion) zone under routine conditions. Additionally, modelling conducted for seabed/surface disposal (refer to Appendix C) indicates a localized affected area. The results of this modelling predict that drill waste sediment thickness of 10 mm could extend up to 155 m from the wellsite, with a maximum footprint of 1.89 ha per well (RPS ASA 2014a). Although specific thresholds for injury or mortality from smothering are species-dependent, a burial depth of 9.6 mm has been calculated as an average threshold under which net adverse effects to most species of benthic organisms are unlikely to occur (Neff *et al.* 2004).

Assuming compliance with OWTG and limited environmental and socio-economic effects associated with seabed/surface disposal, the increased costs of shore disposal of drill waste is not warranted. Re-injection is not considered feasible. Seabed/surface disposal is therefore the preferred alternative for drill waste management.

2.8.5 MODU Lighting

MODU lighting can attract migratory birds and result in stranding and/or harm from flaring. In association with offshore operations, a certain level of lighting on the MODU is required to allow for safe 24-hour operations and, as such, there is minimal opportunity to reduce lighting. Where possible, lighting will be reduced to the extent that worker safety is not compromised. Alternatives to standard MODU lighting include spectral modified lighting, reduced flaring, and/or reduced lighting. Spectral modified lighting (*i.e.*, lighting which omits red light (570–650 nm) has been tested on offshore platforms in the North Sea and has demonstrated a reduced attractiveness to marine birds; however, impediments to its commercial use remain (Marquenie *et al.* 2014). While this lighting has passed regulatory and certification requirements in the Netherlands, Germany and the US, implementation in the offshore oil and gas industry has been hindered by restricted commercial availability, limited capabilities in extreme weather and lower energy efficiency (Marquenie *et al.* 2014).

The CNSOPB requires well testing in order to declare a significant discovery and flaring cannot be avoided. With respect to the timing of flaring and possible avoidance of flaring at night or during inclement weather, this is not considered technically feasible and would also incur an additional economic cost (*i.e.*, additional rig costs and operational delays). Once flaring commences during testing, although it is technically feasible, it is not desirable to shut down the test as the data gained will be less valuable than a continuous test in acquiring an understanding of the subsurface and the extent of the reservoir. Well testing and associated flaring are expected to occur over a period of two to seven days per well. As such, the activity is of short duration in the context of the overall drilling timeline for each proposed well.

Standard lighting and flaring are considered the most technically and economically viable options for this Project, although mitigation measures will be in place to reduce environmental effects on birds to the extent possible, while still maintaining necessary levels of worker health and safety and operational integrity.

2.8.6 Chemical Management

Shell is in an early stage of Project planning and has not presently undertaken chemical selection or identified potential alternatives. The following subsections, however, provide additional detail on the process Shell will employ with respect to chemical management, chemical selection and compliance with relevant regulatory requirements.

2.8.6.1 Regulatory Framework

CEPA, 1999, administered by Environment Canada, addresses pollution prevention and the protection of the environment and human health in order to contribute to sustainable development. CEPA, 1999 supports a "precautionary approach" and makes pollution prevention the cornerstone of national efforts to reduce risks of toxic substances. CEPA, 1999 covers a range of activities to address various pollution issues, inclusive of establishing information-collection authorities; mandating environmental and human health research activities; establishing processes to assess risks posed by substances in commerce; imposing timeframes for managing certain toxic substances; providing a wide range of instruments to manage substances, pollution and wastes; and requiring that the most harmful substances are phased out or not released into the environment in any measurable quantity. In particular, there is a List of Toxic Substances Managed (Schedule 1). The Government of Canada has the authority to regulate and authorize other instruments to prevent or control the use and/or release of these substances.

The *Hazardous Products Act,* administered by Health Canada, establishes standards for chemical classification and hazard communication and the authority to regulate or prohibit consumer products and workplace chemicals which pose a risk to their users.

The *Pest Control Products Act* administered by the Pest Management Regulatory Agency on behalf of the Minister of Health, governs the importation, sale and use of pest control products, including products used as biocides in the offshore. All products to be used as a pest control product must be registered in accordance with that Act and used in accordance with label instructions.

The *Fisheries Act* administered by DFO and Environment Canada, prohibits the deposition of toxic or harmful substances into fish-frequented waters.

The Domestic Substances List (DSL), administered by Environment Canada, created between 1984 and 1986, includes 23 000 substances known to be in use in Canada. For "new" substances, not previously listed on the DSL, a different set of requirements prevail under CEPA, 1999. With categorization complete, the federal government launched the Chemicals Management Plan (CMP) in December of 2006.

The National Pollutant Release Inventory (NPRI), administered by Environment Canada, is Canada's legislated, publicly accessible inventory of pollutant releases (to air, water and land), disposals and transfers for recycling. The owner/operator of the company may be required to submit an NPRI report to Environment Canada if the reporting thresholds for substances/pollutants are reached or exceeded.

Selection of chemicals for use in the drilling program should meet the minimum expectations outlined in the OCSG (NEB *et al.* 2009). The OCSG provide a framework for the selection of drilling and production chemicals intended for use and possible discharge into the offshore areas under the jurisdiction of the CNSOPB. The objective of these Guidelines is to promote the selection of lower toxicity chemicals to minimize the potential environmental impact of a discharge where technically feasible. The OCSG are applicable to drilling and production chemicals intended for use and possible discharge into the offshore areas and generally exclude:

- requirements relating to chemical storage, transportation or onshore disposal
- selection of domestic chemicals and other chemicals that are used on an installation that are not directly associated with drilling and production activities, such as those used for accommodations, catering, equipment and facility maintenance (*e.g.*, lubricants, paints, *etc.*), safety systems and laboratory operations

- selection of chemicals that are used on vessels under contract (*e.g.,* support, standby, construction, *etc.*) to support operational activities

The OCSG provide a step-by-step procedure and criteria for offshore chemical selection, including hazard assessment, risk justification, registration, setting the discharge rate, or decision to find substitute, and reporting. The OCSG use the following lists and criteria for hazard assessment and management:

- CEPA, 1999 Virtual Elimination List – consider alternatives for the substance use

- CEPA, 1999 List of Toxic Substances – ensure use of the chemical is in accordance with CEPA, 1999 risk management strategies for the substance

- OSPAR Pose Little or No Risk to the Environment (PLONOR) List - accept product/chemical for use if a discharge is intended

- PARCOM Offshore Chemical Notification Scheme (OCNS) Hazard Rating – if the substance is rated A or B, or colour band purple, orange, blue or white, assess toxicity, conduct a chemical-specific hazard assessment of the candidate chemical to determine its suitability for use

2.8.6.2 Project Activities Potentially Using Chemicals

As discussed in Sections 2.4.1 and 2.7.1, drilling wells will involve the use of chemicals. Table 2.7.2 lists the categories of materials used in drilling fluids and typical chemicals. Most substances are on the OSPAR PLONOR list and pose little or no risk to the aquatic environment. Categories of chemicals which may contain components that could potentially result in adverse environmental effects at certain concentrations include:

- pH control additives (*e.g.*, lime, sodium bicarbonate, soda ash)
- lubricants (*e.g.*, synthetic liquids, surfactants)
- emulsifiers and surfactants (*e.g.*, detergents, organic acids)
- bactericides (*e.g.*, glutaraldehyde and other aldehydes)
- defoamers (*e.g.*, alcohols, silicones, aluminum stearate, alkyl phosphate)
- pipe-freeing agents (*e.g.*, detergents, soaps, oils)

In addition to chemicals used in drilling fluids, chemicals are also used in the following Project activities and components:

- blowout preventer fluids (typically fresh-water base with additives, such as glycol, biocide, and a lubricant)
- re-fuelling and fuel storage (including diesel fuel)

- use of fuel for combustion (including natural gas, diesel fuel)
- hydraulic oil and greases for equipment
- fire suppressant systems (including fire suppressant chemicals)
- welding (including compressed gases)

Any release of hydrocarbons into the environment, such as fuels or lubricants, is considered an accidental event and is assessed in Section 8. Use of fire suppressant systems would also occur under emergency conditions and not part of routine operations. Details on chemical selection and management are provided below.

2.8.6.3 Chemical Selection and Management

The selection and management of chemicals for the Project will be conducted according to a Chemicals Management Plan which will be developed and implemented prior to the Project commencement. The Plan will be in compliance with applicable regulation and will follow the OCSG for selection of chemicals.

Although a specific inventory is not available at this stage of Project planning, the chemicals stock held on the MODU will be limited primarily to top-up volumes and typically will not exceed several weeks supply with weather contingency.

Shell manages chemicals in accordance with the management hierarchy of elimination, substitution and minimization. In accordance with the Shell Corporate Chemical Management Standard, the principles of chemical management include:

- Minimize the potential impact of chemicals on health, safety and the environment
- Ensure full compliance with all applicable legislation
- Minimize the quantity of chemical waste generated
- Minimize the number of chemicals used
- Maximize the cost effectiveness of chemicals used

Shell will preferentially select lowest toxicity alternatives, and chemicals that minimize residual impact if released into the environment (*e.g.,* biodegradable, non-chlorinated, *etc.*). In particular, chemicals that are on CEPA, 1999's List of Toxic Substances, or not included on the OSPAR PLONAR list and have a PARCOM OCNS Hazard Rating of A, B or purple, orange, blue, or white, or not included on the PLONAR list of chemicals and have not been assigned a PARCOM Offshore Chemical Notification Scheme Hazard Rating, will be evaluated for alternative means of operating or use of less-toxic alternatives. A full Material Safety Data Sheet (MSDS) will be available for all chemicals and oil products employed on the MODU.

2.8.7 Summary of Alternative Means

A summary of the assessment of alternative means for carrying out the Project is presented in Table 2.8.1. Note that the discussion of relative biophysical and socio-economic effects is limited to alternatives that were considered technically and economically feasible.

Table 2.8.1 Summary of Alternative Means of Carrying out the Project

Component of Analysis	Alternative Means of Carrying Out the Project Considered	Technical Feasibility	Economic Feasibility	Biophysical Effects	Socio-economic Effects	Preferred Option
MODU	Drill ship	Yes	Yes	There is no substantive difference in environmental effects between a drill ship versus a DP semi-submersible; but a drill ship will emit a higher noise level. A drill ship travels at faster speeds than a semi-submersible during mobilization; however, the speed range of both is below that considered to be high risk for marine mammal strikes.	There is no substantive difference in socio-economic effect benefit or effect of either MODU alternative. Both require a similar-sized safety zone, resulting in similar effects on fishing activity.	✓
	Semi-submersible	Yes	Yes, but additional costs associated with mobilization/ demobilization activities			
	Jack-up	No	Not applicable (not technically feasible)	Not applicable (not technically feasible)	Not applicable (not technically feasible)	
	Anchored semi-submersible	No	Not applicable (not technically feasible)	Not applicable (not technically feasible)	Not applicable (not technically feasible)	
Drilling Fluid	WBM only	Yes, but technical issues with borehole stability	Yes, but additional costs associated with potential operation delays associated with technical issues	No substantive difference in environmental effects between WBM and WBM/SBM assuming OWTG are followed with respect to SBM discharges. SBMs generally accumulate closer to the wellsite, limiting the zone of influence. WBMs remain suspended longer with greater potential to affect filter-feeding organisms. Both types of drill muds would be in compliance with the OWTG	No substantive difference in socio-economic effects between WBM and WBM/SBM. Biological effects will be in compliance with the OWTG, not cause serious harm to fish, and will not affect fisheries outside the safety zone.	
	SBM/WBM	Yes	Yes			✓

Table 2.8.1 Summary of Alternative Means of Carrying out the Project

Component of Analysis	Alternative Means of Carrying Out the Project Considered	Technical Feasibility	Economic Feasibility	Biophysical Effects	Socio-economic Effects	Preferred Option
				and not cause serious harm to fish.		
Drilling Waste Management	Seabed/surface disposal	Yes	Yes	Onshore disposal would have less environmental effect on marine environment; but transport of drill wastes to shore results in additional transit emissions and the potential effects of onshore waste disposal. Both types of drill muds would be in compliance with the OWTG and not cause serious harm to fish.	No substantive difference in socio-economic effects between WBM and WBM/SBM. Biological effects will be in compliance with the OWTG, not cause serious harm to fish, and will not affect fisheries in outside the safety zone.	✓
	Onshore disposal	Yes	Yes, but additional costs for transport and for possible operational delays			
	Re-injection	No	No	Not applicable (not technically and economically feasible)	Not applicable (not technically and economically feasible)	
MODU Lighting and Flaring	Standard lighting	Yes	Yes	MODU lighting can attract migratory birds and result in strandings and/or harm from flare. Opportunities may exist to reduce lighting and and/or direct lighting to reduce effects without compromising worker safety.	There are no socio-economic effects associated with standard lighting.	✓
	Spectral modified lighting	No (not readily available for commercial use at this time)	No (not considered commercially viable at this time)	Not applicable (not technically and economically feasible)	Not applicable (not technically and economically feasible)	

Table 2.8.1 Summary of Alternative Means of Carrying out the Project

Component of Analysis	Alternative Means of Carrying Out the Project Considered	Technical Feasibility	Economic Feasibility	Biophysical Effects	Socio-economic Effects	Preferred Option
	Timing restrictions on flaring	No	Yes (additional costs if result in scheduling modifications)	Activities are of short-duration.	There is no socio-economic effect associated with this option, assuming health and safety of workers is not compromised by reduced flaring.	✓
Chemical Management and Selection	Refer to Section 2.8.6 for a discussion on chemical management and selection process. Selection of chemicals for drilling activities will adhere to the OCSG.					