1.0 INTRODUCTION

BP Canada Energy Group ULC (BP Canada Energy Group ULC and/or any of its affiliates are hereafter generally referred to as "BP") is proposing to conduct an exploration drilling program on Exploration Licences (ELs) 2431, 2432, 2433, and 2434 known as the Scotian Basin Exploration Drilling Project (the Project) (refer to Figure 1.1.1). BP holds a 40% interest in the Nova Scotia Offshore ELs and will operate the exploration program. Partners, Hess Canada Oil and Gas ULC and Woodside Energy International (Canada) Limited, hold a 40% and 20% interest, respectively.

Offshore exploration drilling is a designated activity under the *Canadian Environmental Assessment Act, 2012* (CEAA, 2012). This document is intended to fulfill requirements for an environmental assessment (EA) pursuant to 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* (hereafter referred to as the "Accord Acts"). This Environmental Impact Statement (EIS) has been prepared to satisfy Project-specific *Guidelines for the Preparation of an Environmental Impact Statement Pursuant to CEAA, 2012* (CEA Agency 2015a; hereafter referred to as the "EIS Guidelines" and included as Appendix A) which were developed by the Canadian Environmental Assessment Agency (CEA Agency) with input from other government departments and agencies, and the public.

1.1 PROJECT OVERVIEW

BP will drill up to seven exploration wells in phases over the term of the licences, from 2018 to 2022. A Mobile Offshore Drilling Unit (MODU) will be contracted to drill wells within the ELs. Logistics support will be provided through a fleet of platform supply vessels (PSVs) and helicopters. A supply base in Halifax Harbour will be used to store materials and equipment. It is expected that drilling activity for the first well in the program will commence in 2018. At this time, it is anticipated that exploration drilling will be carried out in multiple phases so that initial well results can be analyzed to inform the execution strategy for subsequent wells. Information about the proposed Project that is assessed within the EIS can be found in Section 2.

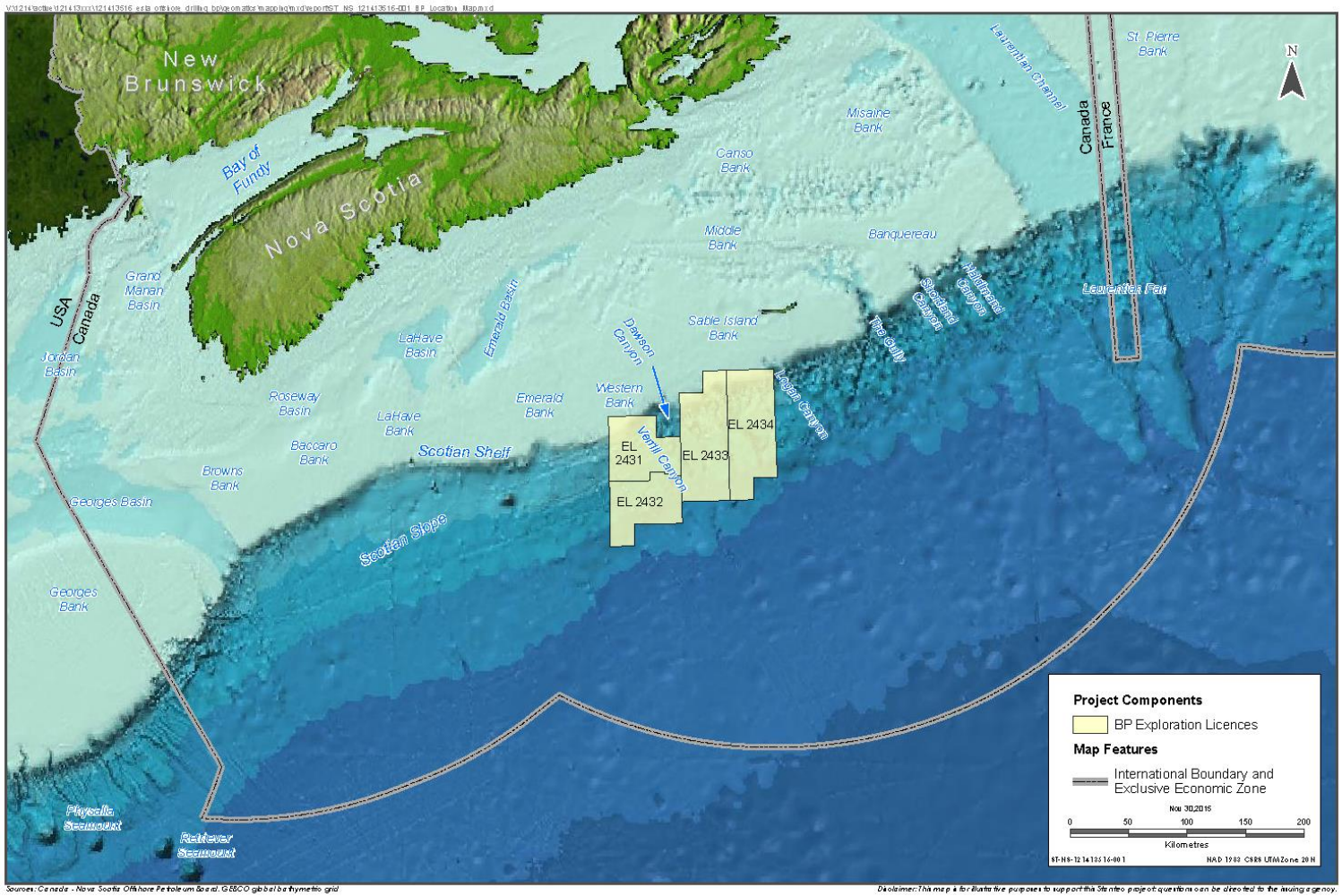

Figure 1.1.1. Scotian Basin Exploration Drilling Project Location

1.2 SCOPE OF THE EIS

The Project that is assessed within the scope of the EIS, in accordance with the EIS Guidelines includes:

- presence and operation of the MODU;
    - establishment of a safety (exclusion) zone, and light and sound emissions associated with MODU presence and operation; and
    - well drilling and testing operations;
- waste management;
    - discharge of drill muds and cuttings; and
    - other discharges and emissions (including drilling and well flow testing emissions);
- Vertical Seismic Profiling (VSP) operations;
- supply and servicing operations; and
    - helicopter transportation; and
    - PSV operations (including transit and transfer activities);
- well abandonment.

Some other components or activities which are not included within the scope of the EIS Guidelines may be described where necessary in relevant chapters for broader context.

The exact well locations have not yet been finalized, however will be confirmed as part of the regulatory approval process for each well in the program as described in detail in Section 1.5.1.

The EIS is defined by spatial boundaries to adequately consider potential adverse environmental effects from the Project. The Project Area encompasses the immediate area in which Project activities and components may occur and includes the area within which direct physical disturbance to the marine benthic environment may occur, and includes ELs 2431, 2432, 2433, and 2434 (Figure 1.1.1). Additionally, a Local Assessment Area (LAA) and Regional Assessment Area (RAA) have also been defined to assess potential environmental effects which may occur beyond the Project Area. Section 6 of this EIS provides additional information on spatial boundaries used to evaluate potential environmental effects from the Project.

1.3 PROPONENT INFORMATION

BP is one of the world's leading international oil and gas companies with decades of experience managing the extraction of oil and natural gas in all types of environments around the world, both onshore and offshore. BP has operations in more than 70 countries across Europe, North and South America, Australasia, Asia and Africa.

BP in Canada focuses on developing energy from Canada's oil sands, home to the third-largest crude reserves in the world, and is also pursuing offshore opportunities in the Beaufort Sea, Newfoundland and Labrador, as well as Nova Scotia. BP's integrated supply and trading (IST) business in Canada spans the country and is one of the top oil and natural gas marketer and trading organizations in Canada, helping to supply customers with safe and reliable energy.

BP Canada's head office is based in Calgary, Alberta. BP has established an office in Halifax, Nova Scotia to oversee the Project. Technical resources will also be drawn from BP's Canadian headquarters in Calgary, Alberta and BP's global headquarters in the United Kingdom (UK) and Houston, Texas.

The overall Project will be managed by BP through a multidisciplinary Project Team based on a functional model to provide technical and management expertise to the Project. The Team will include members of BP's global wells organization who are responsible for delivering a consistent and standardized approach to the safe delivery of wells-related activity across the company. The Project Team will also include professionals responsible for health, safety, environment and emergency response management.

1.3.1 How BP Operates

BP is dedicated to maintaining values of Safety, Respect, Excellence, Courage and One Team, upholding these values in the areas it operates. The BP values are described in Table 1.3.1.

Table 1.3.1 BP Values

Safety
Safety is good business. Everything we do relies upon the safety of our workforce and the communities around us. We care about the safe management of the environment. We are committed to safely delivering energy to the world.
Respect
We respect the world in which we operate. It begins with compliance with laws and regulations. We hold ourselves to the highest ethical standards and behave in ways that earn the trust of others. We depend on the relationships we have and respect each other and those we work with. We value diversity of people and thought. We care about the consequences of our decisions, large and small, on those around us.
Excellence
We are in a hazardous business and are committed to excellence through the systematic and disciplined management of our operations. We follow and uphold the rules and standards we set for our company. We commit to quality outcomes, have a thirst to learn and to improve. If something is not right, we correct it.
Courage
What we do is rarely easy. Achieving the best outcomes often requires the courage to face difficulty, to speak up and stand by what we believe. We always strive to do the right thing. We explore new ways of thinking and are unafraid to ask for help. We are honest with ourselves and actively seek feedback from others. We aim for an enduring legacy, despite the short-term priorities of our world.
One Team
Whatever the strength of the individual, we will accomplish more together. We put the team ahead of our personal success and commit to building its capability. We trust each other to deliver on our respective obligations.

The BP code of conduct sets out the standards of behaviour and working in line with these values, and defines how to work at a group, team and individual level within the company. With clear and concise content setting out the principles and expectations on topics such as equal opportunities, human rights and conflicts of interest, it helps BP's workforce to operate in line with BP's values and maintain the company's commitment to high ethical standards throughout its activities and operations. The BP code of conduct applies to all BP employees, officers and members of the Board, and BP expects and encourages all contractors and their employees to act in a way that is consistent with the BP code of conduct.

One of BP's values is safety. Everyone who works for BP is responsible for ensuring his or her safety and the safety of colleagues, partners, suppliers and local communities. BP's policy on health, safety, security and environment (HSSE) sets out the company's goals of no accidents, no harm to people and no damage to the environment (shown in Figure 1.3.1). Safety is at the heart of everything BP does as a company, driven by leadership and applied across all operations through the operating management system (OMS), which is described below.

bp

BP's Commitment to **health, safety, security** and **environmental** (HSSE) performance

Our HSSE goals are simply stated – no accidents, no harm to people and no damage to the environment.

We strive to be a safety leader in our industry, a world-class operator, a good corporate citizen and a great employer.

Nothing is more important to us than the health, safety and security of our workforce and the communities in which we operate, and behaving responsibly towards our shared environment. We must be vigilant, disciplined and always looking out for one another.

We are committed to:

– Complying with applicable laws and company policies and procedures.
– Systematically managing our operating activities and risks.
– Reporting our HSSE performance.
– Learning from internal and external HSSE events.

Everyone who works for BP has a part to play in meeting our HSSE commitment.

Bob Dudley,
Group Chief Executive
29 September 2014

Figure 1.3.1 BP HSSE Policy

The OMS is a framework that brings together BP's global operating principles. It includes requirements for HSSE management, social responsibility and operational reliability, as well as requirements for other operational aspects, for example, maintenance requirements, contractor relations and organizational learning.

The OMS helps BP to manage and reduce risks throughout its activities globally, as well as continuously improve the quality of its operating activities. It sets out consistent principles and processes that are applied across BP Group. Together these are designed to simplify the organization, improve productivity and enable consistent execution and focus throughout BP. It sets out the requirements of what a BP operation needs to do across eight focus areas under the categories of people, plant, process and performance, shown below in the elements of operating component of OMS illustrated in Figure 1.3.2. The elements of operating are used to inform the performance improvement cycle which sets out how BP should operate.

The OMS includes requirements and guidance for the identification and management of environmental and social impacts within BP. These include topics such as management of drilling waste, wastewater and cultural heritage.

Figure 1.3.2 BP OMS Framework

BP's ability to be a safe and responsible operator depends in part on the capability and performance of contractors and suppliers. Contractors and suppliers can make up a major part of the workforce throughout the life of a project or operation.

BP's OMS defines requirements and practices for working with contractors. Contracts will include clear and consistent information, setting out specific details of BP's expectations. Contracts will be awarded following a bidding and contract tender evaluation process, which shall take account of factors such as safety, technical quality and cost. Contractors and subcontractors shall be required to demonstrate conformance with the requirements that have been established, including HSSE standards and performance requirements. Bridging documents are necessary in some cases to define how BP's safety management systems and those of BP's contractors will co-exist to manage risk on a site.

Contractors, such as drilling and well services contractors, will be accountable for the development and delivery of their safety management systems. Contractors will be responsible for carrying out self-verification activity to assess conformance with their contractual requirements. Contractor safety performance is typically assessed and reviewed by BP using a number of leading and lagging indicators. Additionally, BP will carry out reviews and assurance activity throughout the duration of the contract.

1.3.2 Proponent Contact Information

All communications regarding the EA for the Project, including this EIS, should be directed to the following contacts.

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1.3.3 Project Team

This EIS was prepared by BP 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 the EIS lead, the following consultants provided key expertise and services in support of EIS preparation:

- JASCO Applied Sciences (Canada) Ltd. conducted acoustic modelling;
- Membertou Geomatics Solutions (MGS) and Unama'ki Institute of Natural Resources (UINR) completed the Traditional Use Study (TUS); and
- SayleGroup Inc. provided input regarding offshore regulatory requirements.

1.4 BENEFITS OF THE PROJECT

The Project is predicted to result in several economic, social and technological benefits realized on local, regional and national scales. The following describes some of the predicted benefits the Project will generate.

Energy Diversification and Sustainability

Energy demand is forecast to increase globally over the next 20 years, including in North America. Population growth and increases in per capita income are the key drivers behind the growth in energy demand, and Canada has been recognized as one of the areas within North America where demand is likely to grow the most (BP 2015). The global energy mix continues to shift as the balance of energy demand and supply varies, economies expand and contract and energy prices fluctuate. Political unrest and extreme weather continue to affect energy production and consumption patterns and emphasize the need for secure, sustainable energy supplies.

BP recognizes the energy challenge – managing and meeting growing worldwide demand for energy while addressing climate change and other environmental and social issues (BP 2014a). BP believes that a diverse mix of fuels and technologies can enhance national and global energy security while supporting the transition to a lower carbon economy. Oil and natural gas are likely to play a significant part in meeting energy demand for several decades. Exploration is a critical activity to enable continued oil and gas discoveries to maintain production to meet global demand for energy. The exploration licences in the Scotian Basin present potentially significant geological formations and hydrocarbon reserves.

Nova Scotia's 2009 Energy Strategy – *Toward a Greener Future* (NSDOE 2009a), highlights the importance of a sustainable energy mix, and the role that offshore hydrocarbon exploration and development plays within the province's ongoing energy strategy. In the strategy, Nova Scotia commits to "encourage renewed offshore exploration and development, with its enormous

potential for building future prosperity". In order to achieve their stated goal, the province has stated that it will invest revenues from offshore hydrocarbon activity into expenditures that offer enduring benefits.

Economic Benefits

The Canada-Nova Scotia Offshore Petroleum Resources Accord (1986), promotes the early development of petroleum resources in the offshore area of Nova Scotia "for the benefit of Canada as a whole and Nova Scotia in particular" and recognizes Nova Scotia as "the principal beneficiary of the petroleum resources in the offshore area". The offshore oil and gas industry has generated billions of dollars in economic activity for the people of Nova Scotia through royalties, crown share adjustment payments, offshore accord payments, forfeiture payments from offshore licenses and rental payment from offshore exploration licenses (NSDOE n.d.).

Nova Scotia's 2009 Energy Strategy - *Toward a Greener Future*, recognizes that exploration and production activity has "contributed greatly to Nova Scotia's economy and provincial finances" which pay for public services such as health, education and debt reduction (NSDOE 2009a).

Industrial Benefits

BP is committed to investing in the areas where BP operates. The Project will contribute to the Nova Scotia economy through the procurement of equipment and services, referred to by the Nova Scotia Department of Energy (NSDOE) as industrial benefits. In 2012, BP committed to a total exploration expenditure of approximately $1.05 billion as part of its successful bid for the exploration licences in the Scotian Basin. The qualified work expenditures are associated with exploration activity, including seismic and drilling activity, in the exploration licences over the initial six-year period of the nine-year exploration licence. This exploration expenditure will contribute, in part, industrial benefits to the Nova Scotia economy. BP is committed to incorporating processes and procedures for Nova Scotia and Canadian businesses, manufacturers, consultants, contractors and service companies to receive a full and fair opportunity to provide goods and services to the program on a competitive basis.

Employment Benefits

It is likely that there will be some employment opportunities associated with the Project. These opportunities will be communicated to local and regional audiences, using methods such as local media. Where employment opportunities are identified, all hiring will be carried out according to BP's code of conduct and include a transparent hiring process. First consideration will be given to residents of Nova Scotia and Canada as a whole where they have the appropriate competencies.

BP has established a local office in Halifax. The office will be staffed with management and administrative support staff. During planning and operations, technical staff directly working on

the Project will also work in the Halifax office. BP recognizes the importance of having a local presence and location known to stakeholders and local businesses.

Community Investment

BP's community investment strategy is to invest in people and programs that pursue sustainable and long-lasting progress. BP seeks to work closely with partner organizations so that BP can play an active, dedicated role in the communities we operate within.

The BP community investment program's main focus areas are:

- education;
- environment; and
- community.

Benefits Plan

In accordance with section 45 of the Accord Act, BP, as operator, will submit a benefits plan for approval to the CNSOPB. BP is required to have an approved benefits plan prior to the approval or authorization of any work or activity in the Nova Scotia offshore area (refer to Section 1.5.1). This plan will describe how BP shall provide benefits to Nova Scotia in terms of procurement opportunity for goods and services and employment opportunity. It will also address how BP will develop and implement an education, training, research and development expenditure program in Nova Scotia. The benefits plan will describe how BP will give first consideration to Canadian residents and organizations, particularly from Nova Scotia, where possible within the recruitment and procurement processes.

Knowledge Benefits

In addition to the economic and associated community and social benefits described above, the Project is likely to contribute to technological and scientific knowledge sharing and advancement in Canada and Nova Scotia.

The Scotian Basin includes water depths that extend to greater than 3,000 m. BP has deepwater drilling interests in a number of locations around the globe and can offer a wealth of experience in deepwater operations and technology.

BP will submit reports to the CNSOPB on environmental and operational performance which will also contribute to the understanding of deepwater drilling operations offshore Nova Scotia.

1.5 REGULATORY FRAMEWORK AND THE ROLE OF GOVERNMENT

1.5.1 Offshore Regulatory Framework

Petroleum activities in the Nova Scotia offshore environment 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 to promote social and economic benefits associated with petroleum exploitation. 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* are collectively referred to as the Accord Acts. Under the Accord Acts, the CNSOPB issues licences for offshore exploration and development, the management and conservation of offshore petroleum resources, and protection of the environment as well as the health and safety of offshore workers, while enhancing employment and industrial benefits for Nova Scotians and Canadians.

Offshore petroleum activities and the CNSOPB's decision-making processes are governed by 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:

- an Environmental Assessment report;
- a Canada-Nova Scotia Benefits Plan;
- a Safety Plan;
- an Environmental Protection Plan (including a waste management plan);
- Incident Management Plan and Spill Contingency Plans;
- financial security; and
- 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 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 economic aspects of offshore petroleum exploration and development activities. Of particular relevance to the environmental assessment of this Project are the Offshore Waste Treatment Guidelines (OWTG) (NEB *et al.* 2010) and the Offshore Chemical Selection Guidelines (OCSG) for Drilling and Production Activities on Frontier Lands (NEB *et al.* 2009). Relevant regulations and guidelines that fall under the jurisdiction of the CNSOPB are summarized in Table 1.5.1. Additional legislation and regulations relevant to offshore exploration activity are discussed in Section 1.5.3. BP will comply with all applicable Canadian regulations and the terms and conditions for all permits, authorizations and licenses obtained in support of the Project.

Table 1.5.1 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)/ 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 Geophysical Operations Authorization may be required in support of the Project if walkaway VSP methods are employed in support of exploratory drilling activities, although currently BP plans to conduct zero offset VSP (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 authorization for petroleum exploration and or production drilling in the Nova Scotia Offshore Area.	A Certificate of Fitness will be required in support of the Project.

Table 1.5.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		More specifically, the Regulations are implemented to require that the equipment and/or installation of exploratory or production equipment is fit for the purposes for which it is intended to be used and may be operated safely without posing threat to persons or the environment in a specified location and timeframe.	
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	Compliance with OWTG

Table 1.5.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		• discharges associated with subsea systems • naturally occurring radioactive material.	
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 any restrictions, controls, or prohibitions	Compliance with OCSG

Table 1.5.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		• 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 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	These guidelines describe 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
Environmental Protection Plan Guidelines (EPP Guidelines)	CNSOPB	These guidelines assist an operator in the development of an environmental protection plan (EPP) that meets the requirements of the Accord	Compliance with EPP Guidelines

Table 1.5.1 Summary of Key Relevant Offshore Legislation and Guidelines

Legislation/Guideline	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		Acts and associated regulations and the objective of protection of the environment from its proposed work or activity.	
Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment (SOCP)	Fisheries and Oceans Canada (DFO)/ Environment and Climate Change Canada (ECCC)/CNSOPB/ C-NLOPB	The SOCP specifies the minimum mitigation requirements that must be met during the planning and conduct of marine seismic surveys, in order to reduce effects on life in the oceans. These mitigation measures can be applied to VSP operations. These mitigation requirements focus on planning and monitoring measures to avoid interactions with marine mammal and sea turtle species at risk where possible and reduce adverse effects on species at risk and marine populations.	Compliance with SOCP
Guidelines Respecting Financial Responsibility Requirements	CNSOPB	Pursuant to the Accord Act, proponents wishing to conduct any work or activity in Nova Scotia offshore area are required to provide proof of financial responsibility in a form and amount satisfactory to the CNSOPB. These regulations and guidelines provide guidance to operators in providing proof of financial requirements regarding authorization being sought for any work or activity relating to drilling, development, decommissioning or other operations in the offshore areas.	Compliance with Regulations and Guidelines

Source: Modified from Stantec 2014a

Project activities and associated potential effects are not predicted to extend beyond provincial boundaries. However, if transboundary activities are required (*e.g.*, in the event of a spill which could extend beyond Canada's jurisdictional boundary and require spill response in international waters), then the appropriate regulatory authorities will be consulted, and BP will comply with additional regulatory requirements as applicable.

1.5.2 Environmental Assessment Requirements

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

> *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.*

Although there have been other wells drilled in the Project Area (Shubenacadie H-100 drilled in 1982, Evangeline H-98 drilled in 1984, Newburn H-23 drilled in 2002 and Weymouth A-45 drilled in 2003), these wells were not associated with the current ELs issued to BP. The Project consists of the drilling, testing and abandonment of offshore exploratory wells within the ELs issued to BP by the CNSOPB.

A Project Description was filed by BP with the CEA Agency on July 15, 2015 (Stantec 2015). 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 September 16, 2015 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 on the CEA Agency website on November 4, 2015.

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 of the EA Report, 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.

1.5.3 Other Applicable Regulatory Requirements

Project activities and components in the nearshore and offshore marine environment will take place within federal waters, which, under CEAA, 2012 constitutes "federal lands". Given the focus of offshore activities for this Project, the term "federal waters" is used although it is acknowledged that the Act does not differentiate between federal lands and federal waters. The Project is subject to various federal legislative and regulatory requirements (see Table 1.5.2).

Table 1.5.2 Summary of Key Relevant Federal Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Canada Oil and Gas Operations Act (R.S., 1985, c. O-7)	Natural Resources Canada (NRCan)	The Act is intended to promote, in respect of the exploration for and exploitation of oil and gas: (a) safety, particularly by encouraging persons exploring for and exploiting oil or gas to maintain a prudent regime for achieving safety; (b) the protection of the environment; (b.1) the safety of navigation in navigable waters; (c) the conservation of oil and gas resources; (d) joint production arrangements; and (e) economically efficient infrastructures.	No specific permitting requirements are anticipated under this legislation although new pending legislation (*Energy Safety and Security Act* (ESSA); *Regulations Establishing a List of Spill-treating Agents)* will have implications for spill prevention and response (see below).
Canadian Environmental Assessment Act, 2012 (CEAA, 2012)	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 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. Under current legislation, the CEA Agency is the responsible authority for administering the EA process for projects in the two Atlantic offshore areas (Nova Scotia and Newfoundland and Labrador). However, the proposed *Federal Authority as a Responsible Authority for Designated Projects Regulations* would prescribe the CNSOPB as a responsible authority, thereby minimizing duplication of effort	The Project is contingent upon EA approval (*i.e.*, an EA Decision Statement that allows the Project to proceed).

Table 1.5.2 Summary of Key Relevant Federal Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
		and harmonizing the review process of designated projects under CEAA, 2012 and the Accord Acts. It is anticipated that these changes would come into effect in 2016. The CEA Agency and CNSOPB are therefore working together on the EA process for the Scotian Basin Exploration Drilling Project to improve efficiencies and strive for a smooth transition of authority over the EA process for this Project.	
Canadian Environmental Protection Act, 1999 (CEPA, 1999)	ECCC	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.
Energy Safety and Security Act (ESSA)*(S.C. 2015, c. 4)*	NRCan	Introduced in Parliament as Bill C-22, ESSA received Royal Assent on February 26, 2015 and came into effect on February 26, 2016. ESSA aims to strengthen the safety and security of offshore oil production through improved oil spill prevention, response, accountability and transparency and amends the Accord Acts and the *Canadian Oil and Gas Operations Act* with the intent of updating, strengthening and increasing the level of transparency of the liability regime that is applicable to spills and debris in the offshore areas. The Act also promotes harmonization of the EA process for offshore oil and gas projects and includes provisions to allow the offshore petroleum boards (*e.g.*, CNSOPB) to enable them to conduct EAs under CEAA, 2012.	Financial Responsibility and Financial Resources requirements have increased. Specific additional relevance to be determined, but likely to have specific implications for spill prevention and response.

Table 1.5.2 Summary of Key Relevant Federal Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Fisheries Act	DFO ECCC (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 frequented by fish.	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.
Migratory Birds Convention Act, 1994 (MBCA)	ECCC	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.
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.
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.

Table 1.5.2 Summary of Key Relevant Federal Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Species at Risk Act (SARA)	DFO/ECCC/ 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 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.	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.
Regulations Establishing a List of Spill-treating Agents (proposed; Canada Gazette July 4, 2015)	ECCC	The Minister of the Environment has determined that certain spill treating agents (as listed in the proposed Regulations) are acceptable for use in Canada's offshore. As a result, upon the coming into force of the Regulations, the CNSOPB will be able to authorize the use of one or more of the spill treating agent products listed in the proposed Regulations under the conditions described above to respond to an oil spill.	Specific relevance to be determined, but likely to have specific implications for spill prevention and response.

Source: Modified from Stantec 2014a

1.6 APPLICABLE GUIDELINES AND RESOURCES

Other applicable guidelines and resources include federal government guidelines, Aboriginal policies and guidelines, and other relevant studies that will be used to inform the EA process. 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.

1.6.1 Government Guidelines and Resources

In addition to the EIS Guidelines (CEA Agency 2015a) developed for the Project (refer to Appendix A), other guidance developed by the CEA Agency and federal government has been consulted during the preparation of the EIS.

- The Operational Policy Statement, *Determining Whether a Designated Project is Likely to Cause Significant Environmental Effects under the Canadian Environmental Assessment Act, 2012* (CEA Agency 2015b) 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 2013a) 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 2013b) was consulted with respect to the assessment of Project alternatives (refer to Section 2.9).
- The CEA Agency's *Technical Guidance for Assessing Physical and Cultural Heritage or any Structure, Site or Thing that is of Historical, Archaeological, Paleontological or Architectural Significance under the Canadian Environmental Assessment Act*, 2012 (CEA Agency 2015c) was consulted with respect to the consideration of effects on heritage and culture.
- Health Canada's *Useful Information for Environmental Assessments* (Health Canada 2010) was consulted with respect to the consideration of effects on quality, noise and Aboriginal health.

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 2014b);
- Strategic Environmental Assessment for Offshore Petroleum Exploration Activities – Eastern Scotian Shelf – Middle and Sable Island Banks (Phase 1A)(Stantec 2012a);
- Strategic Environmental Assessment for Offshore Petroleum Exploration Activities – Eastern Scotian Slope (Phase 1B)(Stantec 2012b);
- 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 (ACZISC 2011);
- An Ecological and Biodiversity Assessment of Sable Island (Freedman 2014); and
- Several Canadian Science Advisory Secretariat Science Advisory Reports pertaining to the Scotian Shelf and marine species, including the Review of Mitigation and Monitoring Measures for Seismic Survey Activities in and near the Habitat of Cetacean Species at Risk (DFO 2015a).

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 and Climate Change Canada (ECCC) including marine mammal observation data and fisheries licences and landings from DFO, meteorological data and avifauna observation data (Eastern Canadian Seabirds at Sea [ECSAS], and Programme intégré de recherches sur les oiseaux pélagiques [PIROP] from ECCC's Canadian Wildlife Service), and seabird colony data from Nova Scotia Department of Natural Resources (NSDNR) (refer to Section 5).

The Shelburne Basin Venture Exploration Drilling Environmental Impact Statement (Stantec 2014a) and Environmental Assessment Report (CEA Agency 2015d) have also been drawn on in the preparation of this EIS, along with the Environmental Assessment of Exploration Drilling of the Cabot Licence EL 2403 Final Report (BP 2003) and Environmental Assessment of BP Exploration (Canada) Limited's Tangier 3D Seismic Survey (LGL 2014).

1.6.2 Aboriginal Policies and Guidelines

There are two key Mi'kmaq guidelines that 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 TUS 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 TUS activities involving select Mi'kmaq and Wolastoqiyik (Maliseet) Nations in that province. This approach was used to engage relevant First Nations in New Brunswick (*i.e.*, Fort Folly, St. Mary's, and Woodstock) during the Shelburne Basin Venture Exploration Drilling Project EA process and has been adopted in this case as well.

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); and
- *Reference Guide: Considering Aboriginal Traditional Knowledge in Environmental Assessments Conducted Under the Canadian Environmental Assessment Act, 2012* (CEA Agency 2013c).

2.0 PROJECT DESCRIPTION

This section provides key Project information in support of this EIS, explaining the rationale and need for the Project, describing the location and nature of Project components and activities, including the management of emissions and discharges that would likely be generated by the Project. This section also provides detail on required personnel and the Project schedule, and examines alternative means for carrying out the Project.

2.1 RATIONALE AND NEED FOR THE PROJECT

On January 15, 2013, BP was awarded exploration rights to ELs 2431, 2432, 2433 and 2434 from the CNSOPB with a total work expenditure bid (*i.e.*, amount of money proposed to be spent on exploration activity in the licences) of approximately $1.05 billion. In 2014, following an EA and authorization process under the Accord Acts, BP carried out a 3D Wide Azimuth Towed Streamer (WATS) seismic survey known as the Tangier 3D Seismic Survey. The 3D seismic data acquisition was completed in September 2014 and is being analyzed to identify potential drilling targets.

Exploration drilling is required to determine the presence, nature and quantities of the potential hydrocarbon resources within the ELs further to the information gathered and analyzed as part of the WATS seismic survey. The exploration drilling program also presents an opportunity for the interest holders, including BP, to fulfill their work expenditure commitments that must be met over the term of the licence period.

As indicated in Section 1.4, the Project is expected to result in several economic, social and technological benefits realized on local, regional and national scales, including a contribution to energy diversity and supply. Oil and natural gas are likely to play a significant part in meeting energy demand for several decades. Exploration is a critical activity to enable continued oil and gas discoveries to maintain production to meet global demand for energy. The exploration licences in the Scotian Basin present potentially significant geological formations and hydrocarbon reserves.

2.2 PROJECT LOCATION

BP proposes to drill up to seven wells on ELs 2431, 2432, 2433, and 2434. These licences cover 13,982 km^2 and, at their shortest distance, are located approximately 230 km southeast of Halifax and 48 km from Sable Island National Park Reserve. Sable Island is also the nearest permanent, seasonal or temporary residence to the Project Area except for workers inhabiting offshore platforms at the Sable Offshore Energy Project and the Deep Panuke developments. Water depths in the ELs range from 100 metres (m) to more than 3,000 m. The Project will not take place on lands that have been subject to a regional study as described in sections 73-77 of CEAA, 2012, nor are there any zoning designations or management plans that apply to the Project Area.

Specific drill sites have not yet been finalized but will be located within the ELs delineated in Figure 2.2.1. Corner coordinates for this area are provided in Table 2.2.1.

Table 2.2.1 Project Area Coordinates

Project Area "Corner"	NAD 83_CSRS_UTM Zone 20 N			
	X (metres)	Y (metres)	Latitude DMS	Longitude DMS
1	702995.10700	4790378.89572	42° 10' 0.000" N	61° 45' 0.000" W
2	702995.10700	4790378.89572	43° 10' 0.000" N	61° 45' 0.000" W
3	702995.10700	4790378.89572	43° 10' 0.000" N	61° 15' 0.000" W
4	702995.10700	4790378.89572	43° 0' 0.000" N	61° 15' 0.000" W
5	702995.10700	4790378.89572	43° 0' 0.000" N	61° 0' 0.000" W
6	702995.10700	4790378.89572	43° 20' 0.000" N	61° 0' 0.000" W
7	702995.10700	4790378.89572	43° 20' 0.000" N	60° 45' 0.000" W
8	702995.10700	4790378.89572	43° 30' 0.000" N	60° 45' 0.000" W
9	702995.10700	4790378.89572	43° 30' 0.000" N	60° 0' 0.000" W
10	702995.10700	4790378.89572	42° 40' 0.000" N	60° 0' 0.000" W
11	702995.10700	4790378.89572	42° 40' 0.000" N	60° 15' 0.000" W
12	702995.10700	4790378.89572	42° 30' 0.000" N	60° 15' 0.000" W
13	702995.10700	4790378.89572	42° 30' 0.000" N	61° 0' 0.000" W
14	702995.10700	4790378.89572	42° 20' 0.000" N	61° 0' 0.000" W
15	702995.10700	4790378.89572	42° 20' 0.000" N	61° 30' 0.000" W
16	702995.10700	4790378.89572	42° 10' 0.000" N	61° 30' 0.000" W

Prospective areas will be selected to optimize the potential discovery of hydrocarbon reservoirs. A number of factors are considered with respect to wellsite location, including:

- geophysical data;
- geohazard data; and
- seabed baseline conditions, including environmental sensitivities and anthropogenic features.

Extensive geophysical data acquisition and interpretation has been undertaken within the ELs as part of the Tangier 3D WATS survey, which was executed in 2014. The presence of prospective hydrocarbon reserves is a complex interaction of many factors including time, pressures, source rock, migration pathways and impermeable traps all of which need to be accounted for in interpreting the geophysical data and deciding where to drill. Prospective well locations within the ELs are being identified based on information gathered during the seismic program. Seismic data has provided information about the subsurface formations and consequently has guided the strategy for the location of potential exploration well location.

Within the prospective areas, the selection of wellsite locations also takes in account geohazards. A geohazard is a feature or geological condition which could pose a potential hazard to drilling activity, up to the depth of the first pressure containment casing string (generally from the seabed to 1,000 to 1,200 m depth below mudline). Some examples of geohazards include: faults, erosion and truncation surfaces; shallow gas pockets, gas charged sediments and hydrates; shallow water flow zones; seabed topography and soft seabed conditions; slump or scour features and mud slides; and abnormal pressure zones. These are all factors which could affect the delivery of safe and efficient drilling operations. Geohazard analysis is being carried out using reprocessed seismic data from the 3D WATS survey, and existing regional data, such as geotechnical cores and offset wells where available. Prior to any drilling activity, BP will conduct a comprehensive regional geohazard baseline review (GBR), followed by detailed geohazard assessments for each proposed wellsite.

An assessment of existing anthropogenic features, including unexploded ordnances, shipwrecks and telecommunication cables has been carried out (refer to Section 5.32). BP will conduct an imagery based seabed survey in the vicinity of wellsites to ground-truth the findings of the GBR. This includes confirming the absence of shipwrecks, debris on the seafloor, unexploded ordnance and sensitive environmental features, such as habitat-forming corals or species at risk. The survey will be carried out prior to drilling. If any environmental or anthropogenic sensitivities are identified during the survey, BP will move the wellsite to avoid affecting them if it is feasible to do so. If it is not feasible, BP will consult with the CNSOPB to determine an appropriate course of action.

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 potential 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 or reasonably foreseeable) physical activities. The RAA is restricted to the 200 nautical mile limit of Canada's Exclusive Economic Zone (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 extends into the Laurentian Channel to the Northwest Atlantic Fisheries Organization (NAFO) division 4S boundary and approaches the Nova Scotia coastline along the boundary of NAFO Unit Area 4VSb. The RAA extends along the Nova Scotia coastline from North Fourchu, Richmond County to Comeaus Hill, Yarmouth County. Section 6 of this EIS provides additional information on spatial boundaries used to evaluate potential environmental effects from the Project.

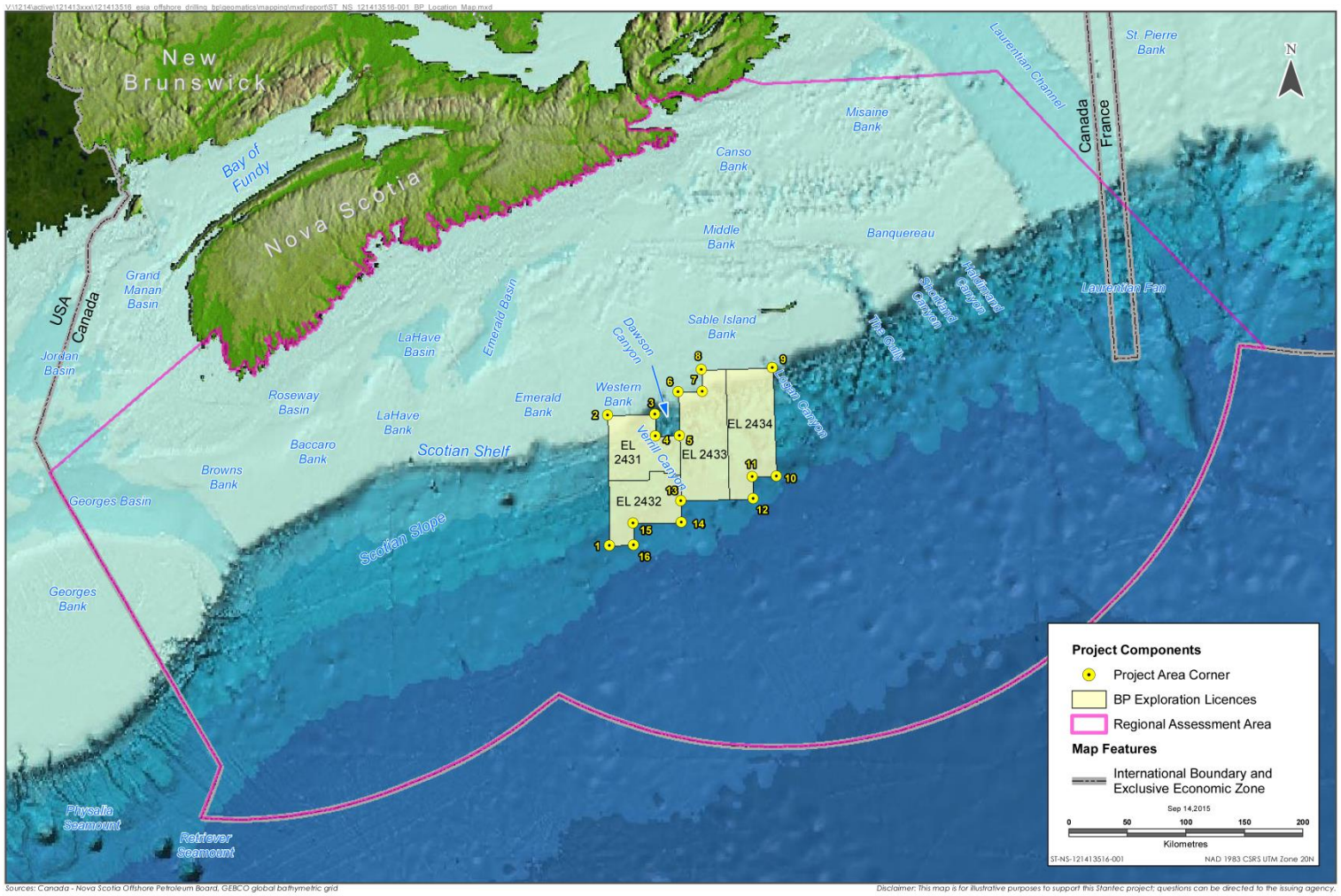


Figure 2.2.1 Project Area and Regional Assessment Area

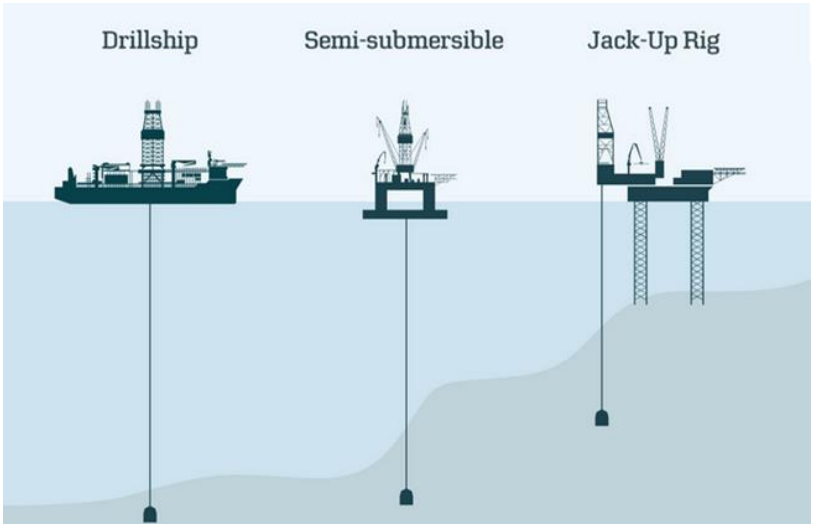
2.3 PROJECT COMPONENTS

The Project includes two main physical components: the drilling vessel and the offshore exploration wells. The Project also includes components for logistics support for servicing and supplying offshore activity. Logistics related components include supply vessels and helicopters for the transportation of personnel and equipment, and a supply base in Nova Scotia.

The offshore exploration wells are the only new pieces of infrastructure that need to be constructed as part of the Project. All other Project components, including the drilling vessel, supply vessels, helicopters and supply base are pre-existing and will be used by the Project on a temporary basis through contractual arrangements.

2.3.1 Drilling Vessel

Within Atlantic Canadian waters, three main types of exploration drilling vessels are typically used. The selection of the drilling vessel generally depends on physical characteristics of the wellsite, including water depth and oceanographic conditions, and logistical considerations (*e.g.*, rig availability). In shallow waters (less than 100 m), a jack-up rig (*e.g.*, Rowan Gorilla II used on Sable Bank) is typically used; in deeper waters a semi-submersible rig or drillship is used. These drilling vessels (*i.e.*, semi-submersible rigs, drillships and jack ups) are often referred to as mobile offshore drilling units (MODU). A schematic of the three types of MODUs described here is shown in Figure 2.3.1.



Source: Modified from Maersk Energy (n.d.)

Figure 2.3.1 Different Types of MODUs Used in Atlantic Canadian Waters

BP has not yet selected the MODU that will be used to drill the wells in the Scotian Basin. In consideration of the water depths in the ELs (up to approximately 3,000 m), it is expected that either a semi-submersible rig or a drillship will be used.

2.3.1.1 MODU Selection and Approval Process

To deliver the goal of drilling safe, compliant and reliable wells, BP will use several criteria for MODU selection, focusing on regulatory compliance, meteorological and physical oceanographic conditions, and the technical capability of the MODU. The MODU is expected to be capable of ultra-deepwater drilling to accommodate the water depths and meteorological and oceanographic (metocean) conditions within the ELs. It is also expected to be winterized to allow year-round drilling if required.

Once the MODU has been identified, it will be subject to a BP internal rig intake process. The rig intake process provides the means to identify and effectively manage risks for rig start-ups and verify that contracted rigs conform to specified BP practices and industry standards. Pursuant to the Accord Acts and the requirements of an OA, a Certificate of Fitness for the drilling vessel will be required which will be issued by a recognized Certifying Authority prior to approval for use. BP will obtain a Certificate of Fitness from an independent third party Certifying Authority for the MODU prior to the commencement of drilling operations in accordance with the Nova Scotia Offshore Certificate of Fitness Regulations.

2.3.1.2 General Operational Requirements

Although not yet identified, the MODU selected by BP shall, as a minimum, satisfy the operational requirements listed in Table 2.3.1.

Table 2.3.1 Operational Requirements for Mobile Offshore Drilling Unit (MODU)

General The MODU will be equipped with the following for the rig to operate:	
Drilling Mast	The support structure for the equipment used to lower and raise the drill string into and out of the wellbore.
Ballast Control	Maintains stability during operations.
Power System	Diesel generated power system to safely operate the MODU and all associated drilling equipment. The rig shall also be equipped with an emergency power system.
Positioning System	Dynamic positioning (DP) to maintain position under a range of meteorological and ocean conditions. Thrusters on the MODU are automatically controlled by the DP system to maintain the MODU in position. A variety of sensors, monitoring the ambient conditions and in combination with global positioning system (GPS) and acoustic referencing control the DP system.
Subsea Equipment	Inclusive of well control equipment such as blowout preventers (BOP), and a marine riser to act as a conduit from seafloor to rig floor. BOPs are devices installed on the wellhead that act as barriers to prevent the uncontrolled release of formation fluids escaping from the wellbore. These can take the form of an annular, pipe rams and blind shear rams.

Table 2.3.1 Operational Requirements for Mobile Offshore Drilling Unit (MODU)

Logistics Support The MODU shall be equipped with the following to support drilling operations:	
Helicopter Deck and Refuelling Equipment	For safe landings and departures for helicopters which are used for transfer of personnel and equipment.
Storage Space	Houses material used in drilling operations. This can include bulk storage for liquids, such as drilling fluid, fuel oil, cement *etc.*, as well as drilling equipment, such as casing, tubular equipment, *etc.*
Cranes	To transfer equipment between the supply vessels and the MODU.
Waste Management Facilities	To allow for offshore treatment or temporary storage of hazardous and non-hazardous waste streams prior to shipment to shore or disposal in line with the OWTG.
Emergency and Lifesaving Equipment	Inclusive of firefighting equipment, lifeboats and rafts for emergency evacuation.
Accommodation	Inclusive of welfare facilities, such as sleeping, washing, toilet and mess facilities, and recreational facilities and medical facilities. Accommodation facilities will provided for a maximum of 200 persons on board.

Additional detail on the two types of MODUs, which are currently under consideration for use by BP (*i.e.*, semi-submersible drilling rig and drillship), is presented below.

2.3.1.3 Semi-submersible MODU

A semi-submersible is characterized by a lower hull of separate pontoons with a number of vertical columns supporting a large upper deck. The upper deck contains drilling equipment, equipment and material storage areas and accommodation. During drilling operations, to ensure stability, the lower hull is submerged to a nominated depth using a ballast system and the semi's configuration minimizes the environmental loading compared to a ship-shaped hull, providing a relatively stable platform for drilling operations. Semi-submersible MODUs can either be moored in position over the drilling site using anchors, or maintained on station by DP.

The standard mooring technique for a semi-submersible in water depths up to approximately 1,200 m is a multi-point mooring system using a combination of wire rope, chains, and anchors. The anchors are set in a pre-determined pattern using an anchor handling offshore vessel. Given the location and water depths of the Project Area, it is assumed that the MODU would employ a DP system for positioning, rather than using anchors.

In DP mode, the drilling vessel maintains position using thrusters positioned on the hulls, which are controlled by a computerized DP system using GPS and acoustic positioning data. The acoustic system transmits energy signals to transponders (receivers) positioned on the seafloor, which

then send signals back to the transmitter allowing an accurate calculation of the position of the transponder relative to the vessel (Kongsberg 2015). This system is used to improve underwater positioning accuracy and redundancy to keep the drilling vessel in its intended position.

Figure 2.3.2 is a photo of the West Hercules, a semi-submersible drilling rig that has been employed by Statoil Petroleum in the Barents Sea and Newfoundland and Labrador.

Source: Offshore Energy Today 2014a

Figure 2.3.2 West Hercules Semi-Submersible

2.3.1.4 Drillship

A drillship is a self-propelled drilling vessel with very large variable deck load (VDL) capacity to allow for increased storage of equipment and materials to drill ultra-deep water wells, similar to those encountered within the ELs, and in remote locations. Drillships utilize DP to maintain position and rotate the ship over well center to head the ship into prevailing weather, following shifts in wind or wave direction to minimize the pitch and roll motion. Drillships are different from typical offshore vessels, such as cargo vessels, by the presence of a drilling package and a moon pool. The moon pool is an opening in the bottom of the hull of the vessel, which allows direct access to the water, enabling drilling equipment on the vessel to connect to equipment on the seafloor in order to drill the well.

Figure 2.3.3 is a photo of the Stena *IceMax* drillship, which has been contracted for use by Shell on the Shelburne Basin Venture Exploration Drilling Project.

Source: Chronicle-Herald 2014

Figure 2.3.3 Stena *IceMax* Drillship

2.3.2 Offshore Exploration Wells

BP will drill up to seven exploration wells within ELs 2431, 2432, 2433, and 2434 in phases over the term of the licences, from 2018 to 2022.

The well design and location for the proposed wells have not yet been finalized. Once confirmed, these details for the wells will be provided for review and approval to the CNSOPB as part of the OA and ADW for each well submitted in association with the Project.

Typically, oil and gas wells are drilled using a drill bit in a number of sections of progressively smaller-diameter intervals. Drill bits are available in many sizes to drill different diameter holes. The top interval is drilled starting at the sea floor and has the largest diameter hole. The drill bit is controlled from the MODU through a series of pipes, referred to as the drill string, which rotate the drill bit. The drill bit is lubricated by drilling fluids, also known as drilling "muds".

Drilling fluids are formulated according to the well design and the expected geological conditions. They comprise a base fluid, weighting agents and other chemicals that give the drilling fluid the properties required to drill a well safely and efficiently. Several types of drilling fluids are available including water-based mud (WBM) and synthetic-based mud (SBM). A framework for chemical selection to minimize the potential for environmental effects from the discharge of chemicals in drilling fluids used in offshore operations is provided in the OCSG (refer to Section 2.9.3 for more information on chemical management).

Drilling fluids flow from the MODU to the drill bit while it is drilling in the wellbore through the drill string. As the drill bit rotates downward through the rock layers, it grinds the rock, breaking it up, which generates rock fragments known as drill cuttings. The drill cuttings are circulated by the drilling fluid out of the wellbore through the annulus, a process illustrated in Figure 2.3.4.

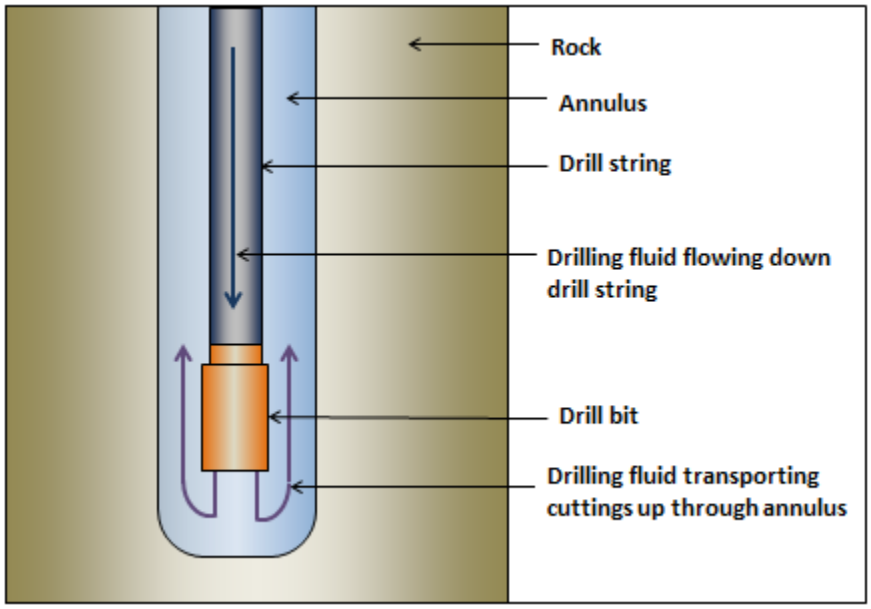


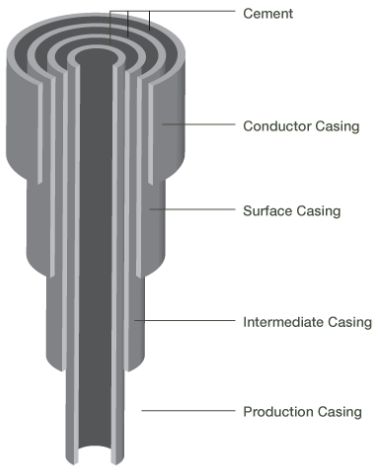
Figure 2.3.4 Drilling Fluid Circulation

The drilling of each well can be broken down into two phases: riserless drilling and riser drilling. During riserless drilling, the well is drilled using an open system with no direct drill fluid return connection to the MODU. Riserless drilling is typically only carried out in the shallow sections of the well before the equipment which allows the riser to be anchored to the seafloor is installed. During riserless drilling, WBM is typically used as the drilling fluid and cuttings are discharged directly to the water column in accordance with regulatory guidelines. Once a wellhead has been installed, a blowout preventer and a riser can be connected to the well. The riser is a conduit which allows drilling fluid and solids from the wellbore to be returned from the well to the surface. Drilling with a riser is therefore a closed loop system which allows drill fluids and cuttings to be returned to the MODU for treatment; therefore WBM or an alternative drilling fluid such as SBM can be used.

Each section will be drilled with an increasingly smaller drill bit and secured with casing. Casing is the liner installed within the wellbore. It is made up of a series of steel pipes that form a major structural component of the wellbore which serves several important functions, such as preventing the formation from caving into the wellbore, isolating the different formations to prevent flow or cross flow of formation fluids, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. Once the casing has been inserted into the wellbore at the end of the drilled section, it is cemented in place to secure it. The cement is used

to permanently seal the annular spaces between the casing and the wall of the borehole. It also seals the formation, preventing the loss of drilling fluid. To cement the casing in place, slurrified cement is flowed through the casing and up into the annular space between the formation and the casing, displacing any drilling fluid. The cement fills the annular space and solidifies. During the riserless phase, excess cement may be discharged to the seafloor. Once the riser has been installed, excess cement can be returned to the MODU.

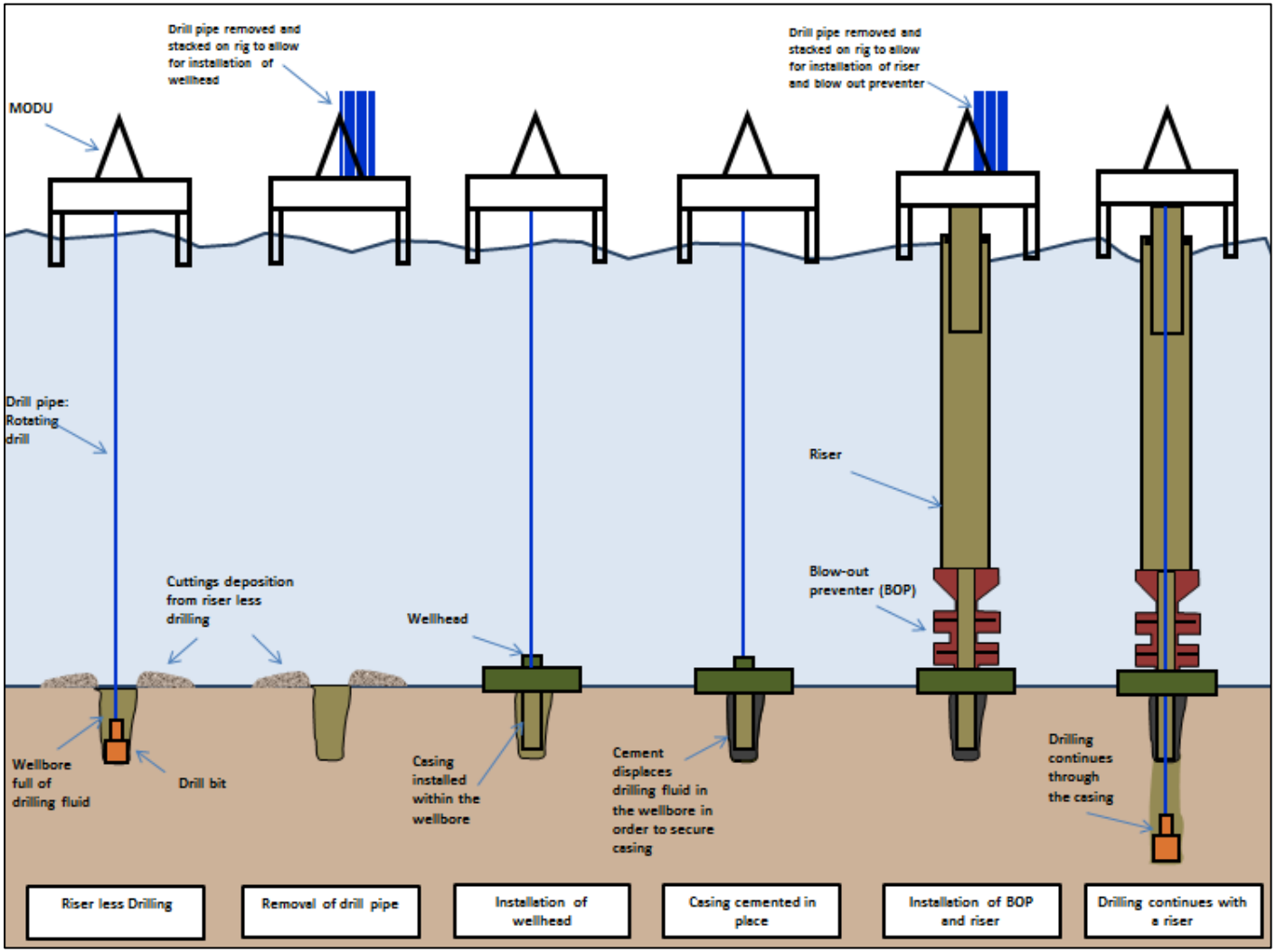
A typical casing configuration is illustrated in Figure 2.3.5 to show the increasingly smaller diameter sections of a well. This figure is indicative and does not represent the Project casing design.



Source: Encana 2015

Figure 2.3.5 Typical Casing Configuration

Figure 2.3.6 illustrates the drilling sequence described above. The wells drilled as part of the Project will be drilled in line with the principles described above. Further information about the Project wells is described in Section 2.4.2.



Source: Modified from Petroleum Club of Western Australia, Drilling for Oil and Gas

Figure 2.3.6 Drilling Sequence (NB – not to scale)

2.3.3 Supply and Servicing Components

Offshore drilling operations will be supported by logistics arrangements for supply and servicing activity. Such arrangements shall allow the transportation and movement of equipment and personnel between the MODU and land, and shall allow sufficient stocks of equipment and supplies to be maintained for reliable, ongoing drilling operations.

In accordance with the Final Guidelines for the Preparation of an Environmental Impact Statement issued to BP by the CEA Agency (CEA Agency 2015a), activity within the supply base is not considered within the scope of this EIS. The supply base is described below with the intent to clarify PSV routes between the supply base and the Project Area. Supply and servicing components and activities included in the scope of assessment comprise PSV operations (*e.g.*, loading, transit and unloading of vessels) and helicopter support (*e.g.*, crew transport and delivery of supplies and equipment).

Additional details on supply and servicing activities are provided in Section 2.4.5.

2.3.3.1 Onshore Supply Base

An onshore supply base will be used to support offshore drilling operations in Nova Scotia. The supply base serves as a location to temporarily store, stage, and load materials onto PSVs to be brought offshore. Likewise, the supply base serves as a location for materials to be returned onshore by PSVs, as needed, throughout the Project.

The Woodside Terminal has been selected as the preferred supply base location that will be used to support the Project. The Woodside Terminal is an existing multi-user industrial port facility located in Dartmouth, Nova Scotia on Halifax Harbour across from downtown Halifax (refer to Table 2.3.2 for geographic coordinates).

Table 2.3.2 Supply Base Location Geographic Coordinates

Supply Base Location	Latitude DMS	Longitude DMS
Woodside Terminal (Halifax Harbour)	44°38'49.00"N	63°32'53.00"W

The proposed facility is made up of two areas. This first area is dedicated to quayside operations and the second area serves as a temporary storage and laydown area (refer to Figure 2.3.7).

Blue Water Group, which has been selected as the third party logistics service provider for BP, operates the Woodside Terminal, providing supply base operations for the Sable Offshore Energy Project (SOEP) and Deep Panuke offshore gas developments as well as the Shelburne Basin Venture Exploration Drilling Project.

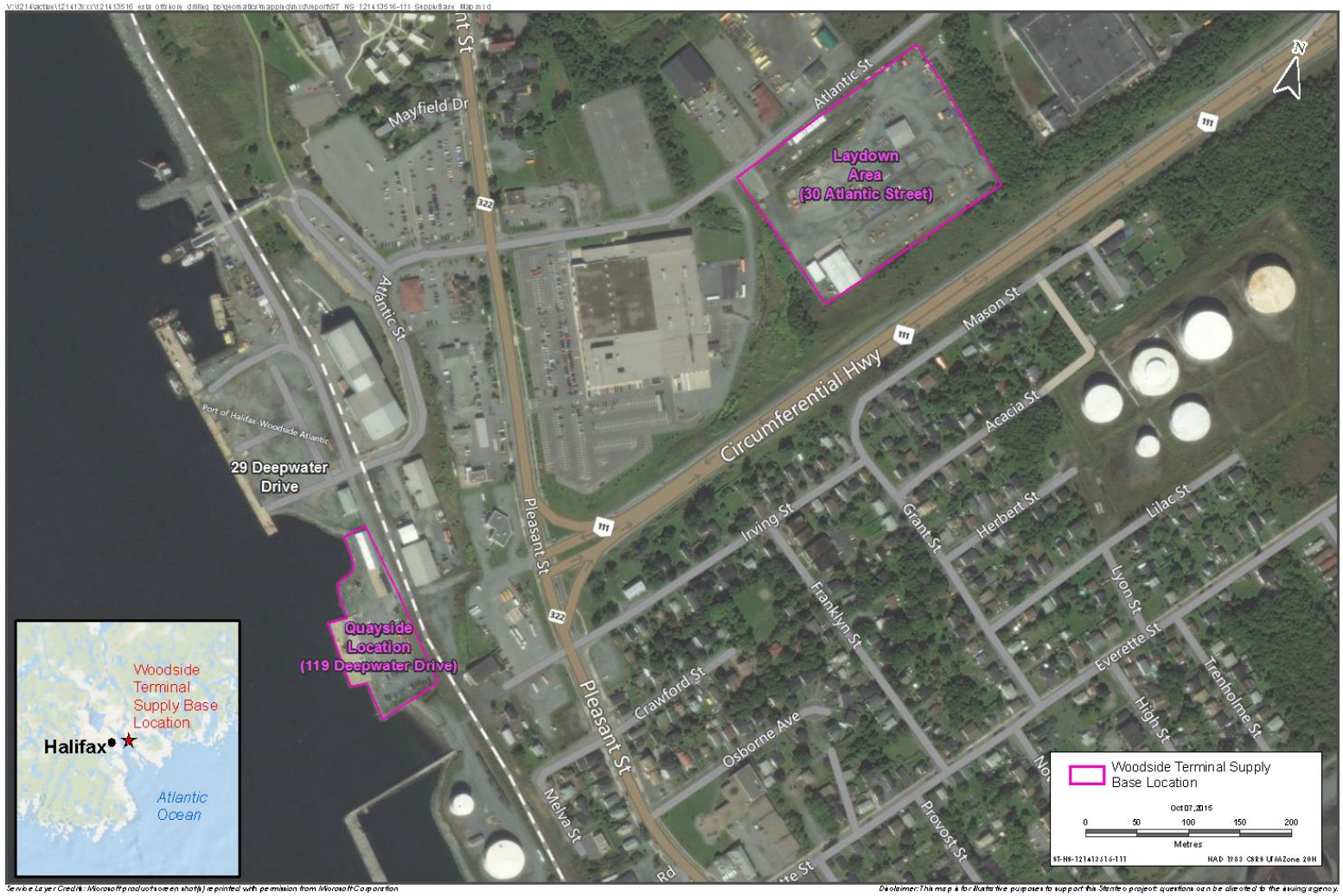


Figure 2.3.7 Woodside Supply Base Location

2.3.3.2 Support Vessels and Helicopters

The Project will require support from PSVs and helicopters for equipment and supplies and for crew changes. Both PSV and helicopter operations will be based out of the Halifax area. Like the supply base, the helicopter and PSVs will be owned and operated by third-party service providers, and will be used to support the Project on a temporary basis through contractual arrangements.

PSVs will be used to re-supply the MODU with equipment and supplies during the drilling program. The PSVs have not yet been identified; however, the fleet will be selected to fulfill the following functions for the MODU:

- supply food, fuel and bulk powders, drilling fluid and drilling materials;
- collect waste;
- assist in emergency response situations; and
- monitor the safety (exclusion) zone around the MODU and intercept vessels if required.

It is anticipated that two or three PSVs will be required in total. A PSV will remain on standby at the MODU at all times in the event that operational assistance or emergency response support is required. Figure 2.3.8 is a photo of a typical PSV that could be used on the Project. PSVs will undergo BP's internal audit process, as well as additional inspections/audits inclusive of the CNSOPB pre-authorization inspection process in preparation for the Project.

Source: Farstad 2012

Figure 2.3.8 Typical Platform Supply Vessel

Helicopters will be used to transfer personnel and light supplies to and from the MODU and land. These will also be used for emergency support services, including medical evacuation from the MODU in the event that it is required, as well as search and rescue operations if requested by the Canadian authorities. Figure 2.3.9 shows a typical offshore helicopter that could be used to support the Project.

Source: Offshore Energy Today 2014b

Figure 2.3.9 Typical Offshore Helicopter

Additional details on PSV and helicopter operations are provided in Section 2.4.5.

2.4 PROJECT ACTIVITIES

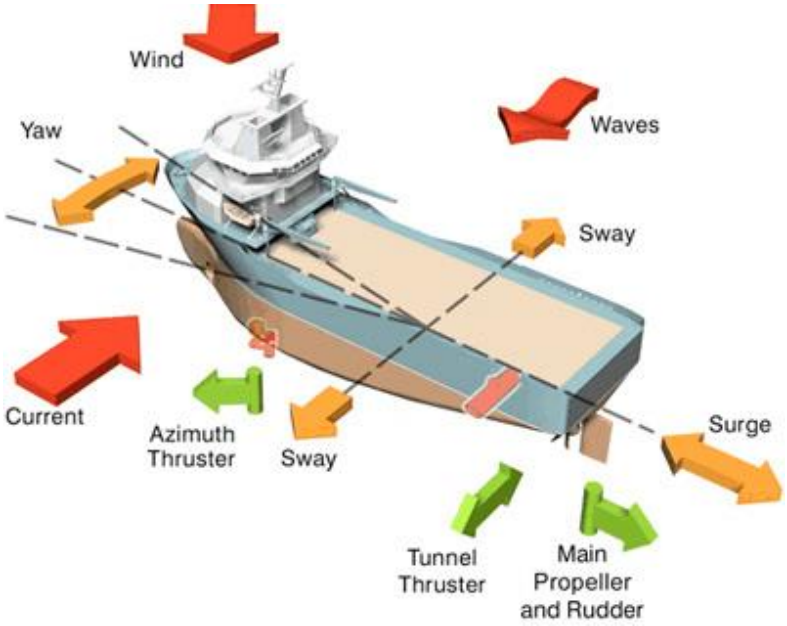
2.4.1 MODU Mobilization

As described in Section 2.2, drilling locations will be selected taking account of geohazard data, geophysical data and seabed baseline conditions. Further information about the reviews for each wellsite location is presented in Section 9.5.5.

As explained in 2.3.1.1, the MODU will be subject to the BP rig intake process as well as regulatory inspections which are required in order to deliver a Certificate of Fitness prior to approval for use. After all of the permits, regulatory approvals and authorizations have been obtained, the MODU will be mobilized to the drilling location.

The MODU will be either towed or will move self-propelled to the drilling location. Once the MODU is in place, positioning and stability operations will occur. This will include ballasting to increase the stability of the MODU and implementing the DP system to maintain position.

The DP system is made up a series of thrusters, which operate to continually adjust the vessel to counteract current, waves and wind forces to maintain the position of the MODU. Figure 2.4.1 illustrates dynamic positioning forces and does not represent the MODU or the configuration of thrusters for the Project, which have not yet been determined.



Source: Rigzone 2015

Figure 2.4.1 Dynamic Positioning Forces

In accordance with the *Nova Scotia Offshore Drilling and Production Regulations*, a safety (exclusion) zone (estimated to be a 500-m wide radius) will be established around the MODU within which non-Project related vessels are prohibited. This safety (exclusion) zone will be established around the MODU during initial mobilization activities and drilling operations, including well evaluation and abandonment processes. The safety (exclusion) zone is put in place to prevent collisions between the MODU and other vessels (*e.g.*, fishing, research or cargo vessels) operating in the area. The safety (exclusion) zone will be monitored by the standby vessel at the MODU. BP will provide details of the safety (exclusion) zone to the Marine Communication and Traffic Services for broadcasting and publishing in the Notice to Shipping and Notice to Mariners. Details of the safety (exclusion) zone will also be communicated during ongoing consultations with commercial and Aboriginal fishers.

To maintain navigational safety at all times during the Project, obstruction lights, navigation lights and foghorns will be kept in working condition on board the MODU and PSVs. Radio communication systems will be in place and in working order for contacting other marine vessels as necessary.

The MODU will be equipped with local communication equipment to enable radio communication between the PSVs and the MODU's bridge. Communication channels will also be put in place for internet access, and enable communication between the MODU and shore.

2.4.2 Drilling

2.4.2.1 Well Execution Strategy and Drilling Sequence

Designs for Project wells have not yet been finalized, although an indicative well design is presented in Table 2.4.1. Well design depends on a number of factors including the geology of the formations. Wells will be drilled in line with the principles set out in Section 2.3.2. The information below sets out the general execution strategy for wells drilled as part of the Project. Detailed plans will be provided for review and approval to the CNSOPB before drilling operations commence as part of the OA and ADW processes.

Table 2.4.1 Indicative Well Casing Plan for Project Wells

Section	Section Name	Drilling Fluid	Hole size (inches)	Casing Size (inches)	Interval Depth (metres)
1	Conductor Section	Seawater / WBM	36" or 42"	36"	100 m
2	Surface Casing	Seawater / WBM	26"	22"	800 m
3	Intermediate Casing 1	SBM / WBM	17" x 20"	16"	950 m
4	Intermediate Casing 2	SBM / WBM	14 3/4" x 17 1/2"	14"	1,100 m
5	Intermediate Casing / Liner 3	SBM / WBM	10 5/8" x 12 1/4"	9 5/8"	2,250 m
6	Production Hole 1	SBM / WBM	8 1/2"		250 m

If a planned section total depth (TD) cannot be reached, contingency casing sections, also referred to as strings, will be available. A contingency string is effectively an additional string inserted into the well to enable the well to be drilled to TD. Typical contingency strings include casing or liner sizes of 18", 11.3/4" and 7". It is expected the well can be completed in six sections or less; however there could be up to three additional sections if contingencies are used.

It is possible, that in the event of well success, a planned sidetrack may be drilled to explore other areas of the reservoir that are nearby. In the event of sidetracking, a secondary wellbore will be "kicked-off" from the original wellbore using a similar methodology described in Section 2.3.2 and below. The original wellbore will be abandoned using cement prior to side track drilling commencing. The details and design of the sidetrack will be contingent on the results of the original well and therefore have not yet been finalized. Once they have been established, plans and designs for the sidetrack will be submitted to CNSOPB for approval.

It is expected that the conductor and surface casing sections of wells drilled as part of the Project will be drilled riserless. During the riserless phase, the well will be drilled with either WBM or seawater. The drilling fluid is used to provide overbalance to the formation pressure with the hydrostatic pressure in the wellbore, keep the drill bit cool and flush out cuttings from the wellbore. During the riserless phase, as there is no mechanism to return cuttings to the MODU, cuttings and any associated fluid will be discharged at the seafloor as is permitted by the OWTG (NEB *et al.* 2010).

The first section of the well will be the conductor section. The conductor section provides the initial structural foundation for the borehole and the foundation for the subsea wellhead. A large diameter hole, potentially 42" in diameter, will be drilled to approximately 100 m depth below the seafloor. Once the section has been drilled, the conductor pipe can be run and cemented to secure the wellbore. The conductor can also be "jetted" into place, which effectively means that the conductor string is directly drilled into place. No cement is required when the conductor string is jetted in place.

After the completion of the conductor section, a smaller size drill bit will be passed through the conductor, and a new hole is drilled to section TD. Once the section is drilled, a surface casing string will be run and cemented to secure the wellbore. The top of the surface string will be connected to the wellhead. The wellhead is a pressure-containing mechanism that is the anchor point for casing used in drilling the well. The wellhead will be lowered down with the surface casing string attached, and installed on the conductor section. The surface casing section will be drilled with seawater or WBM, and like the conductor section, drill cuttings and associated fluids will be discharged to the seafloor as is permitted by the OWTG (NEB *et al.* 2010).

Once the surface casing has been installed, a BOP stack is run on the end of a drilling riser and connected to the wellhead. The riser creates a conduit back to the MODU. The BOP is a critical piece of safety equipment and is put in place to protect the crew and the environment against unplanned fluid releases from the well. It allows the wellbore to be closed through a series of rams and annular preventers, thereby closing the aperture, preventing any hydrocarbons from escaping the wellbore. More information on the BOP and additional well control features is provided in Section 2.5.

Once the riser and BOP have been installed, the drilling fluids and cuttings generated from the wellbore can be circulated back to the MODU for treatment. It is unknown at this stage which drilling fluids will be used to drill the remaining well sections. It is currently proposed that either a WBM or SBM will be used. The choice of which drilling fluids and other components of well design, such as section depths will be determined by the specific geology and predicted pore pressure of each individual well. The process of drilling, casing and cementing is continued for the remaining drill sections. This sequence of events is repeated until the TD of the well is reached. For more information on drilling fluids and drilling waste management, refer to Section 2.8.2.

2.4.3 Well Evaluation

If the exploration drilling results indicate that hydrocarbons are present in the target formations, the wells will be evaluated and possibly tested to provide further information about the stratigraphic column with special emphasis on reservoir characteristics. Well evaluation is an important component of exploration drilling as it helps to determine the viability of a prospect and commercial potential of the reservoirs.

There are a number of processes involved in well evaluation. While drilling, the well will be monitored and evaluated using Measurement while Drilling and Logging While Drilling (MWD/LWD) techniques, mud logging, drilling parameters evaluation and subsurface pressure evaluation activities. Wireline logging, vertical seismic profiling and formation testing may be performed after drilling activity has been completed based on the results of the primary evaluation tools.

2.4.3.1 Wireline Logging

A formation evaluation contractor will be employed to deploy specialized equipment and tools in the well to gather petrophysical data. The logging tools are used to take and record detailed measurements of the geological formations encountered in and around the well and the rock and fluid properties of the targeted reservoirs.

2.4.3.2 Vertical Seismic Profiling

VSP may be carried out which facilitates the correlation of surface seismic data (recorded in time, milliseconds) to well data (recorded in depth, metres). This effectively allows an accurate correlation of seismic reflectivity events to geological formations encountered in the wellbore through time to depth calibration and matching of wavelet character between the surface seismic data and the VSP result.

VSP operations can be carried out in a number of ways; for the BP exploration wells it is likely that a stationary acoustic sound source will be deployed from the MODU while a number of receivers, positioned at different levels within the drilled hole, will measure the travel time of the sound generated at the source as it arrives at those receivers. This form of VSP operation is referred to as zero-offset VSP. An offset VSP could also be used in the exploration wells. This is where the acoustic source is used from a marine vessel, and deployed at a distance of up to 8 km from the well.

Up to 12 sound sources may be used, each with a volume of up to 250 cubic inches. These multiple sources are tuned to one another to effectively simulate one larger sound source. These sound sources are generally positioned at 5 to 10 m below the water surface. VSP operations are typically short duration, normally taking no more than a day to complete the profiling. Longer duration VSP operations for additional characterization may be run, which could extend the duration of the VSP by a few additional days. VSPs are quieter and shorter in duration than exploration seismic surveys (refer to Section 2.8.5 for more information on underwater sound generated by VSP).

VSP activity will be planned and conducted in consideration of the Statement of *Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment* (SOCP, DFO 2007b). Specific details of the VSP program will depend on the geological target and the objectives of the VSP.

2.4.3.3 Well Flow Testing

Well testing may be required for the Project. Well testing can be used to gather information about subsurface characteristics such as potential productivity, connected volumes, fluid properties, composition, flow, pressure, and temperature. This dynamic data set in turn enables the confirmation of data in logs and cores assimilated during drilling activity, which in turn can build a comprehensive picture of reservoir potential. Flow testing is required under the Accords Act to convert an EL to a Significant Discovery Licence (SDL), to demonstrate the potential for sustained production.

It is not currently anticipated that well testing will be carried out on the wells drilled in the initial phase of the Project (*i.e.*, one to two wells). In the event of well success in the initial wells, and if the need for well testing is identified, a well test program will be developed and executed on subsequent wells drilled as part of the primary term of the licence.

In the event that a well test is required, it will be subject to BP's process for well test planning which is designed to promote safe and efficient well test operations. A key requirement of these processes is the use of process safety design methods to ensure effective barriers are in place for the well test activity, and an internal approval process for any well test activity and any associated flaring.

Where well testing is considered necessary, specialized equipment and services will be contracted to carry out the activity. Equipment that will be used in the well test will be designed to be able to safely control the maximum potential pressure that the reservoirs may be able to generate. It is likely that the well test operation will be run using conventional drill stem test (DST) tooling, subsea safety systems and temporary surface flow equipment to manage and measure the well fluids, collect fluid samples and necessary data sets. A DST is envisioned as historically the only acceptable type of flow test to support a SDL application. However alternative testing technologies may be proposed to satisfy the legislated requirements, with benefits that include potentially improved safety and environmental performance and protection.

The primary purposes of the DST tools and tubing are: (i) to provide a controlled flow path for the reservoir fluids to surface; (ii) provide downhole shut in; (iii) facilitate well killing operations; and (iv) convey the data measurement instrumentation and specialized sampling equipment as close to the formation being tested as practically possible. At the seabed level, subsea tools will be placed inside the drilling BOP. These tools are primary safety tools that provide fast acting (emergency) isolation of the well fluids at subsea level and permit disconnection of the test string from the well if required. The subsea tools will also be designed to ensure the emergency BOP functions such as shearing and emergency disconnect are available for use during the well test. The well will subsequently be suspended or abandoned in accordance with the *Nova Scotia Offshore Petroleum Drilling and Production Regulations*.

Any formation hydrocarbons, such as gas, oil or formation water that are brought to surface as part of the well test activity will be flared to enable their safe disposal. All flaring will be via one of

two horizontal burner booms, to either a high efficiency burner head for liquids, or simple open-ended gas flare tips for gases. High efficiency combustion equipment will be used which will maximize complete combustion, thereby reducing the likelihood of black smoke in flaring activity and drop-out of un-combusted hydrocarbons liquids on to the sea surface.

Where it is carried out, it is likely that the full well testing operational process would occur over a one month window after drilling is complete; however it is possible that it could extend up to three months. This would include all testing through to well abandonment. Within this operational window, the well test process will vary in terms of activity and it is likely that there will be a number of periods of short duration where flaring is required. Flaring may be for operational purposes, such as flushing, or bleeding where it will be carried out for between one and six hours each with low flow rates. Flaring may also be required during a series of separate periods of well test flow that could last up to two or three days for any one period. More information on flaring as part of well testing is provided in Section 2.8.1.

2.4.4 Well Abandonment

Once wells have been drilled to TD and well evaluation programs completed (if applicable), the well will be plugged and abandoned in line with applicable BP practices and CNSOPB requirements. Plugs will be placed above and between any hydrocarbon bearing intervals at appropriate depths in the well, as well as at the surface.

It is possible that the subsea infrastructure could be removed. If this is the case, casing will be cut below the seabed and the wellhead removed. The wellhead will be lifted to the surface and brought to shore using a PSV. No infrastructure will be left on the seafloor after the wellhead has been removed. A seabed survey will be conducted at the end of the drilling program using an ROV to survey the seabed for debris. Alternatively, approval may be sought to leave the wellhead in place.

The final well abandonment program has not yet been finalized; however, these details will be confirmed to the CNSOPB as planning for the Project continues.

2.4.5 Supply and Servicing

The existing facility at the Woodside Terminal will be used to support logistical requirements for offshore operations. Supply base activities will be conducted by a third-party contractor and are considered outside the scope of this EIS.

2.4.5.1 Platform Supply Vessel Operations

The rig will be supported by a fleet of PSVs to re-supply the drilling vessel with fuel, equipment, drilling mud, and other supplies during the drilling program, as well as removing waste. It is likely that two to three PSVs will be required, with one vessel on stand-by at the drilling vessel at all

times. It is estimated that the PSVs will make two to three round trips per week between the MODU and the supply base.

Typical PSVs travel at approximately 12 knots at service speed. It is therefore expected that a PSV could take approximately 16 hours to reach the furthest point of the Project Area from Halifax. Existing shipping lanes will be used as practicable to minimize incremental effects.

Supplies will be loaded and unloaded onto PSVs using personnel and cranes for drilling materials and closed piping systems (*e.g.*, pumps, hoses) for bulk powders, liquid supplies and waste (*e.g.*, drilling fluids).

PSVs will undergo BP's internal audit process as well as additional external inspections/audits inclusive of the CNSOPB pre-authorization inspection process in preparation for the Project. Procedures will be put in place to ensure that hoses are inspected and operated correctly to minimize the risk of an unintended release. The PSVs, MODU and supply base will be equipped with primary spill contingency equipment to deal with spills in the unlikely event that they occur.

The PSVs will transfer diesel fuel, also referred to as marine gas oil (MGO) to the MODU from shore. Fuel is required offshore to power the MODU, including drilling equipment and thrusters. Fuel will not be loaded from the Woodside Terminal. Instead, an existing field distribution facility will be used within Halifax Harbor. A number of potential locations have been identified within Halifax Harbor; however, the exact location for fuel loading operations has not yet been confirmed. Fuelling operations, according to standard vessel fuelling procedures, are expected to take place up to two to three times per week by a third party contractor.

2.4.5.2 Helicopter Traffic and Operations

Helicopters will be used for crew changes on a routine basis and to support medical evacuation from the MODU and search and rescue activities in the area, if required.

It is anticipated that approximately one helicopter trip per day would be required to transfer crew and any supplies not carried by the PSV to the MODU. The MODU will be equipped with a helideck for safe landings. Helicopter operations will be run out of Halifax Stanfield International Airport (YHZ).

Routes to the well locations from shore have not yet been finalized, as the well locations have not yet been confirmed. The maximum distance that a journey from Halifax International Stanfield Airport to a well location is 198 nautical miles (nm), based on the boundaries of the ELs. The maximum flight time is therefore expected to be 90 minutes, including taxi time. Military exclusion areas and areas of high environmental sensitivity have been identified and will be avoided as the helicopter flight paths are determined by the helicopter operators.

The helicopters that will make up the helicopter fleet have not yet been contracted; however, it is expected that the helicopters used by the Project will have a capacity of approximately 19 passengers and a maximum range of approximately 540 nm without refuelling. Refuelling

operations are expected to take place at Halifax Stanfield International Airport; however, the MODU will be equipped with refuelling equipment.

2.5 WELL CONTROL AND BLOWOUT PREVENTION

A number of barriers are used in drilling operations to manage formation pressure, including the drilling fluid and casing, and dedicated pressure control equipment. Formation pressures are managed in order to prevent a blowout, which is an uncontrolled flow of formation fluids. A blowout can occur when the specific well control barriers have failed.

Blowouts are prevented in the first instance using primary well control measures and procedures. This includes monitoring the formation pressure and controlling the density of the drilling fluid accordingly. The density, or weight, of the drilling fluid is increased to maintain an overbalance of pressure against the formation, which keeps the wellbore stable. In the event that a primary barrier fails, the next line of defense is a BOP system, which is a secondary well control barrier.

A BOP is a mechanical device, which is designed to seal off a well at the wellhead when required. The system is made up of a series of different types of closing mechanisms. These include rams, which are pistons that move horizontally across the top of the well creating a seal around the drill string. Blind shear rams are also used to sever the pipe in the drill string and create a seal. Additionally, blind shear rams are used to seal the well when no pipe is present in the wellbore. Annular preventers can also be used to physically close off the well aperture around various sizes of pipe.

The BOPs that will be used as part of the Project will comply with American Petroleum Institute (API) standards, specifically Standard 53 (Blowout Prevention Equipment Systems for Drilling Wells). For each well drilled as part of the Project, a BOP rated to 15,000 psi working pressure (which will be able to accommodate the anticipated formation pressures) will be installed and pressure tested. These BOPs will consist of a series of control measures, including hydraulically-operated valves and sealing mechanisms that are open to allow the mud to circulate during drilling, but can be quickly closed if reservoir fluids, referred to as a "kick", enter the well. If a kick occurs and additional controls are required, an annular preventer will be closed to prevent any further influx from the reservoir into the well if there is pipe in the hole. If no pipe is in the hole, blind shear rams will be closed. The next line of defense, provided there is pipe in the hole, are the pipe rams, of which there are multiple for redundancy. The last line of defense is the blind shear rams, which, if necessary, cut right through the drill pipe and seal the well completely. There will also be a ram that is capable of cutting planned casing sizes, which is called a casing shear ram.

Prior to installation on the well, the BOP stack will be pressure tested on the MODU deck, and then again following installation on the well to test the wellhead connection with the BOP. It is expected that the BOP will be function tested every 7 days in accordance with API Standard 53 (Blowout Prevention Equipment Systems for Drilling Wells), and pressure tested every 21 days while connected to the wellhead. Additionally, when the BOP is initially installed, the ROV

intervention capability for operating the BOP, if necessary, will be tested. This is done by physically engaging the ROV control panel to function the controls. The BOP will only be removed once the well has been plugged and abandoned and the casing pressure tested above the abandonment plugs to confirm plug integrity.

A discussion of emergency response measures and strategies is presented in Section 8.

2.6 PROJECT PERSONNEL

The overall Project will be managed by BP through a multidisciplinary Project Team. The Project Team will include members of BP's global wells organization who are responsible for delivering a consistent and standardized approach to the delivery of wells-related activity across the company. This team will be responsible for planning and delivering the Project as a whole; however a number of contractors will be engaged to carry out specific components of the work. Key contractors include: the drilling contractor, who will provide and operate the MODU; well services providers who provide equipment and services to support drilling operations; and logistics contractors who provide and operate the shore base, supply vessels and helicopters.

As the Project progresses, the number of BP and contractor personnel involved in the Project will change. The contractor providing the most number of personnel is the drilling contractor. During drilling operations, a maximum of 200 people from the drilling contractor will work on board the MODU. A small number of BP personnel, such as drilling supervisors and drilling engineers will also work offshore on the MODU. BP and contractor personnel will be trained and capable of carrying out their functions.

During the drilling program, the offshore BP team led by the drilling supervisor, also known as the wellsite leader (WSL), is responsible for coordinating the overall execution of the drilling program and providing oversight of well-related operations. The WSL interfaces with the drilling contractor offshore leadership team to ensure that drilling is carried out safely and efficiently and complies with all relevant regulations. The WSL reports to the BP well superintendent, who is based onshore and is responsible for supervising the execution of the approved drilling program.

Offshore drilling contractor roles will include management positions, such as the offshore installation manager (OIM) and tool pusher, who work with the BP drilling management team to deliver safe, reliable drilling operations. The drilling contractor team will also include a number of roustabouts, technicians and health, safety and environmental (HSE) personnel. BP and drilling contractor personnel will also support drilling operations from offices onshore.

2.7 PROJECT SCHEDULE

BP plans to commence exploration drilling in 2018 pending regulatory approval to proceed. At this time, it is anticipated that exploration drilling will be carried out in multiple phases so that initial well results can be analyzed to inform the strategy for subsequent wells. Up to seven

exploration wells may be drilled in phases over the term of the ELs contingent on the drilling results of the initial wells.

It is anticipated that each well will take approximately 120 days to drill. Figure 2.7.1 shows key elements of the proposed Project schedule.

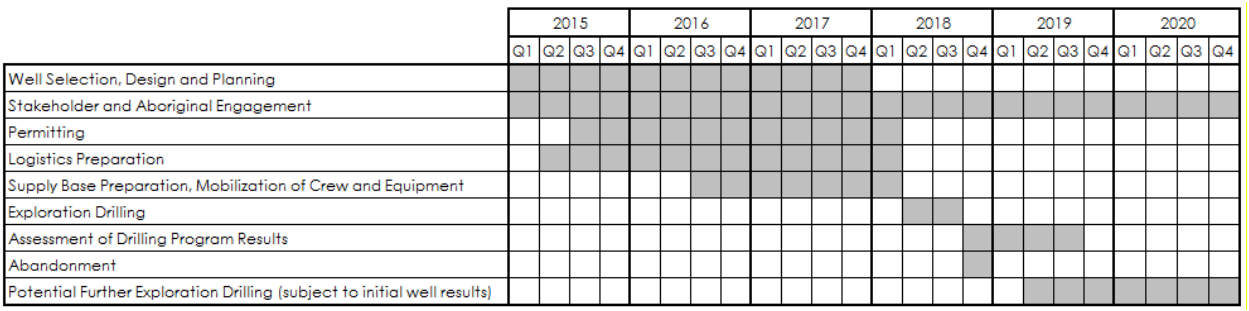


Figure 2.7.1 Proposed Project Schedule

2.8 EMISSIONS, DISCHARGES AND WASTE MANAGEMENT

This section provides an overview of the key emissions, discharges and waste streams, which are likely to originate from the proposed Project activities under routine and accidental conditions.

The key waste streams from the Project have been classified into the following groups:

- atmospheric emissions;
- drilling waste;
- liquid discharges;
- hazardous and non-hazardous waste; and
- heat, light and sound.

Some wastes will be managed and disposed of directly offshore from the MODU and the PSVs, whereas some wastes will be brought to shore for disposal. Offshore waste discharges and emissions associated with the Project (*i.e.*, operational discharges and emissions from the MODU and PSVs) will be managed in accordance with relevant regulations and municipal bylaws as applicable, including the Offshore Waste Treatment Guidelines (OWTG) (NEB *et al.* 2010) and 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*. Waste discharges not meeting legal requirements will not be discharged to the ocean and will be brought to shore for disposal.

Waste management plans and procedures will be developed and implemented to define waste storage, transfer and transportation measures.

Information on the releases, wastes and discharges will be reported as part of a regular environmental reporting program in accordance with regulatory requirements as described in the OWTG.

2.8.1 Atmospheric Emissions

Key Project activities resulting in atmospheric emissions are:

- combustion from the MODU and PSV diesel engines, and fixed and mobile deck equipment, and helicopters; and
- flaring during well test activity, in the event that well testing is required.

Emissions from diesel combustion activity are likely to include carbon dioxide (CO_2), carbon monoxide (CO), sulphur dioxides (SOx), nitrogen oxides (NOx), and particulate matter (PM). Air emissions from the Project will adhere to applicable regulations and standards including the Nova Scotia *Air Quality Regulations* under the Nova Scotia *Environment Act,* the National Ambient Air Quality Objectives (SO_2, NO_2, total suspended PM, and CO) and the Canadian Ambient Air Quality Standards (fine PM).

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. On January 1, 2015, the sulphur limit in fuel in the ECAs in large marine diesel engines dropped from 1.0% to 0.1% in accordance with the Vessel Pollution and Dangerous Chemicals Regulations under the *Canada Shipping Act*. 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 (GHG) in the offshore.

Ultra-low sulphur diesel (ULSD) fuel will be used for the Project wherever practicable and available. Using ULSD instead of regular diesel will reduce the potential for adverse local air quality effects.

Atmospheric emissions from individual components are contingent on fuel consumption. Activity and therefore fuel consumption will be variable throughout the Project; however, expected emissions from individual components are presented below (Table 2.8.1 and Table 2.8.2). Emission factors from US EPA AP-42 (Fifth Edition, Volume 1, Chapter 3.4) have been used to estimate the amount of carbon dioxide and other atmospheric emissions from expected routine emission sources. It has been assumed that evaporation in diesel engines has been negligible, and therefore only exhaust emissions have been considered.

Table 2.8.1 Gaseous Emissions Factors for Large Stationary Diesel Internal Combustion Sources

Air Contaminant	Emission Factor from US EPA AP-42 (lb/MMBtu)
CO_2	165
CO	0.85
NO_x	3.2
SO_x *	1.01S[1]
PM	0.1

* Note:
Assumes that all sulphur in the fuel is converted to SO_2. S[1] is the sulphur in fuel oil and it has been assumed that the sulphur content will be 0.05% The emission factor is therefore 0.0505.

- **MODU**

  As described previously, the MODU for the drilling program has not yet been identified and therefore exact fuel consumption data is not available. It is expected that on average, based on fuel consumption information from a comparable semi-sub DP powered MODU (as an example) that approximately 56 tonnes of fuel will be used by the MODU per day while on station (under extreme metocean conditions).

- **PSV**

  It is possible that up to three PSVs will be required to support MODU operations. PSVs will make approximately two to three trips per week at a service speed of 12 knots and a PSV shall remain on standby at the wellsite at all times. PSV emissions will be dependent on the speed of the vessel; however, it has been assumed that on average, each PSV will consume approximately 12 tonnes of fuel per day.

- **Helicopter**

  A helicopter will be used to transport personnel to and from the MODU. It is expected that one trip will be required per day. The furthest distance that the helicopter will travel from Halifax to the drilling location, based on the boundaries of the ELs is 198 nm. It is likely that approximately 1.2 tonnes of fuel could be used per round trip from Halifax to the wellsite and back again.

Table 2.8.2 Daily Criteria Air Contaminant Emissions for the MODU and Support Vessels and Helicopter

	Daily Fuel consumption (tonnes)	Daily Energy consumption (MMBtu)	CO_2 (tonnes per day)	CO (tonnes per day)	NO_x (tonnes per day)	SO_x (tonnes per day)	PM (tonnes per day)
MODU	56	2,380	178	0.9	3.5	0.006	0.1
PSV 1	12	510	38	0.2	0.7	0.001	0.02
PSV 2	12	510	38	0.2	0.7	0.001	0.02
PSV 3	12	510	38	0.2	0.7	0.001	0.02
Helicopter	1.2	51	3.8	0.02	0.07	0.	0.002
TOTAL	**93.2**	**3,961**	**295.8**	**1.52**	**5.75**	**0.009**	**0.18**

In terms of GHG emissions from routine activity, the Project is predicted to emit approximately 295.8 tonnes of CO_2 equivalent per day from fuel combustion for the MODU, helicopters and PSVs. ECCC reports an annual GHG emission value for the province of Nova Scotia of 17,000 kilotonnes of CO_2 equivalent per year (46,575 tonnes of CO_2 equivalent per day) (Environment Canada 2016). BP's predicted daily CO_2 emissions for the Project therefore represent approximately 0.64% of Nova Scotia's average daily emission.

It is not currently anticipated that well flow testing will be carried out on the wells drilled in the initial phase of the Project (*i.e.*, one to two wells). In the event of well success in the initial wells, and if the need for well flow testing is identified, a well test program will be developed and executed on subsequent wells drilled as part of the primary term of the licence. If well flow testing is carried out, atmospheric emissions will be generated as a result of flaring activity.

Well flow testing is a non-routine activity that occurs over a short period of time at the end of the drilling program. The well flow test window is likely to last no more than a month, although it could extend up to three months. Within this operational window, the well flow test process will vary in terms of activity and it is likely that there will be periods where flaring is required. Flaring may be for operational purposes, such as flushing or bleeding, and it would be carried out over one to six hours per flaring event, with low flow rates. Flaring may also be required during a series of separate well flow test periods that could last two or three days per period. It is also possible that there could be multiple targets containing hydrocarbons within each well, each of which could be subject to a well flow test.

In the event that a well flow test is desired, it will be subject to BP's process for well flow test planning, which is designed to promote safe and efficient well test operations. A key requirement of these processes is the use of process safety design methods and an internal approval process for any well test activity and associated flaring. Once the well design has been defined, a detailed well evaluation plan will be prepared and will be submitted for regulatory approval as part of the OA process.

For the purposes of quantifying GHG emissions from a non-routine flaring event for this assessment, it has been assumed that there could be two targets in each well that could potentially be tested as part of the evaluation program, and that no more than 10,000 bbls of oil would be flared per target in each well. Using a mass balance approach, the tonnes of CO_2 equivalents emitted as a result of flaring 10,000 bbls of oil from one target during a well flow test are 4,362 tonnes. In the assumption that two targets could be tested in each well, it is therefore possible that up to 8,724 tonnes of CO_2 equivalents could be emitted.

In line with the Project schedule, it is possible that two wells could be drilled in any year, and consequently, it is assumed that up to 17,448 tonnes of CO_2 equivalents could be released as a result of non-routine flaring during well flow testing, per year. This represents approximately 0.10 % of Nova Scotia's annual GHG emissions (17,000 kilotonnes CO_{2eq}/yr), as reported for 2014.

2.8.2 Drilling Waste Discharges

A number of drilling related waste streams will be generated as part of the Project; including:

- drill cuttings;
- drill fluids; and
- cement.

All drilling related waste streams will be disposed of in accordance with the OWTG.

The shallow sections of the wells will be drilled with WBM or seawater, and then deeper sections with either WBM or SBM.

WBM is primarily made up of water (approximately 75%), which can be freshwater, seawater or brine. Barium sulphate (barite) is added to the water in WBM to control mud density and thus help balance formation pressures within the well. Bentonite clay is also added which is used as a viscosifier, which thickens the mud to suspend and carry drill cuttings to the surface. Other substances can be added to the WBM to obtain the required drilling properties of the fluid, such as thinners, filtration control agents and lubrication agents. The vast majority of WBMs discharged are classified under the OCNS as substances which pose little or no risk to the environment (PLONOR.)

SBM is a water-in-oil emulsion which contains non-aqueous (water insoluble) fluids manufactured through chemical processes. SBMs can be made up of internal olefins, alpha olefins, polyalphaolefins, paraffins, esters or blends of these materials. The same weighting materials, such as barite, used in WBMs to control density are typically added to SBMs, as well as additives to manage viscosity, fluid loss, alkalinity, emulsion stability and wettability, where required. SBMs may be selected over WBM as they can offer improved lubricity, thermal stability, wellbore integrity and protection against gas hydrates in the well.

It is proposed that cuttings will be disposed to the seabed along with associated WBM or seawater drilling fluids used in the initial riserless sections. Cuttings from subsequent sections drilled with the riser will be returned to the MODU for treatment.

The MODU will be equipped with specialized solids control equipment for cuttings management. Shale shakers will be used to recover drilling fluids from the cuttings. Shale shakers are made up of a system of coarse and fine mesh screens that collect cuttings and allow drilling fluids to pass through and be collected. The purpose of solids control is to quickly and simply remove as much of the drilling fluids as possible from the cuttings for re-use in the drilling process. Additional solids control equipment, such as centrifuges may be required depending on the drilling fluid basis of design, and geological characteristics for reconditioning of the drilling fluid for re-use. Following treatment with solids control, WBM cuttings can be discharged to sea from the MODU through a caisson. Any excess or spent WBM may be discharged to the marine environment without treatment in line with the OWTG.

Additional treatment of cuttings will be required when SBM is used as the drilling fluid to enable disposal in accordance with the OWTG. SBM cuttings will only be discharged once the performance targets in OWTG of 6.9 g/100 g retained "synthetic on cuttings" on wet solids can be satisfied. The concentration of SBM on cuttings will be monitored on the MODU for compliance with the OWTG. It is expected that this SBM treatment will be done using a cuttings dryer, equipment that uses high-speed centrifuge technology to separate drilling fluid from the liquids. In accordance with the OWTG, no excess or spent SBM will be discharged to the sea. Spent or excess SBM that cannot be re-used during drilling operations will be brought back to shore for disposal.

Cement is used in drilling operations to secure casing in the well, and to prevent the escape of hydrocarbons around the outside of the well casing. Cement is pumped into the well and up and around the casing, and typically sets in approximately 5 to 6 hours.

Excess cement slurry may be discharged to the seabed during the initial phases of the well, which will be drilled without a riser. Once the riser has been installed, all cement waste will be returned to the MODU. Cement waste will then be transported to shore for disposal in an approved facility.

Based on the typical well design presented in Section 2.4.2, estimated quantities of cuttings that could be generated by drilling are presented below in Table 2.8.3. Predictive dispersion modelling for cuttings discharges is presented in Appendix C with a summary provided in Section 7.1.

Table 2.8.3 Estimated Drill Cuttings Discharges Based on Typical Well Profile

	Hole Size	Section Depth (m)	Quantity of Cuttings (tons)	Type of Drilling Fluid Used	Treatment	Discharge Location
1	36"x 42"	100	224	Seawater / WBM	None	Seabed
2	26"	800	766	Seawater / WBM	None	Seabed
3	17" x 20"	950	490	SBM / WBM	Shale shakers and cuttings dryers for SBM where used	Water column
4	14.3/4" x 17.1/2"	1,100	439	SBM / WBM	Shale shakers and cuttings dryers for SBM where used	Water column
5	10.5/8" x 12.1/4"	2,250	462	SBM / WBM	Shale shakers and cuttings dryers for SBM where used	Water column
6	8.1/2"	250	26	SBM / WBM	Shale shakers and cuttings dryers for SBM where used	Water column
TOTAL		**5,450**	**2,406**			

Table 2.8.4 Estimated Drill Fluids Discharges Based on Typical Well Profile (assumed that SBM will be Used for Sections 3-6)

		Discharges While Drilling			Batch Discharge of WBM [3]	
	Hole Size	Mud Discharged (tonnes)	Chemicals Discharged [1] (tonnes)	Oil Discharged [2] (tonnes)	Whole Mud Displacement (tonnes)	Chemicals Discharged (tonnes)
1	36"x 42"	146	2	0	703	193
2	26"	1,168	19	0	2,184	772
3	17" x 20"	91	77	40	0	0
4	14.3/4" x 17.1/2 "	101	89	37	0	0
5	10.5/8" x 12.1/4"	128	116	40	0	0
6	8.1/2"	8	8	2	0	0
TOTAL		**1,499**	**183**	**70**	**2,887**	**965**

Note:
[1] Chemicals include commercial solids (barite, bentonite *etc.*) added to the mud system.
[2] Assumes that SBM will be used to drill sections 3, 4, 5 and 6 and that SBM cuttings will be treated with cuttings dryers prior to discharge. Oil discharged is synthetic base oil only.
[3] WBM will be discharged in bulk at the end of sections drilled with WBM in line with OWTG.

2.8.3 Liquid Discharges

A number of liquid wastes could be generated from the MODU and associated drilling equipment, and on the PSVs. Some of these liquid wastes can be discharged directly from the MODU or PSVs, following treatment where necessary, in accordance with the OWTG. Where discharges occur offshore, the points of discharge will be below the water surface.

A short description of the major liquid discharge streams and the way in which they will be managed and disposed is shown below in Table 2.8.5.

Table 2.8.5 Potential Project-Related Liquid Discharges

Discharge	Source and Characterization	Waste Management
Produced water	Produced water includes formation water encountered in a hydrocarbon bearing reservoir. Produced water would only be produced during well evaluation and testing processes when formation fluids are brought to surface.	Small amounts of produced water may be flared. If volumes of produced water are large, some produced water may be brought onto the MODU for treatment so that it can be discharged in line with the OWTG.
Bilge and deck drainage water	Deck drainage is water on deck surfaces of the MODU from - precipitation, sea spray or MODU activities such as rig wash-down, or from fire control system or equipment testing. Bilge water is seawater that may seep or flow into parts of the MODU. Water may pass through pieces of equipment into other spaces of the MODU. As it may come into contact with equipment and machinery, deck drainage and bilge water may be contaminated with oil and other chemicals.	Deck drainage and bilge water will be discharged according to the OWTG which state that deck drainage and bilge water can only be discharged if the residual oil concentration of the water does not exceed 15 mg/L.
Ballast water	Ballast water is used in MODU and PSVs for stability and balance. It is taken up or discharged when the cargo is loaded or unloaded, or when extra stability is needed to manage weather conditions. The water typically does not contain hydrocarbons or chemicals as it is stored in dedicated tanks on the vessel.	Ballast water will be discharged according to IMO *Ballast Water Management Regulations* and Transport Canada's *Ballast Water Control and Management Regulations.* The MODU will carry out ballast tank flushing prior to arriving in Canadian waters.
Grey and black water	Black and grey water will be generated from ablution, laundry and galley facilities onboard the MODU and PSVs. Grey water will be generated from washing and laundry facilities, and black water includes sewage water generated from the accommodation areas.	Sewage will be macerated prior to discharge. In line with the OWTG and International Convention for the Prevention of Pollution from Ships (MARPOL) requirements, sewage will be macerated so that particles are less than 6 mm in size prior to discharge.

Table 2.8.5 Potential Project-Related Liquid Discharges

Discharge	Source and Characterization	Waste Management
Cooling water	Cooling water is seawater that is pumped onto the MODU and passed over or through equipment such as machinery engines using heat exchangers. Cooling water may be required on the MODU; however in the event that it is required, any volumes of seawater used for cooling water are likely to be minimal. Water may be treated through biocides or electrolysis prior to use.	Cooling water will be discharged in line with the OWTG which states that any biocides used in cooling water are selected in line with a chemical management system developed in line with the OCSG. Cooling water is likely to be warmer than the ambient water temperature upon discharge but will be rapidly dispersed, reaching ambient temperatures.
BOP testing fluids	The BOP is regularly pressure and function tested. BOP fluids are released directly to the ocean during testing activity (approximately 5 bbls per test) and whenever the riser unlatches (approximately 50 bbls). BOP fluids are typically freshwater based, seawater soluble chemicals.	BOP fluids and any other discharges from the subsea control equipment will be discharged according to OWTG and OCSG.
Well treatment and testing fluids	Well testing may be required as part of the Project to gather information about the subsurface characteristics, and to convert an EL to a SDL. Depending on well success, formation fluids, including hydrocarbons and associated water are likely to be brought to surface during a well test.	Any hydrocarbons, such as gas, oil or formation water that are brought to surface as part of well test activity will be flared to enable their safe disposal. All flaring will be via one of two horizontal burner booms, to either a high efficiency burner head for liquids, or simple open ended gas flare tips for gases to minimize fall out of un-combusted hydrocarbons. Flaring will be optimized to the amount necessary to characterize the well potential and as necessary for the safety of the operation.

Liquid wastes, not approved for discharge in OWTG such as waste chemicals, cooking oils or lubricating oils, will be transported onshore for transfer to an approved disposal facility. This is described in further detail in Section 2.8.4.

2.8.4 Hazardous and Non-Hazardous Wastes

All waste generated offshore on the MODU and PSVs will be handled and disposed of in accordance with relevant regulations and municipal bylaws. Waste management plans and procedures will be developed and implemented to prevent unauthorized waste discharges and transfers. Putrescible solid waste, specifically food waste generated offshore on the MODU and PSVs, will be disposed of according to OWTG and MARPOL requirements. In particular, food waste will be macerated so that particles are less than 6 mm in diameter and then discharged. There will be no discharge of macerated food waste within 3 nm from land.

Non-hazardous wastes, such as other domestic wastes, packaging material, scrap metal and other recyclables such as waste plastic for example, will be stored in designated areas on board the MODU. At scheduled intervals, waste will be transferred to the PSVs so that it can be transported to shore where it will be transferred to a third party waste management contractor at an approved facility.

Some solid and liquid hazardous wastes are likely to be produced as part of the Project, including oily wastes (*e.g.*, filters, rags and waste oil), waste chemicals and containers, batteries, biomedical waste and spent drilling fluids. Biomedical waste will be collected onboard by the doctor and stored in special containers before being sent to land for incineration. Hazardous wastes will be stored in designated areas on the MODU and will be transferred to shore on a PSV for disposal by a third party contractor at an approved facility. Transfer of hazardous wastes will be conducted according to the *Transportation of Dangerous Goods Act*. Any applicable approvals for the transportation, handling and temporary storage, of these hazardous wastes will be obtained as required.

2.8.5 Sound and Light Emissions

2.8.5.1 Sound Emissions

Underwater sound will be generated by the MODU and PSVs, as well as during VSP operations. The level of underwater sound generated by a MODU can be influenced by the type of MODU and by the method of positioning on station (*i.e.*, DP or mooring system). The extent to which sound travels is determined by environmental conditions, including water depths, water salinity and temperature.

The sound generated by the MODU will be continuous throughout the drilling program, whereas underwater sound generated during the VSP operations are typically impulsive in nature, occurring over a short duration (*e.g.*, typically no more than a day as described in Section 2.4.3.2).

Acoustic modelling of underwater sound generated by the Project is presented in Appendix D. A general overview of underwater sound and how it affects the marine environment is presented in Section 7.1.

Atmospheric sound (*e.g.*, sound above the sea surface) is not of particular concern given the relative low level of atmospheric sound sources (above sea level) and limited transmission of underwater sound through the air-sea interface. The nearest communities to the Project Area are coastal Nova Scotia communities more than 200 km away. Potential receptors on Sable Island (*e.g.*, temporary residents or visitors) would also be geographically separated from the Project Area (approximately 48 km away) such that they would not perceive atmospheric sound generated by Project activities.

Helicopter traffic associated with the Project will generate atmospheric sound emissions although the use of an existing operational airport (Halifax Stanfield International Airport) will reduce effects on human receptors. Effects of helicopter traffic (including atmospheric sound) on wildlife will be mitigated through avoidance of Sable Island and bird colonies (refer to Section 7.4).

2.8.5.2 Light

Artificial lighting will be generated by the Project from several sources.

- MODU and PSV navigation and deck lighting will be operating 24 hours a day throughout drilling and PSV operations for maritime safety and crew safety (refer to Section 2.4.1 for further information).

- Flaring activity during well flow testing, in the event that it is carried out, will generate light and thermal emissions on the MODU. Well flow testing, where it occurs, will be carried out on a temporary basis at the end of drilling operations. It is possible that there could be several, intermittent, short periods of flaring (lasting up to two or three days) during a one to three month window at the end of drilling operations. It is not expected that well flow testing will take place on the first two wells drilled as part of the Project (refer to Section 2.4.3.3 for further information).

2.9 ALTERNATIVE MEANS OF CARRYING OUT THE PROJECT

2.9.1 Options Analysis Framework

As required under section 19(1)(g) of CEAA, 2012, every environmental assessment of a designated project must take into account alternative means of carrying out the project that are considered technically and economically feasible, and considers 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 2013b), the process for consideration of alternative means of carrying out the Project includes the following steps:

- consideration of legal compliance, technical feasibility, and economic feasibility of alternative means of carrying out the Project;
- description of each identified alternative to the extent needed to identify and compare potential environmental effects;
- consideration of the environmental (including 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); and

- selection of the preferred alternative means of carrying out the Project, based on the relative consideration of effects.

There are several components of the Project that remain to be finalized. Some options under review will be confirmed to CNSOPB as part of the OA and ADW process (*e.g.*, wellsite location).

2.9.2 Identification and Evaluation of Alternatives

As per the EIS Guidelines, the analysis of alternative means considers the following alternative means of carrying out the Project:

- drilling fluid selection (*e.g.*, WBM or SBM);
- drilling waste management; and
- platform lighting and flaring options.

A consideration of legal compliance, technical feasibility and economic feasibility, as well as the environmental effects (where applicable) of each alternative means is described for each option.

Technical feasibility considers criteria, which could influence safe, reliable and efficient operations. Technology must be available and proven for use in a similar environment and activity set (*i.e.*, offshore drilling in deep water), and cannot compromise personnel and process safety for it to be considered. Economic feasibility considers capital and operational project expenditure. Project expenditure can be impacted directly (*e.g.*, equipment and personnel requirements) and indirectly (*e.g.*, schedule delays).

Each option for the alternative means identified above is summarized in a tabular format. Options are colour-coded red to demonstrate where an option is unfeasible, orange to demonstrate if there are potential issues and green to demonstrate if there are no issues. The preferred alternative means form the basis for the Project to be assessed (*i.e.*, assumed to be the base case that is assessed for environmental effects in Section 7 of this EIS).

2.9.2.1 Drilling Fluids Selection

Both WBM and SBM could be used to drill wells associated with the Project. Drilling fluids are formulated according to the well design and the expected geological conditions. Both WBM and SBM are acceptable according to local regulations, provided that the components of the drilling fluids are selected according to criteria of the OCSG and their disposal is carried out according to the OWTG.

Both drilling fluids are available within Nova Scotia; however, there are several factors, which determine the technical feasibility of one drilling fluid relative to another. In general, SBM can

enable more efficient drilling operations than WBM when drilling through challenging geological conditions, including areas containing hydrate shales.

A summary of the comparison between WBM and SBM is presented in Table 2.9.1. As a preferred option has not been selected, the EIS considers the use of WBM and SBM in the effects assessment (refer to Section 7).

Table 2.9.1 Summary of Drilling Fluid Alternative Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
WBM only	Yes	Yes – potential challenges with borehole stability	Yes – potential increased cost from non-productive time and losses	No substantial difference between either options. Both are considered acceptable provided that appropriate controls are in place and chemicals are selected in line with OCSG.	A preferred option has not yet been identified as well planning is still underway. It is likely both drilling fluid types will be used and both are assessed in the EIS.
WBM / SBM hybrid for different sections	Yes	Yes	Yes		

2.9.2.2 Drilling Waste Management

Drilling waste management options vary depending on the type of drilling fluid used. In the event that different drilling fluids are used to drill different sections of the well, it is likely that a combination of drilling waste management options will be used.

Figure 2.9.1 describes the options available for treatment and disposal of WBM and SBM wastes, excluding the direct discharge of WBM associated with the riserless section. The options can be broadly categorized into onshore and offshore disposal.

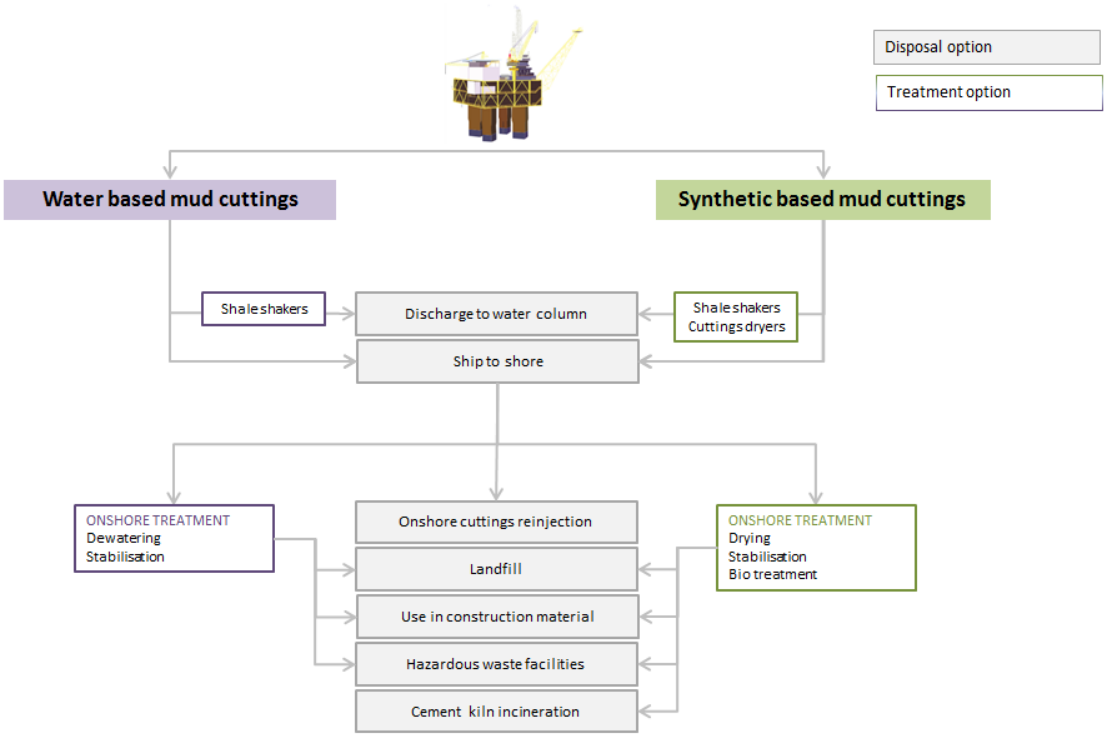


Figure 2.9.1 Drilling Waste Management Options

Offshore disposal treatment on board the MODU is described in Section 2.8.2. An alternative method of offshore disposal is cuttings reinjection. Reinjection involves slurrifying cuttings (*i.e.*, mixing them with a liquid) and then pumping them into a dedicated well, designed for reinjection. Under pressurized conditions, cuttings pass into targeted formations down the well. Offshore injection of cuttings from fixed wellhead platforms is well proven, but subsea injection from mobile drilling units is limited. The subsea injection equipment involved is very specialized (*i.e.*, it requires a flexible injection riser and a specially designed wellhead) and has only been developed for water depths of 1,000 feet (305 m). It is likely that some Project wells will be drilled at water depths much greater than 305 m, so implementing subsea injection at these water depths would require the use of unproven technology. Additionally, equipment weight increases considerably with the length of the pipe, so the use of a flexible pipe at deep water depths would be costly and require a large storage capacity on the rig. There would ultimately be a length limitation for deep water applications. Special installation procedures may also be required. Therefore, subsea cuttings reinjection has never been developed for deep water either by operators or the service sector, because the risked costs are too high especially for exploration drilling.

For onshore disposal, cuttings are shipped to shore where both WBM and SBM waste can be treated prior to onshore disposal. Cuttings would be shipped from the MODU to shore using a PSV. Some typical onshore treatment and disposal options for WBM and SBM waste are presented in Figure 2.9.1. Ship-to-shore treatment of waste reduces offshore effects associated

with drilling waste discharge; however, additional effects due to increased marine transportation (*e.g.*, atmospheric emissions) and onshore treatment and disposal (*e.g.*, habitat alteration) will be introduced instead. Ship-to-shore options are expected to be more expensive than the offshore options due to additional transportation costs. In general, ship-to-shore and associated onshore disposal presents a potentially higher operational risk option as it is dependent on a number of external factors, specifically onshore waste management facility availability and PSV availability. PSV transit may be affected by poor weather conditions, which could impact their ability to collect cuttings on a regular basis from the MODU. If cuttings cannot be removed from the MODU, drilling operations may have to stop.

Discharge to the water column following treatment to OWTG standards is the preferred option for cuttings generated as part of the Project and has been assessed as part of the Project (refer to Section 7). This analysis of alternative means for drilling waste management is summarized in Table 2.9.2.

Table 2.9.2 Summary of Drilling Waste Management Alternative Analysis

Disposal Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
Discharge to water column (following treatment)	Yes	Yes	Yes	Some localized effects are expected on the seafloor from discharge of cuttings.	✓
Offshore Reinjection	Yes	No	Not considered as option has been identified as unfeasible		✗
Ship-to-shore	Yes	Yes	Yes – but increased costs from increased transportation and operational delays	Some limited offshore effects are expected from increased transportation, and some onshore effects from transportation and onshore disposal of waste	✗

2.9.2.3 Offshore Vessel Lighting

Lighting will be used on the MODU and the PSVs for navigation and deck lighting 24 hours a day throughout drilling and PSV operations for maritime safety and crew safety. Lighting is required under Canadian and international law to minimize the risk of collisions between offshore vessels.

Alternative MODU lighting techniques have been tested elsewhere in the industry. In the North Sea, spectral modified lighting, which uses red light (570 nm to 650 nm) has been tested on offshore platforms and has demonstrated a reduced effect on marine birds. The technology is not considered yet commercially viable. The lighting has satisfied regulatory requirements in a number of regions, including in the Netherlands, Germany and in the United States, however implementation in the offshore oil and gas industry has been restricted by commercial availability, limited capability in extreme weather, safety concerns around helicopter approach and landing and lower energy efficiency (Marquenie *et al.* 2014).

Options to reduce lighting on the MODU and PSVs as far as practicable will be investigated; however, it will be maintained at a level that will not impede the safety of the workforce or drilling operations (see Table 2.9.3). The EIS considers the environmental effects associated with standard MODU lighting (refer to Section 7).

Table 2.9.3 Summary of Lighting Alternative Analysis

Disposal Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
No lighting	No – lighting is required by local and international law	Not considered as option has been identified as legally unacceptable			✗
Standard MODU lighting	Yes	Yes	Yes	Some localized visual effect is expected which could affect migratory birds	✓
Spectral modified lighting	Yes	No – not considered ready for commercial use yet	No - not considered as commercially viable yet	Not considered as option has been identified as unfeasible	✗

2.9.2.4 Well Test Flaring

In the event that well flow testing is conducted, flaring will be required. Well flow testing, where it occurs, will be carried out on a temporary basis at the end of drilling operations as described in Section 2.4.4.3.

Well testing is required by the CNSOPB to declare a significant discovery and to convert an EL to an SDL. When well flow testing is carried out, flaring is required to safely dispose of hydrocarbons that may come to surface. No flaring is therefore not an option.

Another alternative option could be to manage the timing of flaring activity. Flaring could be restricted during periods of poor visibility including at night and during inclement weather to reduce light generated during flaring. However, data gathered during the well test could be

compromised if the well flow was restricted during test period (*i.e.*, restricted to certain weather conditions). This could mean prolonged well test activity (*i.e.*, greater than one month as currently predicted) which could also increase operational costs (*i.e.*, increased rig costs).

Flaring is expected to be brief and intermittent in nature (lasting two to three days at a time) which could occur several times in the well flow test period, which in total is expected to last between one to three months. Flaring alternatives are provided in Table 2.9.4. The analysis of Project effects (refer to Section 7) assumes there will be routine flaring. However, it is not currently anticipated that well testing will be carried out on the wells drilled in the initial phase of the Project (*i.e.*, one to two wells).

Table 2.9.4 Summary of Flaring Alternative Analysis

Disposal Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
No flaring	No	Not considered as option; current regulatory practice requires DST/Flaring to secure Significant Discovery Licence. Industry continues to advocate for alternative methods.			
Reduced flaring (*i.e.* no flaring during night time or inclement weather)	Yes	Yes – although activity could give result to compromised data	Yes – but increased MODU costs and risk of delays	Reduced flaring would still result in some measure of light and atmospheric emissions.	
Flaring as required	Yes	Yes	Yes	Some limited offshore effects are expected from the light and atmospheric emissions generated during flaring. These are expected to be intermittent and brief in duration over a temporary period at the end of drilling.	

2.9.3 Chemical Management

The details of chemicals to be used in the Project have not yet been confirmed and potential alternatives have not yet been identified. A drilling fluid contractor for the Project has not yet been selected, and the drilling fluid basis of design for the wells is under development. Nonetheless, as planning for the Project continues, BP will follow chemical management and selection processes to define the ways in which chemicals will be chosen and used.

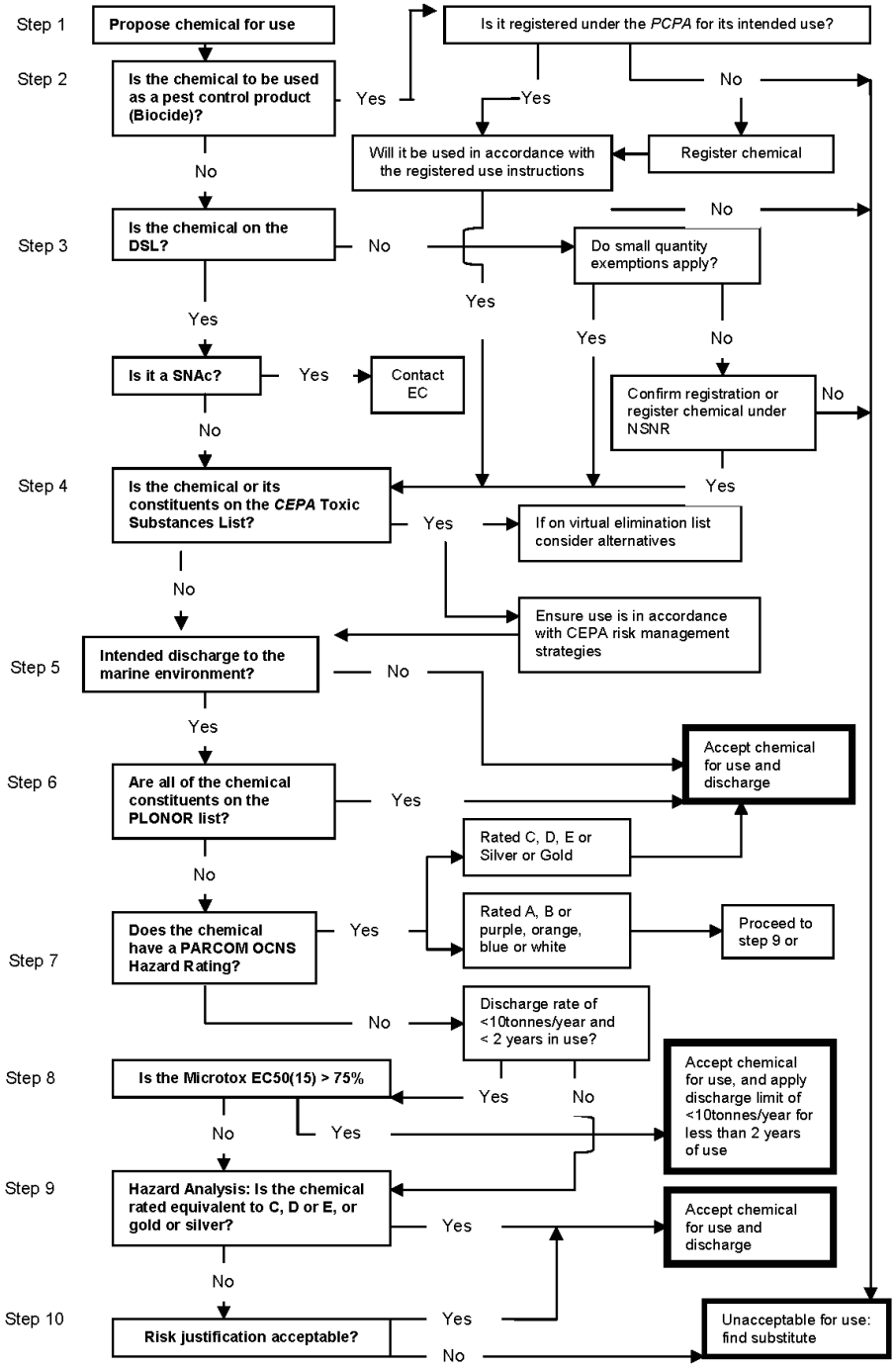
Chemical management processes will be defined prior to the start of any drilling activity and will be conducted in accordance with applicable legislation as summarized in Table 2.9.5.

Table 2.9.5 Applicable Offshore Chemical Management Legislation and Guidelines

Legislation	Regulatory Authority	Relevance
Canadian Environmental Protection Act (CEPA)	ECCC	Provides for the notification and control of certain manufactured and imported substances. The DSL is a list of substances approved for use in Canada. Schedule 1 includes a list of substances that are considered toxic and subsequent restrictions or phase out requirements
Fisheries Act	DFO; ECCC	Prohibits the deposition of toxic or harmful substances into waters containing fish
Hazardous Product Act	Health Canada	Standards for chemical classification and hazard communication
Migratory Birds Convention Act, 1994	ECCC	Prohibits the deposition of harmful substances in waters or areas frequented by migratory birds
Pest Control Products Act	Health Canada	Regulates the importation, sale and use of pest control products, including products used as biocides offshore
Offshore Chemical Selection Guidelines (OCSG)	CNSOPB	Framework for the selection of drilling and production chemicals for use and possible discharge in offshore areas

At a minimum, selection of drilling chemicals will be in accordance with the OCSG. The OCSG establishes a procedure and criteria for offshore chemical selection. The objective of the guidelines is to promote the selection of lower toxicity chemicals to minimize the potential environmental impact of a discharge where technically feasible.

Figure 2.9.2 shows the chemical selection process outlined in the OCSG which will be employed by BP. Furthermore, BP will document the process used to evaluate prospective chemicals.



Source: CNSOPB 2009

Figure 2.9.2 Chemical Selection Flowchart

Proposal for Use: Initial Screening and Regulatory Controls Identification

As shown in Figure 2.9.2, a screening of the proposed chemical will be carried out to determine whether it is restricted through any of the other elements of legislation as described in Table 2.9.5. This includes specific aspects of the use of the chemical, including likely volume demand and discharge assumptions.

In line with the regulations, certain restrictions, controls and prohibitions agreed with applicable regulatory agencies will be placed on:

- chemicals which will be used as a biocide;
- chemicals which have not been approved for use in Canada previously (*i.e*. are not registered on the domestic substances list (DSL)) or have not been used previously for the purpose which is proposed;
- chemicals which have been identified as toxic under Schedule 1 of CEPA. In the event that a chemical is proposed for use that is listed under Schedule 1 of CEPA, BP will consider alternative means of operation, and / or will evaluate less toxic alternatives.

Chemicals Intended for Marine Discharge: Toxicity Assessment

Following the initial screening activity to identify any restrictions, controls and prohibitions on proposed chemicals, BP will conduct a further assessment for chemicals that will be discharged to the marine environment. This assessment will be carried out to evaluate the potential toxicity of proposed chemicals (and any constituents of the chemical as applicable), and to establish if additional restrictions, controls or prohibitions are required.

In line with the OCSG chemical selection framework shown in Figure 2.9.2, any chemicals intended for discharge to the marine environment shall be reviewed against a number of criteria. Chemicals that are intended for discharge to the marine environment must:

- be included on the OSPAR PLONOR list; or
- meet certain requirements for hazard classification under the OCNS; or
- pass a Microtox test (*i.e.,* toxicity bioassay); or
- undergo a chemical-specific hazard assessment in accordance with the OCNS model; or
- have the risk of its use justified through demonstration to the Board that discharge of the chemical will meet OCSG objectives.

BP will review each criteria in turn.

- OSPAR PLONOR List: If a proposed chemical is included on the OSPAR PLONOR list, it will be considered acceptable for use and discharge in line with OCSG.

- OCNS Hazard Classification: If BP proposes the use of a chemical which will be discharged to the marine environment that is not included on the OSPAR PLONOR list, BP will review the

hazard classification in line with the Offshore Chemical Notification Scheme (OCNS). This scheme ranks chemical products according to a hazard quotient (HQ) based on a range of physical, chemical and ecotoxological properties of products, including toxicity, biodegradation and bioaccumulation information.

The Chemical Hazard and Risk Management (CHARM) model is used to determine the HQ which is subsequently used to rank chemicals into groups, linked to their expected hazard rating. If the chemical that is proposed for use is ranked as being least hazardous under the OCNS scheme (*i.e.,* C, D or E, gold or silver), BP will consider the chemical acceptable for use and discharge in line with the OCSG.

- Risk Justification: Where a chemical is identified for potential use which is not ranked as C, D or E, or gold or silver under the OCNS scheme, BP will consider alternative means of operation, and / or will evaluate less toxic alternatives. If it is not possible to identify alternatives, BP will conduct a hazard assessment to determine its suitability of use in line with the OCSG. The hazard assessment process will be documented and will be provided to the CNSOPB to allow them to evaluate whether that the objectives of OCSG have been met.

- Microtox Test and Chemical-Specific Hazard Assessment: In the event that a chemical is proposed for use which does not have an OCNS rating, BP will work with the chemical contractors to carry out a Microtox test to determine the potential toxicity of the chemical. If the chemical passes the test and is considered non-toxic, restrictions will be placed on discharge volumes and time limits in line with the OCSG. If the chemical does not pass the test, it will be subject to a hazard assessment as per OCSG to determine suitability for use.

It is expected that the following categories of chemicals will be used as part of the Project:

- drilling fluids, including sweeps and displacement fluids;
- well conditioning fluids;
- blowout preventer fluids;
- cement slurry;
- fuel, including diesel;
- hydraulic oil and greases;
- fire suppressant systems;
- cleaning fluids; and
- biocides.

A Material Safety Data Sheet (MSDS) will be available for chemicals present on the PSVs and MODU. The inventory of chemicals on board the MODU will be monitored regularly and an annual report will be submitted to the CNSOPB to outline each chemical used including the hazard rating, quantity used, and its ultimate fate.

3.0 STAKEHOLDER CONSULTATION AND ENGAGEMENT

This section of the EIS describes the ongoing and proposed engagement activities with public stakeholders that may have an interest in the Project. This section also provides a summary of questions, comments, and key issues raised in relation to the Project. For information on Aboriginal engagement, including ongoing and proposed engagement activities, and questions and comments raised, refer to Section 4.

3.1 ENGAGEMENT PROCESS

BP recognizes the importance of early and ongoing stakeholder engagement that continues over the life of the Project. BP believes that it is important to build positive relationships with Aboriginal groups and key stakeholders, and their primary objective around engagement is to provide transparent and timely communications to help build understanding and trust. BP views Aboriginal and stakeholder engagement as a continuous process which consists of a number of iterative steps (shown in Figure 3.1.1):

- **INFORM:** Provide accurate, relevant, timely and culturally appropriate information about the Project, its potential effects, and the EIS process;
- **ENGAGE:** Provide opportunities for Aboriginal groups and stakeholders to express their opinions and concerns about the Project, and to seek support for the Project and effects mitigation;
- **UNDERSTAND:** Enable the Project team to understand the concerns and priorities of Aboriginal groups and stakeholders;
- **REVIEW:** Incorporate as appropriate these concerns and priorities into the design, construction and operation of the Project; and
- **INFORM:** Provide feedback to Aboriginal groups and stakeholders as the Project develops so that engagement continues.

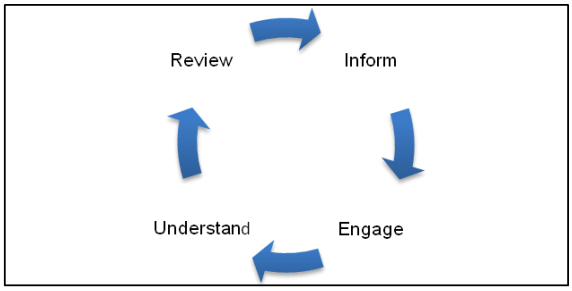


Figure 3.1.1 Consultation and Engagement Process

BP's key objectives for stakeholder engagement are to:

- provide appropriate information in a timely manner to relevant, interested and affected parties based on the nature, location and duration of the Project;
- create an understanding of BP's proposed drilling operations and address questions and concerns that arise; and
- provide feedback to stakeholders so that they are satisfied, or if not satisfied, that they understand how BP has represented and responded to their input.

BP's stakeholder and community outreach objectives include providing transparent and factual information about its plans and activities and encouraging input from stakeholders. As an active member of the broader Nova Scotia community, investing in local energy education and research initiatives and participating in association memberships, BP also has opportunities to develop and maintain positive working relationships with stakeholders.

This section of the EIS discusses ongoing and proposed engagement with public stakeholders along with questions and comments raised during engagement.

3.2 IDENTIFICATION OF STAKEHOLDERS AND MEANS OF ENGAGEMENT

BP employs a broad definition of stakeholders to include fisheries organizations, environmental non-governmental organizations (ENGOs), industry associations, government, and the interested public. BP has developed a preliminary list of stakeholders that potentially have an interest in the Project. The list will be reviewed regularly and updated appropriately throughout the Project planning and execution stages to make sure that the appropriate parties are kept informed and updated about key Project information on a timely basis.

The preliminary list of stakeholders was developed through an evaluation of the economic, social and environmental aspects of the Project, and a review of groups with a potential vested interest in the Project. BP has consulted with regulatory agencies and government departments to further refine the list of potential stakeholders. BP also used the list of stakeholders from the Tangier 3D WATS seismic survey program in developing the preliminary list of stakeholders.

Stakeholders that have been identified to date include the following:

- federal, provincial and municipal governments;
- fish producers and fisheries associations;
- non-governmental stakeholders; and
- the general public.

Each of these stakeholder groups is described below.

3.2.1 Federal, Provincial and Municipal Governments

Federal, provincial and municipal government departments and agencies identified thus far during the Project planning and EIS preparation stages include those that:

- have a regulatory mandate concerning the authorization of Project activities;
- have technical knowledge concerning the assessment or mitigation of environmental effects; and/or
- are involved in Crown consultation.

Specific departments and agencies are listed in Table 3.2.1.

Table 3.2.1 Government Departments and Agencies Identified for Consultation

Level of Government	Specific Department or Agency
Federal	• Canadian Environmental Assessment Agency • Department of Fisheries and Oceans (including Canadian Coast Guard) • Environment and Climate Change Canada • Department of National Defence • Parks Canada • Transport Canada – Navigable Waters • Natural Resources Canada
Provincial	• Nova Scotia Department of Environment • Nova Scotia Department of Energy • Nova Scotia Department of Fisheries and Aquaculture • Nova Scotia Office of Aboriginal Affairs • Emergency Management Office of Nova Scotia
Federal-Provincial	• Canada-Nova Scotia Offshore Petroleum Board
Municipal	• Halifax Regional Municipality • Coastal Nova Scotia municipalities

BP will engage with these stakeholders through face to face meetings, written correspondence, and project presentation meetings. BP has started to engage with a number of the stakeholder groups and will continue to do so over the lifetime of the Project. BP will provide continuous information and opportunities for dialogue to stakeholders as project planning or activity milestones are nearing or achieved. Engagement will continue throughout the CEAA, 2012 and drilling program authorization processes, through to Project completion.

3.2.2 Fish Producers and Fisheries Associations (including the CNSOPB Fisheries Advisory Committee)

Fish producers and fisheries associations have primarily been engaged through the CNSOPB Fisheries Advisory Committee (FAC) meetings. The Board's FAC includes representatives from various fishing groups, DFO, the Nova Scotia Department of Fisheries and Aquaculture, Natural Resources Canada, and the Nova Scotia Department of Energy. FAC members provide advice

and suggestions to the CNSOPB for consideration in work authorization applications, regulations and guidelines. Meetings are held quarterly and briefings are distributed to inform and engage members in discussion of upcoming projects and other petroleum related activities. Committee members are provided with notice of all environmental assessments and are invited to submit comments to the CNSOPB for consideration during the review processes.

Through the FAC, BP has participated in a number of meetings to present an overview of proposed plans and activities, and to gather feedback from interested parties. This will continue throughout the duration of the Project.

3.2.3 Non-Governmental Stakeholders

Non-governmental stakeholders include: environmental non-government organizations (ENGOs) particularly those with an interest in environmental and social issues within the area; industry and business associations; chambers of commerce; the media; and academic institutions. These stakeholders can make important contributions to the EA process due to their knowledge and perspectives on relevant issues and/or their strong links with communities. BP has long-standing relationships with scientific and academic communities, which often have valuable technical perspectives on aspects of Project design and development.

Key groups that have been identified to date include the following:

- ENGOs: Ecology Action Centre (EAC); World Wildlife Fund (WWF); Ducks Unlimited; Pembina Institute; Sierra Club; Canadian Parks and Wilderness (ENGOs may be engaged through the EAC);
- petroleum industry associations (*e.g.*, Maritime Energy Association, Canadian Association of Petroleum Producers) and peer companies;
- economic development agencies and chambers of commerce;
- post-secondary institutions and research organizations (*e.g.*, Offshore Energy Research Association (OERA)); and
- cultural organizations (*e.g.*, Black Business Initiative).

BP will engage with the organizations listed above throughout the duration of the Project and will provide them with information about upcoming activity.

3.2.4 General Public

The general public has been and will continue to be primarily consulted through the public participation opportunities as required under CEAA, 2012. In addition to the Project Description and EIS Guidelines, the EIS and other documents related to public participation opportunities will be posted on the CEA Agency's Registry website for the Project (http://www.ceaa-acee.gc.ca/050/details-eng.cfm?evaluation=80109).

BP also maintains a website with updates on their activity in Nova Scotia (http://www.bp.com/en/global/corporate/about-bp/bp-worldwide/bp-in-canada/bp-in-nova-scotia.html).

3.3 SUMMARY OF CONSULTATION AND ENGAGEMENT ACTIVITIES

A summary of BP's stakeholder engagement efforts on the Project from December 2014 to October 2016 is provided in Table 3.3.1. For a summary of BP's Aboriginal engagement efforts on the Project, refer to Section 4.4.

Table 3.3.1 Summary of Stakeholder Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Topics Discussed
Government Agencies/Departments			
Canadian Environmental Assessment Agency	April 15 & 20 2015	Meeting (face-to-face) - Attended by BP EIS Lead and Regional Manager	Project introduction and discussion of regulatory framework for an EIA.
	September 16, 2015	Meeting (face-to-face) - Attended by BP Senior Advisor Global Deepwater Response and BP EIS Lead	Discussion of lessons learned from Deepwater Horizon (DWH), source control and oil spill response. Discussions about EIS.
	March 1, 2016	Email	Discussion about seabed survey.
	March 2, 2016	Phone Call	Discussion about seabed survey.
	March 22, 2016	Phone Call	Discuss engagement and clarify the level of involvement of Wolastoqiyik (Maliseet) First Nations of NB.
	March 23, 2016	Meeting (face to face) - Attended by BP Regional President and BP Wells Manager	Discussion of seabed survey requirements for the Project (with DFO and CNSOPB).
	September 1, 2016	Meeting (face to face) - Attended by BP Regional Manager and BP EIS Lead	Discussion about EIS
	September 15, 2016	Meeting (face to face) - Attended by BP Regional Manager	Discussion about EIS
	October 14, 2016	Meeting (face to face) attended by BP Regional Manager and BP Community Relations Advisor	Discussion about EIS

Table 3.3.1 Summary of Stakeholder Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Topics Discussed
Canada-Nova Scotia Offshore Petroleum Board	September 17, 2015	Meeting (face to face) - Attended by BP Senior Advisor Global Deepwater Response and BP EIS Lead	Lessons learned from DWH, source control and oil spill response.
	November 11, 2015	Meeting (telecom)	Workshop concerning oil spill modelling approach (with DFO and ECCC).
	November 19, 2015	Meeting (telecom)	Overview of metocean data to be used in modelling work (with DFO and ECCC).
	December 7, 2015	Meeting (telecom)	Discussion about spill modelling thresholds.
	April 13, 2016	Meeting (face-to-face) - Attended by BP Regional Manager and Country President	Project update
	June 28, 2016	Meeting (face-to-face) attended by Attended by BP Regional Manager, BP Wells Manager and BP Exploration Manager	Project technical update
	June 28, 2016	Meeting (face-to-face) – Attended by BP Exploration Manager	Project technical update
	June 29, 2016	Meeting (face-to-face) - Attended by BP Exploration Manager	Project technical update
	July 22, 2016 & August 2, 2016	Meeting (face-to-face) - Attended by BP Regional Manager	Discussion about Project Communication
	August 23, 2016	Meeting (face-to-face) -Attended by BP Regional Manager and BP Business Manager	Discussion about exploration licenses
	September 23, 2016	Meeting (face to face) – Attended by BP Regional Manager	Project update
Fisheries and Oceans Canada (DFO)	March 16, 2015	Meeting (face to face)	Discussion about Aboriginal commercial fishing program.
	April 13, 2015	Meeting (face to face)	Discussion on insights into areas of interest in EIS.

Table 3.3.1 Summary of Stakeholder Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Topics Discussed
	September 15, 2015	Meeting (face to face) – Attended by BP Senior Advisor Global Deepwater Response	Project introduction and EIS update; Discussion of lessons learned from DWH.
	June 27, 2016	Meeting (face-to-face)	Introductions and BP Project overview
	September 20, 2016	Meeting (face to face) Anita Perry, Mike Wamboldt	Discussion about Project approach for baseline data
Environment and Climate Change Canada	April 20, 2015	Meeting (face to face)	Discussed insights into areas of interest in EIS.
Nova Scotia Department of Energy	April 1, 2016	Meeting (face to face)	Update on Scotian Basin Exploration Project.
	June 29, 2016	Meeting (face to face)	Project technical update
	September 21, 2016	Meeting (face to face)	Project update
	September 27, 2016	Meeting (face to face)	Project update
Nova Scotia Office of Aboriginal Affairs	December 4, 2014	Meeting (face to face)	Regulatory requirements around consultation.
	September 17, 2015	Meeting (face to face)	Introductory meeting with environment team to discuss consultation.
Nova Scotia Emergency Management Office	June 29, 2016	Meeting (face to face)	Introductory meeting to discuss project and to provide awareness on where NSEMO can assist with co-ordination to support an offshore incident.
	October 4, 2016	Email	BP provided update on Project schedule.
Joint Rescue Coordination Centre	October 4, 2016	Email	BP provided update on Project schedule.
Fisheries			
Fisheries Advisory Committee (FAC) (CNSOPB)	January 21, 2015	Notes for Meeting	BP provided a written update on the exploration drilling Project for communication at the FAC meeting.
	May 12, 2015	Meeting (face to face)	BP provided a timeline update and discussed the key areas requiring further discussion as BP progresses to an exploration program.
	September 16, 2015	Meeting (face to face) – Attended by BP Senior Advisor Global Deepwater Response	BP presented an overview and update on EIS process, lessons learned from DWH, and an overview of BP's source control methods and Oil Spill Response Plan.

Table 3.3.1 Summary of Stakeholder Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Topics Discussed
	February 17, 2016	Meeting (face-to-face)	BP provided an update on project planning to the FAC, focusing on pending EIS submission to CEA Agency later than anticipated due to taking the time up-front to address matters raised in engagement meetings related to spill modelling. Also discussed FAC members' consultation style preferences (response was face-to-face as much as possible) and what topics they wished to cover. Topics discussed included: BP as an operator, use of dispersants, worst case discharge impact, emergency preparedness, the role of BOPs, cap and containment.
	June 22, 2016	Meeting (face-to-face)	BP provided presentation on EIS and spill modelling approach and results
	September 21, 2016	Meeting (face-to-face)	BP provided update on the Project.
Guysborough County Inshore Fishermen's Association	March 24, 2015	Meeting (face to face)	Identified the key areas requiring further discussion as BP progresses to an exploration program.
Seafood Producers of Nova Scotia (SPANS)	March 25, 2015	Meeting (face to face)	Identified the key areas requiring further discussion as BP progresses to an exploration program.
Other Interest Groups			
Maritime Energy Association	May 12, 2015	Information Session (face-to-face) – Attended by BP's Logistics & Infrastructure Manager and Regional Manager, Procurement Supply Chain Management	BP presented information on logistics including: Project scope; procurement process – approach to local business, local content strategy, expectations from vendors, and procurement process; and proposed timeline on exploration project plan.
Maritime Energy Association	September 29, 2015	CORE Conference Presentation (face-to-face) - Attended by BP Canada Exploration Manager	Updated participants on exploration project area, proposed timeline, expanded exploration joint venture EL2431-2434, project planning and early look at 3D seismic.

Stakeholder engagement will continue beyond the EIS, throughout the full project life-cycle. BP is committed to listening and responding to stakeholder concerns if and as they arise.

3.4 QUESTIONS AND COMMENTS RAISED DURING ENGAGEMENT

Questions and comments raised during engagement, including comments raised during the public comment periods held thus far under CEAA, 2012, have been taken into consideration during the preparation of this EIS. In general, questions and comments include those related to: potential environmental, health and safety implications of an accidental spill; the current regulatory framework and industry response to an accidental spill; potential environmental effects on marine life and fisheries; and economic development opportunities.

A summary of key issues that have been raised during the public comment period under CEAA, 2012 and how they have been addressed is presented in Table 3.4.1.

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
What has BP learned since the Deepwater Horizon (DWH) incident in the Gulf of Mexico?	BP's internal investigation of the DWH incident, which culminated in the Bly Report (BP 2010), involved a team of over 50 internal and external specialists from a variety of fields, including safety, operations, subsea, drilling, well control, cementing, well flow dynamic modelling, BOP systems, and process hazard analysis. Eight key findings relating to the causal chain of events were made, with 26 associated recommendations to enable the prevention of a similar accident and aimed at further reducing risk across BP's global drilling activities. The Bly Report recommended a number of measures to strengthen BPs operational practices, and these are being addressed through the implementation of enhanced drilling requirements. Key requirements have been captured in guidance documents and engineering technical practices. Key areas that have been addressed include: cementing and zonal isolation practices; process safety management through the life cycle of a well; well casing design; and rig audit and verification. In addition to these technical requirements, BP has focused on enhancement of capability and competency; verification, assurance and audit; and process safety performance management. An account of lessons learned from the DWH incident and information about progress against recommendations in the Bly Report are presented in the EIS (refer to Section 8.3.4).	• *Section 8.3.4:* Information about lessons from the DWH incident
Request for more information on BP's environmental management, spill prevention and incident management plans	BP works in line with its operating management system (OMS), a framework which sets out requirements on a range of criteria, such as health and safety, security, environmental management, social responsibility and operational reliability. Contractors, such as drilling and well services contractors, will be accountable for the development and delivery of their safety and environmental management systems. Contractors will be responsible for carrying out self-verification activity to assess conformance with their contractual requirements. Contractor safety performance is typically assessed and reviewed by BP throughout the duration of the contract. Further information will be presented in the Environment Protection Plan which will be submitted to CNSOPB as part of the OA process.	• *Section 1.3.1*: Information about how BP operates, including information about management systems and working with contractors • *Section 8.3.1*: Information about the incident management plan and spill response plan • *Section 12*: Information about environmental management plans for the Project

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
	The Project will operate under an incident management plan (IMP) which will be a comprehensive document including practices and procedures for responding to an emergency event. The IMP will include, or reference, a number of specific contingency plans for responding to specific emergency events, including potential spill or well control events. The IMP and supporting specific contingency plans, such as the spill response plan (SRP) will be aligned with applicable regulations, industry practice and BP standards and will include response strategies, arrangements and procedures. These plans will be submitted to CNSOPB prior to the start of any drilling activity as part of the OA process.	
Concern raised about length of time for a capping stack response to a well blowout	If a blowout incident were to occur, BP would immediately commence the mobilization of the primary capping stack from Stavanger. Analysis indicates that the cap mobilization to the wellsite will take 12 to 19 days with the well capped between 13 and 25 days after an incident. BP has included information in the EIS about spill response and well intervention strategies that would be deployed in the event of a spill.	• *Section 2.5*: Well control measures • *Section 8.3.3.2*: Well intervention response
Concern raised about environmental effects of dispersant use	Dispersants will not be used by BP without prior approval. BP will prepare a net environmental benefit analysis (NEBA) for dispersant use which will be used to support any application for dispersant use. Dispersed oil may cause harm to some marine organisms, particularly coral and plankton. Dispersants are generally non -toxic at the concentrations used for response. In the event that they are used, exposure to any dispersants and dispersed oil is likely to be brief as they are quickly diluted into the marine environment. The NEBA will analyze the trade-off between the potential toxic effects of the dispersed oil relative to the advantages of removing oil from the surface and preventing shoreline effects.	• *Section 8.3.3.3:* Overview of dispersants
Concern raised about possible effects on species at risk and critical habitat	Several species at risk (SAR) and species of conservation concern (SOCC) are known to occur in the vicinity of the Project Area. Potential Project-related effects on SAR, SOCC and critical habitat are assessed in Section 7 of this EIS. In recognition of best management practices and mitigation measures proposed by BP, significant residual adverse effects on SAR and critical habitat are predicted to be not likely.	• *Section 5.2.9*: Summary of marine SAR and SOCC that could be affected by the Project • *Section 7.2:* Assessment of Project-related environmental effects on fish (SAR and SOCC)

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
		• *Section 7.3:* Assessment of Project-related environmental effects on marine mammal (SAR and SOCC) • *Section 7.3:* Assessment of Project-related environmental effects on sea turtle (SAR and SOCC) • *Section 7.4: Assessment of* Project-related environmental effects on marine bird (SAR and SOCC) • *Section 8.5:* Environmental effects of potential accidental events • *Section 10:* Cumulative environmental effects
Concern raised about possible effects on the fishing industry	Routine Project activities and components have potential to interact with fisheries resources by direct or indirect effects on commercially fished species and/or effects on fishing activity from displacement from fishing areas, gear loss or damage that could potentially result in a demonstrated financial loss to commercial fishing interests. For the most part, effects on the fishery will be limited to a 500-m safety (exclusion) zone from the MODU that is standard for the offshore industry. BP has committed to employing mitigation measures and standard practices to reduce Project-related effects on fish and fish habitat, as well as fisheries activities. BP will continue to engage commercial and Aboriginal fishers to share Project details as applicable and facilitate coordination of information sharing. A Fisheries Communication Plan will be used to facilitate coordinated communication with fishers. A Fisheries Communication Plan will facilitate communication of Project updates, issues and concerns as the Project moves past the EA process and into the implementation stage.	• *Section 5.3.5:* Existing conditions regarding commercial fisheries • *Section 7.6*: Project-related environmental effects on commercial fisheries • *Section 8.5*: Environmental effects of potential accidental events • *Section 10:* Cumulative environmental effects

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
Concern raised about possible effects on the tourism industry	The Project is not predicted to interact with the provincial tourism industry. Most tourism and recreational activities occur in coastal or nearshore areas and would not interact with routine Project activities (the Project Area is located more than 200 km offshore and 48 km from Sable Island National Park Reserve). In the event of a large spill (*e.g.*, blowout), there could potentially be an interaction with coastal resources which could be related to local tourism and recreation. As discussed in Section 8, the likelihood of such a spill event is extremely low, and BP would implement spill response measures to reduce interactions with coastal resources.	• *Section 5.3.4.4:* Existing conditions regarding tourism and recreational activities • *Section 7.2:* Project-related environmental effects on fish and fish habitat • *Section 8.5:* Environmental effects of potential accidental events
Concern raised about effect of underwater sound and preventative measures to mitigate effects on marine life	Underwater sound will be generated by the MODU and PSVs, as well as during VSP operations. The extent to which sound travels is determined by environmental conditions, including water depths, water salinity and temperature. The sound generated by the MODU will be continuous throughout the drilling program, whereas underwater sound generated during the VSP operations are typically impulsive in nature, occurring over a short duration (*e.g.*, up to one day per well). BP has commissioned an acoustic modelling study to inform the assessment of underwater sound effects on marine life. BP will assess in consultation with the appropriate authorities the potential for undertaking an acoustic monitoring program during the drilling program to collect field measurements of underwater sound in order to verify predicted underwater sound levels. The objectives of such a program will be identified in collaboration with DFO and the CNSOPB and in consideration of lessons learned from the underwater sound monitoring program to be undertaken by Shell as part of the Shelburne Basin Venture Exploration Drilling Project in 2016.	• *Section 2.8.5:* Information about potential underwater sound sources • *Section 7.2:* Project-related environmental effects on fish and fish habitat • *Section 7.3:* Assessment of project-related environmental effects on marine mammals and sea turtles • *Section 7.6:* Project-related environmental effects on commercial fisheries • *Section 10:* Cumulative environmental effects • *Section 11:* A summary of effects • *Appendix D:* Acoustic Modelling Study
Concern raised about effects of drilling discharges and emissions	Drilling activities give rise to a range of wastes, discharges and emissions. All emissions, wastes and discharges will be disposed of in accordance with applicable legislation and guidelines including MARPOL and the OWTG. In accordance with regulatory requirements, some wastes will be managed and disposed of directly offshore from the MODU and the PSVs, whereas some	• *Section 2.8*: Overview of emissions, discharges and waste management • *Section 7.2:* Assessment of Project-related environmental

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
	wastes will be brought to shore for disposal. The effect of drilling waste, discharges and emissions is considered as part of the EIS. Drilling waste discharges have been quantified and modelled as part of the EIS.	effects on fish and fish habitat • *Section 7.3:* Assessment of Project-related environmental effects on marine mammals and sea turtles • *Section 7.4:* Assessment of Project-related environmental effects on migratory birds • *Section 7.5:* Assessment of Project-related environmental effects on Special Areas • *Section 7.6:* Assessment of Project-related environmental effects on commercial fisheries • *Section 7.7*: Assessment of Project-related environmental effects on Aboriginal use of lands and resources for traditional purposes • *Section 10:* Cumulative environmental effects
Concern raised about proximity to Sable Island, the Gully, and northern bottlenose whale critical habitat	The EIS assesses potential Project-related (and cumulative) effects on Special Areas which include, among other areas, Sable Island, the Gully and SARA-designated critical habitat. Routine Project activities and components could potentially interact with Special Areas, which could affect the ability of the Special Area to continue to provide important biological and ecological functions on which marine species and/or fisheries depend. These potential interactions most closely relate to concerns with the changes to the existing quality and use of natural habitats within these Special Areas. To reduce potential adverse effects on Special Areas, BP has committed to implementing best management practices and mitigation measures including	• *Section 5.2.10:* Existing conditions regarding Special Areas • *Section 7.5:* Project-related environmental effects on Special Areas • *Section 8.5:* Environmental effects of potential accidental events • *Section 10:* Cumulative environmental effects

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
	avoidance of Sable Island, the Gully and northern bottlenose whale critical habitat. Mitigation measures identified for Fish and Fish Habitat, Marine Mammals and Sea Turtles, and Migratory Birds will be implemented to reduce the potential environmental effects of the Project on Special Areas. BP will also implement multiple preventative and response barriers to manage risk of incidents occurring and mitigate potential consequences (refer to Section 8.3 for details on plans and specific response strategies).	
Concern raised about geohazards including slope failure	Prior to any drilling activity, BP will conduct a comprehensive regional geohazard baseline review (GBR), followed by detailed geohazard assessments for each proposed wellsite to identify potential geohazards that may affect drilling operations. The GBR and detailed wellsite assessments will be based primarily on reprocessed 3D Wide Azimuth Towed Streamer (WATS) seismic data acquired by BP in 2014. Existing regional data, such as geotechnical cores and offset wells, will be incorporated where available. The geohazard assessments will focus on identifying potential drilling hazards at the seabed and subsurface. This work will be conducted by a BP geohazards specialist following internal guidelines that either meet or exceed local regulatory requirements.	• *Section 2.2:* Information about well location selection criteria, including geohazards • *Section 9.1.6*: Information about geohazards • *Section 9.2*: Information about mitigation measures for geohazard management
General concern regarding use of fossil fuels and implications for climate change	Energy demand is forecast to increase globally over the next 20 years. Population growth and increases in per capita income are the key drivers behind the growth in energy demand. Energy production and consumption patterns vary and emphasize the need for secure, sustainable energy supplies. Nova Scotia's 2009 Energy Strategy – *Toward a Greener Future* (NSDOE 2009b), highlights the importance of a sustainable energy mix, and the role that offshore hydrocarbon exploration and development plays within the province's ongoing energy strategy. In the strategy, Nova Scotia commits to "encourage renewed offshore exploration and development, with its enormous potential for building future prosperity". In order to achieve their stated goal, the province has stated that it will invest revenues from offshore hydrocarbon activity into expenditures that offer enduring benefits.	• *Section 1.4:* Benefits of the Project, including information about energy diversification and sustainability
Request for information on management of drilling waste, including waste	It is likely that the initial, shallow sections of the well will be drilled without a riser and that deeper sections will be drilled with a drilling riser attached. During riserless drilling, WBM will be used as the drilling fluid and cuttings are	• *Section 2.3.2*: Information about cuttings • *Section 2.8.2*: Information about

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
minimization	discharged directly to the water column in accordance with regulatory guidelines. Once a riser is attached, cuttings can be returned to the MODU for treatment; therefore, WBM or an alternative drilling fluid such as SBM can be used. The MODU will be equipped with specialized solids control equipment for cuttings management. Treatment technology will include shale shakers which recover drilling fluids from the cuttings to minimize the amount of waste fluids. Additional treatment of cuttings will be required when SBM is used to enable disposal in accordance with the OWTG. SBM cuttings will only be discharged once the performance targets in OWTG of 6.9 g/100 g retained "synthetic on cuttings" on wet solids can be satisfied. The concentration of SBM on cuttings will be monitored on the MODU to achieve compliance with the OWTG. BP has modelled the dispersion of predicted drilling waste (refer to Appendix C); this modelling study has been used to inform the assessment of effects of drilling waste on marine life. Overall, the dispersion of sediments associated with drill waste discharges is predicted to be limited to approximately 1,367 m (for a minimum deposition thickness of 0.1 mm). Using a threshold of 9.6 mm to assume burial of benthic species, it is predicted that this sediment thickness could extend approximately 116 m from the discharge point, or cover an area of approximately 0.54 ha per well.	drilling waste discharges • *Section 7*.1.2.1: Summary of drill waste discharges and modelling results • *Section 7.2:* Assessment of Project-related environmental effects on fish and fish habitat • *Section 7.3:* Assessment of Project-related environmental effects on marine mammals and sea turtles • *Section 7.4:* Assessment of Project-related environmental effects on migratory birds • *Section 7.5:* Assessment of Project-related environmental effects on Special Areas • *Section 7.6* Assessment of Project-related environmental effects on commercial fisheries • *Section 7.7* Assessment of Project-related environmental effects on Aboriginal use of lands and resources for traditional purposes • *Section 10:* Cumulative environmental effects • *Appendix C:* Drilling Waste Dispersion Modelling Study
Request for information on anticipated greenhouse gas emissions related to Project activities	Key Project activities resulting in atmospheric emissions are: • Combustion from the MODU and PSV diesel engines, and fixed and mobile deck equipment and helicopter engines; and	• *Section 2.8.1:* Information about atmospheric emissions from Project activities

Table 3.4.1 Summary of Key Issues Raised During Public Stakeholder Engagement

Question or Comment	Response	EIS Reference
	• Flaring during well test activity, in the event that well testing is required. It is currently anticipated that well testing (and associated flaring) will not be carried out on the first two wells drilled as part of the Project. When well testing is required, these emissions will be short-term and intermittent (*e.g.*, flaring from a few hours up to three days). In terms of GHG emissions, the Project is predicted to emit approximately 295.8 tonnes of CO_2 per day. ECCC reports an annual GHG emissions value for the province of Nova Scotia of 17,000 kilotonnes of CO_2 equivalent per year (Environment Canada 2016). BP's predicted daily CO_2 emissions for the Project therefore represent approximately 0.59 % of Nova Scotia's average daily emission. Atmospheric emissions, including GHGs, will be variable over the lifetime of the Project as activity varies.	
Request that the EIS considers how local conditions and natural hazards can affect the Project and result in environmental effects	Aspects of the environment that could potentially affect the Project include: fog; sea ice and superstructure icing; seismic events and tsunamis; extreme weather conditions; and sediment and seafloor stability. The EIS includes information about local conditions and natural hazards which could potentially affect the Project and mitigation measures to manage these.	• *Section 9.1:* Environmental conditions which could affect the Project • *Section 9.2*: Mitigation measures which will be put in place to manage environmental conditions
Request for information on well abandonment including monitoring or inspection	Once wells have been drilled to total depth and well evaluation programs completed, the well will be plugged and abandoned in line with applicable BP practices and CNSOPB requirements. Plugs will be placed above and between any hydrocarbon bearing intervals at appropriate depths in the well, as well as at the surface. The final well abandonment program has not yet been finalized; however, these details will be confirmed as planning for the Project continues. A seabed survey will be conducted at the end of the drilling program using an ROV to survey the seabed for debris. Inspection and monitoring of abandoned wellheads will be conducted according to CNSOPB requirements.	• *Section 2.4.4:* Overview of plan for well abandonment

4.0 ABORIGINAL ENGAGEMENT

This section of the EIS discusses ongoing and proposed engagement with Aboriginal organizations that may have an interest in the Project. For information on public stakeholder engagement including ongoing and proposed engagement activities, and questions and comments raised, refer to Section 3.

4.1 ABORIGINAL ENGAGEMENT OBJECTIVES

BP recognizes the potential for the Project to affect Aboriginal interests including potential or established Aboriginal or Treaty rights, and acknowledges the importance of engaging Aboriginal organizations to provide Project information and obtain feedback on potential issues and concerns. BP also recognizes the importance of supporting Project-related Crown consultation efforts that may arise as part of the EIS process and related government decision-making.

4.2 ABORIGINAL ORGANIZATIONS

4.2.1 First Nations in Nova Scotia

According to the 2011 National Household Survey (Statistics Canada 2013a), 33,850 individuals of Aboriginal identity live in Nova Scotia, of which 12,910 have "registered or Treaty Indian" status. The majority of Aboriginal people in Nova Scotia are from the Mi'kmaw nation (NSOAA 2011).

There are 13 First Nations in Nova Scotia (refer to Table 4.2.1 and Figure 4.2.1). The General Assembly of Nova Scotia Mi'kmaq Chiefs represents the governance for the Mi'kmaq of Nova Scotia. The Kwilmu'kw Maw-klusuaqn Negotiation Office (KMKNO) represents the Assembly with respect to consultation on Mi'kmaq Aboriginal or treaty rights. Sipekne'katik First Nation and Millbrook First Nation are members of the Assembly of Nova Scotia Mi'kmaq Chiefs but in 2013 and 2016 respectively chose to independently represent themselves in consultation, as opposed to representation by the KMKNO. Sipekne'katik First Nation and Millbrook First Nation assert the same rights as other Mi'kmaq communities. Mi'kmaq and other Aboriginal peoples residing off-reserve in Nova Scotia are discussed in Section 4.2.4.

Table 4.2.1 First Nations in Nova Scotia

Band	Census Subdivision/Designated Place[1]	Location	Chief	Registered Population (2015)[2]		
				Total	On Reserve[3]	Off Reserve
Acadia	Gold River 21 (IRI), Medway River 11 (IRI), Ponhook Lake 10 (IRI), Wildcat 12 (IRI), Yarmouth 33 (IRI)	Yarmouth, Nova Scotia	Deborah Robinson	1,511	229	1,282
Annapolis Valley	Cambridge 32 (IRI), St. Croix 34 (IRI)	Kings County, Nova Scotia	Gerald Toney	286	119	167
Bear River	Bear River 6 (IRI), Bear River 6A (IRI), Bear River 6B (IRI)	Bear River, Nova Scotia	Carol Thompson	331	106	225
Eskasoni	Eskasoni 3 (IRI), Eskasoni 3A (IRI), Malagawatch 4 (IRI)	Eskasoni, Nova Scotia	Leroy Denny	4,371	3733	608
Glooscap	Glooscap 35 (IRI)	Hantsport, Nova Scotia	Sidney Peters	367	90	276
Membertou	Caribou Marsh 29 (IRI), Malagawatch 4 (IRI), Membertou 28B (IRI), Sydney 28A (IRI)	Sydney, Nova Scotia	Terry Paul	1,369	880	532
Millbrook	Beaver Lake 17 (IRI), Cole Harbour 30 (IRI), Millbrook 27 (IRI), Sheet Harbour 36 (IRI), Truro 27A (IRI), Truro 27B (IRI), Truro 27C (IRI)	Truro, Nova Scotia	Robert Gloade	1,787	856	893
Paq'tnkek (Afton)	Franklin Manor 22 (IRI), Paqtnkek-Niktuek 23 (IRI), Welnek 38 (IRI)	Afton, Nova Scotia	Paul Prosper	570	405	137
Pictou Landing	Boat Harbour West 37 (IRI), Fisher's Grant 24 (IRI), Fisher's Grant 24G, Franklin Manor 22 (IRI), Merigomish Harbour 31 (IRI)	Trenton, Nova Scotia	Andrea Paul	649	473	154
Potlokek (Chapel Island)	Chapel Island 5 (IRI), Malagawatch 4 (IRI)	Chapel Island, Nova Scotia	Wilbert Marshall	716	547	134
Sipekne'katik	Indian Brook 14 (IRI), New Ross 20 (IRI), Pennal 19 (IRI), Shubenacadie 13 (IRI), Wallace Hills 14A (IRI)	Indian Brook, Nova Scotia	Rufus Copage	2,495	1283	1,212
Wagmatcook	Malagawatch 4 (IRI), Margaree 25 (IRI), Wagmatcook 1 (IRI)	Wagmatcook, Nova Scotia	Norman Bernard	826	604	179

Table 4.2.1 First Nations in Nova Scotia

Band	Census Subdivision/Designated Place[1]	Location	Chief	Registered Population (2015)[2]		
				Total	On Reserve[3]	Off Reserve
We'koqma'q (Whycocomagh)	Malagawatch 4 (IRI), Whycocomagh 2 (IRI)	Whycocomagh, Nova Scotia	Rod Googoo	981	864	83

[1]Aboriginal Affairs and Northern Development Canada: First Nation Profiles (2015).
[2] Population estimates based on Aboriginal Affairs and Northern Development Canada Registered Population (2015).
[3] On reserve population estimates only include registered males and females on own reserve.

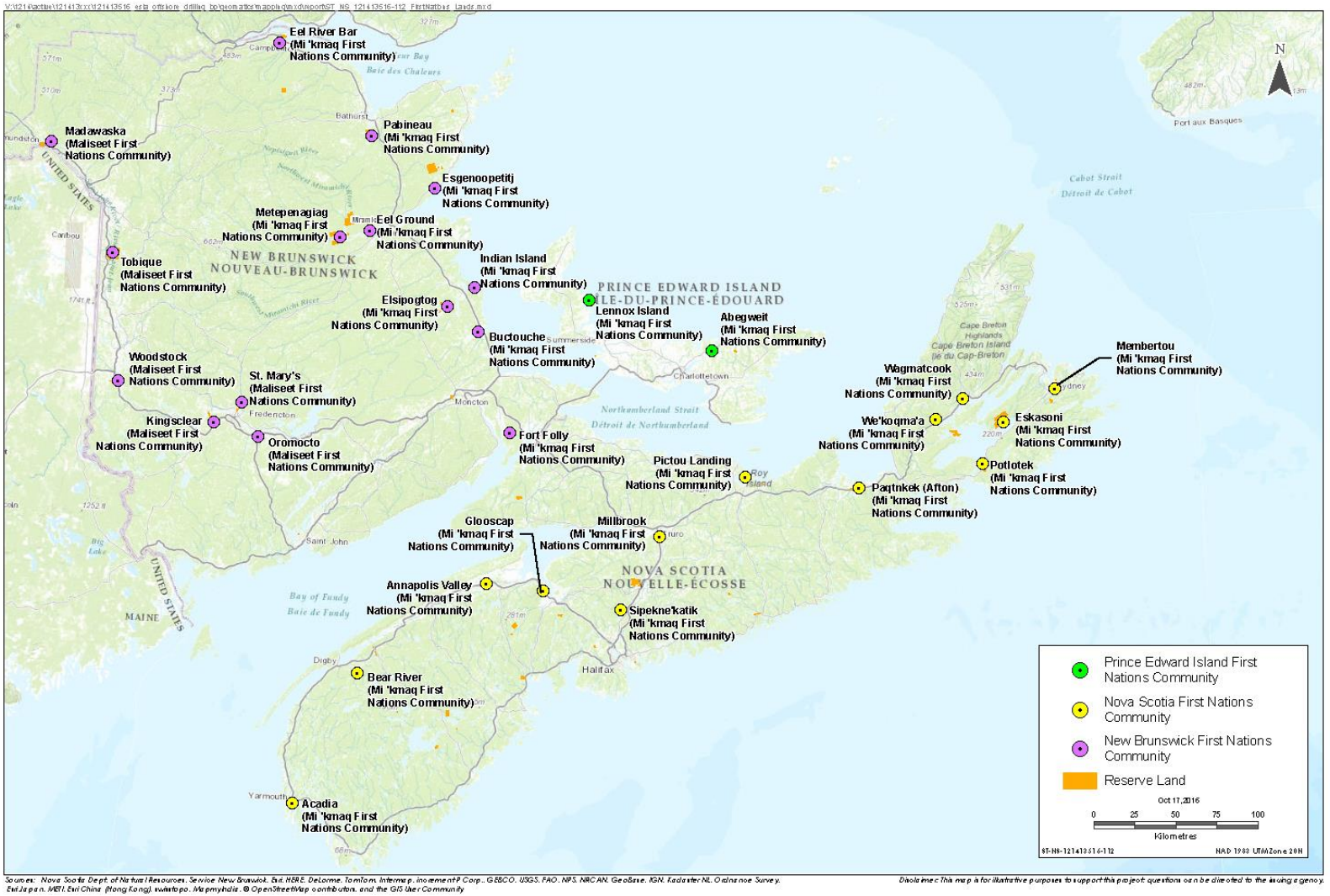


Figure 4.2.1 Location of First Nations Communities in Nova Scotia, New Brunswick and PEI

4.2.2 First Nations in New Brunswick

The 2011 National Household Survey (Statistics Canada 2013b) indicates that there are 22,620 individuals of Aboriginal identity living in New Brunswick, of which 10,275 are "registered or Treaty Indian". In New Brunswick, there are 15 First Nations communities, six are from the Wolastoqiyik (Maliseet) nation and nine are from the Mi'kmaw nation (NBDAA 2015). Wolastoqiyik (Maliseet) First Nations communities reside along the Saint John River, predominately in the west and northwest areas of the province. Mi'kmaq First Nations communities reside along the eastern and northern coasts of the province. Table 4.2.2 provides a summary of demographic information on each First Nation. Locations of band councils for each community are shown on Figure 4.2.1.

The Assembly of First Nations' Chiefs in New Brunswick (AFNCNB), the highest level of decision-making in the negotiation and consultation processes in New Brunswick, was established in 2007. The AFNCNB was a political organization, mandated to promote a unified voice for the 15 First Nations in New Brunswick. In 2015, the six Wolastoqiyik (Maliseet) communities split from the AFNCNB and announced they will be forming their own organization to conduct their administrative affairs. The AFNCNB is now defunct; Mi'gmawe' Tplu'taqn Incorporated (MTI) was created by the Mi'gmag First Nations of New Brunswick.

Table 4.2.2 First Nations in New Brunswick

Band	Census Subdivision/Designated Place[1]	Contact Information	Chief	Registered Population (2015)[2]		
				Total	On Reserve[3]	Off Reserve
Buctouche	Buctoche 16 (IRI)	Buctouche Reserve, New Brunswick	Ann Mary Steele (Simon)	119	75	43
Eel Ground	Big Hole Tract 8 (IRI), Eel Ground 2 (IRI), Renous 12 (IRI)	Eel Ground, New Brunswick	George Ginnish	1,026	559	452
Eel River Bar First Nation	Eel River 3 (IRI), Indian Ranch (IRI), Moose Meadows 4 (IRI)	Eel River Bar, New Brunswick	Thomas Everett Martin	726	346	367
Elsipogtog First Nation	Richibucto 15 (IRI), Soegao 35 (IRI)	Elsipogtog First Nation, New Brunswick	Arren Sock	3,285	2,519	721
Esgenoopetitj First Nation	Esgenoopetitj Indian Reserve 14 (IRI), Pokemouche 13 (IRI), Tabusintac 9 (IRI)	Burnt Church, New Brunswick	Alvery Paul	1,865	1,310	515
Fort Folly	Fort Folly 1, (IRI)	Dorchester, New Brunswick	Rebecca Knockwood	132	35	96
Indian Island	Indian Island 28 (IRI)	Indian Island, New Brunswick	Ken Barlow	183	103	79
Kingsclear	Kingsclear 6 (IRI), The Brothers 18 (IRI)	Kingsclear First Nation, New Brunswick	Gabriel Atwin	1,007	706	200
Madawaska Wolastoqiyik (Maliseet) First Nation	St Basile 10 (IRI), The Brothers 18 (IRI)	Madawaska Maliseet First Nation	Patricia Bernard	367	150	217
Metepenagiag Mi'kmaq Nation	Big Hole Tract 8 (North Half) (IRI), Indian Point 1 (IRI), Red Bank 4 (IRI), Red Bank 7 (IRI)	Metepenagiag Mi'kmaq Nation, New Brunswick	Alan Blowers	668	211	211
Oromocto	Oromocto 26 (IRI)	Oromocto, New Brunswick	Shelly Sabattis	664	311	351
Pabineau	Pabineau 11 (IRI)	Pabineau First Nation, New Brunswick	David Peter-Paul	301	199	100

Table 4.2.2 First Nations in New Brunswick

Band	Census Subdivision/Designated Place[1]	Contact Information	Chief	Registered Population (2015)[2]		
				Total	On Reserve[3]	Off Reserve
Saint Mary's	Devon 30 (IRI), St. Mary's 24 (IRI)	Fredericton, New Brunswick	Candice Paul	1,849	839	966
Tobique	The Brothers 18 (IRI), Tobique 20 (IRI)	Tobique First Nation, New Brunswick	Ross Perley	2,281	1,507	767
Woodstock	The Brothers 18 (IRI), Woodstock 23 (IRI)	Woodstock First Nation, New Brunswick	Timothy Paul	1,004	287	713

[1] Aboriginal Affairs and Northern Development Canada: First Nation Profiles (2015).

[2] Population estimates based on Aboriginal Affairs and Northern Development Canada Registered Population (2015).

[3] On reserve population estimates only include registered males and females on own reserve.

4.2.3 First Nations in Prince Edward Island

In 2011, based on the National Household Survey, Prince Edward Island (PEI) was home to 1,520 First Nations people, of which 770 are "registered or Treaty Indian" (Statistics Canada 2013c). The majority of Aboriginal people are from the Mi'kmaw Nation (Statistics Canada 2013c). There are two First Nation communities in PEI: Lennox Island Mi'kmaq First Nation and Abegweit Mi'kmaq First Nation. Abegweit First Nation was formed in 1972 to improve communication and governance issues that had resulted in part due to geographic separations between the Lennox Island Band Council and member reserves that were geographically separated from Lennox Island. Through a majority vote it was agreed that Morell Reserve #2, Rocky Point Reserve #3, and Scotchfort Reserve #4 would form the new Abegweit Band (Abegweit First Nation 2015).

The Mi'kmaq Confederacy of PEI is a tribal council and provincial territorial organization which provides a common forum for the two First Nations of PEI, offering a unified voice for the advancement of Treaty and Aboriginal rights.

Table 4.2.3 provides a summary of the demographic information on each of two PEI First Nations. Locations of band councils for each community are shown on Figure 4.2.1.

Table 4.2.3 First Nations in Prince Edward Island

Band	Census Subdivision/Designated Place[1]	Contact Information	Chief	Registered Population (2016)[2]		
				Total	On Reserve[3]	Off Reserve
Lennox Island	Lennox Island 1, Lennox Island No. 6, Lennox Island Reserve No. 5	Lennox Island, Prince Edward Island	Matilda Ramjattan	952	389	553
Abeqweit	Morell 2, Rocky Point 3, Scotchfort 4	Scotfort, Prince Edward Island	Brian Francis	374	213	147

[1]Aboriginal Affairs and Northern Development Canada: First Nation Profiles (2015).
[2]Population estimates based on Aboriginal Affairs and Northern Development Canada Registered Population (2016)
[3]On reserve population estimates only include registered males and females on own reserve.

4.2.4 Off-Reserve Aboriginal Peoples

The Maritime Aboriginal Peoples Council (MAPC) is a regional Aboriginal Peoples Leaders Institution established by the Native Council of Nova Scotia (NCNS), the Native Council of Prince Edward Island (NCPEI), and the New Brunswick Aboriginal Peoples Council (NBAPC). MAPC represents the Traditional Ancestral Homeland of the Mi'kmaq, Wolastoqiyik (Maliseet), and Passamaquoddy Aboriginal Peoples of Canada who live off-reserve.

In Nova Scotia, the NCNS advocates for all off-reserve Mi'kmaq and other Aboriginal people throughout traditional Mi'kmaw territory (NCNS 2015) and has established 13 geographic zones encompassing the province of Nova Scotia to administer their affairs (refer to Figure 4.2.2). The NCNS's 13 community zones have an Aboriginal ancestry population of 32,465, which represents 80% of the total Aboriginal ancestry (*i.e.*, having at least one Aboriginal ancestor) population of 40,415 in Nova Scotia (MAPC 2014). The NCNS community identity population of 16,190 represents approximately 67% of the total Aboriginal identity population in Nova Scotia (MAPC 2014).

The NBAPC constitutes a community of off-reserve Aboriginal people residing in New Brunswick, and provides programs and services, including advocacy services. Similar to the NCNS, the NBAPC has organized off-reserve Aboriginal communities into seven zones (refer to Figure 4.2.2). The NBAPC community zones have an Aboriginal ancestry population of 24,550, which represents 78% of the total Aboriginal ancestry population of 31,540 in New Brunswick (MAPC 2014). The NBAPC community identity population of 10,645 represents 60% of the total Aboriginal identity population of 17,655 in New Brunswick (MAPC 2014).

The NCPEI is the self-governing authority for all off-reserve Aboriginal people living on PEI. The NCPEI has organized off-reserve Aboriginal communities into three zones (refer to Figure 4.2.2). The NCPEI's three community zones have an Aboriginal ancestry population of 2,960, representing approximately 88% of the total Aboriginal ancestry population in PEI (MAPC 2014).

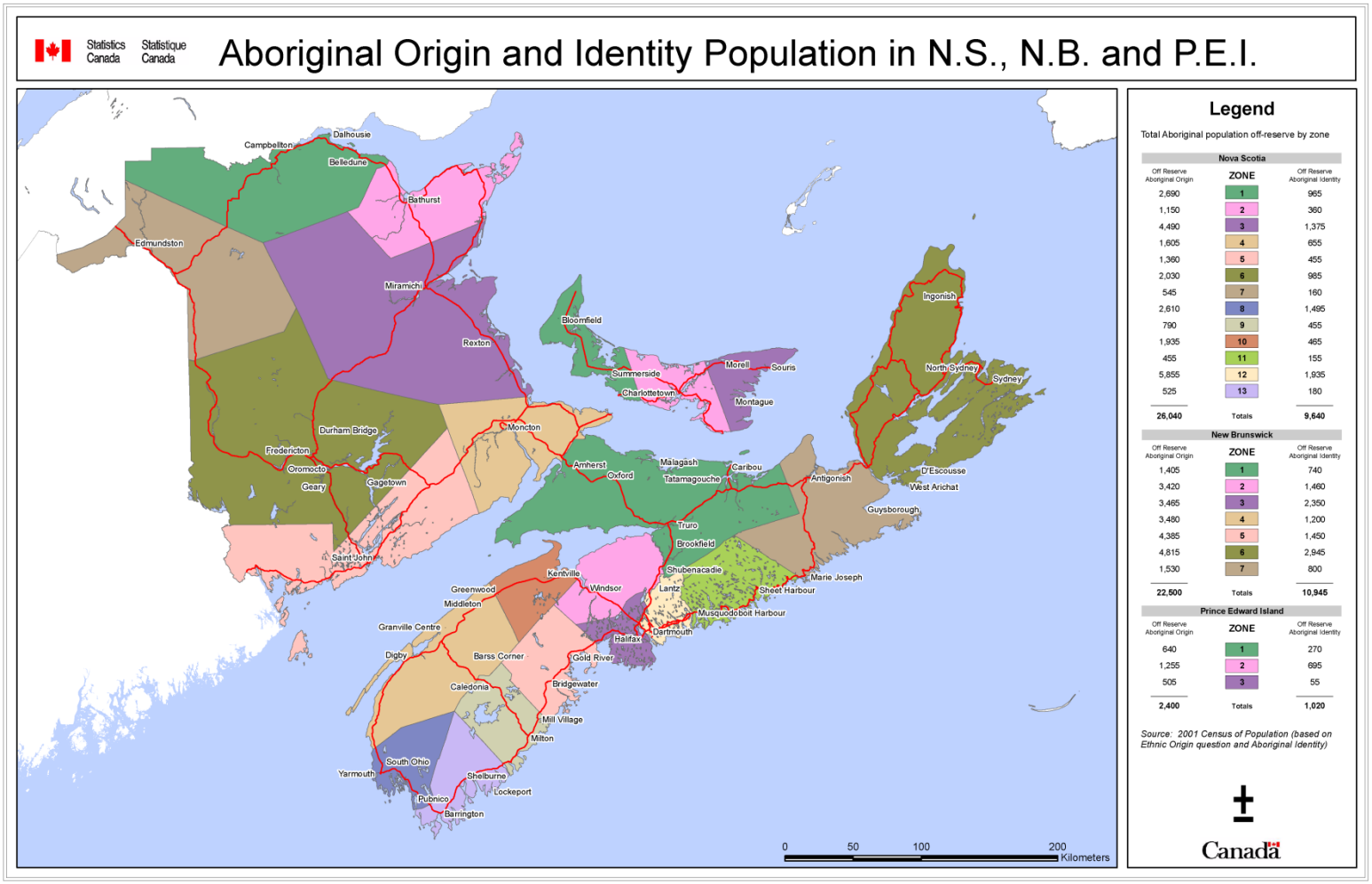


Figure 4.2.2 Off Reserve Aboriginal Origin and Identity by Community Zones (MAPC 2014)

4.3 POTENTIAL OR ESTABLISHED RIGHTS AND RELATED INTERESTS

Under the federal *Constitution Act, 1982*, existing Aboriginal and Treaty rights are recognized as constitutionally protected rights. Various Peace and Friendship Treaties were established between the Mi'kmaq, the Wolastoqiyik (Maliseet), and British settlers between 1725 and 1779, the terms of which were intended to assist in establishing peace and commercial relations (AANDC 2013). As affirmed by various recent Supreme Court decisions, these treaties guarantee Aboriginal rights to hunt and fish throughout the region and to maintain a moderate livelihood. These rights are protected by section 35(1) of the *Constitution Act, 1982*.

In the 1990 Sparrow Decision, the Supreme Court of Canada found that the Musqueam First Nation had an Aboriginal right to fish for food, social and ceremonial (FSC) purposes. This landmark decision highlighted the importance of consulting with Aboriginal groups when their fishing right may be affected (DFO 2008c). The Governments of Canada and Nova Scotia continue to work with First Nations to negotiate outstanding treaty, title and Aboriginal rights questions in Nova Scotia. A description of Mi'kmaq access to FSC and commercial fisheries is provided in Section 5.3.6 and the Traditional Use Study (TUS) (Appendix B).

A "Made-in-Nova Scotia Process" has been established as a process for the Mi'kmaq, the Province of Nova Scotia and the Government of Canada to ensure that the interests of Aboriginal groups in land, resource management and environmental protection are realized and that claimants share in the benefits of development. On February 23, 2007, a Framework Agreement was signed between the Mi'kmaq of Nova Scotia, the Province of Nova Scotia and the Government of Canada to set out the process to promote efficient, effective, orderly and timely negotiations towards a resolution of issues respecting Mi'kmaq rights and title.

In New Brunswick, the Mi'kmaq and Wolastoqiyik (Maliseet), the Province of New Brunswick and the Government of Canada are involved in tripartite exploratory discussions. These discussions are focused on establishing a tripartite process to address issues of mutual concern, including Aboriginal and treaty rights and self-government.

In addition to the engagement efforts by BP, the federal government is consulting with Aboriginal organizations in Nova Scotia and New Brunswick to understand potential Project effects on Aboriginal and Treaty rights and to take any adverse effects into consideration before reaching a regulatory decision on the Project.

To facilitate the engagement process for this Project and provide input to the EIS, a TUS has been conducted (refer to Appendix B) to characterize Aboriginal use of marine waters near the Project. Additional information about the TUS is provided in Section 4.4.

4.4 ABORIGINAL ENGAGEMENT ACTIVITIES

BP's engagement with the Mi'kmaq of Nova Scotia began in October 2013 when BP was planning the Tangier 3D Seismic Survey Project. Since then, their engagement program has expanded in recognition of a potentially larger regional area of influence associated with the exploration drilling program and has included engagement of Mi'kmaq and Wolastoqiyik (Maliseet) in New Brunswick in addition to the Mi'kmaq of Nova Scotia. BP has also commenced engagement with the First Nations in PEI.

Engagement methods used by BP to provide Project information and obtain feedback have included:

- face to face meetings;
- provision of information packages; and
- phone calls and emails.

Table 4.4.1 summarizes the Aboriginal engagement conducted by BP for this Project as of October 2016. BP will continue its Aboriginal engagement over the lifetime of the Project.

Table 4.4.1 Summary of Aboriginal Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Key Issues
Kwilmu'kq Maw-Klusuaqn Negotiation Office (KMKNO)	December 3, 2014	Meeting with Benefits Committee	Emphasis on meaningful engagement and benefits
	December 4, 2014	Meeting with KMK consultant	KMKNO's training and capacity strategic plan discussion
	January 28, 2015	Meeting with KMK consultant	KMKNO's training and capacity strategic plan discussion update
	February 23, 2015	Meeting	Project update and discussion around BP/KMKNO relationship development including engagement principles and commitments
	February 24, 2015	Meeting	Update on timing of EIS related to exploration project
	March 12, 2015	Meeting	Progress made on engagement protocol discussion
	April 15, 2015	Meeting	Detailed discussion on engagement principles
	April 15, 2015	Meeting	Regulatory process and inclusion of KMKNO discussed

Table 4.4.1 Summary of Aboriginal Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Key Issues
	May 27, 2015	Meeting	Detailed discussion on engagement expectations as well as follow up on regulatory process and inclusion of KMKNO
	June 15, 2015	Meeting	Relationship discussion
	July 9, 2015	Meeting	Relationship protocol discussion
	July 17, 2015	Provided information package meeting	BP provided information package for the KMKNO to share with the General Assembly of NS Mi'kmaq Chiefs (meeting agenda could not accommodate a BP presentation)
	August 20, 2015	Email	BP requested guidance for introductory meeting with Chief Paul Prosper, Lead on the Energy file for the Assembly of NS Mi'kmaq Chiefs
	August 26, 2015	Phone Call	Relationship discussion, touching base on sponsorship opportunities and BP's request to be included on the agenda for Assembly of NS Mi'kmaq Chiefs meeting
	September 15, 2015	Meeting/ Presentation	BP presented project overview, provided an update on the EIS, and shared lessons learned from Deepwater Horizon, source control and OSRP; KMKNO recommended an EIS findings workshop be held in February 2016
	October 16, 2015	Meeting	Met to discuss sponsorship opportunities for Annual Youth Trades Fair
	November 27, 2015	Email	Seeking guidance from KMKNO regarding First Nations requesting BP participation; Request came through TUS interview activity
	March 3, 2016	Email	Update on timing of EIS related to exploration project
	March 22, 2016	Email	Relationship update discussion to address any outcomes from upcoming meetings
	March 30, 2016	Phone call	Discussion about Project timeline, EIS submission and planned technical session

Table 4.4.1 Summary of Aboriginal Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Key Issues
	April 4, 2016	Email	Discussion on topics to include in meeting with fisheries managers
	April 5, 2016	Email	Planning for technical session with fisher managers from KMKNO in May
	April 19, 2016	Email	Finalization of topics for meeting with fisheries managers
	May 2, 11, 17, 2016	Emails	Emails to invite and confirm attendance at technical session hosted by BP
	May 24, 2016	Meeting	Technical presentation delivered by BP to provide project update and overview of exploration drilling and emergency response and TUS
	June 7, 13, 14, 24	Emails	Emails from BP to inform the KMKNO of the EIS submission to CEA Agency for review and provision of TUS report to the KMKNO
	July 12, 2016	Email	Provided clarification on engaging KMKNO membership in all phases of the Project
	August 24, 2016	Meeting	Relationship update discussion to address best methods to engage all members within KMK
	September 27, 2016	Email	Notification of upcoming BP technical presentations
	September 29, 2016	Email	Email to confirm upcoming meeting
	October 5, 2016	Email	Invitation to the Technical Session Meeting at the KMKNO office
	October 12, 2016	Meeting	Meeting with the Benefits Committee to better establish working relationship between leadership of KMK and BP
Whycocomagh Wagmatcook Membertou Eskasoni Chapel Island (Potlotek) Pictou Landing Millbrook Acadia	May 24, 2016	Meeting	Technical presentation delivered by BP to provide project update and overview of exploration drilling and emergency response and TUS

Table 4.4.1 Summary of Aboriginal Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Key Issues
Paq'tnkek Bear River Annapolis Valley Glooscap			
Sipekne'katik	February 24, 2015	Meeting	Update on timing of EIS related to exploration project
	May 20, 2015	Meeting	Meeting to engage the community of Sipekne'katik on the Scotian Basin Project
	March 1, 2016	Email	Confirmation of upcoming meeting
	March 24, 2016	Meeting	Meeting to discuss Project, including timeline, location and EIS submission
	May 16, 2016	Email	Email to provide update on Project status including delay in operations schedule
	August 25, 2016	Email	Email to provide an update on Project status
Native Council of Nova Scotia (NCNS)/Netukulimkewe'l Commission	December 3, 2014	Meeting	General discussion around BP's future plans in Nova Scotia
	February 24, 2015	Meeting	Update on timing of EIS related to exploration project
	February 25, 2015	Meeting	Employment and capacity training and contract opportunity discussion
	March 19, 2015	Meeting	Discussion around BP's plans and NCNS's interest in offshore fishery; Identified the key areas requiring further discussion as BP progresses to an exploration program
	March 25, 2015	Teleconference meeting	General discussion around BP's exploration program
	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
	July 11, 2016	Email	Consideration of an initiative that NCNS is promoting in the fall in Nova Scotia
Maritime Aboriginal Peoples Council	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
Kingsclear First Nation -	October 20, 2015	Meeting	Meeting to introduce the Project

Table 4.4.1 Summary of Aboriginal Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Key Issues
Wolastoqiyik (Maliseet) Nation	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
	June 13, 2016	Email	Email to provide update on Project status and submission of EIS to CEA Agency for review
Woodstock First Nation - Wolastoqiyik (Maliseet) Nation	October 20, 2015	Meeting	Meeting to introduce the Project
	March 3, 2016	Email	Reaching out to arrange a time to discuss the Project
	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
	June 13, 2016	Email	Email to provide update on Project status and submission of EIS to CEA Agency for review
	August 4, 2016	Email	Brief Project update
St. Mary's First Nation - Wolastoqiyik (Maliseet) Nation	June 13, 2016	Email	Email to provide update on Project status and submission of EIS to CEA Agency for review
	August 4, 2016	Email	Brief Project update
	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
Tobique First Nation - Wolastoqiyik (Maliseet) Nation	October 20, 2015	Meeting	Meeting to introduce the Project
	March 3, 2016	Email	Update on timing of EIS related to exploration project
	March 18, 2016	Email	Planning for upcoming meeting
	March 21, 2016	Meeting	Meeting to discuss Project, including timeline, location and EIS submission
	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
Oromocto First Nation - Wolastoqiyik (Maliseet) Nation	October 20, 2015	Meeting	Meeting to introduce the Project
	March 3, 2016	Email	Update on timing of EIS related to exploration project
	March 21, 2016	Meeting	Meeting to discuss Project, including timeline, location and EIS submission

Table 4.4.1 Summary of Aboriginal Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Key Issues
	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
	June 2, 2016	Meeting	Meeting to discuss project update; Oromocto indicated Maliseet are looking into having an organization represent interests of all Maliseet in New Brunswick and expressed interest in a technical presentation; Oromocto indicated they are in regular contact with CEA Agency on several projects
	June 13, 2016	Email	Email to provide update on Project status and submission of EIS to CEA Agency for review
Madawaska First Nation - Wolastoqiyik (Maliseet) Nation	March 3, 2016	Email	Update on timing of EIS related to exploration project
	March 21, 2016	Meeting	Meeting to discuss Project, including timeline, location and EIS submission
	May 13, 2016	Email	Email to provide update on Project status including delay in operations schedule
	June 2, 2016	Meeting	Meeting to discuss Project status and ongoing engagement with BP and CEA Agency; Madawaska First Nation expressed interest in broad presentation on offshore oil and gas exploration
	June 13, 2016	Email	Email to provide update on Project status and submission of EIS to CEA Agency for review
St. Mary's First Nation Woodstock First Nation Kingsclear First Nation Madawaska First Nation Oromocto First Nation Tobique First Nation	June 27, 2016	Meeting	Meeting to provide general presentation (technical session) on offshore drilling and incident response as well as the TUS
	October 5, 2016	Email	Confirming meeting at St. Mary's First Nation to discuss the Project
Woodstock First Nation Madawaska First Nation Oromocto First Nation	August 23, 2016	Meeting	BP provided info and update on submission of EIS and shared communal commercial fisheries information from DFO

Table 4.4.1 Summary of Aboriginal Engagement Conducted for the Project (as of October 2016)

Organization	Date	Means of Engagement	Key Issues
Mi'gmawe'l Tplu'taqnn Incorporated (MTI) (formerly Assembly of First Nation Chiefs of New Brunswick)	October 20, 2015	Meeting	Meeting to introduce the Project
	March 3, 2016	Email	Update on timing of EIS related to exploration project
	March 8, 2016	Email	Confirmation of upcoming meeting
	March 16, 2016	Meeting	Meeting to discuss the Project: BP EIS submission date, TUS, MTI involvement, budget
	April 11, 2016	Email	Email to confirm communications with New Brunswick Mi'kmaq is transitioning from AFNCNB to MTI
	May 18, 2016		Email to provide update on Project status including delay in operations schedule
	June 1, 2016	Meeting	Meeting to discuss continued engagement with BP and CEA Agency with preference for MTI First Nations to be engaged as unified group; expressed interest in American eel as important species, and interest in broad presentation informing MTI First Nations in offshore oil and gas exploration
	June 7, 2016	Email	MTI provided BP copy of Indigenous Study Guide
	June 13-14, 2016	Emails	BP provided update of Project status, discussed option for follow up meeting with Wells Manager, and copy of TUS report
	September 23, 2016	Email	Received email informing BP that as of April 1, 2016 Mi'gmawe'l Tplu'taqnn has been designated to hold the mandate of consultation and accommodation, and rights implementation for its member communities in New Brunswick.
Abegweit First Nation	October 12, 2016	Email	Email to introduce the Project
Lennox First Nation	October 12, 2016	Email	Email to introduce the Project

As noted in Table 4.4.1, BP held technical sessions with several First Nations groups in Nova Scotia (through the KMKNO) and New Brunswick in May and June 2016 to provide an overview of offshore exploration drilling activities and emergency planning and response. A further technical session is planned in November 2016.

In addition to activities listed in Table 4.4.1, BP sought to engage the Aboriginal Peoples Training and Employment Commission to meet and discuss the Project.

BP also attended the Business Together Symposium on March 11, 2015 where BP had conversations with several leaders of the Assembly of Nova Scotia Mi'kmaq Chiefs about economic opportunities.

BP will continue to reach out to Aboriginal organizations in Nova Scotia and New Brunswick to share Project information and obtain feedback on issues and concerns. BP will also continue to engage with Aboriginal fishery groups through the FAC.

Information sessions focussed on topics or concerns expressed about the proposed Project will be conducted. BP subject matter experts will participate in the presentations to address concerns highlighted for the discussions.

In an effort to better understand traditional use of marine areas and resources by Aboriginal peoples and potential effects on Aboriginal and Treaty rights, Membertou Geomatics Solutions (MGS) and Unama'ki Institute of Natural Resources (UINR) were commissioned to undertake a Traditional Use Study (TUS). Based on knowledge of fishing interests obtained from DFO and/or through consultation with the CEA Agency, the TUS targeted interviews with the NCNS and all 13 First Nation Bands in Nova Scotia, and Fort Folly, St. Mary's, and Woodstock First Nations in New Brunswick. Interviews with fisheries managers, captains and fishers, along with a literature review and review of DFO licensing information were used to help characterize communal commercial and/or FSC fisheries that could be occurring in the RAA. Organizations that were interested and available to participate are included in the study results. The TUS is not intended to represent an exhaustive inventory of Aboriginal resource use occurring in the RAA but provides a reasonable characterization of potential interactions with the Project. BP has presented information about commercial and FSC fisheries that could interact with the RAA in Section 5. As part of ongoing engagement activity, BP will continue to gather information about commercial and FSC fishing by Aboriginal groups and monitor the suitability of any mitigation measures to manage any potential effects from the Project. Refer to the TUS in Appendix B for more information on study participants, methods, and results.

4.5 QUESTIONS AND COMMENTS RAISED DURING ABORIGINAL ENGAGEMENT

Questions and comments raised during Aboriginal engagement, including comments submitted to the CEA Agency during the public comment periods held thus far under CEAA, 2012, have been taken into consideration during the preparation of this EIS.

Key concerns raised by various Aboriginal organizations were a perceived lack of funding, limited duty to consult, and limited engagement scope. On December 8, 2015, the CEA Agency announced the allocation of federal funding through the Participant Funding Program to assist

public and Aboriginal groups in their participation in the EA process. Federal funding was allocated to 10 applicants; all are Aboriginal organizations in Nova Scotia or New Brunswick.

In addition to concerns raised about the engagement process, Aboriginal organizations raised questions and concerns about the collection and integration of traditional knowledge for the EIS, and potential effects of the Project on potential or established Aboriginal and Treaty rights, through effects on marine resources and/or through potential obstruction to these resources.

A summary of key issues and how they have been addressed is provided in Table 4.5.1.

Table 4.5.1 Summary of Key Issues Raised During Aboriginal Engagement

Question or Comment	Summary of Response	EIS Reference
Recommendation to complete a TUS and Mi'kmaq Fisheries Communication Plan	A TUS has been commissioned by BP to assess the extent and timing of traditional use of the RAA by the Mi'kmaq and Wolastoqiyik (Maliseet). This activity primarily includes fisheries use. The TUS has been completed by MGS and UINR. The results of the TUS have been used to inform the EIS. BP has commenced engagement with community fishery directors, fishers and fisheries organizations. BP will continue to engage commercial and Aboriginal fishers to share Project details as applicable and facilitate coordination of information sharing. A Fisheries Communication Plan will be used to facilitate coordinated communication with fishers.	• *Section 5.3.6:* Description of Aboriginal fishing activities • *Section 7.7*: Assessment of Project-related environmental effects on aboriginal use of lands and resources • *Appendix B*: Traditional Use Study
Concern about scope of TUS, particularly as it pertains to involvement of First Nations in New Brunswick	The TUS includes First Nations from the Mi'kmaq and Wolastoqiyik (Maliseet) communities in Nova Scotia and New Brunswick. Prior to the commencement of the TUS, the First Nation communities as well as the NCNS, were solicited for their participation because of known existing fishing activity. The communities who were invited to participate in the TUS include: Acadia First Nation, Glooscap First Nation, Membertou First Nation, Millbrook First Nation, Sipekne'katik (Indian Brook) First Nation, Woodstock First Nation, St. Mary's First Nation, Fort Folly First Nation, Eskasoni First Nation, Potlotek First Nation, Wagmatcook First Nation, We'koqma'q (Whycocomagh) First Nation, Paq'tnkek (Afton) First Nation, Pictou Landing First Nation, Annapolis Valley First Nation and Bear River First Nation. Sipekne'katik (Indian Brook) First Nation declined to participate in the TUS. As of April 2016, Annapolis Valley First Nation and Bear River First Nation had not been included in the TUS for EIS submission. The area considered by the TUS is consistent with the RAA defined in the EIS.	• *Section 5.3.6:* Description of Aboriginal fishing activities • *Section 7.7*: Assessment of project-related environmental effects on aboriginal use of lands and resources • *Appendix B*: Traditional Use Study
Request to include off-reserve Status and Non Status Indian/Mi'kmaq/Aboriginal Peoples in the TUS	BP has engaged with the NCNS, which represents off-reserve Aboriginal peoples in Nova Scotia, and the NCNS participated in the TUS.	• *Section 5.3.6:* Description of Aboriginal fishing activities • *Section 7.7*: Assessment of project-related environmental effects on aboriginal use of lands and resources • *Appendix B*: Traditional Use Study

Table 4.5.1 Summary of Key Issues Raised During Aboriginal Engagement

Question or Comment	Summary of Response	EIS Reference
Concern that an oil spill could reach the Bay of Fundy and affect species at risk, migratory waterfowl, and tidal salt marshes	Safe operations are BP's priority. BP will implement multiple preventative and response barriers to manage risk of incidents occurring and mitigate potential consequences (refer to Section 8.3 for details on plans and specific response strategies). BP has conducted spill trajectory modelling to determine the likely fate and behavior of a blowout in the extremely unlikely event one should occur over the life of the Project. The results of this modelling indicate that, if left unmitigated (*i.e.*, with no oil spill response measures to manage or contain spilled oil), oil from a blowout could potentially reach the Bay of Fundy under certain oceanographic conditions. However, the probability of oil reaching the Bay of Fundy at levels where environmental effects could be detected is 0 to 5% (if left unmitigated). Furthermore, the length of time it would take to reach the Bay of Fundy at these concentrations is in excess of 50 days, which would be considerable time to implement spill response measures to further reduce the probability of interaction of oil and sensitive receptors.	• *Section 8.3:* Emergency response and spill management • *Section 8.5:* Environmental effects of potential accidental events • Appendix H: Oil Spill Modelling Study
Concern that a spill could affect migration, spawning and/or feeding grounds of species of significance to Mi'kmaq culture including American eel, Atlantic sturgeon, Bluefin tuna, herring and gaspereau, whales, and migratory birds	Safe operations are BP's priority. BP will implement multiple preventative and response barriers to manage risk of incidents occurring and mitigate potential consequences. BP's oil spill response plan will contain specific details of response methods which could be used in the event of an oil spill (refer to Section 8.3 for details on plans and specific response strategies). The EIS has used oil spill modelling (refer to Appendix H) to inform the assessment of effects on valued components of the marine environment (refer to Section 8.5).	• *Section 8.3:* Emergency response and spill management • *Section 8.5:* Environmental effects of potential accidental events • *Appendix H*: Oil Spill Modelling Study
Concern of potential cumulative effects with proposed TransCanada marine terminal and shipping in the Bay of Fundy	Routine Project activities will not interact with the Bay of Fundy, therefore the proposed TransCanada marine terminal and associated shipping was not considered as a foreseeable activity with effects that would likely interact spatially and temporally with effects of the Project. Shipping in general within the RAA is considered in the cumulative effects assessment.	• *Section 10:* Cumulative Effects Assessment

Table 4.5.1 Summary of Key Issues Raised During Aboriginal Engagement

Question or Comment	Summary of Response	EIS Reference
Concern that the Project will result in obstruction of Mi'kmaq fishing areas	Similar to commercial fisheries, the Project could have an effect on fisheries resources by direct or indirect effects on fished species and/or effects on fishing activity from displacement from fishing areas, gear loss or damage. Routine Project activities are not expected to interact with nearshore fishing activities. A 500-m safety (exclusion) zone will be established around the MODU, in accordance with the *Nova Scotia Offshore Petroleum Drilling and Production Regulations*, within which Aboriginal (and commercial) fishing activities will be excluded while the MODU is in operation. This will result in localized Aboriginal fisheries exclusion within an area of approximately 0.8 km^2 (80 ha) for an expected maximum of 120 days for each well to be drilled. Although fishing efforts may be disrupted within this safety (exclusion) zone, it is anticipated to be a temporary and localized fishing exclusion and is not likely to have a substantial effect on Aboriginal fishing activities and fisheries resources. The Project Area does not include any unique fishing grounds or concentrated fishing effort; similar alternative sites are readily available within the immediate area.	• *Section 7.7:* Assessment of project-related effects on aboriginal use of lands and resources • *Appendix B:* Traditional Use Study
Recommendation for compensation and/or accommodation for impacts to fish and fish habitat	The Canada Nova Scotia Offshore Petroleum Board provides guidelines respecting damages relating to offshore petroleum activity. BP adheres to and complies with the principles outlined within the guidelines. Specified concerns regarding BP activity resulting in gear loss or damage will be investigated.	• *Section 7.6:* Assessment of project-related effects on commercial fisheries • *Section 7.7:* Assessment of project-related effects on aboriginal use of lands and resources
Question about PSV fuelling and fuel transfer to the MODU	Fuel will be transferred to the PSV for PSV fuelling and for transfers to the MODU using closed piping systems (*e.g.*, pumps and hoses). Procedures will be implemented for the safe management and use of fuelling systems to minimize the risk of an unintended release. The vessels, MODU and fuelling base will be equipped with primary spill contingency equipment to deal with spills in the unlikely event that they occur. The PSVs will transfer diesel fuel, also referred to as marine gas oil to the MODU from shore. Fuel is required offshore to power the MODU,	• *Section 2.4.5.1*: Information about platform supply vessels and fuelling operations

Table 4.5.1 Summary of Key Issues Raised During Aboriginal Engagement

Question or Comment	Summary of Response	EIS Reference
	including drilling equipment and thrusters. Fuel will be loaded from an existing field distribution facility within Halifax Harbour according to standard vessel fuelling procedures up to two to three times per week by a third party contractor.	
Request for more information on drill waste dispersion modelling exercise and effects on marine life	It is likely that the initial, shallow sections of the well will be drilled without a riser and that deeper sections will be drilled with a drilling riser attached. During riserless drilling, WBM will be used as the drilling fluid and cuttings are discharged directly to the water column in accordance with regulatory guidelines. Once a riser is attached, cuttings can be returned to the MODU for treatment. SBM cuttings will only be discharged once the performance targets in OWTG of 6.9 g/100 g retained "synthetic on cuttings" on wet solids can be satisfied. The concentration of SBM on cuttings will be monitored on the MODU to achieve compliance with the OWTG. BP has modelled the dispersion of predicted drilling waste (refer to Appendix C); this modelling study has been used to inform the assessment of effects of drilling waste on marine life. Overall, the dispersion of sediments associated with drill waste discharges is predicted to be limited to approximately 1,367 m (for a deposition thickness of 0.1 mm). Using a threshold of 9.6 mm to assume burial of benthic species, it is predicted that this sediment thickness could extend approximately 116 m from the discharge point, or cover an area of approximately 0.54 ha per well.	• *Section 2.3.2*: Information about cuttings • *Section 2.8.2*: Information about drilling waste discharges • *Section 7.1.2.1*: Summary of drill waste discharges and modelling results • *Section 7.2:* Assessment of Project-related effects on fish and fish habitat • Section 7.3: Assessment of Project-related effects on marine mammals and sea turtles • Section 7.4: Assessment of Project-related effects on migratory birds • Section 7.5: Assessment of Project-related effects on Special Areas • Section 7.6 Assessment of Project-related effects on commercial fisheries • *Section 7.6:* Assessment of Project-related effects on Aboriginal use of lands and resources for traditional purposes commercial fisheries • *Section 10:* Cumulative effects • *Appendix C:* Drilling Waste

Table 4.5.1 Summary of Key Issues Raised During Aboriginal Engagement

Question or Comment	Summary of Response	EIS Reference
		Dispersion Modelling Study
Question about whether drill wastes will contain naturally occurring radioactive material (NORM) and if so, how it will be managed	NORM is not expected to occur in the drilling waste. NORM typically is created in the production process, when the produced water may create sulfate scale on the wall of production tubing and surface equipment.	None
Request for more information on predictive spill modelling exercise and spill effects on nearshore and inshore resources	BP has conducted stochastic and deterministic modelling to predict the fate and behavior of an oil spill in the unlikely event that one occurs (refer to Appendix H). The results of the modelling have been used to inform the assessment of effects of accidental spills on the marine environment (refer to Section 8.5). As part of stakeholder and Aboriginal engagement efforts, BP intends to present an overview of spill modelling results, as well as spill prevention and response measures that will be implemented to reduce adverse environmental effects from a spill.	• *Section 8.3:* Emergency response and spill management • *Section 8.5:* Environmental effects of potential accidental events • *Appendix H*: Oil Spill Modelling Study
Request for more information on Project effects on sensitive and protected areas (Special Areas)	The EIS assesses potential Project-related (and cumulative) effects on Special Areas which includes sensitive and protected areas including, but not limited to, Sable Island, the Gully and SARA-designated critical habitat. Routine Project activities and components could potentially interact with Special Areas (*e.g.*, drilling and VSP), which could affect habitats in Special Areas. Special Areas could also be affected in the unlikely event of large spills. To reduce potential adverse effects on Special Areas, BP has committed to implementing best management practices and mitigation measures including avoidance of Sable Island, the Gully and northern bottlenose whale critical habitat. Mitigation measures identified for Fish and Fish Habitat, Marine Mammals and Sea Turtles, and Migratory Birds will be implemented to reduce the potential environmental effects of the Project on Special Areas. BP will also implement multiple preventative and response barriers to manage risk of incidents occurring and mitigate potential consequences (refer to Section 8.3 for details on plans and specific response strategies).	• *Section 5.2.8:* Existing conditions regarding Special Areas • *Section 7.5:* Project-related effects on Special Areas • *Section 8.3:* Emergency response and spill management • *Section 8.5:* Environmental effects of potential accidental events • *Section 10:* Cumulative effects