1.0 INTRODUCTION

Statoil Canada Ltd. (Statoil), in association with its partners BP Canada Energy Group ULC, BG International Limited, Chevron Canada Limited and ExxonMobil Canada Ltd., is proposing to undertake an exploration / delineation / appraisal drilling program and associated activities (herein referred to as exploration drilling) in the eastern portion of the Canada-Newfoundland and Labrador Offshore Area between 2018 and 2027 (herein referred to as the Project). Herein, in particular instances, when reference is made to "the Operator" it refers to Statoil and/or ExxonMobil.

The Project requires review and approval pursuant to the requirements of the *Canadian Environmental Assessment Act* (CEAA 2012) as it has been determined that the drilling of a well on ELs 1139, 1140, 1141 and 1142 constitutes a "designated project" under Section 10 of the *Regulations Designating Physical Activities.* In addition, the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) requires a project-specific environmental assessment (EA) be completed for offshore oil and gas activities, pursuant to the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act* and the *Canada-Newfoundland Atlantic Accord Implementation Act* (the Accord Acts). It is intended that the EA review process for the Project will satisfy the requirements of CEAA 2012 and the C-NLOPB's Accord Acts EA processes. This Environmental Impact Statement (EIS) has been prepared in accordance with requirements of CEAA 2012, the project-specific Guidelines for the Preparation of an Environmental Impact Statement (EIS Guidelines [CEA Agency 2016]) issued by the Canadian Environmental Assessment Agency (the Agency) and other generic EA guidance documents issued by the Agency as referenced throughout.

Statoil holds other licenses in the Project Area on which drilling activities may occur (i.e., existing ELs, partner-operated ELs, and/or significant discovery licences (SDLs)). For transparency to stakeholders and clarity in terms of the total exploration activity that may be undertaken by the Operator in the Project Area, these licenses are also included. Although the effects assessment and conclusions are relevant to these licenses, it is the Operator's understanding that the Ministerial EA decision will be limited to the "designated Project" defined as exploration drilling and associated activity in ELs 1139, 1140, 1141 and 1142. Environmental assessment for licences that are not 'designated Projects' are considered under a separate regulatory process through the Accord Acts, administered by the C-NLOPB.

As an introduction to the EIS, this Chapter identifies the Operator, provides a general overview of the Project, outlines the regulatory contexts for the Project, and describes the purpose of the EIS and the overall organization of the document.

1.1 Identification and Overview of the Operator

Statoil is an international energy company focused on upstream exploration and production activities. It is a Norwegian-based company with operations in more than 30 countries. The company employs over 20,000 individuals worldwide and creates value through safe and efficient operations, innovative solutions and technology. Since 1972 Statoil has explored, developed, and produced oil and gas on the Norwegian continental shelf. In the last 40 years, the company has become the world's largest offshore operator and the second largest supplier of natural gas to the European market. Statoil is 67 percent owned by the Norwegian State and is listed on the Oslo and New York Stock Exchanges, and is headquartered in Stavanger, Norway.

Statoil Canada Ltd. is an active player in Statoil's global portfolio. In 1996, Statoil established a Canadian headquarters in Calgary, Alberta, and a local office in St. John's, Newfoundland. Statoil currently owns interests in several exploration, development, and production licenses offshore Newfoundland. As of September 2017, the company operates four SDLs and 10 Exploration Licenses (ELs) in the Canada-NL Offshore Area and continues to apply experience from work on the Norwegian Continental Shelf. Statoil holds interest in 29 SDLs, two ELS, the Terra Nova, Hibernia, Hibernia South Extension, and Hebron oilfields. In 2015, Statoil strengthened its long-term position in the Canadian offshore with two licenses offshore Nova Scotia.

Statoil views change in the oil and gas industry as an opportunity to shape and improve the energy industry of tomorrow. Statoil aims to set an example for how the oil and gas industry must develop, show leadership, and point the way to bolder and better solutions. The company is actively shaping its portfolio to deliver high value with a low carbon footprint and aims to be recognised as the most carbon-efficient oil and gas producer, committed to creating lasting value for communities.

Statoil's approach to sustainability is based on the following principles and themes:

- Aiming for outstanding resource efficiency
- Preventing harm to local environments
- Creating local opportunities
- Respecting human rights
- Being open and transparent

1.1.1 Statoil's Offshore Experience

Statoil was founded in Norway in 1972 and has since become the largest operator on the Norwegian continental shelf. Statoil applies its extensive offshore experience from work on the Norwegian Continental Shelf to its operations offshore Newfoundland, where the company has been present since 1996, when Norsk Hydro first acquired assets. Norsk Hydro's Oil & Gas Division merged with Statoil in 2007. Statoil undertook its first drilling and geophysical program activities offshore Newfoundland in 2008, and had its first offshore oil discovery in 2009 with Mizzen in the Flemish Pass Basin area. Following the Mizzen discovery, Statoil continued its geophysical and exploration drilling activities. Additional geophysical surveys were undertaken offshore Newfoundland in 2011, 2012, and 2014. Further exploration drilling in the Flemish Pass area in 2013 resulted in the Harpoon and Bay du Nord discoveries. Statoil continued its exploration and appraisal drilling program in the Flemish Pass area through a 19-month drilling program which began in the fall 2015, during which a total of nine exploration and/or appraisal wells were drilled. The 19-month drilling program resulted in two oil discoveries at the Bay de Verde and Baccalieu prospects. In 2017, Statoil completed a two-well exploration drilling campaign offshore Newfoundland.

Worldwide, Statoil ASA has considerable experience in drilling and production activities. It operates over 42 fields and platforms in Norway and is responsible for 70 percent of all oil and gas production on the Norwegian Continental Shelf. Internationally Statoil has drilled more than 3,500 offshore wells with 150 wells in water depths greater than 500 m. Offshore Newfoundland, Statoil Canada Ltd. has drilled more than 15 wells in the Flemish Pass area.

1.1.2 Statoil's Management System

Statoil's offshore Newfoundland operations conform to Statoil's corporate management system, which is the set of principles, policies, processes, and requirements that support the organization in fulfilling the tasks required to achieve its objectives. This management system has three main objectives:

1) Contribute to safe, reliable, and efficient operations and enable us to comply with external and internal requirements
2) Help us to incorporate our values, our people, and our leadership principles in everything we do
3) Support our business performance through high-quality decision making, fast and precise execution, and continuous learning

The governing documentation in Statoil's management system is structured in three levels: (1) fundamentals, (2) requirements, and (3) recommendations.

Fundamentals are essential regulations for the company and are valid company-wide. They describe what the company wants to achieve and include values, principles, commitments, and mandates.

Requirements are used to manage risks and to provide safe and efficient operations. They describe what the company needs to comply with when performing tasks. Requirements are set out in various company organization management and control documents, work processes, work requirement documents, technical requirement documents, system and operation documents, key control documents and emergency response plan documents.

Recommendations support people when performing tasks and enable compliance with fundamentals or requirements. They describe suggestions or proposals for the best course of action and are based on the collective learning and experience in the company.

Statoil's management plan encompasses specific components. For drilling programs, these would include, but not be limited to, pollution prevention policies and procedures, and plans for emergency response, spill response, waste management and environmental monitoring.

Compliance means to follow external and internal requirements and to achieve the required performance. The management system is used systematically in day-to-day work. Training in the use of the work processes is part of this systematic approach. When performing a specific activity, it is necessary to consider risks. A risk assessment may lead to a need for improvement or to evaluate an application for dispensation and/or regulatory equivalency from governing documentation. Leadership is also required in order to achieve compliance. This includes communicating the management system, acting as a role model, and coaching the organization in the use of the management system. Statoil regularly tests how well the Management System is working through an assurance process, which includes self-assessments, verifications, and audits.

Statoil complies with applicable laws, acts in an ethical, sustainable and socially responsible manner, practises good corporate governance and respects internationally recognised human rights. Statoil maintains an open dialogue on ethical issues – both internally and externally. Open, honest, and accurate communication is essential to the company's integrity and business success.

Statoil uses a variety of tools that will help to communicate required environmental commitments and mitigations identified for a project during its operations. Notwithstanding its internal processes and requirements for managing, monitoring, and reporting on its environmental performance, Statoil will also adhere to all the applicable legislative and regulatory requirements that pertain to this Project, including terms and conditions imposed as conditions of associated EA review and approval for the Project, and will monitor and report on these in accordance with applicable regulatory procedures or other relevant requirements.

Further information on Statoil and its associated environmental planning and management policies, systems, and procedures in provided in Chapter 2.

1.1.3 Statoil Contacts

Statoil operates an office in St. John's NL where Statoil's offshore Newfoundland and Labrador activities are managed and key technical staff located.

The principal Statoil contacts concerning this Project and its EA review are as follows:

Primary Contact for EA Purposes:

Stephanie Curran
Regulatory Lead
Statoil Canada Ltd.
2 Steers Cove, Level 2, St. John's, NL, A1C 6J5
Tel (709) 726-9091
Fax (709) 726-9053
Email: scurr@statoil.com

Primary Contact for Statoil Canada Ltd., Newfoundland Operations:

David Ralph, P. Eng.
Operations Manager, Newfoundland Offshore
Statoil Canada Ltd.
2 Steers Cove, Level 2, St. John's, NL, A1C 6J5
Tel (709) 726-9091
Fax (709) 726-9053
Email: dral@statoil.com

1.2 Project Location and Overview

This section provides a brief overview of the Project, including its overall location, planned components and activities and its environmental setting and context, as initial background for the EIS. Further details on each of these items are provided in subsequent chapters.

1.2.1 Project Location

The Project Area includes the licences where exploration drilling may occur and also includes a surrounding area (buffer) to account for planned and potential ancillary activities, such as wellsite surveys.

Figure 1-1 shows the Project Area and the various ELs described above. As illustrated, the Project Area is located off eastern Newfoundland, primarily outside Canada's 200 nm Exclusive Economic Zone (EEZ) on the outer continental shelf. A detailed description of the Project Area, including its corner point coordinates, is provided in Section 2.3.

As noted in Figure 1-1 and discussed further later in this chapter, the mapping and much of the content of this EIS addresses the Project Area for, and components and activities associated with, both the Statoil Flemish Pass Exploration Drilling Program (2018-2027) (CEAR 80129), as well as ExxonMobil Canada Limited's Eastern Newfoundland Offshore Exploration Drilling Project (2018-2029) (CEAR 80132), which are undergoing separate but concurrent EA review under CEAA 2012. This coordinated and collaborative approach to EIS development and submission for both of these projects is described in further detail in Section 1.4, including its rationale and the manner in which information and analysis that is common or specific to each project is reflected in the overall structure and content of the EIS.

With regard to Project Area related terminology, the EIS uses the term "Project Area – Northern Section" to refer to that component of the overall Project Area shown in Figure 1-1 that covers Statoil's planned Project-related activities and a portion of ExxonMobil's, while the "Project Area – Southern Section" covers ExxonMobil activities only. Together, the "Project Area – Northern Section" and "Project Area – Southern Section" comprise the overall Project Area for ExxonMobil's planned Project. The assessment also considers related supply and support vessel and aircraft traffic to and from this offshore Project Area.

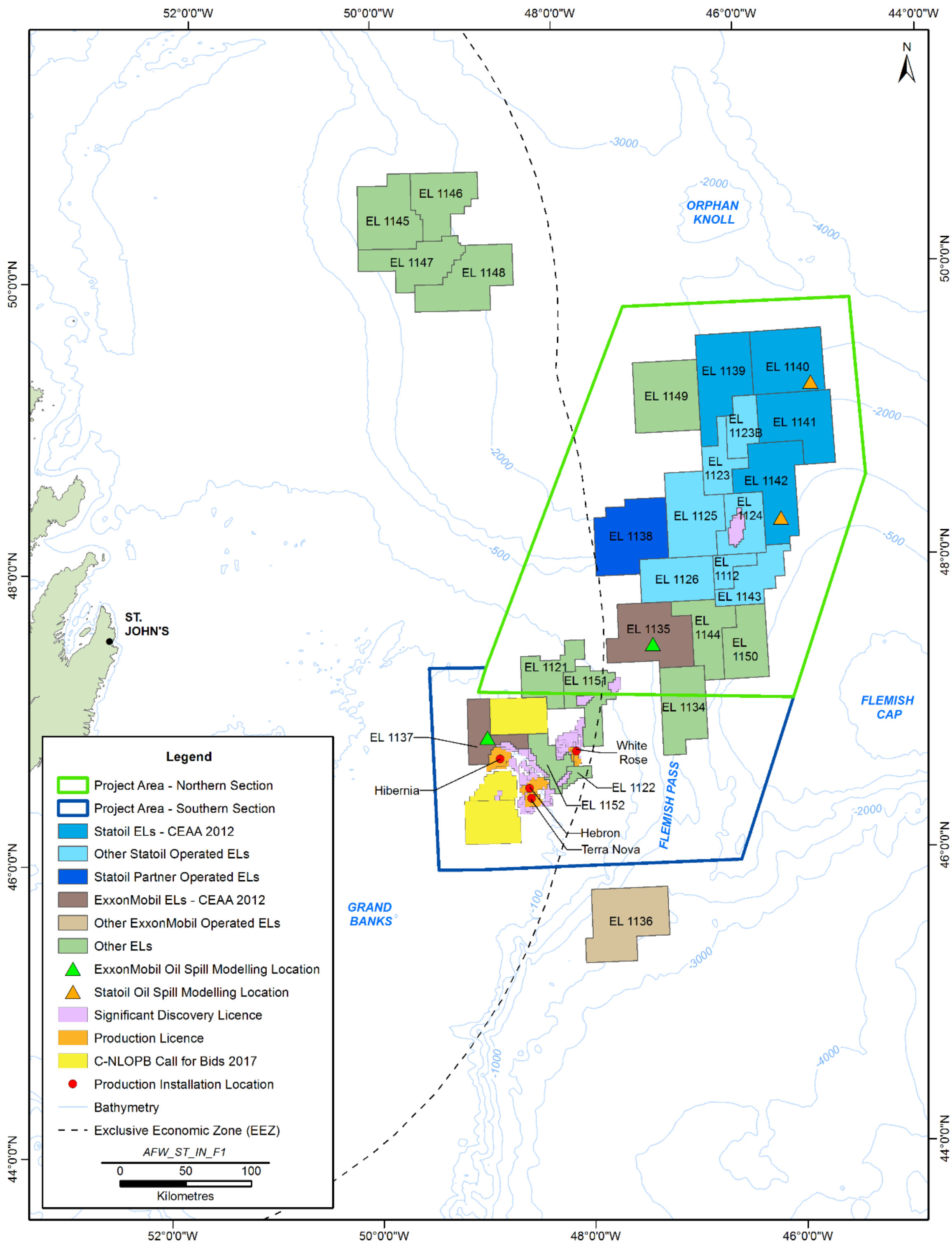


Figure 1-1 Project Area and Associated Licenses

1.2.2 Key Project Components and Activities

The Project includes the drilling, testing, and eventual decommissioning of exploratory wells within the various ELs identified above, using one or more drilling installations, which may include semi-submersibles and/or drill ships. Over the course of the anticipated duration of the Project, it is estimated that up to 30 wells could be drilled, with specific wellsite locations being selected as planning and design activities progress. The Project also includes various supporting activities or techniques that are often associated with offshore exploration drilling, including: delineation/appraisal drilling in the case of a hydrocarbon discovery, geophysical / geohazard / wellsite surveys, vertical seismic profiling (VSP) surveys, batch drilling, formation flow test, geotechnical surveys, environmental surveys, ROV / video surveys, and eventual wellhead decommissioning / removal, as well as associated supply and service activities.

Offshore marine facilities and support craft to support the various exploration activities described above will be required throughout the duration of the Project, and will include drilling installations, supply / stand-by and support vessels, helicopters, well intervention vessels, vessels for the conduct of geotechnical, geological, environmental, and geophysical surveys, and those involved in ice management operations. Project-related supply and support activities will take place at existing, established onshore facilities operated by a third-party service provider, which have been previously approved under applicable regulatory processes and currently provide services to multiple offshore and other industrial operators. No Project-specific construction or expansion of such facilities or other on-shore infrastructure is required or planned. Support vessel and aircraft services and their transits to and from the Project Area from these supply bases and airport facilities will likewise be contracted from third party suppliers and will take a direct route to active drill sites in the Project Area. This will include using a number of existing and well established routes off eastern Newfoundland that have been used for decades.

The planned temporal scope of the Project covers a period of 10 years (from 2018 to 2027), which has been selected to generally align with the terms of the various existing and potential licences described above, as well as to provide an adequate and conservative timeframe within which planned Project activities (including well drilling, testing, abandonment, and associated activities) may occur. Within this 10-year period, the planned exploration activities that comprise this Project may occur at any time throughout the year.

A more detailed description of the Project, including its overall need, purpose and justification, location, key components and activities, schedule, potential environmental emissions and their management, Project alternatives, on-going and future planning and design processes, and overall environmental planning and management systems, is provided in Chapter 2.

1.3 Regulatory Framework and the Role of Government

The Project will require a number of approvals and authorizations under applicable regulatory processes, as summarized in the following sections.

1.3.1 The Accord Acts

The C-NLOPB is a joint federal-provincial agency, responsible, on behalf of the Governments of Canada and Newfoundland and Labrador, for petroleum resource management in the Canada – NL Offshore Area. The *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act* and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* (the Accord Acts), administered by the C-NLOPB, provide for joint management of the Canada – NL Offshore Area and govern all oil and gas activities in the region. The Board's responsibilities under the Accord Acts include:

- The issuance and administration of petroleum and exploration and development rights
- Administration of statutory requirements regulating offshore exploration, development, and production
- Approval of Canada-NL benefits and development plans

The Canada-NL Offshore Area, as defined in the Accord Acts, includes those lands within Canada's 200 nautical mile Exclusive Economic Zone (EEZ) or to the edge of the continental margin, whichever is greater. The Project Area includes marine lands that fall within the C-NLOPB jurisdiction (see Figure 1-1).

1.3.1.1 Land Tenure and Licencing

The C-NLOPB administers a scheduled land tenure system in relation to rights issuance in the Canada-NL Offshore Area. The rights issuance process commences with an initial nomination of "sectors", after which there is a period of time appropriate to the cycle for exploration efforts to be undertaken. This is followed by the issuance of an eventual call for nomination of parcels of lands within an identified sector. A Call for Bids is then issued for specific parcels, from which successful bidders are issued an EL. ELs are issued for a period of nine years covering two periods. A well must be drilled or diligently pursed by the end of Period I in order to obtain tenure to Period II. If drilling results in a discovery, the operator of the licence may apply for an SDL and further delineate the discovery in anticipation of finding commercial resources which may lead to the issuance of a Production Licence.

Of relevance to the offshore exploration activities that are the subject of this Project EIS, once issued by the C-NLOPB an EL confers:

1) The right to explore for, and the exclusive right to drill and test for, petroleum
2) The exclusive right to develop those portions of the offshore area in order to produce petroleum
3) The exclusive right, subject to compliance with the other provisions of the Accord Acts, to obtain a PL

1.3.1.2 Other Licences, Authorizations, and Approvals

All petroleum-related work or activity in the Canada-NL Offshore Area requires an Operating Licence and an Operations Authorization (OA) issued by the C-NLOPB. The issuance of an EL does not, in and of itself, authorize the licence holder to carry out exploration activities within the licence area. The drilling of an exploration well, for example, requires an OA through which the Operator must present detailed information on its planned drilling activity and demonstrate that they can undertake such work in a safe and environmental responsible manner, in keeping with applicable requirements.

Exploration drilling programs require an OA issued by the C-NLOPB. In accordance with the Accord Acts and Section 6 of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*, prior to the issuance of an OA the following information must be submitted by the Operator for approval by C-NLOPB:

- EA Report
- Canada-Newfoundland and Labrador Benefits Plan
- Safety Plan
- Environmental Protection Plan
- Emergency Response and Spill Contingency Plans
- Regulatory Financial Responsibility Requirements
- Certificate of Fitness for the proposed equipment / facilities to be used to carry out drilling activities

For each well in an approved drilling program, an Approval to Drill a Well (ADW) is required. The ADW provides specific details about the drilling program and well design. An ADW covers the operations on a well up to, and including, the termination of the well, which may be suspension or abandonment of the well. A wellsite-geohazard seabed survey (also known as a wellsite survey) must be completed prior to the issuance of such an ADW. Other approvals, notifications or records required for exploration drilling include: formation flow testing, abandonment, or suspension of a well.

There are also a number of associated Regulations under the Accord Acts which govern specific exploration or development activities, as well as various guidelines (some of which have been jointly developed with the National Energy Board and/or the Canada Nova Scotia Offshore Petroleum Board) that are intended to address specific environmental, health, safety and economic issues related to offshore petroleum exploration and production activities. Section 1.5 provides a detail listing of all the relevant regulations and guidelines applicable to exploration drilling and its associated activities.

An important aspect of the C-NLOPB's mandate is the administration of the provisions of the Accord Acts pertaining to industrial and employment benefits resulting from the exploration for, and development of, oil and gas resources in the Canada-NL Offshore Area. This includes the creation and optimization of such benefits for Canada, in general, and specifically for the Province of Newfoundland and Labrador. The Accord Acts require that before work or activity is authorized in Canada-NL Offshore Area, a Canada-Newfoundland and Labrador Benefits Plan must be submitted to, and approved by, the C-NLOPB. This Plan must identify and describe the measures to be taken regarding the employment of Newfoundlanders and Labradorians and other Canadians, as well as providing manufacturers, consultants, contractors and service companies in the province and other parts of Canada with full and fair opportunity to participate on a competitive basis in the supply of goods and services to such a project. The Operator is committed to creating and optimizing opportunities and benefits for Newfoundland and Labrador and Canadian workers and companies as part of its activities and operations in the Canada-NL Offshore Area, and to carrying out its business in full compliance with relevant Canada-Newfoundland and Labrador Benefits Plan Guidelines and other applicable requirements.

1.3.2 Environmental Assessment under CEAA 2012

Proposed oil and gas exploration drilling activities in the Canada-NL Offshore Area may be subject to EA review pursuant to the requirements of CEAA 2012 and its associated Regulations.

The federal EA process under CEAA 2012 focuses on potential adverse environmental effects that are within areas of federal jurisdiction, including: fish and fish habitat, migratory birds, federal lands, and other changes to the environment that are directly linked to or necessarily incidental to federal decisions about a project. CEAA 2012 also has an associated set of *Regulations Designating Physical Activities*, which identify the physical activities that constitute the "designated projects" that may require a federal EA. These Regulations specify a number of types and scales of oil and gas activities that are subject to federal EA review, including (Section 10):

> *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 and Labrador Atlantic Accord Implementation Act or the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act.*

The drilling of an exploration well on ELs 1139, 1140, 1141, and 1142 has been determined to constitute a “designated project”. The EA of the Project was initiated in early August 2016 with Statoil’s submission of a Project Description and associated Summary Documents to the Agency, which were subsequently made available for governmental and public review. Following that review period, on October 3, 2016, the Agency decided that a federal EA was required for the Project and issued the associated Notices of EA Determination and EA Commencement. The EIS Guidelines were issued on December 23, 2016 (Appendix A).

The Project will include environmental components, and requirements that fall within areas of federal jurisdiction. For example, Project activities are planned to take place within the offshore marine environment, which are considered “federal lands” under CEAA 2012. CEAA 2012 specifically defines “federal lands” as including “(i) the internal waters of Canada, in an area of the sea not within a province, (ii) the territorial sea of Canada, in an area of the sea not within a province, (iii) the exclusive economic zone of Canada, and (iv) the continental shelf of Canada.”. The Project has the potential to affect environmental components under federal jurisdiction such as fish and fish habitat, marine / migratory birds, and marine mammals and sea turtles, and a number of relevant permits, authorizations and/or compliance may be required under the federal *Fisheries Act*, *Migratory Birds Convention Act* (MBCA), *Species at Risk Act* (SARA). and possibly others (see Section 1.5). No federal funding has been or will be requested or received from a federal authority to support this Project.

The Project Area is located entirely within the Study Area for the Eastern Newfoundland Strategic Environmental Assessment (SEA) completed by the C-NLOPB in August 2014 (Amec 2014), which has comprised a key source of information for this EIS. It is the Operator’s understanding that the

Project will not take place on lands that have been subject to a regional study as described in Sections 73 to 77 of CEAA 2012.

1.3.3 Other Potential Regulatory and Policy Requirements and Interests

Federal and provincial government departments and agencies, which may have regulatory responsibilities, information, and advice regarding the Project pursuant to their associated legislation and mandates include the following:

- Fisheries and Oceans Canada (DFO)
- Environment and Climate Change Canada
- Transport Canada
- Department of National Defence
- NL Department of Municipal Affairs and Environment
- NL Department of Fisheries and Land Resources
- NL Department of Natural Resources

Legislation, and regulations thereunder, that may be relevant to the Project and its EA and subsequently required regulatory approvals include the following:

- Accord Acts and its associated Regulations and Guidelines (as discussed above)
- *Fisheries Act*
- *Canadian Environmental Protection Act*
- *Oceans Act*
- *Navigation Protection Act*
- *Canada Shipping Act, 2001*
- MBCA
- SARA
- Newfoundland and Labrador *Endangered Species Act* (NL ESA)
- Seabird Ecological Reserve Regulations (NL)

A list of the some of the key legislation, regulations and associated approvals that may be required in relation to proposed offshore oil and gas exploration drilling programs and associated activities are provided in Section 1.5.

Any applicable and known government policies, resource management plans, planning or study initiatives that are related to the Project, and specifically its existing environmental setting and potential environmental effects and mitigation, are discussed where relevant in this EIS (Existing Environment, Chapters 5-7). In addition, cases where legislation, regulations, policies or applicable national, provincial, or regional objectives and guidelines are relevant to, and have been considered and used in, the evaluation of the environmental effects are discussed in the relevant environmental effects assessment sections (Chapters 8-15) of this EIS.

The Project is located in the marine offshore environment and will not involve the development and use of new on-land or nearshore infrastructure or Project-related expansions or modifications to existing infrastructure. The Newfoundland and Labrador Department of Municipal Affairs and

Environment has confirmed that the Project would not require registration under Section 47 of the *Environmental Protection Act, SNL 2002, cE-14.2* (J. Sweeney, pers. comm). It is not anticipated that municipal permits or authorizations will be required, nor that associated land use plans or land zoning will be applicable.

In planning and conducting its oil and gas exploration activities, the Operator will comply with these and all relevant provincial and federal legislation, regulations, and guidelines, as well as applicable international conventions and standards. As described in Sections 1.1 and 2.11, the Operator also has in place its own comprehensive environmental policies, plans and procedures for planning and conducting its oil and gas exploration and development activities, and requires its contractors to adhere to these, as applicable.

1.4 Purpose and Organization of the EIS

This EIS has been developed and is being submitted by Statoil, as the Operator of the Project, in accordance with the provisions and requirements of CEAA 2012 and the Accord Acts and in full compliance with the EIS Guidelines issued for the Project by the Agency in December 2016.

The preparation and submission of the EIS is an important step in the EA review process for this Project. It provides the required information on the Project and its potential environmental effects and associated mitigation, including the:

- Project purpose
- Project description (components, activities, schedule)
- Project alternatives
- Changes to the Project that may be caused by the environment
- Existing environmental setting (biophysical and socioeconomic)
- Government, stakeholder, and Indigenous engagement activities, including the various comments provided
- Environmental effects of the Project (planned activities and potential malfunctions or accidents)
- Mitigation measures to avoid or reduce environmental effects
- Residual effects and their significance
- Cumulative environmental effects
- Any proposed environmental monitoring and follow-up activities

The EIS will form the basis for further review, consideration and discussion of the Project and those items identified by regulatory agencies, Indigenous groups, stakeholders and interested public as part of the EA process. Based on the results of the EA and the associated reviews and input, the Government of Canada will eventually decide whether the Project can proceed, including associated terms and conditions.

The EIS has been prepared and structured to provide the results of the EA and other required information in a clear, concise, and well-organized manner, in keeping with current EA practice and with a view to ensuring overall readability and utility for all stakeholders.

1.4.1 EIS Coordination – Statoil and ExxonMobil

Statoil and ExxonMobil are co-venturers in a number of the exploration licences (ELs 1135, 1139, 1140, 1141 and 1142) that comprise the Project. Additionally, both Operators have worked together on a wide range of petroleum activities offshore Newfoundland and Labrador including ongoing production in the Hibernia Field, development of the Hebron Field, acquisition of geophysical data, drilling of exploration wells and acquisition of ELs. Considering the similarities in the Projects scope, activities, Project Area, and time frame, Statoil and ExxonMobil have collaborated in the planning and completion of the required EIS for their planned exploration drilling programs. This planned approach was referenced in the original Project Description submissions for each project, and was communicated to the Agency in December of 2016. The EIS collaboration will therefore lead to improved efficiency in the EA process by reducing duplication and regulatory, Indigenous and stakeholder burden. The joint EIS will facilitate a more comprehensive and integrated environmental analysis, including cumulative effects analysis, and the identification and application of mitigation. Further details on the manner in which this coordinated approach is reflected in the structure and content of the EIS (including common and Project-specific content) is provided in Section 1.4.2.

In recognition that other operators (Husky Energy, Nexen) are also preparing EISs for exploration drilling programs in the same or overlapping areas of the Canada-NL Offshore Area, Statoil and ExxonMobil are working with these operators to identify further efficiencies to reduce Indigenous and stakeholder burden.

1.4.2 EIS Organization and Content

The EIS document is structured as outlined in Table 1.1 and indicates where there are differences between the Statoil and ExxonMobil EIS reports.

Table 1.1 EIS Organization and Content

EIS Chapter	Overview
Chapter 1: Introduction (some differences between Operator EIS)	• Identifies the Operator, provides a general overview of the Project, outlines the regulatory context for the Project and its EA, and describes the purpose of the EIS and the overall organization of the document • Differences between Operator EIS: Sections 1.0, 1.1, and 1.2 include information that is specific to each Project and its EIS • With the exception of Section 1.3.2, Sections 1.3, 1.4 and 1.5 are identical and equally applicable to both Projects and EISs • Differences between Operator EIS: The Executive Summary and the Table of Concordance includes information that is specific to each Project and its EIS

Table 1.1 EIS Organization and Content

EIS Chapter	Overview
Chapter 2: Project Description (some differences between Operator EIS)	• Sets the overall context for the Project by discussing its need, purpose and rationale and alternatives • It provides an overview and detailed description of the Project, including its location, key components and activities, schedule, potential environmental emissions and their management, Project alternatives, on-going and future planning and design processes, and the Operator's overall environmental planning and management systems • Differences between Operator EIS: Sections 2.0, 2.1, 2.2, 2.3, 2.7, 2.9.3.2, 2.11 and 2.12 include information that is specific to Statoil and ExxonMobil and its Project • Sections 2.4 to 2.10 are identical and equally applicable to both Projects and EISs
Chapter 3: Regulatory, Indigenous and Stakeholder Engagement (same between Operator EIS)	• Describes previous and on-going governmental, Indigenous and stakeholder engagement initiatives related to the Project and its EA, as well as identifying the comments raised regarding the Project and its potential effects and where and how these are addressed in the EIS • As all EA-related engagement activities for both projects have been planned and undertaken collaboratively by Statoil and ExxonMobil, the information in this chapter is common to and equally applicable to both Projects and EISs
Chapter 4: Environment Assessment Scope, Approach, and Methodology (same between Operator EIS)	• Outlines the scope of the Project and its EA, including the factors considered, the scope of these factors, and the overall approach and methods used to conduct the assessment • As both Projects and their EAs have comparable scopes and their EISs have been designed and completed using the same overall approach and methodology, the information in this chapter is common to and equally applicable to both Projects and EISs
Chapter 5: Existing Physical Environment Chapter 6: Existing Biological Environment Chapter 7: Existing Human Environment (same between Operator EIS)	• Provide a description of the existing environmental setting for the Project, including the biophysical and socioeconomic environments that overlap and may interact with the Project • While each of the two exploration drilling projects (as proposed by Statoil and ExxonMobil) have somewhat different Project Areas involved, for completeness and efficiency these chapters present an overall and common description of the existing environmental settings that covers both of the Project Areas • A single set of Figures, for example, covering both the Project Area - Northern Section and Project Area - Southern Section is included, and the text and tables provide (where applicable) overall information that pertains to both Project Area sections, when the relevant information and analysis are inherently regional in nature • The existing environment descriptions do, however, also give specific information that describes or summarizes the existing environmental conditions within each Project Area Section as separate subsections and/or tables within these chapters, as relevant

Table 1.1 EIS Organization and Content

EIS Chapter	Overview
	• The information presented in these chapters is common to both Projects and EISs
(Chapters 8-13 same between Operator EIS) Chapter 8: Marine Fish and Fish Habitat: Environmental Effects Assessment	• Provide the detailed environmental effects assessments for the selected Valued Components (VCs) upon which the EIS is focused, each of which is addressed in a separate Chapter using the EA approach and methods described earlier • Given the commonality between the planned exploration activities being proposed by Statoil and ExxonMobil as part of their respective projects, as well as their existing environments, potential environmental effects and associated mitigations, the environmental effects assessments (VC chapters) have been written to address both the Project Area - Northern Section and Project Area - Southern Section • Effects assessment conclusions are provided both on an overall Project and an EL specific basis • Any potential Project-specific environmental effects and associated mitigation or follow-up requirements are highlighted specifically in these chapters as appropriate • The information presented in these chapters is common to and equally applicable to both Projects and EISs
Chapter 9: Marine and Migratory Birds: Environmental Effects Assessment	
Chapter 10: Marine Mammals and Sea Turtles: Environmental Effects Assessment	
Chapter 11: Special Areas: Environmental Effects Assessment	
Chapter 12: Indigenous Communities and Activities: Environmental Effects Assessment	
Chapter 13: Commercial Fisheries and Other Ocean Users: Environmental Effects Assessment	
Chapter 14: Cumulative Environmental Effects (same between Operator EIS)	• Assesses and evaluates the potential environmental effects resulting from those of the Project in combination with other relevant physical activities that have been or will be carried out • The information presented in this chapter is common to and equally applicable both Projects and EISs
Chapter 15: Accidental Events (some differences between Operator EIS)	• Describes and assesses possible accidental events and malfunctions that could occur as a result of the Project, including the results of associated modelling conducted for the Project and its EA. • It also describes relevant accident prevention and emergency response plans and procedures, and assesses and evaluates the potential effects of these possible accidental events for each VC • Chapter 15 includes information that is specific to Statoil and ExxonMobil and each Project
Chapter 16: Effects of the Environment on the Project (same between Operator EIS)	• Describes how environmental conditions and factors have or may influence the design and execution of the Project, and the various planning, design and operational measures that will be taken to help protect human health and safety and the environment in that regard • The information presented in this chapter is common to and equally applicable both Projects and EISs

Table 1.1 EIS Organization and Content

EIS Chapter	Overview
Chapter 17: EIS Summary and Conclusions (some differences between Operator EIS)	• Provide a summary of the key results and conclusions of the EIS • Several sections of Chapter 17 (17.1 and 17.4) are identical and equally applicable to both Projects, and several sections (17.2, 17.3, and 17.5) are similar for both Projects

These EIS chapters and components have been planned and prepared as part of a fully integrated EIS document, with cross referencing throughout. Each Chapter also contains its own list of references, including literature cited and personal communications.

This EIS has been directed and submitted by Statoil, as the Operator, and was prepared by an EIS Study Team comprised of personnel from Stantec Consulting Ltd (Stantec) and Amec Foster Wheeler Environment and Infrastructure (Amec Foster Wheeler).

An overview of the key personnel that have been involved in the planning and writing of this EIS (Statoil, Stantec, Amec Foster Wheeler, and subconsultants) is provided in Appendix B.

1.5 Key Legislation, Regulations, and Associated Approvals

Table 1.2 provides a list of key legislation, authorizations and associated approvals that may be required in relation to proposed offshore oil and gas exploration drilling programs and associated activities.

1.6 References

CEA (Canadian Environmental Assessment) Agency. 2016. Guidelines for the Preparation of an Environmental Impact Statement pursuant to the *Canadian Environmental Assessment Act, 2012*: Statoil Canada Ltd. Flemish Pass Exploration Drilling Program. 46 pp.

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
Specific to Oil and Gas Activities in the Canada-NL Offshore Area			
Accord Acts	C-NLOPB	The C-NLOPB is responsible, on behalf of the Governments of Canada and Newfoundland and Labrador, for petroleum resource management in the Canada-NL Offshore Area. The Accord Acts, administered by the C-NLOPB, govern all petroleum operations in that offshore area. The mandate of the C-NLOPB is to interpret and apply the provisions of the Accord Acts to all activities of operators in the Canada-Newfoundland and Labrador Offshore Area and, to oversee operator compliance with those statutory provisions. The Board's role is to facilitate the exploration for and development of petroleum resources in the Canada-Newfoundland and Labrador Offshore Area in a manner that is consistent with the C-NLOPB's mandate including: • health and safety of workers • environmental protection; • effective management of land tenure; • maximum hydrocarbon recovery and value; and, • Canada/Newfoundland and Labrador benefits.	The various regulations and guidelines described below have been developed and issued under the Accord acts (and in some cases, also with other relevant legislation) The regulatory approvals and authorizations identified below may also be required pursuant to Section 138(1)(b) of the *Canada-Newfoundland Atlantic Accord Implementation Act* and Section 134(1)(b) of the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act* and the various regulations made under the Accord Acts.
Accord Act Regulations	C-NLOPB	A number of Regulations made under the Accord Acts may be relevant to offshore oil and gas exploration drilling and associated activities, including the following: • Certificate of Fitness • Drilling and Production Regulations • Marine Installations and Structures Transitional Regulations • Occupational Health and Safety Transitional Regulations • Offshore Petroleum Administrative Monetary Penalties Regulations • Offshore Petroleum Cost Recovery Regulations • Offshore Petroleum Financial Requirements Regulations	The regulatory approvals and authorizations identified below may also be required pursuant to the relevant sections of the Accord Acts and/or one or more Regulations made under the Accord Acts. An Operating Licence, for example, is a prerequisite for oil and gas activity in the Canada-NL Offshore Area that involves fieldwork. The statutory requirements pertaining to Operating Licences are specified in Sections 137 and 138 of the Atlantic Accord Act and in

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
		• Oil and Gas Operations • Oil and Gas Spills and Debris Liability • Petroleum Geophysical Operations • Petroleum Installations • Requirements Respecting the Security of Offshore Facilities	the *Newfoundland Offshore Area Oil and Gas Operations Regulations.* There are also three types of authorizations administered by the C-NLOPB: 1) Operations Authorization (OA) 2) Geophysical Program Authorization 3) Diving Program Authorization An OA may include authorization for a drilling program, production project, well operations or other activities or components that are not covered by other types of authorizations. Also, Operators applying to undertake a geophysical program, a wellsite seabed survey, VSP, an electromagnetic program, any other type of geological or geophysical program (including those that do not involve fieldwork), a geotechnical program or an environmental program, may apply for a Geophysical Program Authorization. C-NLOPB approvals may also involve the approval of certain documents, plans or other matters as specified by the legislation or regulations, or the approval of specific activities conducted under an earlier authorization. These include an: • Approval to Drill a Well (ADW) • Approval to Alter the Condition of a Well • Approval of a Formation Flow Testing Program • Approval of a Canada-Newfoundland and Labrador Benefits Plan

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
			Of relevance to this Project, an ADW is required for operations involving drilling within or under the marine environment. An ADW covers the operations on a well up to, and including, the termination of the well, which itself could include suspension, abandonment, or completion. A wellsite seabed survey must be completed prior to the issuance of such an ADW. If the well is to be tested, Approval of a Formation Flow Testing Program is also required in accordance with the *Newfoundland Offshore Petroleum Drilling and Production Regulations*.
Offshore Waste Treatment Guidelines (OWTG)	C-NLOPB	These guidelines outline recommended practices for the management of waste materials from oil and gas drilling and production facilities operating in the Canada-NL Offshore Area. 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	Adherence to OWTG

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
		• water for testing of fire control systems • discharges associated with subsea systems • naturally occurring radioactive material	
Drilling and Production Guidelines (updated August 2017)	C-NLOPB	These guidelines were developed and implemented by the C-NLOPB and Canada-Nova Scotia Offshore Petroleum Board to provide criteria for compliance requirements for operators planning to conduct offshore drilling activities on the east coast of Canada. Offshore oil and gas activities that involve drilling (including exploration and production) must be in compliance with the Drilling and Production Guidelines, in order to attain an approval to drill a well and an Operations Authorization. These guidelines are based on past experiences in offshore oil and gas, legislation from the C-NLOPB, and from industry best practice. These guidelines provide direction and compliance standards for all aspects of offshore exploration drilling, including, but not limited to: • well approval applications • well installations, facilities, support craft • drilling fluid systems • riser specifications • drilling practices • formation flow testing equipment • well control • well casing and cementing design and processes • well abandonment • flaring • surveys • reporting and data requirements The guidelines also cover aspects of production activities, should production be planned in the case of a discovery.	Adherence to Drilling and Production Guidelines

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
Offshore Chemical Selection Guidelines for Drilling and Production Activities on Frontier Lands (OCSG)	C-NLOPB	These guidelines provide a framework for chemical selection that reduces 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 work or activity related to offshore oil and gas exploration and production.	Adherence to OCSG
Compensation Guidelines Respecting Damage Relating to Offshore Petroleum Activity	C-NLOPB	These guidelines describe compensation sources available to potential claimants for loss or damage related to petroleum activity offshore Newfoundland and Labrador, and outline the regulatory and administrative roles which the Board exercises respecting compensation payments for actual loss or damage directly attributable to offshore operators.	Adherence to Guidelines
Environmental Protection Plan Guidelines	C-NLOPB	These guidelines assist operators in developing Environmental Protection Plans (EPP) to meet the requirements of Sections 6 and 9 of the *Drilling and Production Regulations*	Adherence to Guidelines
Canada-Newfoundland and Labrador Exploration Benefits Plan Guidance	C-NLOPB	This document provides an operator engaged in petroleum exploration activities, including geophysical, geotechnical, and drilling, in the Canada-NL Offshore Area with guidance for the preparation of a Canada-Newfoundland and Labrador Benefits Plan (Benefits Plan) which is required under Section 45 of the Accord Acts. The guidance also addresses related contracting, expenditure, and employment reporting requirements.	Adherence to Guidance

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
Geophysical, Geological, Environmental and Geotechnical Program Guidelines (Updated April 2017)	C-NLOPB	These Guidelines have been prepared to assist Applicants who wish to conduct geophysical, geological, geotechnical, or environmental programs within the offshore area. They replace those issued by the C-NLOPB in January 2012	Adherence to Guidelines and associated Geophysical Program Authorization
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)/ C-NLOPB	The SOCP specifies the minimum mitigation requirements that must be met during the planning and conduct of marine geophysical surveys, in order to reduce effects on life in the oceans. These mitigation measures can be applied to VSP operations. These 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.	Adherence to SOCP
Guidelines Respecting Financial Requirements (amended August 2017)	C-NLOPB	Operators wishing to conduct work or activity in the Canada-NL Offshore Area are required to provide proof of financial responsibility in a form and amount satisfactory to the Board. These regulations and guidelines provide guidance to operators in providing proof of financial requirements regarding authorization being sought for work or activity relating to drilling, development, decommissioning or other operations in the offshore areas.	Adherence to Guidelines
Other Guidelines	C-NLOPB	Other Guidelines administrated by the C-NLOPB that do or may apply to aspects of offshore exploration programs such as those being proposed as part of this Project include:	Adherence to Guidelines as applicable

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
		• Measures to Project and Monitor Seabirds in Petroleum-Related Activity in the Canada – Newfoundland and Labrador Offshore Area • Atlantic Canada Standby Vessel Guidelines • Cost Recovery Guidelines • Data Acquisition and Reporting Guidelines • Incident Reporting and Investigation Guidelines • Measurement Under Drilling and Production Regulations • Monitoring and Reporting • Physical Environmental Programs • Research and Development Expenditures • Safety Plan Guidelines • Transboundary Crewing	
Other Relevant Legislation			
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" is included in the list of designated activities under CEAA 2012. The Agency has determined that exploratory drilling for the Project requires an EA under CEAA 2012.	The Project is contingent upon EA approval (i.e., an EA Decision Statement that allows the Project to proceed).
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 (S.C. 2015, c. 4)	NRCan	Introduced in Parliament as Bill C-22, *Energy Safety and Security Act* received Royal Assent on February 26, 2015 and came into effect on February 26, 2016. *Energy Safety and Security Act* aims to strengthen the safety and security of offshore oil production through improved oil	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 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
		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 to enable them to conduct EAs under CEAA 2012.	
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 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 (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 other substance harmful to migratory birds in waters or area frequented by migratory birds.	The salvage of stranded birds during offshore Project operations will require a handling permit under section 4(1) of the *Migratory Birds Regulations* pursuant to the MBCA.
Canada Shipping Act (CSA)	Transport Canada (TC)	The *Canada Shipping Act, 2001* and related regulations set out the requirements for safety and environmental protection for Canadian vessels and their operator	Project components and activities will be required to comply with the relevant requirements of the Act and its Regulations.
Navigation Protection Act (NPA)	TC	The NPA came into force in April 2014 and replaced the former *Navigable Waters Protection Act*. The NPA is intended to protect specific inland and nearshore navigable waters (as identified on the list of "Scheduled Waters" under	No applicable permitting requirements have been identified for the Project, as the Project Area is located offshore, outside of the Scheduled Waters specified in the NPA.

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
		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.	
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 have been identified for the Project.
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, operators 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 reduce 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, 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.
NL Endangered Species Act	NL Department of Fisheries and Land Resources	The provincial *Endangered Species Act* provides special protection for plant and animal species considered to be endangered, threatened, or vulnerable in the province. The Act applies to species, sub-species and populations that are native to the province but does not include marine fish, bacteria, and viruses. It also does not apply to introduced species, except in extraordinary circumstances. Designation under the Act follows recommendations from the Committee	No applicable permitting requirements have been identified for the Project.

Table 1.2 Summary of Key Relevant Legislation, Regulations, and Guidelines

Legislation / Regulation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
		on the Status of Endangered Wildlife in Canada (COSEWIC) and/or the Species Status Advisory Committee (SSAC) on the appropriate assessment of a species. Currently there are 35 species, subspecies, and populations listed under the Act. Thirteen of these species are listed as endangered, nine are listed as threatened and thirteen are listed as vulnerable.	
Seabird Ecological Reserve Regulations, NLR 66/97	NL Department of Fisheries and Land Resources	Prohibit or limit industrial development and certain activities that can cause disturbance to breeding seabirds, including hiking, boat traffic and low-flying aircraft near the colonies during the breeding season, and the use of ATVs at all times.	No applicable permitting requirements have been identified for the Project.

2.0 PROJECT DESCRIPTION

This Chapter provides an overview description of the proposed Project. It initially sets the overall context for the Project by discussing its need, purpose and rationale, benefits, and alternatives. It then goes on to provide an overview and detailed description of the Project, including its location, key components and activities, schedule, potential environmental emissions and their management, on-going and future planning and design processes, and the Operator's overall environmental planning and management systems.

2.1 Project Scope

The Project includes the drilling, testing and decommissioning/abandonment of exploratory wells (includes delineation and appraisal wells) using one or more drilling installations, as well as associated exploration and supporting activities. The environmental effects analysis considers the drilling of up to 30 wells. The Project will occur in the Flemish Pass area within the Canada-NL Offshore Area, as shown in Figure 2-1. The designated project ELs under review for Statoil are denoted as "Statoil EL-CEAA 2012" in Figure 2-1.

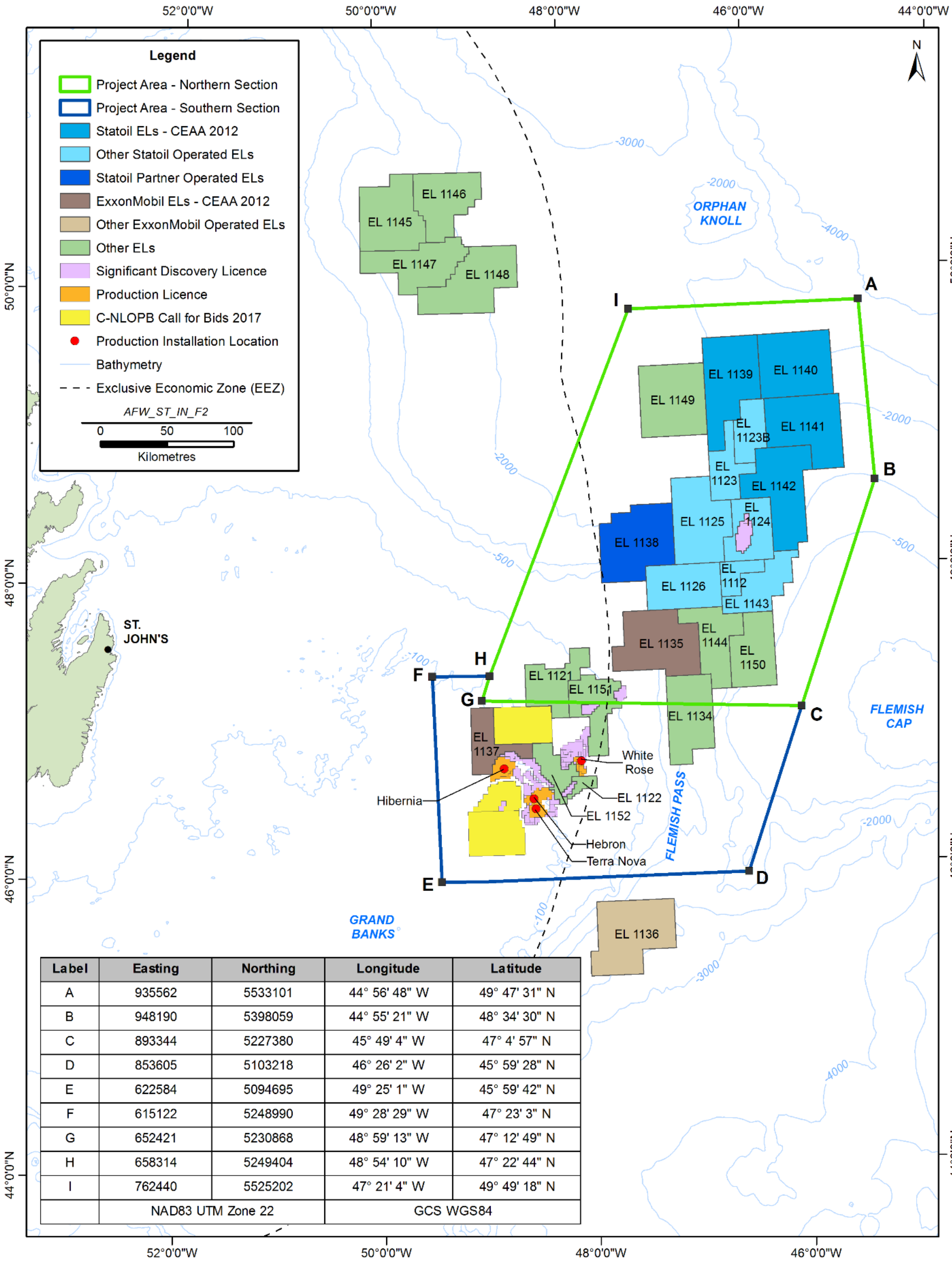
The Project also includes various supporting activities typically associated with offshore drilling, including: formation flow testing, vertical seismic profile (VSP) surveys, geophysical (e.g., wellsite) survey, ice management operations, environmental and geotechnical sampling, and autonomous underwater vehicle (AUV) / remotely-operated vehicle (ROV) / video surveys.

Vessels to support the list of activities described above will be required throughout the life of Project as needed, and may include, but not limited to: drilling installation(s), supply / stand-by and support vessels (offshore supply vessels), helicopters, geophysical survey vessels, well intervention vessels, vessels for the conduct of geotechnical and environmental surveys, and ice management operations.

2.2 Purpose of the Project

In January 2015, Statoil was awarded EL 1139, 1140, 1141 and 1142 in the Flemish Pass area of the Canada-NL Offshore Area.

The purpose of the Project is to determine the potential for oil and gas resources through an exploratory drilling program on Operator-held land holdings within the Project Area (see Figure 2-1). Exploration/delineation/appraisal drilling is required to determine the presence, nature and volume of potential oil and gas resources within the ELs. The Project also enables the licence interest holders to meet the work expenditure commitments that must be fulfilled over the term of the licence.



Label	Easting	Northing	Longitude	Latitude
A	935562	5533101	44° 56' 48" W	49° 47' 31" N
B	948190	5398059	44° 55' 21" W	48° 34' 30" N
C	893344	5227380	45° 49' 4" W	47° 4' 57" N
D	853605	5103218	46° 26' 2" W	45° 59' 28" N
E	622584	5094695	49° 25' 1" W	45° 59' 42" N
F	615122	5248990	49° 28' 29" W	47° 23' 3" N
G	652421	5230868	48° 59' 13" W	47° 12' 49" N
H	658314	5249404	48° 54' 10" W	47° 22' 44" N
I	762440	5525202	47° 21' 4" W	49° 49' 18" N
	NAD83 UTM Zone 22		GCS WGS84	

Figure 2-1 Project Area and Corner Point Coordinates

Exploration drilling is essential to enable continued oil and gas discoveries to maintain production, and meet global energy demands. Statoil-held land holdings within the Project Area have the potential to contain important and commercially significant hydrocarbon resources. The Project is expected to result in economic, social, and technological benefits at the regional level. This includes contributing to energy diversity and supply. Oil continues to play an important part in meeting energy demands and exploration is necessary to enable oil and gas companies to maintain production. In addition, revenues and economic benefits generated from oil production form a significant part of the Newfoundland and Labrador economy and provincial government revenues.

2.2.1 Environmental, Economic, and Social Benefits

The following sections describe some of the anticipated environmental, economic and social benefits of the Project.

2.2.1.1 Energy Diversification and Sustainable Development

Population growth and increases in per capita income are the key drivers behind the growth in energy demand. The global population is predicted to reach 9.6 billion by 2050 (UN DESA 2015) and energy demand is forecasted to increase by 48 percent between 2012 and 2040 (USEIA 2016). The global energy mix continues to shift as the balance of energy demand and supply varies, economies expand and contract and energy prices fluctuate. There is therefore a continuing need for reliable and sustainable energy supplies.

One of the goals of Newfoundland and Labrador's Energy Plan, Focusing Our Energy (the Plan) (Newfoundland and Labrador Department of Natural Resources 2007), is to ensure that there is a secure, reliable and competitively-priced supply of energy for the current and future needs of the people of Newfoundland and Labrador. The Plan also emphasizes the importance of sustainable economic development. In order to maximize the long-term value of oil and gas, the Government of Newfoundland and Labrador aims to effectively invest the value received from these resources to provide current and future generations benefit from their development, while providing a fair return to oil and gas companies that participate in resource development. Exploration is a critical activity to enable continued oil and gas discoveries, and subsequently to maintain production that meets global demand for energy.

As an operator, Statoil recognizes that oil and gas will be an important part of the energy mix for decades to come and that global energy systems must be transformed to become more sustainable. Sustainability management is an integral part of Statoil's overall management system (Statoil 2015). The implementation of Statoil's sustainability strategy is guided by its Corporate Sustainability Unit and the strategy's progress is measured through performance indicators, which include:

- CO_2 emission reductions (tonnes CO_2)
- Serious oil and gas leakages (per year)
- Well control incidents
- Establish country sustainability plans in countries where our operations involve several business entities

Statoil also aims to be recognized as the most carbon-efficient oil and gas producer, committed to creating lasting value for communities (Statoil 2016a). Statoil actively works to reduce climate emissions, including CO_2, nitrogen oxide (NO_X), sulphur oxide and non-methane volatile organic compounds (VOCs). Efforts to reduce direct emissions from projects include:

- improving energy efficiency
- reducing methane emissions
- eliminating routine flaring
- scaling up carbon capture and storage

The Paris Agreement on climate change negotiated in December 2015 provides the prospect of improved policy support around the world for accelerating the shift to low-carbon solutions. Statoil has a key role to play in making this transition work and supports the associated development of viable policies and regulatory frameworks. In 2015, Statoil joined the Oil and Gas Climate Initiative, a voluntary, Chief Executive Officer-led group that aims to accelerate and guide the industry's shift towards a low-carbon world (Statoil 2016a).

2.2.1.2 Benefits to the Provincial Economy and Community Investment

Newfoundland and Labrador's Energy Plan discusses the importance of the energy industry to the economy of Newfoundland and Labrador. Energy accounts for more of the province's exports than any other sector and the oil and gas industry (and supporting activities) is the largest contributor to provincial Gross Domestic Product (GDP). It is estimated that the industry accounted for 25.7 percent of the province's nominal GDP in 2014 (Newfoundland and Labrador Department of Finance 2016). The offshore oil and gas industry has generated billions of dollars in economic activity for the people of Newfoundland and Labrador through royalties, crown share adjustment payments, offshore accord payments, forfeiture payments from offshore licenses and rental payment from offshore exploration licenses (C-NLOPB 2016).

Statoil has a total commitment of approximately $480 million in work expenditure bids for their awarded ELs. This represents the amount of money that Statoil has committed to spending exploring hydrocarbons in the offshore, and on research and development, education and training, within the first six years of the EL term. This expenditure can benefit the provincial economy and communities through capital expenditures, wages, and supplies and services contracts with local providers.

In addition to the Project-specific benefits for the provincial economy and communities, Statoil has made investments in youth talent development and the local Newfoundland and Labrador society for more than 10 years. The following are examples of Statoil's commitments to local communities in Newfoundland and Labrador:

- Since 2014, Statoil supports the province-wide ArtsSmarts grant program aimed at inspiring children to develop their creative abilities by increasing arts and cultural activities in classroom curriculums. In addition, each year a Statoil ArtsSmarts scholarship is awarded to a Newfoundland and Labrador high school student who is enrolled for first year full-time art studies in a degree or diploma program at a Canadian university or college.

- Statoil is a partner with the Marine Advanced Technology Education Centre's annual ROV competition, where high school students are challenged to design and develop ROVs to solve underwater challenges and build their skills in the areas of STEM (science, technology, engineering and math).
- To support folk arts culture in the province and youth talent development in music, Statoil is the presenting sponsor of the Newfoundland and Labrador Folk Festival and hosts an interactive workshop for youth in collaboration with the headlining children's entertainer as well as sponsors the Statoil MusicNL NewFound Talent Contest for musicians 19 and under.
- Techsploration provides grade nine girls the opportunity to explore occupations in science, trades, engineering and technology, while raising awareness about the importance of math and science-based work in their future lives. Every year, Statoil welcomes a group of young girls from a local high school into its St. John's office to learn from females working in STEM followed by a 2-day forum to strengthen their skills in communication, leadership, and teamwork.
- Statoil has invested in the Rock Rugby programs, which provide youth with competitive experiences in a team environment, as well as Buddy's Book Club summer reading program to increase youth literacy rates.
- Statoil has been recognized for its contributions to arts, culture, and community initiatives with the Patron of the Arts Award and also the Award of Excellence for Contribution to Community and Community Service.

2.2.1.3 Employment Benefits

Oil and gas industry employment in Newfoundland and Labrador in 2016 was approximately 7,000 person years, or 3.0 percent of total provincial employment (Newfoundland and Labrador Department of Finance 2017).

The Accord Acts require that before any work or activity is authorized in the Canada-NL Offshore Area, a Canada-Newfoundland and Labrador Benefits Plan must be submitted to, and approved by, the C-NLOPB. This Plan must identify and describe the measures to be taken regarding the employment of residents of Newfoundland and Labrador, and other Canadians, as well as providing manufacturers, consultants, contractors and service companies in the province and other parts of Canada with full and fair opportunity to participate on a competitive basis in the supply of goods and services to such a project. The Operator is committed to creating and optimizing opportunities and benefits for Newfoundland and Labrador and Canadian workers and companies as part of its activities and operations in the Canada-NL Offshore Area, and to carrying out its business in full compliance with relevant Canada-Newfoundland and Labrador Benefits Plan Guidelines and other applicable requirements.

Statoil holds interests in several exploration, development and production licenses offshore Newfoundland, and has an office in St. John's, staffed with approximately 40 staff. For any drilling campaign, up to 70 persons (total St. John's staff) could be employed, depending on the duration and operational needs of the drilling campaign. As described in Section 2.5.1, drilling installations generally can accommodate up to 180 persons. Crewing requirements are dependent on technical requirements of the drilling campaign and typically averages between 120-160 persons. These direct employment benefits will result in further indirect and spin-off employment benefits within Newfoundland and Labrador.

2.2.1.4 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 in Newfoundland and Labrador. Statoil is committed to supporting local Research and Development (R&D) and fostering education and training to facilitate the growth of the petroleum industry in Newfoundland and Labrador, as well as contribute to Statoil's current and future activities. More specifically, Statoil is making investments in Newfoundland and Labrador through:

- the establishment of the Statoil Chair and Associate Chair in Reservoir Engineering to foster the development of a new Petroleum Engineering program in the Faculty of Engineering and Applied Science at Memorial University
- an investment of up to $5 million in local R&D projects (Statoil 2016b)
- ongoing participation in collaborative R&D projects through our local joint industry project facilitator, Petroleum Research Newfoundland and Labrador (PRNL)

2.3 Project Location and Designated Project Area

The Project Area is defined as the overall geographic area within which all Project-related components and activities will take place, and based on those aspects that are considered to be within the defined scope of the Project for EA purposes (see Section 4.1). As illustrated in Figure 2-1, the Project Area includes "CEAA 2012-designated project" ELs currently operated by Statoil (EL 1139, 1140, 1141 and 1142) where exploration drilling activities may be conducted between 2018 and 2027. The Project Area also encompasses other existing Statoil operated licences and partner operated licences. The Project Area includes a surrounding area to account for planned and potential ancillary and support activities at and around the wellsites themselves.

It should be noted that while this overall Project Area covers an offshore area of approximately 100,800 km² and encompasses all defined Project-related activities, the planned drilling activities will take place within the boundaries of the ELs. In rare circumstances, the spatial extent of activities supporting the drilling operations may extend beyond the border to an EL. This can occur where a well location is near the border of an EL and a site survey is required. In such cases, the footprint of the survey may extend outside the EL. In shallower areas when the wellsite is on the border of the EL, the anchor patterns may extend outside the EL. For such instances of a well located near the boundary of an EL, the 20 km buffer established around the EL will cover any project footprint outside the ELs. Moreover, these and other Project-related activities will each occupy relatively small areas within this overall Project Area. The wellsite area encompasses the drilling installation and surrounding Safety Zone, which is based on a radius of 500 m from the outer extent of the facility. For a drill ship using Dynamic Positioning (DP) to stay on-location, this area is approximately 1 km². For a semi-submersible requiring anchors for positioning, this area can be up to approximately 12 km².

The Project Area - Northern and Southern Section corner point coordinates are listed in Tables 2.1 and 2.2, respectively and are illustrated in Figure 2-1. The EL corner point coordinates and water depth ranges are presented in Tables 2.3 to 2.8. The EIS will assess drilling activities within the ELs identified above. Specific drilling locations cannot be identified at this time as they will be based on the interpretation of seismic data, which is an ongoing activity, and the results for each drilled well within the Project Area.

Table 2.1 Project Area – Northern Section Coordinates

Project Area Vertices	Coordinates - NAD83 UTM ZONE 22N			
	Longitude (DMS)	Latitude (DMS)	Easting (m)	Northing (m)
A	44° 56' 48" W	49° 47' 31" N	935562	5533101
B	44° 55' 21" W	48° 34' 30" N	948190	5398059
C	45° 49' 04" W	47° 04' 57" N	893344	5227380
G	48° 59' 13" W	47° 12' 49" N	652421	5230868
I	47° 21' 04" W	49° 49' 18" N	762440	5525202

Table 2.2 Project Area – Southern Section Coordinates

Project Area Vertices	Coordinates - NAD83 UTM ZONE 22N			
	Longitude (DMS)	Latitude (DMS)	Easting (m)	Northing (m)
C	45° 49' 04" W	47° 04' 57" N	893344	5227380
D	46° 26' 02" W	45° 59' 28" N	853605	5103218
E	49° 25' 01" W	45° 59' 42" N	622584	5094695
F	49° 28' 29" W	47° 23' 03" N	615122	5248990
G	48° 59' 13" W	47° 12' 49" N	652421	5230868
H	48° 54' 10" W	47° 22' 44" N	658314	5249404

Table 2.3 Exploration Licence 1135 - Corner Point Coordinates

Coordinates - NAD83 UTM ZONE 22N	
Longitude (DMS)	**Latitude (DMS)**
46°45’W	47°50’N
47°00’W	47°50’N
47°15’W	47°50’N
47°30’W	47°50’N
46°45’W	47°40’N
47°00’W	47°40’N
47°15'W	47°40’N
47°30’W	47°40’N
46°45’W	47°30’N

Table 2.3 Exploration Licence 1135 - Corner Point Coordinates

Coordinates - NAD83 UTM ZONE 22N	
Longitude (DMS)	**Latitude (DMS)**
47°00'W	47°30'N
47°15'W	47°30'N
47°30'W	47°30'N

Notes: Coordinates provided by C-NLOPB Land Registry
Water depth ranges from 240 m to 1,130 m

Table 2.4 Exploration Licence 1137 - Corner Point Coordinates

Coordinates - NAD83 UTM ZONE 22N	
Longitude (DMS)	**Latitude (DMS)**
48°45'W	47°10'N
49°00'W	47°10'N
48°30'W	47°00'N
48°45'W	47°00'N
49°00'W	47°00'N
48°30'W	46°50'N
48°45'W	46°50'N
49°00'W	46°50'N

Notes: Coordinates provided by C-NLOPB Land Registry
Water depth ranges from 70 m to 115 m

Table 2.5 Exploration Licence 1139 - Corner Point Coordinates

Longitude (DMS)	Latitude (DMS)
46°00'W	49°40'N
46°15'W	49°40'N
46°30'W	49°40'N
46°00'W	49°30'N
46°15'W	49°30'N
46°30'W	49°30'N
46°00'W	49°20'N
46°15'W	49°20'N
46°30'W	49°20'N
46°15'W	49°10'N
46°30'W	49°10'N
46°15'W	49°00'N
46°30'W	49°00'N

Notes: Coordinates provided by C-NLOPB Land Registry
Water depth ranges from 3,000 m to 3,500 m

Table 2.6 Exploration Licence 1140 - Corner Point Coordinates

Longitude (DMS)	Latitude (DMS)
45°15'W	49°40'N
45°30'W	49°40'N
45°45'W	49°40'N
46°00'W	49°40'N
45°15'W	49°30'N
45°30'W	49°30'N
45°45'W	49°30'N
46°00'W	49°30'N
45°15'W	49°20'N
45°30'W	49°20'N
45°45'W	49°20'N
46°00'W	49°20'N
Notes: Coordinates provided by C-NLOPB Land Registry Water depth ranges from 3,000 m to 3,500 m	

Table 2.7 Exploration Licence 1141 - Corner Point Coordinates

Longitude (DMS)	Latitude (DMS)
45°00'W	49°10'N
45°15'W	49°10'N
45°30'W	49°10'N
45°45'W	49°10'N
45°00'W	49°00'N
45°15'W	49°00'N
45°30'W	49°00'N
45°45'W	49°00'N
45°00'W	48°50'N
45°15'W	48°50'N
45°30'W	48°50'N
Notes: Coordinates provided by C-NLOPB Land Registry Water depth ranges from 2,000 m to 3,000 m	

Table 2.8 Exploration Licence 1142 - Corner Point Coordinates

Longitude (DMS)	Latitude (DMS)
45°30’W	48°50’N
45°45’W	48°50’N
46°00’W	48°50’N
45°30’W	48°40’N
45°45’W	48°40’N
46°00’W	48°40’N
46°15’W	48°40’N
45°30’W	48°30’N
45°45’W	48°30’N
45°30’W	48°20’N
45°45’W	48°20’N
45°45’W	48°10’N

Notes: Coordinates provided by C-NLOPB Land Registry
Water depth ranges from 1,000 m to 3,000 m

2.4 Resource Use and Environmental Features

Resource use is characterized by commercial fishing and oil and gas exploration and production activities. The commercial fishery occurs year-round at some level, with greatest level of activity from April to August. The main commercially harvested species within and around the Project Area are snow crab, yellowtail flounder, turbot / Greenland halibut, redfish, Northern shrimp, American plaice, and halibut. There are no documented food, social, or ceremonial licences within or in the vicinity of the Project Area. Chapter 7 provides additional details on the commercial fishery in the vicinity of the Project Area. Oil and gas exploration and production activities are the other main uses of resources in the region; related activities include geophysical surveys and drilling programs undertaken during exploration programs, and ongoing production activities at Hibernia, Terra Nova, White Rose, and Hebron (first oil scheduled in December in 2017).

A range of other activities also take place in the region. General shipping traffic, fisheries survey programs undertaken by DFO and/or industry, marine research surveys conducted by government and / or educational institutions, and naval training exercises are the primary examples. There are several marine cable networks in the region and a fibre optic cable network connecting the Hibernia and Hebron Platforms. There is no other major existing infrastructure.

The Project Area - Northern Section overlaps with portions of one Ecologically and Biologically Significant Area (EBSA), three Vulnerable Marine Ecosystems (VMEs), and eight NAFO Fisheries Closure Areas (FCAs), none of which have associated prohibitions of offshore exploration activities. The Project Area - Southern Section overlaps with the same EBSA, two VMEs, and one NAFO FCA, which have no prohibitions of oil and gas exploration activities. By their nature and definition, some of the VME areas and FCAs overlap and outline the same areas within the Project Area. Section 6.4 provides additional details on special areas in the vicinity of the Project.

2.5 Project Components and Activities

The Project includes the mobilization and operation of drilling installations, drilling activities, supporting / ancillary activities to a drilling program, and well decommissioning or suspension. These components and the equipment required to execute the Project activities are described in the following sections.

2.5.1 Drilling Installation

Drilling activities may be undertaken by either a floating semi-submersible or a drill ship, depending on availability and operability offshore Newfoundland and Labrador. Semi-submersibles can be used in either shallow or deep waters whereas drill ships are better suited to deeper waters. A schematic of a drill ship and a semi-submersible is provided in Figure 2-2. While the Operator has not yet selected the specific drilling installation to be used for the Project, it must be capable of drilling year-round in the environmental conditions prevalent in the North Atlantic. For the purposes of environmental assessment, including the assessment of cumulative effects, the effects assessment considers the operation of up to two drilling installations actively engaged in drilling activities in the Project Area at any one time. The following sub-sections provide summaries of each type of unit along with example photographs. These are provided as examples of a semi-submersible (West Hercules) and a drill ship (Stena Carron) that have previously been used in the Canada-NL Offshore Area for drilling programs. They are provided as examples for EA purposes only as the Operator has yet to contract a drilling unit for this Project.

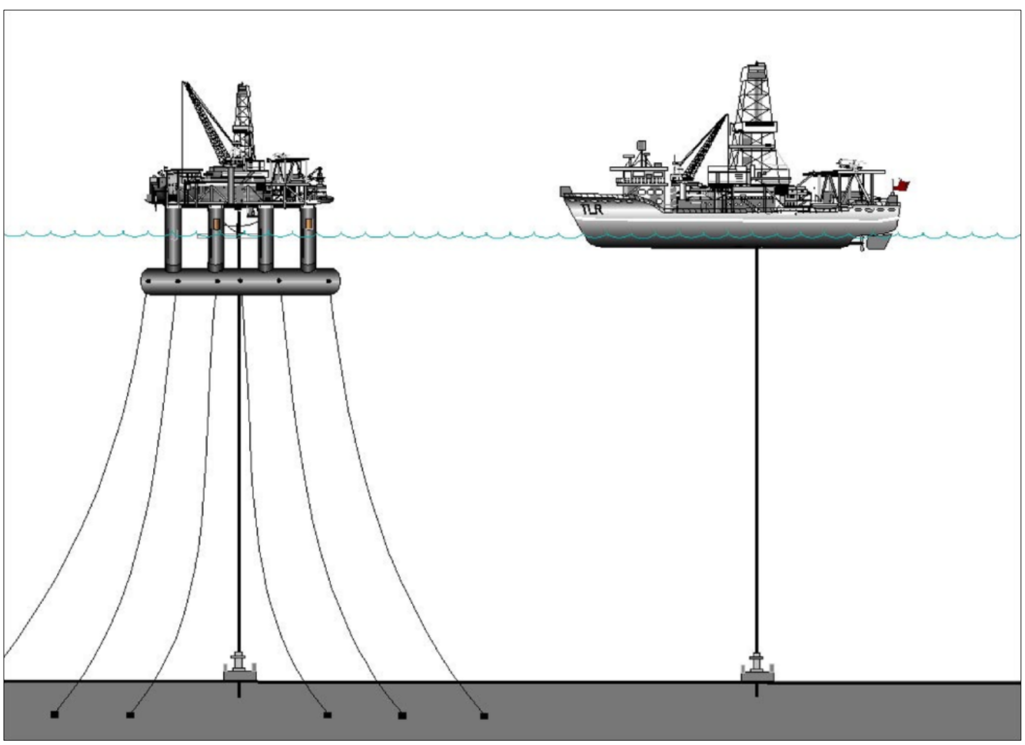


Figure 2-2 Schematic of a Semi-submersible and Drill Ship

2.5.1.1 Drilling Installation Selection and Regulatory Approval Process

The Operator's drilling installation selection process includes consideration of several factors: drilling target depth, water depth at drilling location, oceanographic and meteorological conditions, and technical capability of a drilling installation to operate in deep water. The drilling installation must be able to operate in the met-oceanographic conditions of the North Atlantic and be winterized should year-round drilling be required. In addition, through the Operator's drilling installation intake process, the Operator confirms that contracted drilling installation conform to company practices and industry standards. In order to operate in the Canada-NL Offshore Area, pursuant to the Newfoundland Offshore *Certificate of Fitness Regulations* under the Accord Acts and the C-NLOPB OA requirements, a drilling installation requires a Certificate of Fitness to be issued from a recognized independent third-party Certifying Authority. The purpose of this additional certification is to provide independent third-party assurance and verification that the drilling installation is fit for purpose, functions as intended, and remains in compliance with the regulations without compromising safety and polluting the environment.

For drilling installations operating in the Canada-NL Offshore Area, the Operator requires the following operational specifications. The storage capacity for various agents specified below are based on drilling installations that have previously operated offshore Newfoundland and could vary depending on the specific drilling installation chosen. They are provided as estimates only.

- DP system - DP is used to maintain position while drilling, to monitor environmental conditions using a satellite global positioning system, acoustic positioning data, wind sensors and gyroscopes. Thrusters and propellers are controlled and automatically turned off and on by the DP system using transmitted acoustic energy signals, to keep the drilling installation in position
- Drilling derrick - houses the drilling equipment used to insert the drill string into and out of the wellbore, and to operate the drilling equipment
- Ballast control - used to maintain stability during drilling operations. Seawater is taken into dedicated tanks or discharged when extra stability is needed (e.g., during inclement weather)
- Power system – typically supplied through drilling installation-based generators
- Storage for drilling materials and equipment - these include fuel oil, drilling muds, cement and tubulars
- Storage for petroleum products on board - these include a fuel oil tank (approximately 3,000 to 11,000 m^3), base oil tank (approximately 650 m^3), diesel oil service tanks (up to 6; total capacity approximately 300 m^3), lube oil storage tanks (approximately 20 m^3) and helifuel storage tanks (up to 3 tanks store on drilling installation; 2,900 L capacity per tank)
- Storage of reagents used for drilling - these may include bulk cement, bulk bentonite / barite, and liquid muds
- Storage for subsea equipment- these include well control equipment and marine risers
- Accommodations - typically up to 180 persons on board

- Waste management facilities- this includes the treatment of wastes for offshore disposal (following the OWTG (NEB et al. 2010)) and temporary storage of waste for shipment to shore.
- Helideck-used for personnel transfer, with refueling capabilities
- Cranes - transfer of supplies and equipment between supply vessels and drilling installation
- Emergency and life-saving equipment- this includes lifeboats and rafts for emergency evacuation
- Water- supply/storage of drinking water and/or processing water system

2.5.1.2 Semi-submersible Drilling Unit

A semi-submersible consists of a number of vertical pillars extending up from a horizontal system of pontoons to an upper deck. The upper deck contains drilling equipment, other equipment and material storage areas, and personnel quarters. Semi-submersible drilling installation can either be moored in position over the drilling site using mooring lines and anchors (generally in shallower water depths up to 500m), or maintained on station by a DP system (generally in deeper water greater than 500m). In DP mode, position is maintained by the drilling unit's thrusters, controlled by a computerized DP systems and acoustic positioning system. Energy signals are sent from the acoustic positioning system to transponders (receivers) on the seafloor and back to the drilling installation. This system improves underwater positioning accuracy and redundancy to keep the drilling installation on position. The positioning maintenance method is typically determined based on the location of the well and the water depth. Figure 2-3 is a photo of the West Hercules, a semi-submersible that has operated in the Canada-NL Offshore Area.

2.5.1.3 Drill Ship

A drill ship is a self-propelled ship-shape drilling vessel with larger storage capacity than a semi-submersible for drilling ultra-deep water wells. Drill ships, like semi-submersibles also use DP systems to maintain position at the well site and to rotate the ship into prevailing weather. Figure 2-4 is a photo of the Stena Carron, owned by Stena Drilling and which has operated in the Canada-NL Offshore Area.

Source: Seadrill (2017)

Figure 2-3 West Hercules – Example of a Semi-Submersible

Source: Stena Drilling (2017)

Figure 2-4 Stena Carron - Example of a Drill Ship

2.5.2 Project Activities

Project activities include the drilling, testing, and decommissioning, suspension, or abandonment of exploration, delineation and appraisal wells associated with the Project. The following sections provide a description of these activities in addition to a Project schedule, a summary of personnel requirements, and a summary of any changes that have been made to the Project since originally proposed.

Drilling and testing activities include operation of the drilling installation and VSP, as described in the following sections. Geophysical, environmental, and geotechnical surveys, equipment requirements and storage are also described.

Herein, the term “drilling campaign” will be used and refers to a drilling program where one or more wells may be drilled in any one year, under a specified OA from the C-NLOPB.

2.5.2.1 Wellsite Surveys – Drill Planning

Wellsite surveys are conducted to collect information necessary for well location planning and well design.

Geohazard wellsite surveys are used to identify unstable areas beneath the seafloor (i.e., shallow gas deposits), hazards (large boulders, ocean debris, shipwrecks) so as to avoid these hazards when drilling. These can involve the mapping of the seabed through the use of seismic sound sources, multibeam echosounder (MBES), side-scan sonar (SSS), sub-bottom profiler (SBP), video and other non-invasive equipment. The equipment is deployed either by vessel or ROV / AUV. Vessel deployment options include hull-mounted, on a towfish[1] or on ROV / AUV or equipment may be towed by the vessel (e.g., sound source and/or streamers). Geohazard surveys may not be required for each well location; existing geophysical data may be used to analyze potential geohazards.

As discussed in Chapter 8, cold water corals may be particularly vulnerable to seabed disturbances associated with drill cuttings discharge and/or drilling installation anchors (in shallower waters). Therefore, a pre-drill coral survey will be completed to identify and map corals, if present. Cold water corals are present in other regions of the world that conduct oil and gas exploration and development activities including the Norwegian Continental Shelf (NCS). Cold water corals are relatively common in regions on the NCS, with the NCS holding the largest known *Lophelia pertussa* reef system in the world (Det Norske Veritas (DNV) 2013). In 2013, the Norwegian Oil and Gas Authority (NOROG) produced a guideline that summarises the most relevant matters (research and experience on the NCS) related to drilling activities in areas with the presence of cold water corals. This guideline, “Monitoring of Drilling Activities in Areas with Presence of Cold Water Corals” (DNV 2013), presents the required methods for pre-drilling coral identification / mapping and risk assessment.

Building on the experience in the NCS, the Operator proposes to use the NOROG guideline approach to pre-drilling coral identification / mapping and risk assessment, as it is considered an industry best practice approach in areas with potentially high concentrations of corals (e.g., Vulnerable Marine

[1] A towfish is an apparatus that is dragged beside or behind a vessel and upon which gear, such as side-scan sonar can be mounted.

Ecosystem (VME) or Fisheries Closure Areas (FCAs) within the Project Area) and has been demonstrated to be effective on the NCS. Statoil operational experience on the NCS also confirms the efficacy of this approach. The Operator proposes to use this approach in all wellsite locations in the Project Area, including those with lower potential for sensitive benthic habitat.

It is understood that DFO is reviewing the coral mitigation practices currently applied to offshore drilling in the Atlantic Canada region. The Operator will collaborate with DFO and C-NLOPB to develop the details of the final coral survey requirements that will be applied to the Project. A coral survey plan will be developed and submitted to the C-NLOPB and DFO for acceptance prior to commencing the survey. The coral survey plan will be based on the NOROG guideline, Statoil experience on the NCS, adapted to offshore Newfoundland as appropriate and will adhere with any DFO guidelines or best practices that are issued on this topic.

The key elements of the proposed procedure for the coral survey include:

- SSS and MBES seabed survey of the area surrounding proposed well location and anchor moorings, if applicable. The spatial resolution of the survey is approximately 0.5 m x 0.5 m. The survey area is based on results of drill cuttings dispersion modelling and anchor patterns (for anchored drilling installation). Dispersion modelling results indicate that the survey extent may range from 500 to 2,000 m from the well location. For anchored drilling installation, the radius is a minimum of 50 m from the extent of the proposed anchor pattern.
- The coral survey data are analyzed and interpreted on board the vessel to identify potential coral structures or other anomalies for further investigation. Potential coral structures are visually identified using high-definition images (camera / video). Coral data collected include species present, abundance, size, and condition (health).

The use of a SSS / MBES seabed coral mapping survey allows a larger footprint survey area to be covered than can be practically surveyed using only high-definition imaging. Experience with this SSS / MBES technology has proven that resolution of <1 m has high accuracy (DNV 2013). For relatively small survey areas, high-definition video of the survey area may be used instead of the SSS / MBES seabed survey.

The survey team will include, at a minimum, a geophysical specialist that is responsible for interpretation of the SSS / MBES data for potential coral targets, an ROV / drop camera operator and a marine scientist. The marine scientist will be contracted and will act as an independent, qualified professional with specialty knowledge of cold water benthic habitat and will be responsible to identify and assess the coral structures.

If corals are identified, a risk assessment is prepared to assess potential levels of environmental risks. The risk assessment approach outlined in the NOROG guideline (DNV 2013) considers factors such as size, abundance, degree of exposure, and coral condition. The Operator proposes that a similar risk assessment approach be applied to the Project.

A report summarizing the coral survey results, risk assessment (if corals are observed) and Operators proposed mitigations specific to the conditions of the wellsite. Mitigations may include relocation of the well, and / or redirection of WBM / cuttings discharge. The coral survey and risk assessment report with proposed mitigations will be submitted to the C-NLOPB / DFO for review and acceptance before drilling commences. Reports will be submitted a minimum of 30 days prior to drilling commencing.

As noted above, DFO is completing a review of wellsite surveys and coral mitigations currently applied to offshore drilling in the region. The Operator will continue to collaborate with C-NLOPB and DFO as requested in that review process. A wellsite coral survey plan will be developed and submitted for regulatory approval prior to commencing the coral surveys. It is recognized that details of the coral survey and risk assessment requirements may be refined and improved over time by C-NLOPB / DFO as technology develops, operational experience is gained, scientific research is published, and further data are collected in the area.

2.5.2.2 Mobilization of the Drilling Installation

Once permits and regulatory approvals have been granted for a drilling campaign, the drilling installation is mobilized to the wellsite location. Depending on the type of drilling installation selected, it will either be towed or self-propelled. If a DP system is required to maintain position, acoustic transponders will be installed on the seafloor prior to the drilling installation being positioned over the wellsite. Typically, the transponders are installed one to two weeks before the drilling installation arrives on site and can take up to 18 hours to install once the vessel is on location. If the drilling installation is moored, anchors are set on the sea bed. A visual inspection of the wellsite (approximately 200 m radius from the well location) is completed with an ROV to confirm that there are no drilling hazards present.

If the drilling installation is moored, anchors are set on the sea bed. Anchors can be pre-set on the seabed prior to the hook up of the drilling installation or set at the time the drilling installation arrives on location. Mooring anchor spreads typically consist of 8-12 anchors with anchor chain and/or wire to connect the moorings back to the drilling installation. In a pre-set scenario, the anchors, associated chain / wire, and locator buoys are deployed by an anchor handling vessel or supply vessel prior to drilling installation arrival. A surveyor confirms the anchor deployment position as per mooring plan and the anchor is tensioned by the vessel winch to ensure it is installed with sufficient strength. The location of each pre-set anchor is marked with a floating buoy and the mooring may be pre-set a few months ahead of drilling installation arrival. For water depths greater than 1,000 m, the anchors can be more than 2,500 m from the drilling installation while in shallower water (e.g., Project Area-Southern Section) anchors are approximately 1,500 m from the drilling installation. Once the drilling installation arrives, anchor handling vessels retrieve the end of the anchor chain/wire from each anchor winch on the drilling installation and connect it to the respective pre-set anchor by retrieving the chain/wire attached to each buoy. Once connection is made, the drilling installation will use the anchor winches to set operating tension. If not pre-set, the drilling installation will pass the anchors to the vessel for deployment and then tension.

In addition, a visual inspection of the wellsite (approximately 200 m radius from the well location) is completed with an ROV to confirm that there are no drilling hazards present.

Pursuant to the *Newfoundland Offshore Drilling and Production Regulations (SOR/2009-316)*, a safety zone will be established around the drilling installation. The safety zone is set at 500 m from the drilling, or when moored, 50 m from the outer extent of the anchors. Therefore, a safety zone for a drilling installation may range from 1 km^2 (DP) to approximately 12 km^2 (moored). The safety zone is established for the protection of the drilling installation as well as other ocean users, and to prevent collisions between the drilling installation and other vessels. It is monitored by the drilling installation stand-by vessel. Communications regarding the safety zone will be sent out to mariners via the Canadian Coast Guard Notice to Shipping (NOTSHIP).

2.5.2.3 Offshore Well Drilling

Wells may be drilled at varying water depths, which range from approximately 80 m to 3,800 m within the Project Area. The following information provides a general overview of the requirements and sequence for drilling a well.

Well design and location of the proposed wells have yet to be determined as drilling plans have not been finalized. Well design includes a consideration of many factors, including water depth, reservoir potential and geological properties of the reservoir. Individual well design will be determined for each well and will be submitted for approval to the C-NLOPB as required per the OA and Approval to Drill a Well (ADW) applications. Each well is drilled in sections, gradually reducing the size of the wellbore with increased depth of the well, as illustrated in Table 2.9.

Table 2.9 Typical Well Design Various Water

Well Section	Hole Size	Casing / Liner Size	True Vertical Depth (TVDss)	Drilling Fluid Type
Wells in 80 m water depth				
Conductor	42” (1,067 mm)	36” (914 mm)	159 m	Seawater / WBM[1]
Surface	26” (660 mm)	20” (508 mm)	459 m	Seawater / WBM
Intermediate Hole	17 ½” (445 mm)	13 3/8” (340 mm)	1,809 m	SBM[2]
Production Hole	12 ¼” (311 mm)	N/A	2,918 m	SBM
Wells in 350 m water depth				
Conductor	42” (1,067 mm)	36” (914 mm)	425 m	Seawater / WBM
Surface	26” (660 mm)	20” (508 mm)	1,100 m	Seawater / WBM
Intermediate Hole	17 ½” (445 mm)	13 3/8” (340 mm)	2,050 m	SBM
Production Hole	12 ¼” (311 mm)	N/A	2,650 m	SBM
Wells in 1,200 m water depth				
Conductor	42” (1,067 mm)	36” (914 mm)	1,275 m	Seawater / WBM
Surface	26” (660 mm)	20” (508 mm)	1,950 m	Seawater / WBM
Intermediate Hole	17 ½” (445 mm)	13 3/8” (340 mm)	2,700 m	SBM
Production Hole	12 ¼” (311 mm)	N/A	3,500 m	SBM
Wells in 2,500 m or deeper water depth				
Conductor	42” (1,067 mm)	36” (914 mm)	2,575 m	Seawater / WBM
Surface	26” (660 mm)	20’ (508) mm)	3,200 m	Seawater / WBM
Intermediate Hole	17 ½” (445 mm)	13 3/8” (340 mm)	4,000 m	SBM

Table 2.9 Typical Well Design Various Water

Well Section	Hole Size	Casing / Liner Size	True Vertical Depth (TVDss)	Drilling Fluid Type
Production Hole	12 ¼" (311 mm)	N/A	4,700 m	SBM
[1] Water-based mud [2] Synthetic-based mud				

It typically takes 35 to 65 days to drill a well in this area; the time to drill each well is dependent on water depth, well design, depth of the reservoir and weather and technical requirements.

Drilling can be divided into two stages – riserless and riser drilling. For the first sections of the well (conductor and/or surface) there is no closed- loop riser; the water-based drilling muds, cuttings and excess cement are released directly to the seafloor. Once the initial sections are drilled, a closed-loop system (riser) is installed and fluids used in the drilling of the well are recirculated back to the drilling installation, where they are either recycled and reused, treated and discharged or stored onboard for disposal at shore (refer to Section 2.9.3 for more information regarding drilling waste management).

Drilling mud or fluid is required to lubricate the drill bit and move the drill cuttings up the wellbore. Different types of drilling fluids (e.g., water-based mud (WBM), synthetic-based mud (SBM)) are used depending on well design and anticipated geological conditions. Drilling fluids include a base fluid, weighting agents and other chemicals to formulate a drilling fluid required to drill a well safely and efficiently. The selection and use of drill fluids will be determined based on well design and will be in accordance with the Operator's chemical selection procedures which adhere to regulatory requirements and C-NLOPB guidance documents (refer to Section 2.10.1.7 regarding chemical selection and management).

Once the initial sections are drilled, a steel casing is cemented in place to prevent the wall of the wellbore from caving in and to prevent the seepage of muds and other fluids. The riser and blowout preventer (BOP) are then installed onto a wellhead. The riser is a large diameter pipe that acts as a conduit connecting the drilling installation to the wellhead through the water column, and the wellhead provides structural integrity to house the BOP and pressure integrity for drilling operations. A BOP is a critical piece of safety equipment which houses a system of high pressure valves that prevent water or hydrocarbons from escaping into the environment in the event of an emergency or equipment failure. Conventional subsea wellhead systems consist of two major components, the low-pressure wellhead housing (also referred to as the conductor housing) and the high-pressure wellhead housing (or more commonly referred to as the wellhead). The profile for connecting the BOP to the well is on the top of the high-pressure wellhead housing. The low-pressure wellhead housing is installed as part of the conductor casing and the high-pressure wellhead housing is installed as part of the surface casing, requiring a minimum of two casing strings prior to connecting the BOP/riser. The remaining sections of the well are drilled to predefined depths At intervals along the well, casing is cemented in place at set depths to reinforce the wellbore. More information regarding SBM and WBM can found in Section 2.9.3.

Drilling activities may also include batch drilling, which is the process of consecutively drilling the top hole portions of a well for multiple wells. During batch drilling activities, the conductor hole section and surface hole section are drilled without risers using WBM, as described above. The number of top hole sections to be batch drilled at any one time is dependent on the number of wells proposed in a drilling campaign, and will be determined to optimize drilling installation efficiency and overall logistics.

2.5.2.4 Formation Flow Testing with Flaring

A formation flow test involves the flowing of well fluids from the reservoir to gather additional information on the potential reservoir properties (e.g., potential productivity, connected volumes, fluid composition, flow rate, pressure, temperature). Information from a formation flow test can help in the assessment of the potentiality of a discovery. Formation flow testing is required pursuant to the Accord Acts in order to obtain an SDL. It may occur while the drilling installation is drilling the well, immediately after the well is drilled, or at a later date by re-entering a suspended well.

A formation flow test may be carried out on wells where hydrocarbons are discovered and additional reservoir data is needed. Based on historical discovery data in the region (C-NLOPB Schedule of Wells; C-NLOPB n.d.), it is estimated that five to six wells may include a formation flow test. It is possible that the formation flow test operation may require flaring of hydrocarbons at surface. This type of test generally requires perforating a casing that has been set across the hydrocarbon-bearing reservoir. Once perforated, reservoir fluids flow into and up the wellbore to the drilling installation where the well fluids are measured and, if required, stored for future analysis. A formation flow test with flaring may include up to three days of flaring; however, if an extended flow test is required (depending on data requirements) flaring could last up to five days. During a formation flow test with flaring, some of the hydrocarbons recovered and the small volume of produced water can be sent to a flare.

An alternative to formation flow testing with flaring exists and may be used on exploration wells to assess the discovered hydrocarbon resources and to potentially support an SDL application. These types of tests, called Formation Testing While Tripping, may be conducted without the requirement for topside production equipment, flaring of hydrocarbons, and exposure of personnel to pressurized equipment containing live hydrocarbons.

Upon completion of a formation flow test, the well may be suspended or abandoned in accordance with regulatory requirements.

2.5.2.5 Geophysical, Environmental and Geotechnical Surveys

Throughout the Project, surveys may be required to support drilling operations such as geophysical, environmental, and geotechnical surveys and/or ROV video surveys. Geophysical surveys include geohazard / wellsite and VSP surveys. ROV / AUV surveys may also be used during any or all of the above-named surveys.

<u>Geophysical / Geohazard / Wellsite and Seabed Surveys</u>: These surveys are used to identify unstable areas beneath the seafloor (i.e., shallow gas deposits), hazards (large boulders, ocean

debris, shipwrecks) so as to avoid these hazards when drilling, or corals. Surveys typically take between 5 to 21 days to complete but can be shorter (i.e., coral surveys) or longer, depending on the area to be surveyed and weather/operational delays. These can involve the mapping of the seabed through the use of seismic sound sources, MBES, SSS, SBP, video and other non-invasive equipment. The equipment is deployed either as hull-mounted equipment, on a towfish or on ROV / AUVs. Equipment may be towed by the vessel (e.g., sound source and/or streamers) or hull-mounted. Geohazard surveys may not be required for each well location; existing geophysical data may be used to analyze potential geohazards. These surveys may occur at any time of the year over the temporal scope of the Project.

<u>VSP Surveys:</u> vertical seismic profiling VSP is a tool used to further define the depth of geological features and potential petroleum reserves by obtaining high resolution images of the target. VSP surveys will be conducted as required throughout the Project life.

VSP surveys are similar to surface geophysical surveys in that a sound source and a receptor (or hydrophone) is required to measure the refraction and reflection of the sound waves, thereby providing data that can be interpreted to delineate geological features used to identify potential hydrocarbon deposits. VSP differs from surface geophysical surveys in that it is conducted in a vertical wellbore using hydrophones inside the wellbore and a sound source near the surface at or near the well; a VSP is quieter and more localized than a surface geophysical survey, being smaller in size and volume. Up to 12 individual smaller sound sources may be used for VSP, each of which has a maximum volume of 250 cubic inches and is generally placed 5 to 10 m below the water surface. Additionally, a VSP is shorter in duration than surface geophysical surveys, with VSP operations usually taking less than 48 hours per well to complete the profiling.

During a VSP program, various VSP configurations are used depending on the objectives. For example, an offset VSP is the conventional configuration, in which the energy source is positioned directly above the hydrophone(s), typically close to the wellbore. A walkaway VSP is where the sound source is towed from a vessel and is moved progressively away from the hydrophones, generally resulting in higher resolution than surface data and providing more continuous coverage than an offset VSP. VSP surveys may be carried out at any time of the year.

Geophysical activities for the Project 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; and appended to the Geophysical, Geological, Environmental and Geotechnical Program Guidelines (C-NLOPB 2017)). If a VSP is required, specific details of the VSP operations for the Project will depend on the geological target and the objectives of the VSP in question. This information will be provided to the C-NLOPB at the time of application for a “Geological/Geotechnical/Environmental Program” authorization.

<u>Environmental Surveys</u>: These surveys are conducted to collect samples to analyze the physical, chemical, and biological aspects of the selected drilling area. Sampling is typically carried out from a support / supply vessel or a dedicated vessel suitable to the survey. Environmental surveys may include oceanography, meteorology, and ice / iceberg surveys. It can also include biota, water, and sediment sample collection, and ROV-video or drop camera surveys. Environmental surveys may

occur throughout Project life at any time of the year using vessels of opportunity associated with the Project, typically taking five to 20 twenty days to complete.

Geotechnical Surveys: These surveys measure the physical properties of the seabed and subsoil through the collection of sediment samples and in-situ testing. Methods to collect the samples typically include drilled boreholes or gravity coring. In-situ testing is done through cone penetration testing and pore pressure measurements. Installation of piezometers in boreholes to measure soil properties may also be carried out. Piezometers could be left in place to collect data for up to 12 months or longer. Geotechnical surveys may occur throughout the Project life at any time of the year, using dedicated vessels provided by marine geotechnical specialist suppliers.

ROV / AUV surveys: These surveys are used to conduct visual inspections (camera equipped) of facilities. ROV / AUV surveys may also be used during pre-drill surveys and before marine installations to determine presence / absence of physical objects on the seafloor. They may also be used during any or all of the surveys described above to support drilling operations. They will be conducted throughout the Project-life at any time of the year using vessels of opportunity associated with the Project.

2.5.2.6 Supply and Servicing

Offshore drilling activities are supported by a number of logistical activities, including an existing onshore supply base, offshore supply vessels, and helicopters.

2.5.2.6.1 Onshore Supply Base

A supply base provides temporary storage, re-fueling, staging and loading of materials and supplies to support offshore drilling and other exploration activities. Shore base facilities have operated on the island of Newfoundland since the 1970s when offshore exploration activity began. Shore base facilities are owned and operated by independent third-party service providers and are subject to provincial and / or municipal regulatory requirements. These facilities operate with the required government permits and approvals and are certified as compliant port facilities under the *Marine Transportation Security Act*. The Operator has no care or control of operations or modification at these onshore supply bases. Therefore, the supply base and associated activities are not considered in the EIS.

2.5.2.6.2 Offshore Supply Vessels

Offshore supply vessels will be engaged to support Project activities. Supply vessels will be contracted from third-party suppliers to provide support in transporting of equipment, supplies and personnel. The Operator has yet to engage the services of support vessels for the Project. Supply vessels contracted by the Operator will be required to have valid marine certification (i.e., Certification of a supply vessel as a Passenger Vessel from Transport Canada) and meet regulatory requirements as set out by Canada and international organizations as well as meeting Operator marine-vessel vetting requirements.

The following Project vessels are likely to be engaged during the Project life

- Two to three support / supply vessels for drilling installation(s)
- Geophysical vessels (e.g., wellsite / geohazard surveys; VSP surveys)
- Seabed survey vessels (e.g., MBES surveys, SSS, SBP, magnetometer)
- Geotechnical vessels (e.g., soil investigation programs, cone penetration testing, piezometers)
- Construction / light intervention vessels for wellhead decommissioning activities
- Vessels of opportunity capable of undertaking environmental sampling
- Vessels of opportunity equipped with ROVs / AUVs, and the deployment of ROVs / AUVs
- Vessels engaged in ice management operations (only when iceberg conditions warrant) (typically contracted from existing support vessels servicing offshore oil and gas activities)
- Support / picket vessels for any of the above

It is anticipated that an average of eight to ten vessel transits per month will occur in support of a drilling campaign using one drilling installation. Based on data from the St. John's Port authority (R. McCarthy pers. comm. 2016), eight to ten transits per month from a previous exploration drilling program in the Flemish Pass area accounted for approximately 8 percent of total vessel traffic in St. John's Harbour. Therefore, it is anticipated that the Project will not result in an increase in the number of vessel transits over previous levels. If two drilling installations are operating concurrently, it is estimated that there could be up to 16 supply vessel transits per month. Vessels used in the Canada-NL Offshore Area are typically part of a pool of supply vessels supporting ongoing oil and gas activity. These are specialized vessels which operate under specific regulatory and training requirements.

From 2010 to 2015, a total of 1,300 to 1,601 (1,358 in 2015) vessel transits in and out of the Port of St. John's were recorded, of which 749 to 1,027 annual transits were offshore energy vessels (R. McCarthy, pers. comm. 2016). As noted above, a similar exploration program's contribution to 2015 vessel transits represents approximately 8 percent of traffic in St. John's Harbour, and is expected to remain at this level.

Supply vessels supporting the Project will transit in a straight-line approach to and from a port to a drilling installation, a common industry practice for energy efficiency employed for over 30 years by operators with facilities offshore Newfoundland. Incidents related to offshore oil and gas activities are reported to and recorded by the C-NLOPB. A total of 99 incident disclosures have been reported by the C-NLOPB to date. Of these, four were related to supply vessels. One was related to a fire on an supply vessel while in-transit, approximately 100 km from St. John's. Three were related to supply vessels while "in-field" (at a drilling installation or production installation) and included a contact between a supply vessel and drilling installation, a medevac, and the loss of an empty container overboard (C-NLOPB 2016c). For other vessel incidents (not oil and gas related), between 2005 and 2016, there were five vessel collisions involving two or more vessels in, near, or east of St. John's in the designated Atlantic Region. All were fishing, commercial or government vessels not associated with the offshore oil industry. Three of these occurred in or near St. John's Harbour (2007, 2008, 2009), one at Cape Race (2008), and one off the east coast of NL (2012). Of the five incidents, four involved collisions between vessels, and one was a collision with an object or vessel (not distinguished) (Transportation Safety Board of Canada 2017). Supply and support vessel traffic routes servicing the existing production facilities, and a potential traffic route to the Project Area, are illustrated in Figure 2-5. The potential route is representative only and the route will change depending on the location of the drilling installation. If operators shared supply vessels, the vessel could transit from St. John's to one facility and then transit to another facility; however, the transit out of and to St. John's will be similar to that shown in Figure 2-5. During the ice season, the routes will likely be altered to avoid pack ice along the transit route.

2.5.2.6.3 Helicopters

Helicopter support will be used for crew transfers to and from the drilling installation. Helicopter support will be supplied by a third-party licensed operator under contract to the Operator. An estimated one to three helicopter transits per day will be required (e.g., greater than 300 km offshore). Up to four transits per day for facilities that are within 300 km will be required. However, helicopter transit does not occur every day as flights may be grounded due to weather and/or technical matters. Helicopter support will be based out of St. John's and operate out of the St. John's International Airport. Aviation is regulated by Transport Canada and includes regulations and operational requirements for helicopter flight traffic. The C-NLOPB has also implemented specific operations requirements for helicopter flight traffic (e.g., lighting, hours of operation) when servicing offshore installations. The Operator is not planning to construct or operate a new helicopter base nor modify an existing base; therefore, the helicopter base is not considered to be within the scope of the Project of this EIS. Helicopters supporting the Project will transit to and from the Project using routes commonly used over the past 30 years of oil and gas activities (see Figure 2-5) and generally follow the shortest straight line between locations.

2.5.2.7 Well Suspension, Abandonment, Decommissioning and Demobilization

When drilling on a well is complete, the well may be suspended or abandoned, following the requirements set out in the *Newfoundland Offshore Petroleum Drilling and Production Regulations SOR/2009-316*. In instances where it may be necessary to re-enter the wellbore, the well is *suspended,* and the wellhead remains in place; when the well will not be re-entered, it is *abandoned.* Removal of the wellhead varies depending on water depth. Suspension and abandonment involves the isolation of the wellbore by placing cement and/or mechanical plugs at varying depths in the wellbore, thereby separating and isolating subsurface zones to prevent hydrocarbons from escaping. If a wellhead is removed, the surrounding seabed is inspected (typically with an ROV) to check that no equipment / obstructions remain in place.

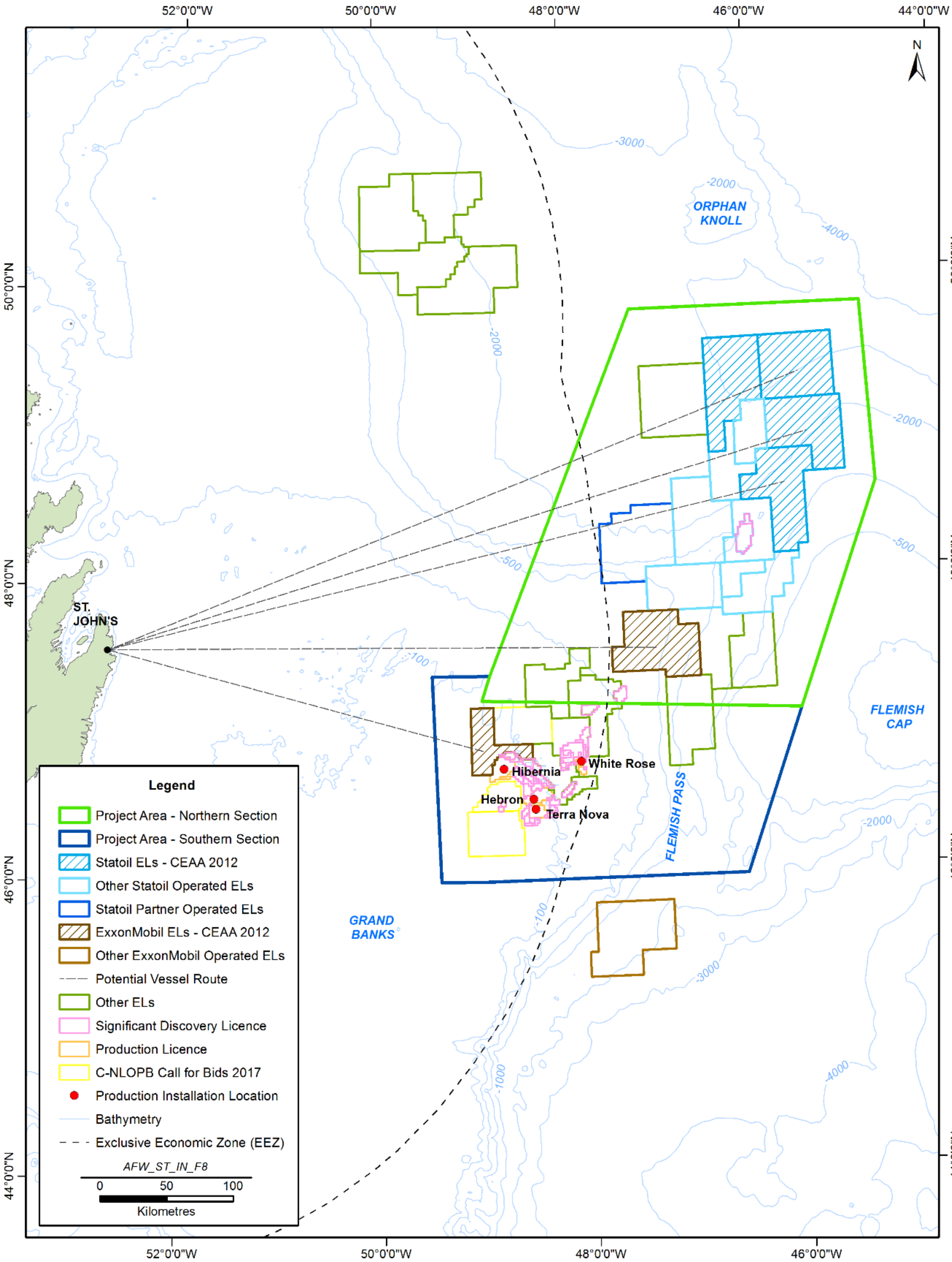


Figure 2-5 Potential Aircraft and Supply Vessel Transit Routes (for illustrative purposes)

The Operator has developed a wellhead removal strategy for wellheads in varying water depths.

- In water depths less than 500 m, conventional internal cutting using the drilling installation to remove the wellheads below the seafloor
- In water depths between 500 m and 1,500 m, wellheads may be removed by cutting the wellhead externally, leaving a portion of the casing above the seafloor (maximum of 0.85 m)
- In water depths greater than 1,500 m, the wellhead will remain in place and will not be removed

For external cutting of the wellhead, a vessel equipped with an exterior diamond wire cutting saw via ROV will be used to cut and remove the wellheads above the sea floor. Cutting of the wellheads above the seafloor will be completed as close to the natural seabed as practicably and technically feasible. A pipe stub with a maximum height of approximately 0.85 m may remain above the seabed. For each wellhead that is decommissioned using this cutting technique, it is anticipated that it may take up to two days to complete the removal. Decisions regarding which method to be used in wellhead removal at water depths between 500-1,500 m will be in consideration of available technology, water depth, well casing design, and previous experience removing wellheads at the specified water depth. At water depths greater than 1,500 m, it is planned to leave the wellhead in place. Decommissioning of wellheads may be carried out using the drilling installation either following the drilling of the final well in the campaign, or later during another drilling campaign. External cutting may be carried out at the end of a drilling campaign or at any other time during the year. Explosives will not be used to sever wellheads for retrieval.

2.6 Project Personnel

Each drilling campaign, within the overall Project will be managed by the Operator’s multidisciplinary drilling team in its St. John’s office. The team will include members of the Operator’s global drilling organization who are responsible for delivering the Company’s standardized approach to exploration drilling programs. Certain members of the drilling team work offshore. The Operator’s Team led by the Drilling Supervisor, is responsible for coordinating the overall execution of the drilling program and providing oversight of well-related operations. The Drilling Supervisor reports to the Operators’ onshore well superintendent, who is responsible for supervising the execution of the approved drilling program. Contractors will also be retained for specific work components, including but not limited to delivery and operation of the drilling installation, onshore supply base support, supply and operation of supply vessels, and helicopter services. The drilling installation contractor, during drilling operations, employs the largest number of personnel associated with a drilling program. Typically, between 120-160 persons may work on the drilling installation during a drilling program. Offshore drilling contractor roles include the offshore installation manager (OIM), labourers, technicians, and health, safety and environmental (HSE) personnel. The Operator’s Drilling Supervisor will work with the drilling contractor’s OIM on the drilling installation to provide safe and efficient drilling operations, and supervision of compliance with Company and local regulatory requirements. The Operator and contractor personnel are highly trained to carry out their specific roles.

2.7 Project Schedule

Project activities, including well decommissioning, will be aligned with the EL period terms and will end once regulatory obligations and commitments have been met and the licence has either reverted back to the Crown or is converted to an SDL. The Project is scoped for a period of 10 years (Statoil) and 12 years (ExxonMobil) (2018 to 2027 / 2029), providing an adequate and conservative timeframe within which Project activities may occur. Exploration drilling campaigns may progress year-to-year and from well-to-well based on the results and evaluation of previously drilled wells, interpretation of geophysical data, and the Operator's exploration requirements, with Project activities being carried out throughout the year. As the EIS is being undertaken early in the planning stages for exploratory drilling in the Project area, there is no Project commencement date. The EIS assumes that Project activities can occur at any time of the year.

For a single drilling campaign, in any single year the following is an estimate of the timelines involved from mobilization to demobilization.

- Wellsite (geohazard) Survey – for deep-water locations this would use existing 3D geophysical data, for shallow water locations a separate geohazard survey may need to be completed. Normally completed three months to one year in advance; typically takes between 7-21 days to complete per well location
- Installation of transponders for DP system – up to 18 hours once vessel is on location (can be done weeks in advance of the drilling installation transiting to site)
- Pre-drill coral survey – normally at least three months in advance; may take between 3-7 days to complete per well location
- Drilling installation transit to site and ballasting – dependent on whether it is DP or anchored (two to six days, assuming transit from the Avalon peninsula)
- Drilling the well – 35-65 days (depending on weather, operational delays; depth of water); includes well suspension and or abandonment activities
- Demobilization – a few hours to a day; includes pulling the BOP and either moving to another well location or leaving the Project area
- Wellhead removal – normally up to two days per wellhead, depending on water depth and methods employed

Table 2.10 provides a timeframe estimate for activities associated with drilling a single well. Therefore, if more than one well was to be drilled in any one year, the timeframe would be sequential and additive to that presented in Table 2.10. Note that activities may be longer or shorter in duration and activities such as geohazard or pre-drill coral surveys may occur earlier in the schedule depending on the availability of equipment and regulatory authorizations. For a multi-well drilling campaign, the wellsite survey / pre-drill coral survey and drilling activities would be repeated. Regulatory approval and stakeholder engagement include all wells in a drilling campaign and are therefore not repeated for each well in a given campaign.

Table 2.10 Project Schedule – For a Single Well Drilling Campaign

Task	Year 1				Year 2				Year 3				Year 4			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Regulatory Approvals																
Stakeholder Engagement																
Well Selection and Design																
Pre-drill Coral Survey and/or Wellsite (Geohazard) Survey																
Logistics Preparation																
Drilling a single well (may include formation flow test) and well decommissioning																
End-of-well regulatory reporting																

2.8 Summary of Changes to the Project

As noted throughout Chapter 3, the various governmental, stakeholder, and Indigenous engagement initiatives undertaken as part of this EIS have yielded useful and informative perspectives related to the Project and its potential environmental effects. These inputs have helped shape the nature and focus of the EIS regarding VC selection. The specific content and focus of the description of the existing environment (Chapter 5-7) and the environmental effects assessments (Chapters 8-15).

For the most part, however, these consultation and engagement initiatives to date, did not result in the identification or elaboration of new and / or previously unidentified environmental components or issues of concern, over and above those specified in the EIS Guidelines and considered in the EIS. The nature of exploration drilling means that, during the EA stage, the Project description does not include a detailed “design” and proposal of particular components, as a development project might. Rather, this exploration drilling project is based on standard and typical equipment and methods in compliance with regulatory standards. This means that the Project description (Chapter 2) has not been subject to any specific “design changes” as a result of these engagement initiatives and their outcomes.

The EIS Guidelines contemplated the inclusion of any new ELs that the Operator may have acquired through the C-NLOPB Call for Bids process as the EIS was being prepared. No new ELs were acquired, nor has the operatorship changed for any existing EL.

The Operator will, however, continue to review governmental, stakeholder, and Indigenous inputs and perspectives as the planning and implementation of the Project progresses, and will consider them in its Project-related planning and decision-making as applicable. Project implementation will also include on-going communication with key stakeholders and Indigenous groups to allow for continued discussion of Project related activities and any issues as they may arise over the life of the Project.

2.9 Waste Discharges and Emissions

The primary waste streams from the Project are categorized as follows:

- Air emissions
- Drilling waste
- Liquid discharges
- Hazardous waste
- Non-hazardous waste
- Heat, light and sound

For these waste streams, some will be discharged overboard after treatment, whereas others are shipped to shore for disposal in approved waste management facilities. The following sections provide an overview of waste management for the Project.

The OWTG provide performance targets for overboard discharges from drilling and production operations. In accordance with the OWTG and where applicable, discharges will be treated before being released overboard. The Project's Environmental Protection Plan (EPP), as required by the OA, will provide details regarding the management of wastes, discharges and emissions for the drilling campaign and is specific to the drilling installation. The EPP will be prepared in accordance with the Environmental Protection Plan Guidelines (C-NLOPB and Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) 2011) pursuant to the *Drilling and Production Regulations* and submitted to the C-NLOPB as a requirement of the OA application process. Chemicals used for drilling operations will be screened in accordance with the Operator's chemical management and selection process that adheres to the guideline requirements (NEB et al. 2005). The chemical selection and management process is included in the EPP. The EPP will also include the procedures and processes for handling, storage, transfer and disposal of wastes during the Project.

The water management system will be dependent on the configuration of the drilling installation's water system. The water system will manage the following water and waste water streams: potable water, produced water, bilge and deck drainage water, ballast water, grey / black water (sewage), cooling water, and fire control water. The nature and management of each are described in Section 2.9.4.

2.9.1 Air Emissions

Air emissions from the drilling installation and other drilling activities will regularly occur during the Project. The main source of atmospheric emissions will be the exhausts of the drilling installation, flaring (should it occur during a formation flow test, the supply vessels and helicopters.

The primary source of atmospheric emissions for the Project include exhaust gases from the combustion of fuel in engines powering the drilling installation, OSVs, and helicopters. Depending on the type of formation flow test carried out, atmospheric emissions could result if a formation flow test with flaring is undertaken. For the purposes of environmental assessment regarding estimation of air emissions, it is assumed that flaring would be required. Typically flaring during a formation flow test is two to three days; however, if an extended flow test is required (depending on data requirements) flaring could last up to five days (refer to Section 2.5.2). Should flaring be required, it will be carried out in accordance with provisions of the Drilling and Production Guidelines (C-NLOPB and CNSOPB 2017).

Project activities that will result in air emissions, including CACs and greenhouse gas (GHG), include:

- drilling installation, vessel and helicopter traffic (CO, NO_2, TPM, SO_2, VOCs, GHGs)
- power generation (CO, NO_2, TPM, SO_2, VOCs, GHGs)
- formation flow testing with flaring (CO, NO_2, TPM, GHGs)

The Project will operate in accordance with the *Canadian Environmental Protection Act*, through the National Ambient Air Quality Objectives for specified criteria air contaminants, the Ambient Air Quality Standard for fine particulate ($PM_{2.5}$), and the International Maritime Organization's (IMO) relevant regulations and emission limits under MARPOL. The IMO is also considering mandatory energy efficiency measures on vessels and data collection systems, which will further reduce GHG emissions in the offshore. Currently, there is no federal regulatory requirement to reduce GHGs. However, the federal government has indicated they will implement federal legislation that will mandate a national carbon pricing program by 2018 (ECCC 2016b). Such a program may impose a carbon tax on fossil fuel use. Any province that does not set its own carbon price will use the federal government's minimum floor price. On a federal level, GHG emission reduction targets have also been set and include the following (ECCC 2016c):

- A 17 percent reduction below the 2005 emission levels by 2020 (under the 2009 Copenhagen Accord)
- A 30 percent reduction below the 2005 emission levels by 2030 (2015 submission to the United Nations Framework Convention on Climate Change)

Provincially, air emissions, including CACs, are regulated under the NL *Air Pollution Control Regulations* and GHGs under the *Management of Greenhouse Gas Act*. It is not known at this time whether GHG emissions for oil and gas projects in the Newfoundland and Labrador offshore will be regulated under provincial or federal frameworks.

The sulphur content in the diesel fuel used for the Project will meet the *Sulphur in Diesel Fuel Regulations* for each regulated activity, and will comply with the sulfur limits in fuels for large marine diesel engines, in accordance with the *Vessel Pollution and Dangerous Chemicals Regulations* under the *Canada Shipping Act, 2001*.

An estimate of the atmospheric emissions, including CACs and GHGs, by Project activity are provided in the following subsections. A description of the methods and practices that will be implemented by the Operator to reduce and control atmospheric emissions throughout the life of the Project are also described.

2.9.1.1 Criteria Air Contaminants

2.9.1.1.1 Drilling Installation

As described in Section 2.5.1, drilling activities will be undertaken by a floating semi-submersible or a drill ship. The drilling installation for the drilling program has not been identified, therefore, for emission calculation purposes, a representative drill ship (i.e., the Stena Carron (Stena Drilling 2017)) and a representative semi-submersible (i.e., West Hercules (Seadrill 2017)) was assumed.

Atmospheric emissions factors from the operation of the drilling installation ere calculated using emission factors published by the United States Environmental Protection Agency (US EPA) in AP-42 (Fifth Edition, Volume 1, Chapter 3.4) for large stationary diesel internal combustion sources (refer to Table 2.11) and manufacturers specifications pertaining to the Stena Carron and the West Hercules. The calculated emissions assume that all of the main power engines (i.e., six Wartsila gensets with a rated output of 9,280 kW for the Stena Carron, and eight Wartsila gensets with a rated output of 4,707 kW for the West Hercules) on the drilling installation operate simultaneously, a conservative assumption. Typically, a combination of generators operating at reduced power levels are used. For instance, the drilling installation can be powered with each engine operating at 20 percent power, or two running at 60-80 percent power, or four running at 40 percent power, or other similar combination. Therefore, the estimates reflected below are the most conservative as it is assumed that all engines are running at 100 percent power. Actual emissions from the operation of the drilling installation may vary from those presented here based on the specifications (i.e., engine type, load, and capacity) of the drilling installation contracted for the Project.

Table 2.11 Gaseous Emissions Factors for Large Stationary Diesel Internal Combustion Sources

Air Contaminant	Emission Factor (fuel input) (lb/MMBtu)
NO_X	1.9
CO	0.85
SO_X	$1.01S_1$
PM	0.1
S_1 = % Sulphur in Fuel, assumed to be 0.1% US EPA 1996	

2.9.1.1.2 Supply Vessel

During the course of the Project, atmospheric emissions will be emitted from the operation of the supply vessels servicing the drilling installation. It is anticipated that approximately eight to ten trips per month will be required to service one drilling installation and up to sixteen trips to service two drilling installations, with the longest one-way route ranging from 300 km in the Project Area-Southern Section to approximately 600 km in the Project Area – Northern Section. The vessels that will be used for this Project have not been identified, but will likely be an anchor handler or platform supply vessel as typically used in the Canada-NL Offshore Area. On average, the most fuel-efficient vessels operating in offshore NL burn 15 m^3 of fuel per day and the least fuel-efficient vessels burn 26 m^3 of fuel per day.

The emissions resulting from the operation of the supply vessels were calculated using the methodologies and emission factors published by the US EPA, in “Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories” (2009) and manufacturers information pertaining to two anchor handling type vessels, an older and a newer vessel (i.e., the Maersk Nascopi (1997) and the Secunda Avalon Sea (2016)) (Secunda 2016; Maersk 2017). The emission factors are presented in Table 2.12. The presented emissions assume that both main engines (9,600 BHP per engine) on the Maersk Nascopi and four main engines (3,860 BHP per engine) on the Secunda Avalon operate simultaneously at their suggested rated output.

Table 2.12 Emission Factors for Offshore Supply Vessels

Air Contaminant	Emission Factor (g/kw-hr)
	Main Engine
NO_x	13.2
CO	1.1
SO_2	-
PM_{10}	0.47
$PM_{2.5}$	0.43
US EPA 2009	

2.9.1.1.3 Helicopter

Helicopters will be used to transport crew to and from the drilling installation. As with the drilling installation and supply vessels, the model of helicopter to be used for the Project has not been identified; typically the Canada-NL Offshore Area is serviced by the Sikorsky S-92.

If travelling to the Project Area – Northern Section, it is assumed that one to three helicopter transits per day will be required and that the furthest distance the helicopter would travel from St. John's to the drilling location, based on the aircraft limitations and current practices, is approximately 450 km one way; however, estimates were done based on farthest distance from shore to edge of Project Area, which is approximately 600 km. Using the assumption of 600 km, based on the anticipated class of helicopter to be used, and the route distance, it is likely that approximately 3,400 L could be used per round trip from St. John's to the Project Area – Northern Section.

If travelling to the Project Area – Southern Section, it is assumed that one to three helicopter transits per day will be required and that the furthest distance the helicopter would travel from St. John's to the drilling location, based on the boundaries of the ELs, is approximately 300 km one way. Based on the anticipated class of helicopter to be used, and the route distance, it is likely that approximately 1,700 L could be used per round trip from St. John's to the Project Area– Southern Section.

The emissions from the operation of the support helicopter were calculated using guidance published by the Swiss Confederation (Rindlisbacher and Chabbey 2015) and manufacturer data for the Sikorsky S-92 (Cougar 2017) for NO_x, CO and PM. The emission factors are presented in Table 2.13. The emission estimates for NOx, CO, and PM are based on a fuel consumption rate of 0.14 kg/s per engine. The emissions of SO_2 were calculated based on the anticipated amount of sulphur in the aviation fuel (i.e., 1,000 ppm) and manufacturer data pertaining to fuel consumption.

Table 2.13 Emissions Factors for Helicopter Operation

Air Contaminant	Emission Factor (g/kg)
NO_X	18.0
CO	0.95
PM	0.40
Rindlishbackher and Chabbey 2015; http://www.cougar.ca/Fleet/sikorsky-s92.asp	

2.9.1.1.4 Formation Flow Testing with Flaring

Atmospheric emissions may also be generated if a formation flow test with flaring is undertaken. A formation flow test is a non-routine activity. It is estimated that up to five tests could be performed if the total number of exploration wells were drilled, based on C-NLOPB data of the history of discoveries from exploration drilling. For the purposes of air contaminant emission estimations, it is assumed that testing would be carried out with the formation flow test with flaring. Typically flaring during a formation flow test is two to three days, however, if an extended flow test is required (depending on data requirements) flaring could last up to five days. For the purposes of estimating air emissions from flaring during formation flow testing, it has been assumed that that no more than

38,032 m^3/day of gas and 1,879 m^3/day of oil would be flared per day during each well test, using data from previous well testing with flaring emissions.

The emission factors used to calculate emissions from flaring during formation flow testing are presented in Table 2.14.

Table 2.14 Emissions Factors for Flaring during a Formation Flow Test

Air Contaminant	Emission Factor (lb/10^6 Btu)
NO_X	**0.068**
CO	**0.31**
US EPA 2016	

These emissions factors, along with the anticipated amount of fuel to be flared, on a daily basis, were used to estimate the daily air emissions resulting from flaring during a formation flow test.

2.9.1.1.5 Daily Air Contaminant Emissions

The daily air contaminant emissions based on the operation of the Project, including flaring during formation flow testing, were estimated as described above and are presented in Table 2.15.

Table 2.15 Daily Air Contaminant Emissions for the Drilling Installation, Supply Vessels, Helicopters and Flaring

Project Activity	Air Contaminant	Air Contaminant Emissions (tonnes/day)
Drilling Installation[1]	NO_X	7.14 – 10.5
	CO	3.02 - 4.47
	SO_2	0.44 - 0.65
	PM	0.38 - 0.57
Supply Vessels[2]	NO_X	3.10 - 3.86
	CO	0.26 - 0.32
	SO_2	0.93 - 1.16
	PM_{10}	0.11- 0.14
	$PM_{2.5}$	0.10 - 0.13
Helicopter[3]	NO_X	0.15 – 0.30
	CO	0.01 – 0.02
	SO_2	1 - 2
	PM	0.003 – 0.007
Flaring	NO_x	1.99
	CO	9.05

[1] Emission range based on semi-submersible to a drill ship
[2]Emission range, newer vessel (2016) to older vessel (1997)
[3]Emission range based on distance to Project Area

2.9.1.2 Greenhouse Gas Emissions

Emissions of GHGs will also occur from the operation of the drilling installation, supply vessels, helicopters, and flaring during formation flow tests. The GHG emissions from the drilling installation, supply vessels, and helicopters were calculated using published emission factors from ECCC and the US EPA, and manufacturers data. For formation flow testing, GHG emissions were based on well flow test data provided by Statoil for a recent formation flow test in the Flemish Pass area.

The emission factors used to calculate the GHG emissions for the drilling installation, supply vessels, and helicopter are presented in Table 2.16 and the calculated emissions, by individual pollutant, for Project activities are presented in Table 2.17.

Table 2.16 Greenhouse Gas Emission Factors for the Drilling Installation, Supply Vessels and Helicopter

GHG	Project Activity		
	Drilling Installation (g/L)	Supply Vessel (g/kwh)	Helicopter (g/L)
CO_2	2,690	646	2,560
CH_4	0.133	0.004	0.029
N_2O	0.4	0.031	0.071
US EPA 2009; ECCC 2016d			

Table 2.17 Greenhouse Gas Emissions by Project Activity

	Greenhouse Gas Emissions (t CO_{2eq}/day)			
	CO_2	CH_4	N_2O	CO_2eq
Drilling Installtion[1]	460 - 679	0.58 - 0.84	20 - 30	481 - 710
Supply Vessels[2]	150 - 189	0.02 – 0.03	2.17 – 2.70	152 - 192
Helicopter[3]	13 - 26	0.004 - 0.007	0.11 - 0.22	13 - 26
Total	623 - 894	0.604 - 0.877	22.3 - 32.9	646 - 928
[1] Emission range based on semi-submersible to a drill ship [2]Emission range, newer vessel (2016) to older vessel (1997) [3] Emission range based on distance to each Project Area				

Note, for the drilling installation, for the purposes of GHG calculations and estimations, it is assumed that all six / eight engines on the drilling installation are operating at the same time at 100 percent power. As stated above, however, a combination of a number of engines running at reduced power are used. The Project is anticipated to emit approximately between 646 and 928 tonnes of CO_2 equivalent per day from fuel combustion for the drilling installation, helicopters, and supply vessels. The total annual reported GHG emissions for 2015 for the province of Newfoundland and Labrador is 4,925 kilotonnes of CO_2 equivalent per year (13.5 kilotonnes of CO_2 equivalent per day), and for Canada is 264,163 kilotonnes of CO_2 equivalent per year (723 kilotonnes of CO_2 equivalent per day) (Environment Canada 2017). The predicted daily CO_2 emissions for the Project therefore represent approximately 0.01 to 0.02 percent of Newfoundland and Labrador's average daily GHG emissions and 0.0003 percent of Canada's average daily GHG emissions.

Emissions of GHGs may also be generated as a result of flaring associated with formation flow testing. For the purposes of estimating GHG emissions from flaring, formation flow test data from a recent well drilled by Statoil was used. Based on the information provided, approximately 40,000 m^3 of an oil / gas mixture could be flared each day during a formation flow test. Therefore, approximately 5,223 tonnes of CO_2 equivalents could be emitted per day as a result of flaring during formation flow testing. It is conservatively estimated that based on historical drilling and formation flow testing data, over the life of the Project up to five wells could have a formation flow test. Assuming that these tests involved flaring, between 50,000 to 130,000 tonnes of CO_2 equivalents could be released over the life of the Project.

2.9.1.3 Summary and Potential for Accumulation and Interactions of Air Emissions (Cumulative Effects)

In summary, the above includes a description of the anticipated types and levels of Project-related air emissions and their contribution to regional ambient air quality and GHG levels. This analysis has shown that the Project will make a negligible contribution to same, and therefore will not result in or contribute to detectable effects on the atmospheric environment overall. The atmospheric environment has therefore not been considered as a separate VC in the Project-specific environmental effects assessment presented in this EIS.

In terms of potential cumulative environmental effects, the Project-related atmospheric emissions presented above have the potential to interact and accumulate with the emissions from other sources in the RSA and beyond, including other marine vessel traffic (including fishing vessels) in the area, other exploration activities (seismic, drilling, and others) and the operation of existing offshore oil production operations in the Jeanne d'Arc Basin (see Section 5.4 for an overview of air emissions from these facilities and their effects on ambient air quality in the region). In terms of other exploration activities, fishing, and other marine vessel traffic, the short-term and transient nature of these activities and thus their air emissions, as well as the types and levels of air emissions resulting from these activities, limits the potential for direct interaction with air emissions from this Project. Similarly, in terms of the existing production projects offshore Eastern Newfoundland, the locations of these sources with respect to the Project makes an interaction unlikely, especially one with the potential to result in a detectable (and especially, significant) effects. This is supported by results presented in the 2013 ESRF Air Emissions Study – Effects of Offshore Oil and Gas Production on Air Quality in Canada's East Coast Offshore Areas (Stantec 2013), which concluded that air emission concentrations (in this case NO_X) generally meet onshore ambient air quality regulations within 500 m of the emitting platform.

Although by considering the relative and overall contribution of Project emissions to local and regional air quality (as also influenced by other projects and activities) the above described analysis has inherently considered any potential cumulative effects, as noted above the Project will not result in detectable effects on regional air quality, nor will its emissions likely interact with those of other projects and activities. Therefore, there was no requirement to consider the atmospheric environment as a VC in the cumulative environmental effects assessment presented in this EIS (Chapter 14).

2.9.2 Hazardous and Non-hazardous Wastes

As outlined above, the Operator's EPP will include plans for the management of waste material during a drilling campaign. Hazardous wastes generated during the Project, including dangerous goods, will be stored in designated areas in appropriate containers/containment for transport to shore in compliance with the *Transportation of Dangerous Goods Act* and its regulations. Applicable approvals for the transportation, handling and temporary storage, of these hazardous wastes will be obtained as required. Hazardous wastes that may be produced and require management include 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 health professionals and stored in special containers before being sent to land for incineration. Non-hazardous wastes generated during the Project that are not allowed to be disposed overboard, will be stored in appropriate containers onboard, and transported back to shore. Non-hazardous wastes include domestic wastes, packaging material, scrap metal and other recyclables such as waste plastic. Hazardous and non-hazardous wastes shipped to shore for disposal will be collected on-shore by a third-party contractor for disposal of the waste at an approved facility and in compliance with federal and provincial regulations and requirements.

2.9.3 Drilling Waste

The primary wastes associated with drilling a well are drill mud and cuttings (either WBM or SBM), and cement.

2.9.3.1 Drill Mud and Cuttings

A combination of WBM and SBM will be used to drill the wells. Wastes generated from drilling include drilling muds and cuttings that retain a portion of the drilling mud. Drilling wastes will be disposed of in accordance with the OWTG. The results of drilling waste dispersion modeling are provided in Chapter 8.

WBM is comprised primarily of water, barite, and bentonite. Salt or fresh water is the carrier liquid for WBM. WBM and SBM additives could typically include barite, bentonite or other clays, silicates, lignite, caustic soda, sodium carbonate/bicarbonate, inorganic salts, surfactants, corrosion inhibitors, lubricants and other additives for unique drilling problems such as viscosity and mobility (Thomas 1984; GESAMP 1993). Chemicals used in drilling muds (SBM and WBM) are screened in accordance with the Operator's chemical screening and management practices per C-NLOPB and CNSOPB (2009), and are classified under the offshore chemical notification system as substances which pose little or no risk to the environment.

Barite (barium sulphate) is used to control mud density, which helps balance formation pressures within the well. Bentonite clay is a viscosifier, which thickens the mud to suspend and carry drill cuttings to the surface.

The carrier fluid in SBM is a synthetic base fluid which can be made up of internal olefins, alpha olefins, polyalphaolefins, paraffins, esters or blends of these materials (BP 2016). Offshore Newfoundland, most operators currently use PureDrill IA35-LV as the base fluid for SBM (Petro-Canada 2017).

The initial surface sections are normally drilled riserless with WBM, with cuttings and water-based fluids discharged at depth. Water-based cuttings are discharged for the first sections of the well and in accordance with the OWTG. Once the riser is connected, SBM is generally used. Synthetic-based cuttings are treated prior to discharge to the sea as per the OWTG. For SBM cuttings, the drilling installation will be equipped with solids control equipment for cuttings management for the treatment of the SBM cuttings prior to discharge. Typically, a combination of shale shakers and cuttings dryers / centrifuges are used to collect the SBM from the cuttings and treat SBM cuttings. Shale shakers are a system of fine and course mesh screens that collect cuttings while enabling the fluid to pass through for collection. The cuttings are sent to a cuttings dryer or high speed centrifuge which separates the drilling fluid from the cuttings. The treated cuttings are discharged overboard when the base oil retained on cuttings is below a threshold of 6.9 g/100g or less oil on wet solids. Excess or spent SBM that can no longer be used is sent to shore for disposal at an approved waste management facility. Per the C-NLOPB OA process, the Operator will assess available drill cuttings treatment technology with the intent of using proven and practicable best technology considering that technologies may change over the temporal scope of the Project.

Drill mud and cuttings discharge volumes for different hole sections and mud type are summarized in Table 2.18.

Table 2.18 Drill Mud and Cuttings Discharge Volumes

Open Hole Section (Hole Diameter in inches)	Casing OD Section length (m)	Casing ID Mud type	Cuttings Volume per day	
			Metric ton (MT)[1]	m³
2,700 m Water Depth - Northern Project Area Modelling Location				
Conductor (42)	75	Seawater/WBM	207.7	80
Surface (26)	700	Seawater/WBM	675	260
Intermediate (17.5)	1,500	SBM	363.4	140
Production (12.25)	2,200	SBM	155.8	60
Total WBM Cuttings Discharge (NPA Well)[2]			882.6	340
Total SBM Cuttings Discharge (NPA Well)[2]			519.2	200
WBM Cuttings Discharge Rate (per well section/per day)[3]				
Conductor			69.2	26.7
Surface			112.5	43.3
SBM Cuttings Discharge Rate (per well section/per day)[3]				
Intermediate			36.3	14
Production			9.7	3.75
SBM retained on cuttings				
TOTAL Cuttings Volume Discharge (NPA Well)			1,401.8	540

Table 2.18 Drill Mud and Cuttings Discharge Volumes

Open Hole Section (Hole Diameter in inches)	Casing OD Section length (m)	Casing ID Mud type	Cuttings Volume per day	
			Metric ton (MT)[1]	m^3
1,100 m Water Depth - Eastern Project Area Modelling Location				
Conductor (42)	75	Seawater/WBM	207.7	80
Surface (26)	750	Seawater/WBM	363.4	140
Intermediate (17.5)	1,500	SBM	324.5	125
Production (12.25)	2,300	SBM	246.6	95
Total WBM Cuttings Discharge (EPA Well)			571.1	220
SBM Cuttings Discharge (EPA Well)			571.1	220
WBM Cuttings Discharge Rate (per well section/per day)				
Conductor			103.8	40
Surface			181.7	70
SBM Cuttings Discharge Rate (per well section/per day)				
Intermediate			40.6	15.6
Production			24.7	9.5
SBM retained on cuttings				
TOTAL Cuttings Volume Discharge (EPA Well)			1,142.2	440
362 m Water Depth - Southern Project Area Modelling Location				
Conductor (42)	75	Seawater/WBM	207.7	80
Surface (26)	750	Seawater/WBM	324.5	125
Intermediate (17.5)	1,700	SBM	207.7	80
Production (12.25)	2,300	SBM	65	25
Total WBM Cuttings Discharge (SPA Well)			532.18	205
Total SBM Cuttings Discharge (SPA Well)			272.58	105
WBM Cuttings Discharge Rate (per well section/per day)				
Conductor			103.8	40
Surface			162.3	62.5
SBM Cuttings Discharge Rate (per well section/per day)				
Intermediate			26	10
Production			6.5	2.5
SBM retained on cuttings				
TOTAL Cuttings Volume Discharge (SPA Well)			804.76	310
89 m Water Depth - Jeanne d’Arc Basin Modelling Location				
Conductor (42)	79	Seawater/WBM	238.8	92
Surface (26)	379	Seawater/WBM	345.3	133
Intermediate (17.5)	1,729	SBM	449.1	173
Production (12.25)	2,838	SBM	184.3	71

Table 2.18 Drill Mud and Cuttings Discharge Volumes

Open Hole Section (Hole Diameter in inches)	Casing OD Section length (m)	Casing ID Mud type	Cuttings Volume per day	
			Metric ton (MT)[1]	m³
WBM Cuttings Discharge (JDB Well)			584.1	225
SBM Cuttings Discharge (JDB Well)			633.4	244
WBM Cuttings Discharge Rate (per well section/per day)				
Conductor			119.4	46
Surface			172.6	66.5
SBM Cuttings Discharge Rate (per well section/per day)				
Intermediate			56.1	21.6
Production			18.4	7.1
SBM retained on cuttings				
TOTAL Cuttings Volume Discharge (JBD Well)			1,217.5	469

Notes:
[1]The model assumes specific weight of 2,596 kg/m^3
[2]This total is the volume for the entire well. E.g., the NPA well in its entirety would discharge 340 m^3 of WBM, and 200 m^3 of SBM.
[3]These discharge rates are completed for each section of the well, as amounts will be discharged at different rates for each hole section, as opposed to being discharged equally throughout the well completion.

2.9.3.2 Cement

Cement constitutes a part of the well barrier envelope and is used during casing installation and plug and abandonment. For the initial riserless sections of the well, a spacer fluid is typically pumped ahead of the cement which is pumped down the drillstring and up the outside of the casing, with cement (and spacer fluid) returns to the seabed in riserless sections. For casing operations with the riser installed, cementing / drilling fluid interface is returned up the riser to the rig. For most casing cement jobs, the cement / spacer mud / mud interface will be left in the annulus; exceptions include lines and plugs, where cement may be circulated back to surface. After every cementing operation, the cement unit must be cleaned / rinsed to prevent cement from hardening in the mixing tanks and liners. Each cleaning operation typically results in a discharge of approximately 1.5 m^3 of water (80 percent) and residual cement slurry (20 percent) below surface. For a typical well, there are three to four casing cement jobs and several plug and abandonment (two to six) plugs. Therefore, total cement slurry discharges from a typical well operation ranges between 7.5 and 15 m^3. During initial commissioning and testing of a cementing unit, a small volume "test mix" may also be performed (less than 10 m^3) which is also discharged to sea. Unused cement bulks and cementing additives are returned to shore for future re-use or disposed of at an approved facility.

Drilled (hard) cement during the operation are discharged to seabed / sea when riserless. When drilling with the riser installed, drilled cement is processed by shakers and discharged overboard or captured in cutting skips and transported to shore. Although unlikely, cement unit failures, premature set up of cement, or environmental conditions (weather) may require a cement job to be aborted. If this occurs when drilling riserless, the cement is circulated out of the well to seabed. However, if the riser is installed, the cement is circulated out of well via the riser and may be discharged at surface. In this instance, a maximum of 200 m^3 of cement slurry and 20 m^3 of water based spacer fluids could be discharged.

2.9.4 Liquid Wastes

The following liquid wastes, if generated, will be treated and managed in accordance with the OWTG:

- Produced water – formation flow test may result in produced water, including formation fluids, being brought to the surface, in which case it may be flared or treated on the drilling installation in accordance with the OWTG prior to discharge
- Bilge and deck drainage water - bilge water is seawater that enters parts of the drilling installation, passing through pieces of equipment as it does so. Deck drainage water occurs on the surface decks of the drilling installation, resulting from precipitation and sea spray, as well as operational activities such as wash-down, fire control testing or equipment testing. Bilge and deck drainage water often can come in contact with equipment and machinery, and may be contaminated with oil. As provided for in the OWTG, the limit of residual oil concentration in the water is 15 mg/L if it is to be discharged. Bilge and deck drainage water will be managed in accordance with the OWTG
- Ballast water - ballast water is loaded into and discharged from drilling installation and supply vessels as required for stability and balance (e.g., managing inclement weather conditions). Ballast water is stored in dedicated tanks on the vessel, and does not make contact with oil or equipment. Ballast water will be discharged according to IMO Ballast Water Management Regulations, and Transport Canada's Ballast Water Control and Management Regulations, and the OWTG
- Grey / black water (sewage) - grey water will be generated from galley, washing, and laundry facilities, and black water will be generated from the accommodation areas (sewage). Consistent with the OWTG, sewage will be macerated so that particles are less than 6 mm in size prior to discharge
- Cooling water - cooling water may be used to cool equipment and engines on the drilling installation. If required, a small volume of seawater is pumped onto the drilling installation and passed over or through equipment and engines using heat exchangers. The seawater may be treated with biocides or through electrolysis to prevent microbiotic contamination of machinery. If biocides are used, they will be selected using the Operator's chemical selection system and consistent with the OCSG, and will be discharged in accordance with the OWTG. The temperature of the discharged cooling water will be warmer than the receiving seawater, but the seawater temperature will quickly achieve background levels
- Fire control water – fire prevention and response systems, including a dedicated fire water system, will be used on the drilling installation and supply vessels

- BOP testing fluids - To facilitate proper functioning of the BOP for safe well operations, a regular program of function testing and pressure testing the BOP mechanism is required. Function testing is carried out every seven days, while pressure testing is carried out every 14 to 21 days, depending upon ongoing drilling installation operations. BOP systems use a water-based hydraulic fluid. Typically, the BOP fluid consists of fresh water and a solution of water-based Erifon and glycol. Approximately 35 m^3 of this solution could be discharged per month during testing. Occasionally, it may be required to disconnect the Lower Marine Riser Package from the subsea BOP and move the drilling installation to a safe location when weather events pass through the area, or to pull the BOP to surface if maintenance is required. When the BOP is disconnected, the fluid contained in the subsea accumulator bottles may be discharged. The total estimated control fluid discharged in each disconnection of the Lower Marine Riser Package is approximately 0.7 m^3. The total estimated control fluid discharged in each BOP pull is approximately 3.3 m^3. BOP fluids are screened for acceptability prior to use
- Food waste – food waste will be reduced prior to discharge, in accordance with the OWTG
- Liquid wastes such as waste chemicals, cooking oils or lubricating oils, that do not meet the performance, sampling and analysis targets set out in the OWTG are stored and transported to shore for disposal at an approved facility

2.9.5 Heat, Light, and Sound Emissions

Sound emissions will typically be generated during regular drilling operations and geophysical surveys. Light emissions will be generated at night on the drilling installation, through flaring when required during a formation flow test. Heat will be generated primarily through exhaust. Additional information on light is provided in Section 9.3.

2.9.5.1 Light and Heat Emissions

The Project will present several sources of artificial lighting during drilling activities. The duration at any one location will be less than 65 days, with some lighting operating 24 hours a day. This includes navigation and deck lighting for the drilling installation and supply vessels necessary for maritime safety and crew safety requirements.

Flaring activity during a formation flow test will generate light and thermal emissions. Formation flow testing, as described in Section 2.5.2 is generally carried out on a temporary basis at the end of drilling operations. During formation flow testing it is possible that short, intermittent periods of flaring can last up to three days, or up to five days if an extended flow test is required

Heat emissions generated by engines and flaring will be dissipated to the atmosphere without likely interactions to receptors.

2.9.5.2 Sound Emissions

Sound will be generated underwater during the operation of the drilling installation and supply vessels. The level of sound will be dependent on the type of drilling installation being used and method of positioning. Underwater sound generated from a drilling installation is continuous during a drilling program, while underwater sound from VSP operations is a temporary sound source (e.g., typically completed within 48 hours (refer to Section 2.5.2). The extent to which sound travels is determined by water depth, salinity, and temperature. An overview of underwater ambient sound and sound from drilling operations is provided in Section 5.6 and is based on two Project-specific reports, which are appended to this EIS:

- Eastern Newfoundland Drilling Noise Assessment: Qualitative Assessment of Radiated Sound Levels and Acoustic Propagation Conditions (Appendix C)
- Marine Mammals and Sound Sources in the Flemish Pass: Analysis from 2014 and 2015 Acoustic Recordings (Appendix D)

Appendix C includes a summary of ambient noise levels in the Project Area based on data collected along Canada's east coast in 2015/2016, a summary of environmental parameters in the Eastern Newfoundland Exploration Drilling Project Area, the expected Project underwater source levels based on the type of drilling installation, DP systems and VSP arrays likely to be used in this Project, and a qualitative comparison of environmental properties and expected source levels between the Project Area and specifications and those considered in the acoustic modeling conducted for the Scotian Basin Exploration Drilling Project (Appendix C). The estimated sound levels attributable to the operation of the drilling installation were qualitatively assessed by comparison to the previously modelled Scotian Basin Exploration Drilling project, as the water depths and geoacoustic profiles in the deep-water sites for the proposed activity are similar to those from the Scotian Basin project.

Appendix D reviews acoustic recordings collected by Statoil in the Flemish Pass between June and October 2014, and from May to September 2015. The data were analyzed to characterize the baseline soundscape, identify the presence of marine mammals, and characterize the soundscape during Statoil's 2014-2016 drilling program. Drilling operations by the semi-submersible West Hercules generated sound levels similar to those previously reported for the Stena IceMAX off Nova Scotia.

Atmospheric sound is not of concern for the Project given the anticipated low levels of atmospheric sound emissions, the limited transmission of underwater sound above the surface and location of receptors. Helicopter traffic will generate atmospheric sound at the airport, in transit and at the drilling installation. However, with the use of the existing St. John's International airport potential effects on human receptors is reduced. Helicopters are required to avoid important bird areas, so potential interactions with birds are reduced. Given the distance from the Project Area to shore (over 250 km) and occupational and safety requirements on the drilling installation, there will be no likely interaction with human receptors.

2.10 Alternative Means of Carrying Out the Project

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

Consistent with the Operational Policy Statement: Addressing "Purpose of" and "Alternative Means" under CEAA 2012 (CEA Agency 2013b) and the EIS Guidelines, the process for consideration of alternative means of carrying out the Project includes the following steps:

- Identification of alternative means of carrying out the Project
- Consideration of the environmental effects of alternative means are deemed to be technically and economically feasible
- Selection of the preferred alternative means of carrying out the Project, based on the relative consideration of effect
- Assessment of environmental effects of the preferred alternative

2.10.1 Identification and Evaluation of Alternatives

The EIS Guidelines require consideration of the alternative means for the following Project aspects:

- Drilling fluids selection
- Drilling Installation selection
- Drilling waste management
- Water management
- Location of final effluent discharge points
- Offshore drilling installation lighting
- Formation flow testing and flaring at night
- Chemical selection

The alternatives within each Project aspect are identified, and if determined to be technically and economically feasible, without affecting safety and reliability of operations, are evaluated in terms of their potential environmental effects. If an option is not considered to be technically feasible, no further assessment is undertaken. Alternative technology considered must be available in the market and proven for use in a similar operating environment. Economic feasibility includes consideration of capital and operational expenditures. Effects on expenditures can be direct (e.g., equipment and personnel requirements) or indirect (e.g., schedule delays).

Based on the alternatives analysis, the preferred option is selected and this preferred option is then carried through the EIS as a Project component/activity for a more detailed assessment (please refer to Chapter 4).

Several of these project aspects are not finalized. The options considered below will be finalized and confirmed with the C-NLOPB at the OA application and authorization phase. In assessing alternative means, each of the identified alternative means of carrying out the project are evaluated, and the associated results are summarized in this section.

2.10.1.1 Drilling Fluids Selection

Well drilling typically involves the use of both WBM and SBM as drilling fluid. For this Project, both WBM and SBM will be used. While WBM and SBM are both technically and economically feasible for drilling, the choice of either or both fluids is dependent on well design and geological features. Refer to Section 2.9.3 for more information regarding WBM and SBM.

A specific SBM drilling fluid has not yet been identified for the Project. Regardless of the final decision, the selection of drill fluids will be conducted in accordance with the Offshore Chemical Selection Guidelines (NEB et al. 2009) and their management will be carried out in accordance with the OWTG.

The Operator considers best practice and related offset well history in drilling fluid selection during well design. Based on this information, and in previous history drilling in deep waters of the Flemish Pass, seawater and WBM will be used in the riserless hole sections. When drilling with the riser, below the surface casing, SBM will be used. This combination of WBM and SBM drilling fluid system has been proven in previous exploration drilling campaigns.

The use of SBM is superior to WBM for the following technical reasons:

Wellbore stability

SBM provides greater hole stability and maximizes the opportunity for casing strings to be installed and properly cemented at the desired depths. The use of WBM would likely result in increased hole washouts, which would increase the volumes of drilling fluid and drill cuttings that will be discharged to the environment. The use of WBM would also likely result in increased drilling-related issues such as stuck pipe and hole collapse, thereby increasing operational and scheduling costs.

Gas hydrate inhibition

The more free water available in the fluid, the easier hydrates form around the wellhead and the BOP stack. WBM does not provide adequate hydrate protection. The SBM design is used to mitigate against hydrate formation at the expected seabed temperature and wellhead pressure, thereby reducing potential safety concerns while drilling.

Casing wear

SBM can reduce casing, riser and drill pipe wear since it has a lower coefficient of friction and a higher lubricity than WBM. The use of WBM could accelerate wear, which may compromise the integrity of casing in the case of extended drilling operations.

Reusable fluid

SBM typically has a longer usable shelf life than WBM and the potential for multiple reuses is much greater. This would ultimately result in less environmental effects for drilling fluid disposal (either at site in the case of WBM, or in shorebase waste management facility for SBM).

As described in Section 2.9.3, for the use of SBM, the best available treatment technology available will be used on-board the drilling installation to achieve the synthetic oil-on-cuttings (SOC) value outlined in Section 2.4 of the OWTG.

A high-level comparison between WBM and SBM is provided in Table 2.19. The preferred option is the use of a combination of WBM and SBM. The EIS considers the use of both fluids in the assessment of potential environmental effects.

Table 2.19 Comparison of Water-based and Synthetic-based Drilling Muds

<table>
<tr><th>Option</th><th>Legal Acceptability</th><th>Technical Feasibility</th><th>Economic Feasibility</th><th>Potential Environmental Issues</th><th>Preferred Option</th></tr>
<tr><td>WBM</td><td>YES
Use and management in accordance with OWTG and OSCG</td><td>NO
Technically inferior at deeper sections of well</td><td>NO
Potential economic increases if used at deeper sections of well</td><td rowspan="2">WBM acceptable for upper hole sections; SBM acceptable for lower well sections.
For both options, it is assumed appropriate controls are implemented and OSCG is followed.
Both options considered in assessment of potential environmental effects</td><td>✓
Use of WBM for initial well sections when drilling without riser installed</td></tr>
<tr><td>SBM</td><td>YES</td><td>YES
Technically superior for deeper sections of well</td><td>YES</td><td>✓
SBM to be used at lower well sections, when riser installed.</td></tr>
</table>

2.10.1.2 Drilling Installation Selection

There are three main types of drilling installations which are used for offshore drilling: a jack-up rig, a semi-submersible drill rig, and a drill ship. The technical feasibility of each of these alternatives is largely dependent on drilling water depths. In water depths less than 100 m, a jack-up is a technically feasible option. However, water depths in the Project Area range from approximately 80 to 3,800 m, and so while a jack-up may be feasible in the shallow water depths, it is not considered as it requires more limited metocean conditions for installation and would not enable flexibility to drill on the deeper licences.

In shallower waters in the Project Area, drilling activities can be carried out with a floating semi-submersible. Semi-submersibles can be used in either shallow or deep waters; they can be moored via anchors in shallower waters, or use DP to maintain location in deep water. In deeper waters (greater than 500 m), semi-submersibles or drill ships are the preferred drilling installation. Drill ships maintain position through dynamic positioning. The drilling installations must be capable of drilling year-round and in the environmental conditions predominant in the North Atlantic. Over the life of the Project, there may be multiple drilling installations actively engaged in drilling activities in the Project Area at any one time. The process for drilling installation selection will evaluate technical feasibility in consideration of previous operating history, water depths and environmental operating conditions in the Project Area. A competitive process will be used to select the drilling installation(s) for the Project. Table 2.20 provides a comparison of drilling installation options.

Table 2.20 Comparison of Drilling Installation Options

Option	Legal Acceptability	Technical Feasibility	Economic Feasibility	Potential Environmental Issues	Preferred Option
Semi-submersible	YES	YES	YES	Both semi-submersible and drill ship options considered acceptable assuming appropriate controls are implemented	✓ Preferred option not yet chosen. Both semi-submersibles and drill ships are considered in assessment of potential environmental effects
Drill ship	YES	YES	YES		

2.10.1.3 Drilling Waste Management

Drilling wastes will be dependent on the drilling fluid selected and will be managed in accordance with the OWTG (NEB et al. 2010). There are three potential options for the management of drilling waste: disposal at sea, shipping waste to shore, and re-injection of waste.

In accordance with the OWTG, WBM and associated cuttings can be discharged at sea without treatment. With the use of WBM for the initial sections of the well, during riserless drilling, WBM muds and cuttings cannot be returned to the drilling installation for collection and disposal by an alternate method (i.e., ship to shore). The only technically feasible option for the management of WBM and cuttings is when the flow stream of the fluid and cuttings directly disperses at the seafloor. Other options are not assessed. When drilling without a riser, an option to discharge WBM muds and cuttings away from the wellhead is with the use of a cuttings transfer system (CTS). With CTS, a hose is connected to the wellhead and cuttings are pumped to a designated location on the seabed (up to approximately 500 m away from the well location). This option will be evaluated as a potential mitigation for WBM discharge should the results of the pre-drill coral survey and risk assessment indicate that mitigation is required and relocation of the well is not feasible.

The options for disposal of SBM drill cuttings include overboard discharge after treatment, re-injection into a disposal well or shipped to shore for disposal at an approved waste management facility.

There are no approved treatment facilities in the province of Newfoundland and Labrador to treat and dispose of SBM cuttings. The cuttings would have to be shipped to shore in Newfoundland, and then trucked to the nearest waste treatment facility in eastern Canada for a total distance of approximately 1,300 km. There are additional safety and environmental risks with increased handling, transfer and transportation. While ship-to-shore reduces potential effects on the marine environment, there is the potential for increased environmental effects due to increased transport-related air emissions. There is also potential for additional effects to be realized onshore related to onshore treatment and disposal (e.g., potential habitat loss). With respect to economic feasibility, there are increased costs associated with transportation and operational delays if waiting on a supply vessel to ship the material. There is also potential for additional effects to be realized onshore related to onshore treatment and disposal (e.g., potential habitat loss).

Re-injection involves processing cuttings waste into a slurry and pumping it into a dedicated disposal well. Re-injection from fixed wellhead platforms is a proven technology, but execution from a drilling installation is not practical. The process requires specialized equipment and a viable subsurface injection zone near the wellsite. Additional equipment and a large storage capacity is required on the drilling installation, which adds both complexity and cost to the operation. With geological uncertainty inherent to exploration drilling, and the economics required to install the additional equipment, re-injection of cuttings in a dedicated disposal well is not considered to be a technically or economically feasible alternative for an exploration drilling program.

As described in Section 2.9.3, the preferred alternative for the Project is the disposal of WBM at sea and treatment of SBM cuttings on the drilling installation prior to discharge at sea. The recovered SBM is reconditioned and reused until it is spent, at which point it is returned to shore for disposal at an approved facility. A comparison of drilling waste disposal options is provided in Table 2.21.

Table 2.21 Comparison of Drilling Waste Disposal Options

Fluid Type	Option	Legal Acceptability	Technical Feasibility	Economic Feasibility	Potential Environmental Issues	Preferred Option
WBM	Disposal at Sea	YES	YES Will only be used during riserless drilling; therefore cannot be returned to drilling installation for collection	N/A	Localized effects on seafloor	✓ Disposal at sea during riserless drilling
	Disposal on shore	YES	NO Will only be used during riserless drilling; therefore, cannot be returned to drilling installation for collection	✗ Not considered as an option as not technically feasible		
	Offshore re-injection	YES	NO	✗ Not considered as an option as not technically feasible		

Table 2.21 Comparison of Drilling Waste Disposal Options

Fluid Type	Option	Legal Acceptability	Technical Feasibility	Economic Feasibility	Potential Environmental Issues	Preferred Option
SBM	Disposal at Sea	YES	YES	YES	Localized effects on seafloor	✓
	Disposal on shore	YES	YES	YES But increased costs from increased transportation and operational delays	Increase in GHG emissions, larger environmental footprint	✗
	Offshore re-injection	YES	NO	✗ Not considered a technically feasible option and not assessed		

2.10.1.4 Water Management and Location of Final Effluent Discharge Points

The discharge points on a drilling installation are fixed and cannot be changed or re-configured. A drilling installation has yet to be selected for the Project. Therefore, alternative locations for effluent discharge points are not available. Typically, effluent discharge points are located near or under the water's surface. Similarly, the water management system (e.g., intake, storage, distribution, discharge) will be dependent on the configuration of the drilling installation's water system, and alternative systems will not be available. In both cases, a Certificate of Fitness for the drilling installation will be required, and obtained from a certifying authority, in accordance with requirements of the Accord Acts and an OA from the C-NLOPB, to confirm that the effluent discharge and water management system comply with relevant legislation.

2.10.1.5 Offshore Drilling Installation Lighting

Lighting is required under Canadian and international law. Deck lighting is required 24 hours a day for maritime and crew safety. Therefore, a reduction of lighting on the drilling installation as an alternative means is not practical given the possibility of compromising the safety of drilling installation personnel and / or third-party navigators.

Spectral modified lighting, which uses green light (approximately 510 nm) has been tested on offshore platforms and has demonstrated a reduced effect on migratory birds efficiency (Marquenie et al. 2014). However, this technology has not been proven to be technically or economically feasible at a commercial scale. Although this form of lighting has been shown to satisfy regulatory requirements in some jurisdictions, implementation in the offshore oil and gas industry is restricted by commercial availability, limited capability in extreme weather, safety concerns related to helicopter approach / landing when helicopter windows are glazed with a UV-blue filter ("Military Clear" windshields required), and lower energy efficiency (Marquenie et al. 2014).

Due to operational and regulatory requirements for lighting, light levels will be maintained at level that does not impede the safety of the workplace or drilling operations.

A comparison of lighting options is provided in Table 2.22.

Table 2.22 Comparison of Lighting Options

<table>
<tr><th>Option</th><th>Legal Acceptability</th><th>Technical Feasibility</th><th>Economic Feasibility</th><th>Potential Environmental Issues</th><th>Preferred Option</th></tr>
<tr><td>No or limited lighting</td><td>NO – required by Canadian and international regulations</td><td colspan="4">✗
Not considered as an option due to regulatory requirements</td></tr>
<tr><td>Standard lighting</td><td>YES</td><td>YES</td><td>YES</td><td>Potential localized effects on migratory birds</td><td>✓</td></tr>
<tr><td>Spectral modified lighting</td><td>YES</td><td>NO
Not yet considered ready for commercial use</td><td>NO
Not considered commercially viable</td><td colspan="2">✗
Not considered as an option due to technical/economic limitations</td></tr>
</table>

2.10.1.6 Formation Flow Testing and Nighttime Flaring

As described in Section 2.5.2 a formation flow test is a regulatory requirement in order to obtain an SDL. Depending on the type of data required, either a formation flow test with flaring using production equipment onboard the drilling installation, or a Formation Testing While Tripping, where production equipment is not required and flaring is not carried out, may be undertaken.

Depending on data requirements by the C-NLOPB, either one of the formation flow test options may be carried out. If a formation flow test with flaring is required, flaring would occur to safely dispose of hydrocarbons that may come to surface. Therefore, the option of no flaring cannot be considered with this type of testing.

An alternative is to manage the timing of flaring. Flaring could be restricted to daylight in fair weather conditions, to reduce light generation during night and poor weather when visibility is low. However, avoiding these periods during 24-hour operations on the drilling installation could compromise information generated by the formation flow test. If flaring could not be carried out continuously, it would mean a prolonged period for formation flow testing, which could lead to increased safety risk due to exposure of personnel to pressurized equipment containing live hydrocarbons, and increased operational costs.

Flaring is expected to be intermittent and short-term when it occurs, lasting two to three days or up to five days for an extended flow test. The C-NLOPB, under its "Measures to Protect and Monitor

Seabirds in Petroleum-Related Activity in the Canada-NL Offshore Area" requires operators to provide notification of plans to flare. The C-NLOPB would subsequently consult with ECCC-Canadian Wildlife Service (CWS) to determine a safe timeline for flaring to reduce effects on migratory birds.

If an Formation Testing While Tripping was carried out, flaring would not occur. However, Formation Testing While Tripping may not be able to be performed if certain data is required, per C-NLOPB requirements, which can only be obtained from a formation flow test with flaring. A comparison of flaring options is provided in Table 2.23.

Table 2.23 Comparison of Flaring at Night Options – Conventional Formation Flow Test

Option	Legal Acceptability	Technical Feasibility	Economic Feasibility	Potential Environmental Issues	Preferred Option
No flaring	NO	Not considered as an option due to regulatory and safety requirements			
Reduced flaring (no flaring at night or during low-visibility weather)	YES	YES Note – potential to result in compromised data from formation flow test; increased safety risk	YES Note – increased cost and potential schedule extension	Reduced potential effects compared with standard flaring	✗
Flaring as required	YES	YES	YES	Potential localized effects on migratory birds; C-NLOPB will consult with ECCC-CWS to determine safe timeline for flaring	✓
Formation Testing While Tripping	YES	YES	YES	No Flaring	✓

2.10.1.7 Chemical Selection

As the EIS is prepared prior to well planning or drilling program design, information regarding chemicals required for drilling are not yet determined nor have alternatives been identified. However, in terms of chemical selection, the Operator has established chemical selection and management processes, which will be used during well planning and design, prior to the start of drilling. The chemical selection and management process is aligned with the OCSG, and other regulatory requirements (Table 2.24) to enable the selection of chemicals that, once discharged at sea, would have the least effect on the receiving environment.

Table 2.24 Legislation and Guidelines for Offshore Chemical Management

Legislation	Regulatory Authority	Relevance
Canadian Environmental Protection Act (CEPA)	ECCC	Provides for notification / control of certain manufactured and imported substances. It includes the Domestic Substances List (DSL), which is a list of substances approved for use in Canada. Schedule 1 of the DSL includes substances considered toxic and associated restrictions or phase-out requirements.
Fisheries Act	DFO; ECCC	Prohibits deposition of toxic / harmful substances into fish-bearing waters.
Hazardous Product Act	Health Canada	Chemical classification and hazard communication standards.
Migratory Birds Convention Act, 1994	ECCC	Prohibits deposition of harmful substances into waters / areas frequented by migratory birds.
Pest Control Products Act	Health Canada	Regulates importation, sale, and use of pest control products including biocides used in offshore oil and gas operations.
Offshore Chemical Selection Guidelines (OCSG) (2009)	NEB, CNSOPB and C-NLOPB	Framework for selection of drilling and production chemicals for use and potential discharge in the offshore marine environment.

The OCSG provides a procedure and criteria for offshore chemical selection. Its objective is to promote the selection of lower toxicity chemicals to reduce the potential environmental effects of a discharge where technically feasible. The OCSG chemical selection process is presented in Figure 2-6.

2.10.1.7.1 Proposal for Use: Initial Screening and Regulatory Controls Identification

As shown in Figure 2-6 (Steps 1-4), the proposed chemical is screened to determine whether it is restricted for use by other legislation, as identified in Table 2.24. Screening 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 may be placed on:

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

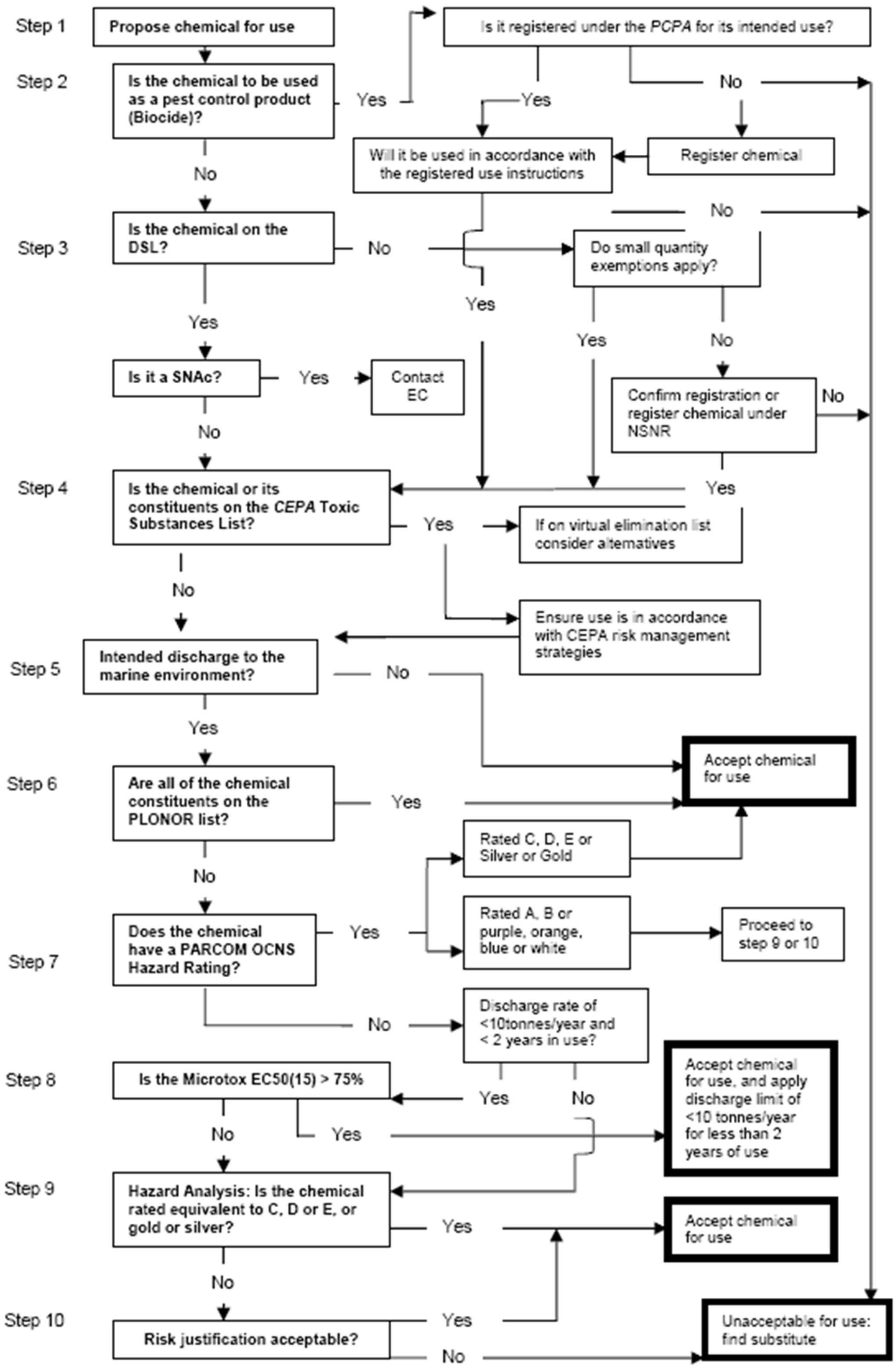


Figure 2-6 Chemical Selection Flowchart (NEB et al. 2009)

2.10.1.7.2 Chemicals Intended for Marine Discharge: Toxicity Assessment

For those chemicals that are proposed for discharge to marine environment, further assessment is undertaken (Steps 5-10). This assessment evaluates the potential toxicity of the proposed chemicals (and any constituents of the chemical as applicable), and to establish if additional restrictions, controls or prohibitions are required.

As outlined in Figure 2-6, chemicals intended for discharge to the marine environment are reviewed against various criteria. Chemicals intended for discharge to the marine environment must:

- Be included on the Oil Spill Prevention, Administration and Response (OSPAR) list of substances that Pose Little or No Risk (PLONOR) to the environment, or
- Meet certain requirements for hazard classification under the OCNS; or
- Pass a Microtox test (i.e., toxicity bioassay); or
- Uundergo a chemical-specific hazard assessment in accordance with the OCNS model; or
- Demonstrate that the risk of its use is justified through demonstration to the C-NLOPB that discharge of the chemical will meet OCSG objectives

Each criterion, as outlined below, is reviewed for applicability before preceding to the next step.

- 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 the proposed chemical that is intended for discharge to the marine environment is not included on the OSPAR PLONOR list, it is reviewed to determine the Offshore Chemical Notification Scheme (OCNS) hazard rating. This scheme ranks chemical products per 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 then 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), the chemical is considered acceptable for use and discharge.
- Microtox Test and Chemical-Specific Hazard Assessment: Where a proposed chemical intended for discharge does not have an OCNS rating, the Operator will work with the chemical contractors to undertake toxicity testing (Microtox test) to determine the potential toxicity of the chemical. If the chemical passes the test and is considered non-toxic, restrictions may be required 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.

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

Based on previous drilling experience by the Operator, the following categories of chemicals are anticipated to be required during the Project. Note, not all of these types of chemicals would be intended for discharge to the marine environment.

- 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
- biocides

A Material Safety Data Sheet (MSDS) is available for chemicals on board the drilling installation.

2.11 Environmental Planning and Management

The Operator has a clear goal to facilitate sustainable development and is committed to reducing environmental effects. This section introduces Statoil's Safety and Sustainability policy, the Management System and how it will be implemented for the Project.

The Operator will implement and adhere to relevant environmental mitigation requirements outlined in applicable legislation and regulations, including those committed to in this EIS, and eventually required as enforceable conditions of an EA approval. This will include requiring its contactors and subcontracts to implement and adhere to those mitigation measures and compliance standards that apply to their specific work scopes, which will be required and enforced through its relevant commercial and contractual arrangements with these providers or goods and services to the Project.

2.11.1 Safety and Sustainability Policies

Statoil's Safety and Sustainability policies are two of several policies included in the Statoil Book, which forms the foundation of how we conduct our business. We will use natural resources efficiently, and will provide energy which supports sustainable development.

2.11.1.1 Our Approach to Safety

We will ensure safe operations which protect people, the environment, communities and material assets. We believe that accidents can be prevented.

<u>We are committed to:</u>

- Integrating safety in the way we do business
- Improving safety performance in all our activities
- Demonstrating the importance of safety through hands-on leadership and behaviour
- Openness in all safety issues and active engagement with stakeholders

<u>How we work:</u>

- We take responsibility for the safety of ourselves and others
- We work systematically to understand and manage risk
- We provide our people with the necessary resources, equipment and training to deliver in accordance with their designated responsibilities
- We cooperate with our contractors and suppliers on the basis of mutual respect
- We stop unsafe acts and operations
- We aim for a safe and attractive working environment characterized by respect, trust and cooperation
- We monitor risk related to the working environment, and we monitor the occupational health of our people
- We establish work processes as well as goals and performance indicators to control, measure and improve these processes
- We run safety improvement processes based on surveys and risk assessments, and we involve our people in this work
- If accidents occur, our emergency response organization will do its utmost to reduce injury and loss. Saving lives is our highest priority
- We transform lessons learned into improved safety measures through continuous learning

2.11.1.2 Our Approach to Sustainability

We contribute to sustainable development through our core activities wherever we work. We use natural resources efficiently, and provide energy which supports sustainable development.

We are committed to:

- Integrating sustainability in the way we do business
- Contributing to the development of sustainable energy systems and technology
- Making decisions based on the way they affect our interests as well as the interests of the societies and the ecosystems in which we operate
- Respecting human rights and labour standards

- Ensuring anti-corruption and transparency on all sustainability issues and active engagement with stakeholders
- Contributing to local content by developing skills and opportunities in the societies in which we operate

How we work:

- We identify and manage environmental and social risks and opportunities based on stakeholder dialogue, as well as risk and impact assessments
- We apply clean and efficient technologies to reduce the negative environmental impact of existing operations
- We work to limit GHG emissions
- We respect international labour standards and the rights of Indigenous peoples
- We promote transparency through support for international industry standards, and by publishing our income, expenditures and taxes in all the countries in which we operate
- We hire and develop local people and promote local sourcing
- We ensure that local suppliers comply with applicable laws and meet our expectations and standards
- We work with others to help establish sustainable local enterprises and support the efforts of our suppliers to close gaps in order to meet our standards
- We exchange experience with national partners and support education and skill building in oil- and gas-related disciplines to build lasting capacity
- We undertake sustainable social investment projects in affected communities so that they can share in the benefits provided by our activities

2.11.2 The Statoil Management System

The Statoil management system defines how we work and describes how we lead and perform our activities. Our management system has three main objectives:

1. Contribute to safe, reliable and efficient operations and enable us to comply with external and internal requirements
2. Help us to incorporate our values, people and leadership principles in everything we do
3. Support our business performance through high-quality decision-making, fast and precise execution, and continuous learning (Statoil 2016d)

Commitment to and compliance with our management system are a requirement.

Sustainability in Statoil means responsible environmental, social and economic performance enabling business resilience. The sustainability function in Statoil includes these elements:

- Balance reliable energy supply and climate impact
- Aim for outstanding resource efficiency
- Prevent harm to local environment
- Create lasting local value
- Respect for human rights

- Lead an open and transparent business

The Statoil environmental management system (EMS) is fully compatible with recognized environmental management standards including ISO 14001.

2.12 Environmental Planning

As part of its project planning and as a requirement of the C-NLOPB operations authorization process, the Operator will submit the following documents to the C-NLOPB:

- Safety Plan
- Environmental Protection and Compliance Monitoring Plan (EPCMP)
- Oil Spill Response Plan
- Emergency Response Plan
- Spill Impact Mitigation Analysis (SIMA) (previously referred to as Net Environmental Benefit Analysis)

2.12.1 Project Planning, Assessment, and Implementation: Application of the Precautionary Principle

The consideration of environmental issues from the earliest stages of project planning and design and throughout eventual implementation is an integral and fully integrated part of the Operator's approach to its petroleum exploration programs and other activities.

As illustrated throughout this EIS, potential environmental issues and interactions that may be associated with the Project can be avoided or reduced through the use of good planning and sound operational practices and procedures, supported by standard mitigation measures that are well established and outlined in relevant regulatory procedures and guidelines, and which have been routinely and effectively applied to similar offshore exploration programs carried out in the Canada-NL Offshore Area and internationally for decades. For this Project, these standard mitigation measures will be implemented through and/or supplemented by Operator-specific policies and procedures that have been identified through this EIS, and through the various post-EA regulatory review processes that will apply to the project (see Section 1.3). The Project will not likely result in significant adverse environmental effects due to the implementation of these environmental protection measures.

In planning and designing the Project and throughout the course of the EA - including the environmental effects analysis and the identification of mitigation included in this EIS - the Operator has applied a precautionary approach to assessing and attempting to avoid or reduce adverse environmental effects. This has included consideration of the precautionary principle, which was defined by the 1992 Rio Declaration on Environment and Development (Principle 15) as follows:

> Where there are threats of serious or irreversible damage, lack of full scientific certainty shall not be used as a reason for postponing cost effective measures to prevent environmental degradation. (UNCED 1992).

As illustrated throughout the EIS, the Project does not require or propose the use of new or different equipment, methods or other technologies during its planned components and activities. Rather, it uses standard and proven exploration components and methods, for which potential environmental issues are well understood and fully manageable through existing and effective mitigation measures. Withstanding this, the application of a precautionary approach is reflected in a number of aspects of Project planning and design, and in the conduct of the EA reported herein. Some examples of this precautionary approach are provided below:

1) In many cases, the EIS environmental analysis, including the effects predictions and the planned application of mitigation, are quite conservative and therefore precautionary in nature. They inherently assume, for example, that an environmental component is present in the area and within the Project's environmental zone of influence, and therefore, is "available" for a Project-VC interaction. In reality, in many cases the likely abundance and spatial and temporal distributions and movements of the VCs limits the potential for interactions and effects with the Project's relatively short-term activities and localized disturbances.
2) Similarly, and in keeping with the spirit of the precautionary principle as defined above, many of the mitigation measures identified in the EIS are committed to and will be implemented even where it is not certain that a Project-related interaction and resulting effect will occur. For example, prior to the start of a drilling campaign, a pre-drill coral survey will be undertaken to investigate the potential presence of coral colonies in the area. This pre-drill coral survey and associated mitigation will be applied to all wells drilled as part of the Project, and not just those in identified high potential areas for corals in the Project Area.
3) Also, for some key potential environmental issues, such as accidental events, the EIS has involved the completion and use of conservative environmental modelling and analysis, including in the associated oil spill modelling (see Chapter 15 and associated Appendix E), which is based on an "unmitigated" spill event. In reality, such a spill is both unlikely to occur, and would be responded to immediately by the Operator through the various response plans and procedures described in this EIS.

In addition to Operator- derived and implemented mitigation measures and precautionary approaches, an added layer of such precaution comes from the various post-EA regulatory review and planning processes that will apply to this exploration drilling program. The regulatory review and approval processes and other requirements that apply to oil and gas activities in the Canada-NL Offshore Area are amongst the most rigorous and stringent in the world, and operators are required to demonstrate that they have the ability and capacity to undertake such activities in a safe and environmentally responsible manner through various project deign measures, operational procedures, and response mechanisms. As part of its regulatory review and decision-making regarding drilling programs and other activities in this jurisdiction, for example, the C-NLOPB receives and considers information from operators that detail the proposed drilling locations and activities, the equipment and procedures involved, and the qualifications and training of personnel. The C-NLOPB's regulatory approval process is two-tiered in nature and requires, firstly, an authorization of the overall drilling program in the form of an OA, and secondly, a well approval in the form of an ADW for each well to be drilled.

The Operator will obtain the required permits, approvals and authorizations for the Project, and the company and its contractors will comply with these and relevant regulations and guidelines in planning and implementing the exploration program that is the subject of this EIS. This includes the various mitigation measures identified and committed to in the sections that follow, the implementation and effectiveness of which will be directed, managed and monitored in accordance with the Operator's applicable policies and procedures.

2.12.2 Environmental Management

Where the environmental effects analyses have identified potentially significant environmental effects that cannot be avoided, mitigation measures have been proposed. Such measures should remove, reduce or manage the effect to a point where the residual significance of that environmental effect is reduced to an acceptable level. Mitigation has also been recommended in order that environmental effects remain 'not significant'. Chapters 8-13 and 15 provide a summary of mitigation and management measures identified during the EIS process on a topic by topic basis.

These commitments will be integrated into the EPCMP. The full EPCMP will be implemented in accordance with the relevant regulatory requirements and submitted to the C-NLOPB in accordance with its OA requirements. The EPCMP is a working document that details:

1) Roles, responsibilities and chain of command for drilling personnel, and contractors or sub-contractors in respect of environmental management for the protection of the environment and operation of the Project
2) Mitigation measures as identified in the EIS to prevent significant adverse effects to the receiving environment
3) Pollution prevention measures
4) Measures to reduce, recycle, reuse and dispose of waste streams

2.12.3 Environmental Monitoring

Monitoring is an important activity for measuring performance against the environmental regulatory and corporate requirements. Monitoring enables the assessment of progress against goals as well as the gathering of information to track overall environmental performance. There are three inter-related drivers in such monitoring:

- Regulatory requirements
- Corporate and Project expectations and goals
- Validation of EIS predictions

Monitoring can therefore be split into two broad categories: compliance monitoring; and potential environmental effects monitoring.

Compliance monitoring involves the monitoring of emissions, discharges, and waste generations against performance standards or regulatory requirements as set out the Project EPCMP. Details of compliance monitoring and reporting is described in Section 17.4.

Environmental effects monitoring, if required, will be used to validate EIS predictions. If required, an EEM plan will be submitted to C-NLOPB for review and acceptance prior to the start of the first drilling campaign. Further information is provided in Section 17.4.

2.13 References

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3.0 REGULATORY, INDIGENOUS, AND STAKEHOLDER ENGAGEMENT

This Chapter describes previous and on-going governmental, Indigenous and stakeholder engagement initiatives related to the Projects and their EISs. It also identifies the comments raised regarding the Projects and where and how these are addressed in the EIS. As all related engagement activities for both Projects have been planned and undertaken collaboratively by Statoil and ExxonMobil, the information and findings reported in this chapter are common to and equally applicable to both Projects and EISs.

3.1 EIS Guidelines

In late 2016, the CEA Agency issued Draft EIS Guidelines for each Project for public review and comment. These were eventually finalized and issued to Statoil and ExxonMobil on December 23, 2016, to guide the planning and preparation of this EIS. The EIS Guidelines specify various information requirements and potential issues that are to be addressed in the EISs, including required information and analysis around the Project Description, aspects of the existing biophysical and socioeconomic environments, Indigenous and stakeholder engagement, potential environmental issues and interactions, mitigation, and other items. The Guidelines have therefore formed a key part of the issues scoping component of EIS planning and preparation.

The EIS Guidelines also outline a number of general principles (Sections 2.2 and 2.3) and specific requirements around public participation and engagement with Indigenous groups as part of the EA process for the Project. This includes the following:

> *The EIS will describe the ongoing and proposed public participation activities that the proponent will undertake or that it has already conducted on the project. It will provide a description of efforts made to distribute project information and provide a description of information and materials that were distributed during the consultation process. The EIS will indicate the methods used, where the consultation was held, the persons and organizations consulted, the concerns voiced and the extent to which this information was incorporated in the design of the project as well as in the EIS. The EIS will provide a summary of key issues raised related to the project and its potential effects to the environment as well as describe any outstanding issues and ways to address them. (Section 4).*
>
> *With respect to engagement activities, the EIS will document:*
>
> *(I) the engagement activities undertaken with each group prior to the submission of the EIS, including the date and means of engagement (e.g. meeting, mail, telephone);*
> *(II) any future planned engagement activities; and*
> *(III) how engagement activities by the proponent allowed groups to understand the project and evaluate its effects on their communities, activities, potential or established section 35 rights, including title and related interests.*
>
> *In preparing the EIS, the proponent will ensure that groups have access to timely and relevant information on the project and how the project may adversely impact them. The proponent will structure its engagement activities to provide adequate time for groups to review and*

> *comment on the relevant information. Engagement activities are to be appropriate to the groups' needs, arranged through discussions with the groups and in keeping with established consultation protocols, where available. The EIS will describe all efforts, successful or not, taken to solicit the information required from groups to support the preparation of the EIS.*
>
> *The proponent will ensure that views of groups are recorded and that groups are provided with opportunities to validate the interpretation of their views. The proponent will keep detailed tracking records of its engagement activities, recording all interactions with groups, the issues raised by each group and how the proponent addressed the concerns raised. The proponent will share these records with the Agency* (Section 5.1).

These and other procedures and requirements for engagement are also reflected and referenced throughout the EIS Guidelines, including specifications about the conduct of these activities, and the manner in which their outcomes are to be used in the planning and completion of the EIS. This EIS has been completed and submitted in accordance with the above referenced EIS Guidelines. A detailed Table of Concordance identifying where each Guideline requirement is addressed in the EIS is provided at the beginning of this EIS.

3.2 Government Departments and Agencies

The Operators recognize that a number of federal and provincial government departments and agencies have specific responsibilities or interests related to the Projects and their potential environmental effects, as a result of associated government policies, legislation, and regulations (including required regulatory decisions and/or compliance requirements), and other relevant issues, mandates, programs, and services. The Operators engaged with various government departments and agencies during the development of the original Project Descriptions at the EA initiation stage. The subsequent governmental review of the Project Descriptions also helped to identify any important environmental questions and issues related to the Projects, and were considered by the CEA Agency in determining whether an EA was required and the scope and focus of that review as reflected in the EIS Guidelines.

In planning and developing the EIS, the Operators have also engaged further with these and other regulatory agencies to share information on the proposed Projects, identify and obtain useful and relevant environmental baseline information for the EIS, and identify any other questions or issues, which required consideration in the assessment.

A summary of Project-related engagement activities involving federal and provincial government departments or agencies is provided in Table 3.1, with a focus on any meetings and other associated discussions. Table 3.1 includes information on timing, the specific organizations involved, engagement method and the general purpose and focus of each session. Engagement initiatives with government departments and agencies have also included discussions and on-going information sharing through various other means (such as through letters, email, telephone conversations), the results of which have also been considered in the scope and content of the EIS as applicable.

Table 3.1 Meetings and Discussions with Government Departments and Agencies

Date	Organization	Type / Format and Location	Operator	Purpose and Focus
April 14, 2016	CEA Agency	Meeting	Statoil	Project introduction, EA process, information requirements for Project Description, proposed collaborative approach to EIS
April 29, 2016	C-NLOPB	Meeting	Statoil	C-NLOPB role in EA process
May 9, 2016	CEA Agency	Meeting	ExxonMobil Statoil	Project scope, EA process, information requirements for Project Description, proposed collaborative approach to EIS
May 10, 2016	DFO	Meeting	Statoil	Food, Social and Ceremonial (FSC) licensing and commercial communal licences issued to Indigenous groups in NL
May 12, 2016	CEA Agency	Meeting	ExxonMobil Statoil	EA engagement strategy
May 26, 2016	CEA Agency	Conference call	ExxonMobil Statoil	Information requirements for Project Description
July 8, 2016	CEA Agency	Conference call	Statoil	Draft Statoil Project Description
July 25, 2016	CEA Agency	Conference call	Statoil	Scope of project to be assessed and EA development to satisfy both CEAA 2012 and C-NLOPB EA processes
August 2, 2016	CEA Agency	Conference call	ExxonMobil	Scope of Project to be assessed
August 12, 2016	CEA Agency	Conference call	ExxonMobil	Draft Project Description
August 16, 2016	CEA Agency	Conference call	Statoil	Draft Project Description
August 31, 2016	CEA Agency	Conference call	Statoil	Scope of project to be assessed (licences)
October 3, 2016	CEA Agency	Conference call	Statoil	EA commencement and Draft EIS Guidelines
October 18, 2016	CEA Agency, C-NLOPB, DFO, ECCC, Transport Canada, Health Canada	Meeting	ExxonMobil Statoil	Overview of EIS approach, structure and content, overview of spill trajectory modelling approach
October 19, 2016	CEA Agency, C-NLOPB	Meeting	ExxonMobil Statoil	Draft EIS Guidelines and associated information and analysis requirements
October 28, 2016	CEA Agency	Conference call	Statoil	Indigenous engagement
November 24, 2016	CEA Agency	Conference call	ExxonMobil Statoil	EIS collaboration

Table 3.1 Meetings and Discussions with Government Departments and Agencies

Date	Organization	Type / Format and Location	Operator	Purpose and Focus
December 14, 2016	CEA Agency	Conference call	Statoil	EIS Guidelines and collaboration
January 5, 2017	CEA Agency	Conference call	ExxonMobil Statoil	Final EIS Guidelines and EA collaboration
March 1, 2017	CEA Agency, C-NLOPB, DFO, ECCC, Transport Canada, Health Canada	Meeting	ExxonMobil Statoil	Overview of EIS approach, structure, and content
April 6, 2017	CEA Agency	Conference call	ExxonMobil Statoil	Indigenous engagement and potential interests in the Project and its effects (especially, salmon and swordfish).
April 10, 2017	CEA Agency	Conference call	ExxonMobil Statoil	Indigenous engagement
April 11, 2017	DFO	Meeting	ExxonMobil Statoil	Fish habitat and special areas
April 27, 2017	CEA Agency	Conference call	ExxonMobil Statoil	Indigenous engagement
May 2, 2017	CEA Agency	Conference call	ExxonMobil Statoil	Indigenous engagement
May 25, 2017	CEA Agency	Conference Call	ExxonMobil Statoil	Indigenous engagement
September 13, 2017	CEA Agency	Meeting	ExxonMobil Statoil	Indigenous engagement
October 16, 2017	DFO	Phone Call	ExxonMobil Statoil	To clarify Indigenous commercial-communal fisheries licences for NL groups
October 20, 2017	DFO	Meeting	ExxonMobil Statoil	To discuss pre-drill coral survey and strategy to develop survey plan in cooperation with DFO

3.3 Indigenous Groups

The Operators respect the Aboriginal and Treaty Rights of Indigenous peoples in Canada and recognize the potential impact the Project on these rights. The Operators also recognize the potential environmental effects the Projects may have on Indigenous communities.

The Operators conduct their business in a manner that respects the land, environment, rights, and cultures of Indigenous communities within the laws of Canada and corporate policies and guidelines that underline their company’s commitment to ethics, transparency, environment, and safety. They are committed to ensuring that Indigenous groups are appropriately informed and respectfully engaged through a variety of means (meetings, phone calls, emails, reports, and others), in a timely manner regarding the company's Project in order to understand the likely interaction with indigenous groups.

3.3.1 Aboriginal and Treaty Rights

When engaging Indigenous communities on the proposed Projects, the Operators acknowledge the Obligation of the Crown to consult with Indigenous communities where a potential Crown decision may impact potential or established Aboriginal and Treaty rights. Those obligations are reflected in the associated guidance provided to the Proponents within the EIS Guidelines.

As determined by the Supreme Court of Canada (*Haida Nation v. British Columbia*, SCC 2004 and *Taku River Tlingit First Nation v. British Columbia* SCC 2004), the scope of the government's consultation obligation is proportionate to the strength of the asserted right and the extent of the potential impact of the proposed decision. In its communication to Indigenous groups regarding its preliminary determination of potential implications of the Project for potential or established Aboriginal or Treaty rights, the CEA Agency communicated to the Indigenous groups that the depth of engagement would be on the low end of the engagement spectrum.

Additional direction from the CEA Agency to the Proponents included Indigenous groups in Nova Scotia, New Brunswick, Prince Edward Island, and Quebec. Communications by the CEA Agency to these Indigenous groups indicated that the preliminary determination of the potential impacts of the Projects on potential or established Aboriginal or Treaty rights would be at the low end of the engagement spectrum, based upon its preliminary understanding of the Indigenous groups' Aboriginal and Treaty rights. Regarding the Maritime Provinces and Québec groups, this assessment was based on the potential effects that the Project may have on possible salmon migrating through the Project Area and the resulting potential impact this could have on the Aboriginal or Treaty rights of the additional communities. In addition, the CEA Agency noted that the Project may also affect commercial-communal swordfish licences overlapping with the Project Area that are held by various communities in Nova Scotia and Prince Edward Island. In addition, the federal Department of Fisheries and Oceans (DFO) also identified seven additional communities in New Brunswick and Nova Scotia who also hold commercial-communal swordfish licences overlapping with the Project Area.

Indigenous groups were asked by the CEA Agency, upon review of the Project, to provide additional information regarding, 1) the potential impacts of the Project on the exercise of their Aboriginal, and where applicable, Treaty rights, or 2) their potential or established Aboriginal or Treaty rights that would further contribute towards the analysis. In addition, the CEA Agency, in its preliminary analysis and dependent upon a specific Indigenous group's potential or established Aboriginal and/or Treaty right, recognized that, "*the potential impacts of the Project on potential or established aboriginal and treaty rights include impacts to harvesting due to*:

(a) potential exclusion from swordfish fishing areas within a prescribed safety zone around drilling units
(b) potential routine effects on swordfish and Atlantic salmon

(c) potential effects on Atlantic salmon, swordfish, and swordfish fisheries in the unlikely event of a large spill or blowout."

3.3.2 Assessment of Potential Environmental Effects on Indigenous Peoples – CEAA 2012, Section 5(1)(c)

In addition to the consideration of potential impacts the Projects may have on existing or potential Aboriginal and Treaty rights, the CEA Agency's EIS Guidelines indicated the proponent will engage Indigenous groups to understand the: "*effects of changes to the environment on Aboriginal peoples (health and socio-economic conditions; physical and cultural heritage, including any structure, site or thing that is of historical, archaeological, paleontological or architectural significance; and current use of lands and resources for traditional purposes) pursuant to paragraph 5(1)(c) of CEAA 2012*".

Proponent Response

In responding to this guidance, the Operators have endeavored to provide timely, plain language information on the Projects, with consistent follow up through a variety of methods. When engaging communities, effort has been made to respectfully listen and understand what concerns communities have expressed, to not assume to know what is important, and to provide information efficiently in response to questions and concerns, or indicate answers would be forthcoming in the EIS.

A number of these Indigenous groups did not respond to engagement efforts regarding the Projects while others indicated a specific interest with the potential need for more information in the future. Some indicated a need to better understand the overall process – both from a regulatory and Project implementation perspective. For those Indigenous groups who responded to these efforts to date, the Operators provided further information, such as salmon studies and personal discussions with competent experts. Where appropriate, if issues or questions were to be addressed in the EIS, the Operators committed to ensuring follow up with Indigenous groups upon the release of the EIS in a manner that meets the groups' needs and interests.

The Operators have been clear regarding their commitment to ongoing engagement as required and requested by the Indigenous groups, through all phases of the EA process. The Operators have expressed a willingness to continue to provide more information, follow up phone calls and/or to personally meet with the groups and provide appropriate expertise in areas of concern or interest, as has been done to this point in the engagement process. While the current understanding of potential impacts from the Project to Section 35 potential or established Aboriginal and Treaty rights suggests an engagement program at the low end of the spectrum, the Operators have remained respectful and responsive to the feedback that has been provided by Indigenous groups to date and will continue to respond as the EIS process progresses.

3.3.3 Engagement with Indigenous Groups

The EIS Guidelines (Section 5.1) and subsequent correspondence from the CEA Agency specify that the Proponent is to ensure that the following Indigenous groups "are notified about key steps in the EIS development process and of opportunities to provide comments on key EA documents and/or information to be provided regarding their community":

The following Indigenous groups in Newfoundland and Labrador:

- Nunatsiavut Government
- Innu Nation
- The NunatuKavut Community Council

The following Indigenous groups in Nova Scotia:

- Acadia First Nation
- Annapolis First Nation
- Bear River First Nation
- Eskasoni First Nation
- Glooscap First Nation
- Membertou First Nation
- Paq'tnkek Mi'kmaw Nation
- Pictou Landing First Nation
- Potlotek First Nation
- Wagmatcook First Nation
- Waycobah First Nation
- Millbrook First Nation
- Sipekne'katik First Nat

The following Indigenous groups in New Brunswick:

- Elsipogtog First Nation
- For Folly First Nation
- Eel Ground First Nation
- Pabineau First Nation
- Esgenoôpetitj First Nation
- Buctouche First Nation
- Eel River Bar First Nation
- Metepenagiag First Nation
- Kingsclear First Nation
- Madawaska Maliseet First Nation
- Oromocto First Nation
- St. Mary's First Nation
- Woodstock First Nation
- Passamaquoddy of New Brunswick

The following Indigenous groups in Prince Edward Island:

- Abegweit First Nation
- Lennox Island First Nation

The following Indigenous groups in Quebec:

- Micmacs of Gesgapegiag
- La Nation Micmac de Gespeg
- Listuguj Mi'gmaq Government
- Les Innus de Ekuanitshit
- Montagnais de Natashquan

This section of the EIS Guidelines also specifies that "The proponent will ensure these groups are reflected in the baseline information and assessment of potential environmental effects as described under paragraph 5(1)(c) of CEAA 2012 and/or impacts to potential or established section 35 rights, including title and related interest in the EIS".

The EIS Guidelines (Section 5.1) also state that "In addition, for the purposes of good governance, the proponent should also provide information to and discuss potential environmental effects from the Project…with the.":

- Qalipu Mi'kmaq First Nation Band (QMFNB)
- Miawpukek First Nation (MFN)

In June 2016, Statoil and ExxonMobil individually wrote to each of the above noted Indigenous groups in Newfoundland and Labrador, along with the Mi'kmaq Alsumk Mowimsikik Koqoey Association (MAMKA), which is an Aboriginal Aquatic Resources and Oceans Management (AAROM) Program organization formed by MFN and QMFNB. The purpose of this correspondence was to provide an initial notification of the proposed Projects and an opportunity for these groups to identify any questions or comments regarding the Projects and their potential effects for consideration in the EIS, as well as inviting further information sharing and engagement as the EA review progressed. The Operators have followed up a number of times with each of these groups to confirm receipt of correspondence, request information related to their respective fishing licences in or near the Project Area off Eastern Newfoundland, and to identify a specific contact for future engagement. In addition, the Operators have asked these Indigenous groups to provide any information regarding traditional uses that may be affected by the Project as well as other aspects related to environmental effects as per Section 5(1)(c) of CEAA 2012.

Subsequently, in April 2017 the CEA Agency informed the Operators that there were potential adverse impacts of the Project on potential or established Aboriginal and/or Treaty rights and potential environmental effects from the Project on other Indigenous groups in the Maritime Provinces and Quebec, and thus, engagement with these groups was also required. Additionally, in July 2017, the Passamaquoddy of New Brunswick was included in this scope of engagement, as stated above. During their engagement with these additional Indigenous groups, the Operators asked for information regarding any additional traditional uses that may be affected by the Project, as well as potential impacts to commercial-communal swordfish licences.

These Indigenous groups and their identified potential interests in the Projects are outlined in Table 3.2.

Table 3.2 Indigenous Groups in Newfoundland and Labrador, the Maritime Provinces and Quebec and their Identified Interest in the Projects and Their EAs

Province	Group(s)	Identified Interest(s)
Newfoundland and Labrador	NunatuKavut Community Council Innu Nation Nunatsiavut Government Miapuwkek Mi'kamawey Mawi'omi Qalipu Mi'kmaq First Nation	Commercial-Communal licences in NAFO Division 2J3KL Commercial-communal licences in 2P FSC fishing activity that could be affected by Project Hunting of migratory birds and seals
Prince Edward Island	Abegweit First Nation	Commercial-communal swordfish licence in NAFO Divisions 3, 4, 5 FSC fishing activity that could be affected by Project-related effects to Atlantic salmon population(s)
	Lennox Island First Nation	
Nova Scotia	Acadia First Nation*	Commercial-communal swordfish licences in NAFO Divisions 3, 4, 5
	Glooscap First Nation*	
	Paq'tnkek First Nation *	
	Pictou Landing First Nation*	
	Wagmatcook First Nation*	
	We'ko'kmaq First Nation*	
	Millbrook First Nation*	
	Sipekne'katik First Nation*	
New Brunswick	Elsipogtog First Nation	FSC fishing activity that could be affected by Project-related effects to Atlantic salmon population(s)
	Buctouche First Nation	
	Eel Ground First Nation	
	Eel River Bar First Nation	
	Esgenoôpetitj First Nation	
	Fort Folly First Nation*	
	Indian Island First Nation	
	Metepenagiag Mi'kmaq Nation	
	Pabineau First Nation	
	Kingsclear First Nation	
	Madawaska Maliseet First Nation	
	Oromocto First Nation	
	St. Mary's First Nation*	
	Tobique First Nation	
	Woodstock First Nation*	

Table 3.2 Indigenous Groups in Newfoundland and Labrador, the Maritime Provinces and Quebec and their Identified Interest in the Projects and Their EAs

Province	Group(s)	Identified Interest(s)
	Passamaquoddy of New Brunswick	
Nova Scotia	Acadia First Nation*	FSC fishing activity that could be affected by Project-related effects to Atlantic salmon population(s)
	Annapolis Valley First Nation	
	Bear River First Nation	
	Eskasoni First Nation	
	Glooscap First Nation*	
	Membertou First Nation	
	Paq'tnkek Mi'kmaw Nation*	
	Pictou Landing First Nation*	
	Potlotek First Nation	
	Wagmatcook First Nation*	
	We'koqma'q First Nation*	
	Millbrook First Nation*	
	Sipekne'katik First Nation*	
Quebec	Conseil des Montagnais de Natashquan	Assorted FSC fishing activity that could be affected by Project-related effects to Atlantic Salmon population(s)
	Conseil des Innus de Ekuanitshit	
	La Nation Micmac de Gespeg	
	Listuguj Mi'gmaq Government	
	Micmacs of Gesgapegiag	
*Indigenous groups that have commercial-communal swordfish licences and may also be exercising rights related to endangered Atlantic salmon		

In seeking to establish an engagement approach with Indigenous Groups, the Operators respected the fact that a number of Indigenous Groups have established engagement process in place and adhered to them. For those who did not have identified processes in place, the Operators proactively provided information on the Project and sought ongoing engagement through a variety of mechanisms (phone calls, emails, personal meetings).

The Operators have provided Project overview information to all identified Indigenous groups, and when asked or where applicable, provided additional information In all cases, the Operators consistently followed up with the Indigenous Groups, seeking feedback in order to ensure the engagement approach was appropriate based on the potential interests, concerns and issues raised. For those Indigenous Groups that responded to the engagement, many expressed a need to see information within the EIS in order to more effectively comment on the Project and how they wished to be engaged. In addition, some expressed a general comment regarding the need for greater capacity funding in order to effectively engage.

As illustrated, the Operators have been making considerable efforts to engage with each of these Indigenous groups to provide information and seek feedback on the Projects and their potential interactions/impacts and proposed mitigations. The key objectives and elements of the Indigenous engagement initiatives for the EIS have included:

- Providing Indigenous Groups with clear and timely information on the proposed Projects, including their purpose, location, associated components and activities and schedule (with information being provided in French where applicable)
- Asking communities for information specific to the potential impact the Project may have on Aboriginal or Treaty rights and associated potential environmental effects
- Identifying, documenting, and responding to any questions or concerns about the Projects and their potential impacts, including whether and how these might have implications for Indigenous communities and their activities and interests
- Seeking to collect and share information on any Indigenous activities or interests in or near the Project Area or elsewhere that might be relevant to the assessment of the Project and its potential effects, as well as relevant Indigenous knowledge about the existing environment

The following sections provide an overview of previous and on-going engagement activities with these Indigenous groups, including the nature and outcomes of these initiatives up to October 21, 2017. As mentioned previously, the Operators are continuing to engage with interested Indigenous Groups throughout the EIS process.

The Operators have committed to ongoing engagement with Indigenous Groups throughout the EIS process and as the Project progresses.

3.3.4 Newfoundland and Labrador Indigenous Groups

3.3.4.1 Labrador Inuit (Nunatsiavut Government)

A summary of engagement initiatives with Nunatsiavut Government (NG) to date is provided in Table 3.3, as well as an overview of the key questions and issues raised and where these are addressed in this EIS.

Table 3.3 Engagement Activities with Nunatsiavut Government and Key Outcomes

Date	Activity	Organization	Purpose and Focus
June 5, 2016	Email	Statoil	Project overview and notification of upcoming EA initiation.
June 8, 2016	Phone Call / Voicemail	Statoil	Follow-up to initial notification. Left voicemail seeking call back.
June 15, 2016	Letter	ExxonMobil	Project overview and notification of upcoming EA initiation.
June 23, 2016	Email	Nunatsiavut Government	Response to ExxonMobil to June 15 regarding identified contact for future engagement respecting the EIS.

Table 3.3 Engagement Activities with Nunatsiavut Government and Key Outcomes

Date	Activity	Organization	Purpose and Focus
June 29, 2016	Email	Nunatsiavut Government	NG confirmed to ExxonMobil the Project Area is within three of their commercial fishing licences.
July 6, 2016	Phone Call / Voicemail	Statoil	Follow-up to initial notification. Left voicemail seeking call back.
July 6, 2016	Phone Call	Nunatsiavut Government	NG returned Statoil's phone call to indicate interest in participating in EA process. Will review Project Description and provide feedback. Operator committed to following up after Project Description submitted.
August 23, 2016	Email	Statoil	Notification of Project Description publication on CEA Agency website as well as a link. Requested a convenient time for follow up.
August 24, 2016	Email	Nunatsiavut Government	NG emailed Statoil regarding deadline for comments. The Operator provided info on *CEAA 2012* process and asked NG to contact them with any questions.
August 26, 2016	Email	Nunatsiavut Government	NG emailed with Statoil a question regarding EA process under *CEAA 2012*. The Operator provided clarity about the roles of CEA Agency and the proponent.
n/a	Letter	Nunatsiavut Government	NG sent letter to CEA Agency with comments on Draft EIS Guidelines where the group raised concerns regarding accidental events.
January 31, 2017	Email / Letter	Statoil	Letter regarding potential further engagement, and request for feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 7, 2017	Letter	ExxonMobil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 10, 2017	Phone Call	Statoil	Follow-up call to ensure receipt of Jan. 31 letter and determine if additional information was required. NG indicated the information was currently being reviewed and a response would be provided by March 3.
February 20, 2017	Phone Call	ExxonMobil	Follow-up regarding Feb. 7 letter. Left voicemail seeking call back.
February 28, 2017	Phone Call	ExxonMobil	Follow-up regarding Feb. 7 letter; NG confirmed as received and question about CEA Agency as regulatory body.

Table 3.3 Engagement Activities with Nunatsiavut Government and Key Outcomes

Date	Activity	Organization	Purpose and Focus
March 6, 2017	Email / Phone Call / Voicemail	Statoil	Follow-up regarding above. Left message seeking feedback on Feb 10 discussion.
October 12, 2017	Email	ExxonMobil Statoil	Follow-up on previous correspondence seeking input on the Project. Indicated that spill modelling will be included in EIS and committing to follow-up with NG post-EIS submission
October 16, 2017	Phone call	Statoil	Follow-up to ensure email was received, answer any questions and discuss Project. NG indicated no concerns from the information to date, confirmed intention to participation in CEA Agency workshop and provide feedback on EIS.
Key Comments, Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from Statoil / ExxonMobil**
No concerns identified to Operators to date.			n/a
NG to CEA Agency: EA process for the Project			Section 1.3
NG to CEA Agency: Accidental events and potential effects from blowout modelling should be included in the EIS – along with an impact assessment on coastal zones – including seasonal or temporary residences			Chapter 15
NG to CEA Agency: Role of the proponent vs. CEA Agency in the engagement process			Section 1.3
NG to CEA Agency: EIS should not reference other previous environmental assessments that are not provided			n/a
NG to CEA Agency: Selection of VCs should consider the communities right to harvest at all times of the year throughout the Land Claim area			Section 7.3.1
NG to CEA Agency: Climate change should be considered in “physical oceanography’ section			Section 5.8
NG to CEA Agency: NG have a specific interest in the accidental event worst case modelling			Chapter 15 • The Operator has offered to engage further on any outstanding questions/concerns upon EIS review by NG
NG to CEA Agency: NG want assessments of malfunctions/accidents to include commercial fishing licence areas(2GHJ3KL) and potential impacts to subsistence / commercial species (cod, turbot, snow crab) and SARA listed species (Atlantic Blue Whale, North Atlantic Right Whale) that may migrate through impacted area to the Marine Zone of the Labrador Inuit Land Claim Agreement.			Chapter 15

3.3.4.2 Labrador Innu (Innu Nation)

A summary of engagement initiatives with Innu Nation to date is provided in Table 3.4, as well as an overview of the key questions and issues raised and where these are addressed in this EIS.

Table 3.4 Engagement Activities with Innu Nation and Key Outcomes

Date	Activity	Organization	Purpose and Focus
June 5, 2016	Email	Statoil	Project overview and notification of upcoming EA initiation.
June 8, 2016	Phone Call / Voicemail	Statoil	Follow-up seeking feedback on Project overview. No response.
June 10, 2016	Phone Call / Voicemail	Statoil	Additional follow-up on Project overview.
June 15, 2016	Letter	ExxonMobil	Project overview and notification of upcoming EA initiation.
July 5, 2016	Phone Call	Innu Nation	Innu Nation called Statoil to identify a contact person for the EA.
July 5, 2016	Email	Statoil	Forwarded notification of upcoming Project Description.
July 7, 2016	Phone Call	Statoil	Follow-up call regarding above notification.
July 15, 2016	Email	Innu Nation	Innu Nation sent email to Statoil regarding interest in participating in EA process. Requested information on timelines for participation. Operator indicated willingness to discuss Project at a time convenient to the Innu Nation and committed to contact after Project Description is published and during EIS development.
August 23, 2016	Email	Statoil	Notification of Project Description publication on CEA Agency website and provided a link. Requested a convenient time for Statoil to follow up.
August 23, 2016	Phone call	Innu Nation	Innu Nation email to Statoil to confirm interest in discussing Project Description.
September 9, 2016	Phone call	Innu Nation	Innu Nation called Statoil to discuss involvement in commercial fishery and concerns about potential effects of underwater noise on sensitive species, such as beluga whales. Operator clarified this is not a seismic project and referred Innu Nation to C-NLOPB website for more information. Innu Nation also indicated that fishing quota may be fished by other harvesters such as Ocean Choice International (OCI). Also discussed EA process and timelines.

Table 3.4 Engagement Activities with Innu Nation and Key Outcomes

Date	Activity	Organization	Purpose and Focus
January 31, 2017	Email / Letter	Statoil	Letter regarding potential further engagement, and request for feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 7, 2017	Letter	ExxonMobil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 10, 2017	Phone Call	Statoil	Follow-up on EIS engagement. Innu Nation indicated a letter regarding the Project was currently being drafted.
February 14, 2017	Phone Call	Innu Nation	Innu Nation called Statoil regarding contacts for future engagement.
February 15, 2017	Phone Call	Statoil	Follow-up on Innu Nation correspondence of Jan. 31. Innu Nation indicated the response letter was being drafted in coordination with their fisheries group.
February 20, 2017	Phone Call	ExxonMobil	Follow-up regarding Feb.7 letter. Left message.
February 24, 2017	Email	Statoil	Follow-up to Feb. 15 discussion regarding response to Jan. 31 letter.
February 24, 2017	Email	Innu Nation	Innu Nation emailed Statoil regarding response to initial correspondence and indicated a response would be sent by Feb. 27
February 28, 2017	Phone Call	ExxonMobil	Follow-up call to Feb. 7 letter. Left message.
March 2, 2017	Letter	Innu Nation	Innu Nation sent letter to Statoil regarding Jan. 31, Project Letter – concerned about potential impacts of a major oil spill on commercial fishery and associated compensation, any future exploration that could move to near shore where FSC harvesting takes place, opportunities for economic participation in Project, seeking an opportunity for future meeting and associated budget.
March 9, 2017	Phone Call	ExxonMobil	Follow-up to Feb. 7 letter. Left message.
March 28, 2017	Phone Call	ExxonMobil	Follow-up to Feb. 7 letter. Was requested to call back following week.
April 3, 2017	Phone Call	ExxonMobil	Follow-up to Feb. 7 letter. Innu Nation indicated that a response would be provided the following week.
April 13, 2017	Phone Call / Voicemail	Statoil	Follow-up call to Innu Nation March 2 letter. Left message.

Table 3.4 Engagement Activities with Innu Nation and Key Outcomes

Date	Activity	Organization	Purpose and Focus
April 19, 2017	Email	Statoil	Follow-up seeking confirmation of how Innu Nation wished to proceed based on March 2 letter.
April 20, 2017	Email	ExxonMobil	Follow-up to February 7 letter to inquire about a response.
April 24, 2017	Phone Call / Voicemail	Statoil	Left message seeking to discuss March 2 letter.
June 26, 2017	Email / Letter	Statoil	Letter and information responding to concerns and questions from Innu Nation's March 2 letter and indicating willingness to meet with Innu Nation.
October 11, 2017	Email	ExxonMobil	Follow-up on previous correspondence seeking input on the Project, indicating spill modelling would be included in EIS and committed to follow up with Innu Nation post-EIS submission
October 12th, 2017	Email	Statoil	Follow-up on previous correspondence seeking input on the Project, indicating spill modelling would be included in EIS and committing to follow up with Innu Nation post-EIS submission
October 16, 2017	Phone call	Statoil	Left message regarding receipt of email, if any questions on the Project and to June 26 letter.

Key Questions and Issues Raised	Where Addressed in the EIS and/or Follow up from the Operator
EA process and schedule	Section 1.3
Innu commercial fishing activity off eastern Newfoundland	Section 7.3.1, Chapter 12
Underwater sound and its effects on marine mammals	Section 10.3, 10.4 • Operator clarified the Project was related to exploration drilling, not seismic.
Compensation to commercial fishery in the unlikely event of a major oil spill	Section 13.3 • Operator indicated they will establish a compensation program that meets requirements of the C-NLOPB Compensation Guidelines
Capacity to engage independent experts	The Operator directed the Innu Nation to CEA Agency's Participant Funding Program
If future exploration could move to nearshore Labrador	n/a, Not within the scope of the Project under EA review

3.3.4.3 NunatuKavut Community Council

A summary of engagement initiatives with NunatuKavut Community Council (NCC) to date is provided in Table 3.5, as well as an overview of the key questions and issues raised and where these are addressed in this EIS.

Table 3.5 Engagement Activities with NunatuKavut Community Council and Key Outcomes

Date	Activity	Operator	Purpose and Focus
June 5, 2016	Email	Statoil	Project overview and notification of upcoming EA initiation.
June 8, 2016	Phone Call	Statoil	Follow-up to June 5 correspondence. EA processes, and general discussion of NCC commercial and subsistence fishing. NCC indicated Project Area is south of main commercial and subsistence fishing area. Operator committed to following up once Project Description published.
June 8, 2016	Email	Statoil	Exchanged emails with NCC regarding process for review of Project Description.
June 15, 2016	Letter	ExxonMobil	Project overview and notification of upcoming EA initiation.
August 23, 2016	Email	Statoil	Notification of Project Description publication on CEA Agency website as well as a link. Requested convenient time for follow-up.
January 31, 2017	Email	Statoil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 7, 2017	Letter	ExxonMobil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 10, 2017	Phone Call / Voicemail	Statoil	Called to discuss potential further engagement. Left message.
February 17, 2017	Phone Call	Statoil	NCC indicated they would send a response in the following week and asked the Operator to follow up then. Indicated CEA Agency process was new to them.
February 20, 2017	Phone Call	ExxonMobil	Follow-up to February 7 letter. Left voicemail.
February 24, 2017	Phone Call / Voicemail	Statoil	Follow-up to Feb. 17 phone call. Left message.
February 28, 2017	Phone Call / Voicemail	ExxonMobil	Follow-up to Feb. 7 letter. Left message.

Table 3.5 Engagement Activities with NunatuKavut Community Council and Key Outcomes

Date	Activity	Operator	Purpose and Focus
March 6, 2017	Phone Call / Voicemail / Email	Statoil	Follow-up to Feb. 17 phone call. Left voicemail and sent email asking if NCC had any additional questions or needed more information.
March 9, 2017	Phone Call	ExxonMobil	Follow-up to Feb. 7 letter. Spoke to reception who suggesting calling back in the following week after NCC Council meeting.
October 11, 2017	Email	ExxonMobil	Follow-up on previous correspondence seeking input on the Project, indicating spill modelling would be included in EIS and committing to follow up with NCC post-EIS submission.
October 12, 2017	Email	Statoil	Follow-up on previous correspondence seeking input on the Project, indicating spill modelling would be included in EIS and committing to follow up with NCC post-EIS submission.
October 16, 2017	Phone Call	Statoil	Follow-up to October 12 email. Left message.
Key Comments, Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator			n/a
Location of NCC commercial and subsistence fishing activities is north of the Project Area			Section 7.3.1, Chapter 12
EA process and timelines			Section 1.3

3.3.4.4 Miawpukek First Nation

A summary of engagement initiatives with Miawpukek First Nation (MFN) to date is provided in Table 3.6, as well as an overview of the key questions and issues raised and where these are addressed in this EIS.

Table 3.6 Engagement Activities with Miawpukek First Nation and Key Outcomes

Date	Activity	Operator	Purpose and Focus
June 5, 2016	Email	Statoil	Project overview and notification of upcoming EA initiation.
June 8, 2016	Phone Call / Voicemail	Statoil	Follow-up to June 5 email. Left message.
June 10, 2016	Phone Call / Voicemail	Statoil	Follow-up to June 5 email. Left message.
June 15, 2016	Letter	ExxonMobil	Project overview and notification of upcoming EA initiation.
July 6, 2016	Phone Call / Voicemail	Statoil	Follow-up to June 5 email. Left message.

Table 3.6 Engagement Activities with Miawpukek First Nation and Key Outcomes

Date	Activity	Operator	Purpose and Focus
July 7, 2016	Phone Call	Statoil	Follow-up to June 5 email. Left message.
July 11, 2016	Phone Call	MFN	MFN called Statoil to discuss commercial fishing licences, current activities and engagement in EA process. Indicated MFN fishing licences overlap with Project Area but no fishing currently occurs in the area. Will likely defer to Fish Food and Allied Workers-Unifor (FFAW-Unifor) for input as commercial interests are the same. MFN will confirm this information in an email to Statoil/ExxonMobil. Statoil/ExxonMobil committed to send Project Description once published and to follow up with MFN.
August 23, 2016	Email	Statoil	Notification of Project Description publication on CEA Agency website as well as a link. Requested a time to follow up.
January 31, 2017	Email/Letter	Statoil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 7, 2017	Letter	ExxonMobil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 10, 2017	Phone Call	Statoil	Called to discuss engagement in the EA. MFN indicated that they will be responding confirming that they do not have Aboriginal Title or Rights claimed in the Flemish Pass and no commercial fishing interests.
February 20, 2017	Phone Call	ExxonMobil	Follow-up to February 7, 2017 letter. Left voicemail.
February 28, 2017	Phone Call	ExxonMobil	Follow-up to February 7, 2017 letter. Left voicemail.
March 6, 2017	Email	Statoil	Requested follow-up to discussion on February 10, 2017.
March 7, 2017	Email	MFN	MFN sent response to Statoil with confirmation that they do not have commercial fishing activity in the area of the Project and therefore no concerns in that regard.
March 8, 2017	Email	Statoil	Follow-up to MFN March 7. Operator thanked MFN for response and asked that the First Nation contact Statoil with any further questions / concerns.

Table 3.6 Engagement Activities with Miawpukek First Nation and Key Outcomes

Date	Activity	Operator	Purpose and Focus
July 27, 2017	Letter	MFN	MFN sent letter to the Operators indicating issues: environmental, cultural, and socioeconomic concerns with regards to traditional and commercial fisheries and potential impacts from spills. Indicated all species are important but especially salmon. Requested Project details and expressed the need for capacity support to be properly engaged.
August 23, 2017	Email/Letter	Statoil	Responded to concerns and provided a report discussing salmon migration and potential interactions with the Project Area. Also indicated that additional answers to specific questions would be in the EIS. Also asked for clarity around previous communication from MFN (February 10 and March 7, 2017) indicating no commercial fishing activity in the area and no Aboriginal Title or Rights claimed in the Flemish Pass.
September 5, 2017	Emailed letter and attached Atlantic salmon report	ExxonMobil	Responded to concerns and provided a report discussing salmon migration and potential interactions with the Project Area. Also indicated that additional answers to specific questions would be in the EIS.
October 13, 2017	Email	ExxonMobil Statoil	Follow-up to previous correspondence seeking input on the Project, discussing spill modeling, as well as indicating intention to submit EIS and committing to follow up.
Key Comments, Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
Confirmed that they do not have any Aboriginal title or rights claimed in the Project Area and have no current commercial fishing interests there			Section 7.1, 7.3.1
Location of MFN fishing activities and licences was identified as being outside the Project Area			Section 7.1, 7.3.1
EA process and timelines			Section 1.3
Fishing industry contacts for the EA process			Section 7.1, 7.3.1
Potential for direct / indirect impacts to fisheries (commercial/traditional), traditional activities, culture and need for mitigation/accommodation measures			Section 7.1, 7.3.1, Chapter 12
Potential impact on all species but especially Atlantic salmon, which is already threatened			Section 8.3, 8.4, 12.3, 15.5.5.1
Lack of capacity to effectively engage in Project			Section 3.1

3.3.4.5 Qalipu Mi'kmaq First Nation

A summary of engagement initiatives with Qalipu Mi'kmaq First Nation Band (QMFN) to date is provided in Table 3.7 as well as an overview of the key questions and issues raised and where these are addressed in this EIS.

Table 3.7 Engagement Activities with Qalipu Mi'kmaq First Nation Band and Key Outcomes

Date	Activity	Organization	Purpose and Focus
June 5, 2016	Email	Statoil	Project overview and notification of upcoming EA initiation.
June 8, 2016	Phone Call / Voicemail	Statoil	Follow-up to initial notification.
June 10, 2016	Phone Call / Voicemail	Statoil	Follow-up to initial notification.
June 15, 2016	Letter	ExxonMobil	Project overview and notification of upcoming EA initiation.
July 5, 2016	Phone Call	Statoil	Discuss EA process, engagement with fishing industry and other stakeholders, and to request information on the nature and location of QMFN fishing activities in or near the Project Area. QMFN indicated no concerns at this point. Fishing area is presently outside of Project Area but may fish in Project Area in future. QMFN will stay engaged with FFAW-Unifor. Statoil indicated they would follow up once Project Description published.
August 23, 2016	Email	Statoil	Notification of Project Description publication on CEA Agency website as well as a link. Requested convenient time to follow up.
November 2, 2016	Letter	QMFN	QMFN sent a letter to CEA Agency with comments on Draft Guidelines, indicating that supply bases and transportation corridors should be included in Project scope due to use and storage of chemicals and hydrocarbons potential effects of accidents in the near-shore environment.
January 31, 2017	Email/Letter	Statoil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 7, 2017	Letter	ExxonMobil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.

Table 3.7 Engagement Activities with Qalipu Mi'kmaq First Nation Band and Key Outcomes

Date	Activity	Organization	Purpose and Focus
February 13, 2017	Phone Call / Voicemail / Email	Statoil	Follow-up to Jan. 31 letter.
February 17, 2017	Email	Statoil	Follow-up to Jan. 31 letter.
February 20, 2017	Phone Call	ExxonMobil	Follow-up to Feb. 7 letter. Instructed to call back after March 13.
February 24, 2017	Phone Call / Voicemail / Email	Statoil	Follow-up to Jan. 31 letter with voicemail and email seeking feedback.
February 28, 2017	Phone Call	ExxonMobil	Follow-up to Feb. 7 letter. Left voicemail.
March 6, 2017	Phone Call / Voicemail / Email	Statoil	Follow-up to Jan. 31 letter with voicemail and email seeking feedback.
March 6, 2017	Email	QMFN	QMFN sent email to Statoil indicating that the group has no specific questions at this time but would like further discussion.
October 12, 2017	Email	Statoil	Follow-up to previous correspondence seeking input on the Project, discussing spill modeling and committing to follow up with QMFN.
October 12, 2017	Email	QMFN	Email to ExxonMobil committing to respond with any questions, either before or after EIS is submitted.
October 16, 2017	Phone call	Statoil	Follow up call regarding Oct 12 email from Statoil. Left message.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator			n/a
QMFN to CEA Agency: Scope of the Project for EA purposes (use of supply bases and transportation corridors) and associated concerns around chemicals and hydrocarbons use and storage.			Section 1.2, 2.9, 4.1
QMFN to CEA Agency: Location of current and potential future QMFN fishing activities and licences in relation to Project Area			Section 7.1, 7.3.1
QMFN to CEA Agency: Encourages direct engagement between the QMFN and Operator			Section 3.1
QMFN to CEA Agency: Consider the effects of accidents in the near shore environment as a requirement for EIS			Chapter 15

3.3.4.6 Mi'kmaq Alsumk Mowimsikik Kaqoey Association

A summary of engagement initiatives with Mi'kmaq Alsumk Mowimsikik Kaqoey Association (MAMKA), which is an Aquatic Resources and Oceans Management Organization (AAROM) formed by MFN and QMFNB under the AAROM program, to date is provided in Table 3.8, as well as an overview of the key questions and issues raised and where these are addressed in this EIS.

Table 3.8 Engagement Activities with MAMKA and Key Outcomes

Date	Activity	Operator	Purpose and Focus
June 5, 2016	Email	Statoil	Project overview and notification of upcoming EA initiation.
June 8, 2016	Phone Call / Voicemail	Statoil	Follow-up on initial notification.
June 10, 2016	Phone Call / Voicemail	Statoil	Follow-up on initial notification.
June 15, 2016	Letter	ExxonMobil	Project overview and notification of upcoming EA initiation.
July 5, 2016	Phone Call	Statoil	Follow-up on initial notification. MAMKA indicated no questions at this point. Discussion of EA process, engagement with fishing industry and other stakeholders and nature and location of MAMKA fishing activities. Statoil described planned engagement with FFAW-Unifor. MAMKA indicated that this would be useful and that they would wait until Project Description available.
August 23, 2016	Email	Statoil	Notification of Project Description publication on CEA Agency website and provided a link.
January 31, 2017	Email / Letter	Statoil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 7, 2017	Letter	ExxonMobil	Letter requesting feedback or information on Aboriginal rights and traditional uses and how they might be affected by the Project. Commitment to follow up on spill trajectory model once completed.
February 10, 2017	Phone Call	Statoil	Discussed interest in the Project. MAMKA's Miawpukek representative confirmed that Miawpukek does not currently assert Aboriginal title or rights in the Project and has no current commercial fishing interests there. Committed to sending an email indicating this.
February 20, 2017	Phone Call	ExxonMobil	Follow-up to February 7, 2017 letter. Instructed to call back after March 13, 2017.
February 28, 2017	Phone Call	ExxonMobil	Follow-up to February 7, 2017 letter. Left voicemail.

Table 3.8 Engagement Activities with MAMKA and Key Outcomes

Date	Activity	Operator	Purpose and Focus
March 6, 2017	Phone Call	Statoil	Statoil/ExxonMobil emailed to follow-up to above discussion and formal response.
October 12, 2017	Email	ExxonMobil	Follow-up to previous correspondence seeking input on the Project, discussing spill modeling and committing to follow up with QMFN.
Key Comments, Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See Miawpukek First Nation and Qalipu First Nation			See earlier tables

3.3.5 Maritime Provinces and Quebec Indigenous Groups

A summary of engagement initiatives with the various Indigenous groups in Prince Edward Island, Nova Scotia, New Brunswick, and Québec identified previously is provided in Tables 3.9 to 3.12, as well as an overview of the key questions and issues raised and where these are addressed in this EIS.

Table 3.9 Engagement Activities with Prince Edward Island Indigenous Groups and Key Outcomes

Prince Edward Island			
Mi'kmaq Confederacy of Prince Edward Island (MCPEI) – Aggregate body for the Abegweit First Nation and Lennox Island First Nation with regard to engagement.			
Date	**Activity**	**Organization**	**Purpose and Focus**
June 6, 2017	Letter	MCPEI	MCPEI sent letter to CEA Agency indicating the Mi'kmaq of PEI will defer to the Indigenous groups of NL regarding the proposed Project at this time.
June 13, 2017	Email / Letter	Statoil	Provided Project overview letter and summary information regarding commercial-communal fishing licences in the area. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should the MCPEI have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area. Requested feedback or information on any FSC or commercial-communal rights and traditional uses and how they might be affected by the Project. Provided contact information should MCPEI have any further questions / concerns.

Table 3.9 Engagement Activities with Prince Edward Island Indigenous Groups and Key Outcomes

Prince Edward Island			
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter.
June 22, 2017	Email	ExxonMobil	MCPEI informed ExxonMobil that June 15 letter was received.
June 28, 2017	Phone Call	Statoil	Follow-up on June 13 email/letter to confirm receipt – asked for call back.
July 14, 2017	Phone Call	ExxonMobil	Follow-up on June 15 letter. Left message.
October 17, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial communal swordfish licence (Lennox Island & Abegweit) activity is taking place within Project Area.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
MCPEI to CEA Agency: MCPEI deferred to Indigenous groups of NL			n/a
Abegweit First Nation			
June 13, 2017	Email / Letter	Statoil	Provided overview and summary information regarding commercial-communal fishing licences in the area. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Abegeit First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Overview letter about the Project and summary information regarding commercial-communal fishing licences in the area. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Abegeit First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15, 2017 letter; attached copy of letter.
July 12, 2017	Phone Call	ExxonMobil	Follow-up on June 15, 2017 letter. Left message for Chief
October 17, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial-communal swordfish licence held by Abegweit First Nation activity is taking place within Project Area.

Table 3.9 Engagement Activities with Prince Edward Island Indigenous Groups and Key Outcomes

Prince Edward Island			
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator			n/a
Lennox Island First Nation			
June 13, 2017	Letter	Statoil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Lennox Island First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Lennox Island First Nation have any further questions / concerns.
June 22, 2017	Email and resent June 15, 2017 Letter	ExxonMobil	Follow-up to confirm receipt of June 15, 2017 letter; attached copy of letter.
July 12, 2017	Phone Call	ExxonMobil	Follow up on June 15, 2017 letter. Left message for Chief
October 17, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial-communal swordfish fishing by Lennox Island First Nation is taking place within Project Area.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator			n/a

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
Kwilmu'kw Maw-Klusuaqn Negotiation Office (KMKNO) – Aggregate body for the Acadia First Nation, Annapolis Valley First Nation, Bear River First Nation, Potlotek First Nation, Eskasoni First Nation, Glooscap First Nation, Membertou First Nation, Paqtnkek First Nation, Pictou Landing First Nation, Wagmatcook First Nation, and We'koqma'q First Nation, with regard to engagement. For all engagement with KMKNO, the Operators understand that KMKNO is acting on behalf of the groups listed above.			
Date	**Activity**	**Organization**	**Purpose and Focus**
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should KMKNO have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should the KMKNO have any further questions / concerns.
June 20, 2017	Email	Statoil	Email to KMKNO to confirm KMKNO and associated First Nations had received project information. KMKNO confirmed receipt.
June 22, 2017	Email	ExxonMobil	Follow-up email to each member First Nation regarding confirmation of receipt of June 15 letter; attached copy of letter; KMKKNO copied on email.
July 18, 2017	Meeting	ExxonMobil Statoil	Met with KMKNO, confirmed KMKNO was intending to send a response to the Project letter. No written response received. KMKNO also seeking salmon study information and analysis of impacts to commercial-communal swordfish licence.
August 11, 2017	Email	ExxonMobil Statoil	Sent KMKNO a report summarizing research related to potential salmon migration in the Project Area. Operator also indicated they would like to meet in September (on another project) at which time they could review any questions related to the salmon report.

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
August 16, 2017	Email	KMKNO	KMKNO to Operators confirmed receipt of the salmon report and indicated they would review and respond.
August 21, 2017	Email	ExxonMobil Statoil	Sent email to KMKNO to request a meeting for week of Septembers 18.
September 18, 2017	Meeting	ExxonMobil Statoil	Met with KMKNO and discussed salmon report. KMKNO indicated they would have the Unama'ki Institute of Natural Resources (UINR) Director of Aquatic Research and Stewardship review the report and would like to have UINR discuss any issues/concerns with the EIS fish biologist author to discuss further in mid-October. Indicated the need for operators to collaborate on EAs in order to reduce the burden on communities reviewing.
October 12, 2017	Meeting	ExxonMobil Statoil	Met with KMKNO and followed up on review of the salmon report. KMKNO to confirm potential meeting dates for following week, also indicated need for capacity funding to review EAs. Asked whether American eel are located in or migrate through the Project Area.
October 16, 2017	Email	ExxonMobil Statoil	Provided a summary of information regarding American eel and their potential interaction with the Project, indicating that it is unlikely they pass through the Project Area during migration.
October 19, 2017	Email	ExxonMobil Statoil	Sent email indicating outreach to Mi'kmaq Fisheries Managers attempting to determine commercial-communal swordfish licence activity in the Project Area.
October 19, 2017	Email	KMKNO	Indicated they will need more time to respond to the Operators in a coordinated fashion.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
Potential impacts of Project on Atlantic salmon migration / populations			Section 8.3, 8.4, 12.3, 15.5.5.1
Potential impacts of Project on commercial-communal swordfish fisheries			Section 12.3
Potential impacts of Project on American eel migration			Section 8.4
Desire for operators to collaborate on EAs in order to reduce burden on communities.			Section 1.4

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
Acadia First Nation			
June 13, 2017	Email/Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Acadia First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Acadia First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up email regarding confirmation of receipt of June 15 letter; attached copy of letter; KMKNO copied on email.
July 12, 2017	Phone Call	ExxonMobil	Call to follow up on June 15 letter. Left contact if needed but Acadia First Nation indicated that KMKNO office would be dealing with this matter
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Annapolis Valley First Nation			
June 13, 2017	Email/Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Annapolis Valley First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Annapolis Valley First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up regarding confirmation of receipt of June 15 letter; attached copy of letter

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
July 13, 2017	Phone Call	ExxonMobil	Call to follow up on June 15 letter. Left message.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Bear River First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Bear River First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Bear River First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up regarding confirmation of receipt of June 15 letter; attached copy of letter
July 13, 2017	Phone Call	ExxonMobil	Call to follow up on June 15 letter. Left message.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Potlotek First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Potlotek First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Potlotek First Nation have any further questions / concerns.

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
June 22, 2017	Email	ExxonMobil	Follow-up regarding confirmation of receipt of June 15 letter; attached copy of letter.
July 14, 2017	Phone Call	ExxonMobil	Call to follow up on June 15 letter.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Eskasoni First Nation			
June 13, 2017	Email / Letter	Statoil	Overview letter about the Project and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Eskasoni First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Eskasoni First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 13, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Glooscap First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Glooscap First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
			information should Glooscap First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 13, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Left message for Resource Manager.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Membertou First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Membertou First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Membertou First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 14, 2017	Phone Call	ExxonMobil	Follow-up on June 15 letter. Left message with Chief's assistant.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Paq'tnkek First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Paq'tnkek First Nation have any further questions / concerns.

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding Commercial-Communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Paq'tnkek First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
June 22, 2017	Email	Paq'tnekek First Nation	Contacted ExxonMobil to provide email address for Chief
June 22, 2017	Email	ExxonMobil	Emailed June 15 letter to Chief.
July 14, 2017	Phone Call	ExxonMobil	Follow-up on June 15, 2017 letter. Left message for Director of Administration.
October 17, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial communal swordfish licence activity taking place within Project Area.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Pictou Landing First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Pictou Landing First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Pictou Landing First nation have any further questions / concerns.

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 14, 2017	Phone Call	ExxonMobil	Call to follow up on June 15 letter. Left voicemail.
October 17, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial-communal swordfish license activity taking place within Project Area.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Wagmatcook First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Wagmatcook First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Wagmatcook First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 14, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Left message for Chief.
October 17, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial-communal swordfish license activity taking place within Project Area.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
We'koqma'q First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
			on any rights and traditional uses and how they might be affected by the Project. Provided contact information should We'koqma'q First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should We'koqma'q First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 14, 2017	Phone Call	ExxonMobil	Follow-up on June 15 letter. Left message for Chief
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See KMKNO			See table above
Sipekne'katik First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Sipekne'katik First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Sipekne'katik First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
June 28, 2017	Voicemail	Statoil	Follow-up on Project letter to determine if there were any questions or concerns. Left voice message.
July 14, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Could not leave a message as to voice mailbox was full.

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
July 19, 2017	Letter	Sipekne'katik First Nation	Response to ExxonMobil that they do not have the capacity to review EA and provide feedback by requested deadline.
July 20, 2017	Email	ExxonMobil	Responded to Sipekne'katik First Nation to inform them that the EIS is in progress and will have further opportunities to comment once submitted to the CEA Agency.
July 28, 2017	Phone call	Sipekne'katik First Nation	Call regarding Project letter. Group indicated it would like a copy of the salmon report
July 28, 2017	Email	ExxonMobil	Sent a copy of the salmon report and provided a Project overview letter. Acknowledged that there may be efficiencies if engaging on the proposed offshore exploration project together with the Sable Decommissioning Project in Nova Scotia and will work towards such efficiencies.
August 11, 2017	Email	Statoil	Sent a copy of the salmon report and provided a Project overview letter as well as asked to meet with the First Nation in the week of Sept 18.
September 12, 2017	Meeting	ExxonMobil Statoil	Met with Sipekne'katik First Nation to discuss Project information and salmon report. First Nation indicated they would review the report and meet with Chief and Council, and should provide a response by mid-October. Concerns raised listed below. Indicated a preference for operators to collaborate on EAs due to number of EAs community receives and lack of capacity.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
Potential impacts of the Project on Atlantic salmon migration/populations			Section 8.3, 8.4, 12.3, 15.5
Lack of capacity to review EIS			Section 3.1
Concerns with Alton Gas project and possible use of BP and Statoil projects with further development			Not applicable to the scope of this Project and EIS
Concerns regarding impacts to FSC and commercial-communal fishing rights			Section 7.3.2, Chapter 12, Chapter 13
Concerns regarding engaging separately on ExxonMobil proposed Offshore Exploration Project and Sable Decommissioning Project in Nova Scotia			Section 3.1
Desire to have operators collaborate on EAs to reduce burden on communities			Section 1.4

Table 3.10 Engagement Activities with Nova Scotia Indigenous Groups and Key Outcomes

Nova Scotia			
Millbrook First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Millbrook First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding commercial-communal fishing licences in the area and salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Millbrook First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up email to regarding confirmation of receipt of June 15 letter; attached copy of letter
June 28, 2017	Call	Statoil	Follow-up to Millbrook First Nation to determine if they had received Project letter. Millbrook First Nation asked for it to be resent. Statoil resent the letter.
July 14, 2017	Phone Call	ExxonMobil	Follow-up on June 15 letter. Left message for Chief
September 5, 2017	Email	ExxonMobil Statoil	Seeking meeting with Millbrook First Nation to discuss Project.
October 11, 2017	Email	ExxonMobil	Follow-up to previous correspondence seeking input on the Project, and committing to follow up.
October 12, 2017	Email	Statoil	Follow-up on previous correspondence seeking input on the Project and committing to follow up.
October 17, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial-communal swordfish license activity taking place within Project Area.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator			n/a

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
Date	**Activity**	**Operator**	**Purpose and Focus**
Mi'gmawe'l Tplu'taqnn Inc. (MTI) – Aggregate body for Pabineau First Nation, Esgenoopetitj First Nation, Buctouche First Nation, Indian Island First Nation, Eel River Bar First Nation, Metepenagiag Mi'kmaq Nation, Fort Folly First Nation, and Eel Ground First Nation with regards to engagement. For any engagement with MTI, the Operators understand that MTI is acting on behalf of the groups listed above.			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should the MTI have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should MTI have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
June 28, 2017	Email	MTI	Responded to Operators indicating concerns about potential impacts to Aboriginal and Treaty rights, potential effects on water quality and migratory species including salmon and whales that travel through the Project Area. Also indicated the need for capacity funding.
June 29, 2017	Email	ExxonMobil	Response to MTI June 28 to confirm email request was received and to expect a response in the following week.
July 7, 2017	Email	Statoil	Provided salmon report to MTI and responded to some of the concerns from their June 28 email.
July 11, 2017	Call	Statoil	Statoil spoke to MTI, MTI indicated they will review salmon study and follow up with any concerns. Asked about capacity funding.
July 12, 2017	Email	ExxonMobil	Provided salmon report to MTI and responded to some of the concerns from their June 28 email.
August 17, 2017	Email	ExxonMobil Statoil	Emailed MTI seeking a meeting the week of Sept 18 to discuss salmon report.

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
Aug 29, 2017	Email	MTI	Email indicating they were trying to confirm a meeting date.
September 7, 2017	Email	MTI	Confirmed meeting date for September 20.
September 20, 2017	Meeting	ExxonMobil Statoil	Operators provided an overview of operations in offshore Newfoundland. The Operators' fish biologist provided an overview of the salmon study. MTI provided feedback on the importance of salmon to their culture and the impact the inability to harvest it has had. Indicated that they were disappointed that there had not been more recent studies conducted and also indicated the salmon report did not cover populations of interest to them. Statoil / ExxonMobil indicated they would provide a report to capture the populations of interest.
September 27, 2017	Email / Report	ExxonMobil Statoil	Re-sent original salmon study asking for clarification as it appeared to cover the population of interest to MTI.
Oct 3, 2017	Email	ExxonMobil Statoil	Follow-up email confirming salmon study information provided met MTI's needs and asked for a conference call to further discuss capacity funding concerns, the salmon study, and how the Indigenous group would like to be engaged moving forward.
October 18, 2017	Email	MTI	MTI responded to Operators with additional question on information in salmon report. Also indicated a desire to conduct community engagement sessions on four proposed projects in one round of community sessions. Indicated a budget for this and Indigenous Knowledge Studies could be submitted for consideration.
October 24, 2017	Email	ExxonMobil Statoil	Email to Fort Folly First Nation seeking to determine if any commercial-communal swordfish license activity taking place within Project Area
October 24, 2017		ExxonMobil Statoil	Statoil / ExxonMobil responded to Oct 18 email seeking community contact for further Salmon report discussions and asked MTI to send additional information regarding capacity needs.

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

<table>
<tr><td colspan="4">New Brunswick</td></tr>
<tr><th colspan="3">Key Questions and Issues Raised</th><th>Where Addressed in the EIS and/or Follow up from the Operator</th></tr>
<tr><td colspan="3">Potential impact of Project on Atlantic salmon population/migration – specifically concerned about DU12, and the need for more current research.</td><td>Section 8.3, 8.4, 12.3, 15.5</td></tr>
<tr><td colspan="3">High cultural value of fisheries including Atlantic salmon, eels and swordfish.</td><td>Section 7.1, 7.3.2, Chapter 12</td></tr>
<tr><td colspan="3">Inability to fully carry out FSC rights due to limited salmon population and conservation programs, which impact food security</td><td>Section 7.3.2, Chapter 12 and 13</td></tr>
<tr><td colspan="3">Type of drilling installation used, depths of wells, timing of drilling, effects of drilling mud discharge on salmon feeding areas</td><td>Chapter 2, 8.3, 12.3</td></tr>
<tr><td colspan="3">Impact of the Project on migratory species that travel through the Project Area – including right whales and salmon</td><td>Section 8.3, 8.4, 10.3, 10.4, Chapter 12</td></tr>
<tr><td colspan="3">Displacement of prey species as a result of operations</td><td>Section 8.3, 8.4, 10.3, 10.4</td></tr>
<tr><td colspan="3">Adequacy of CEA Agency participant funding</td><td>Section 3.1</td></tr>
<tr><td colspan="3">Seeking to coordinate all four Flemish projects into one round of community engagement</td><td>Section 1.4</td></tr>
<tr><td colspan="4">Wolastoqey Nation in New Brunswick (WNNB) – Aggregate coordinating body for Kingsclear First Nation, Madawaska First Nation, Oromocto First Nation, St. Mary’s First Nation, and Tobique First Nation – direct engagement with communities. For any engagement with WNNB, the Operators understand that WNNB is acting on behalf of the groups listed above.</td></tr>
<tr><td>June 13, 2017</td><td>Email / Letter</td><td>Statoil</td><td>Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Letter sent to Kingsclear First Nation, Madawaska First Nation, Oromocto First Nation, St. Mary’s First Nation, Tobique First Nation, and Woodstock First Nation; cc’d WNNB.</td></tr>
<tr><td>June 15, 2017</td><td>Letter</td><td>ExxonMobil</td><td>Provide Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Letter sent to Kingsclear First Nation, Madawaska First Nation, Oromocto First Nation, St. Mary’s First Nation, Tobique First Nation, and Woodstock First Nation; cc’d WNNB.</td></tr>
</table>

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 11, 2017	Email	WNNB	WNNB email to Statoil confirming receipt of June 13 correspondence.
July 24, 2017	Email	WNNB	WNNB on behalf of all members indicated that a letter regarding initial interest in the Projects has been sent to CEA Agency. WNNB has requested funding from CEA Agency to review potential effects of the Projects on salmon population. WNNB cannot provide further input or complete review and uncertain if CEA Agency will cover full costs. WNNB requested that any documents, data or other information including research on salmon migration and associated activity be sent to them to review.
July 25, 2017	Email	ExxonMobil	Responded to the July 24 letter and included a report pertaining to potential impacts of the Project on migrating salmon indicating that further information would be provided in the EIS.
Aug 11, 2017	Email	Statoil	Responded to the July 24 letter and included a report pertaining to potential impacts of the Project on migrating salmon indicating that further information would be provided in the EIS. In addition, a request was made to meet with WNNB regarding the salmon report the week of Sept 18.
Aug 14, 2017	Email	Statoil	Followed up on potential meeting date availability and also indicated to WNNB that the salmon report had been sent to the communities associated with WNNB.
September 19, 2017	Meeting	ExxonMobil Statoil	Provided a Project overview and had their fish biologist discuss the salmon report. WNNB indicated they had not exercised their FSC rights since 1996 due to poor salmon stocks, asked if there were more recent reports that would be included in the salmon study overview, if there was currently any research being done by oil and gas companies regarding salmon or any research being done in Norway, asked about number of wells being contemplated and their depths. Statoil / ExxonMobil answered questions and indicated they would follow up on additional research being added to the salmon study. Indicated it would be beneficial if there was greater collaboration amongst Operators on the EAs in order to reduce the burden on community to review.

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

<table>
<tr><td colspan="4">New Brunswick</td></tr>
<tr><th colspan="3">Key Questions and Issues Raised</th><th>Where Addressed in the EIS and/or Follow up from the Operator</th></tr>
<tr><td colspan="3">Potential impact of Project on Atlantic salmon populations and migration – need for more current research to be included in salmon report – need for more research regarding Atlantic salmon generally</td><td>Section 8.3, 8.4, 12.3, 15.5</td></tr>
<tr><td colspan="3">Primary salmon interest is for FSC purposes. Maliseet/Wolastoqey have had no FSC fishing activity since 1996 due to low salmon populations and conservation efforts</td><td>Section 8.3, 8.4, 12.3</td></tr>
<tr><td colspan="3">More information on drilling program</td><td>Chapter 2</td></tr>
<tr><td colspan="3">Capacity funding issues</td><td>Section 3.1</td></tr>
<tr><td colspan="3">Collaboration amongst Operators on the EAs in the region to reduce burden on community.</td><td>Section 1.4</td></tr>
<tr><td colspan="4">Kingsclear First Nation</td></tr>
<tr><td>June 13, 2017</td><td>Email / Letter</td><td>Statoil</td><td>Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Kingsclear First Nation have any further questions/concerns.</td></tr>
<tr><td>June 15, 2017</td><td>Letter</td><td>ExxonMobil</td><td>Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Kingsclear First Nation have any further questions / concerns.</td></tr>
<tr><td>June 22, 2017</td><td>Email</td><td>ExxonMobil</td><td>Follow-up to confirm receipt of June 15 letter; attached copy of letter</td></tr>
<tr><td>June 22, 2017</td><td>Email</td><td>Kingsclear First Nation</td><td>Confirmed receipt of June 15 letter indicating that comments were to follow</td></tr>
<tr><td>July 14, 2017</td><td>Phone Call</td><td>ExxonMobil</td><td>Follow-up to June 15 letter. Left voicemail.</td></tr>
<tr><td>July 24, 2017</td><td>Email and Letter</td><td>WNNB</td><td>WNNB on behalf of Kingsclear First Nation indicated that a letter regarding initial interest in the Projects has been sent to CEA Agency. WNNB has requested funding from CEA Agency</td></tr>
</table>

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
			to review potential effects of the Projects on salmon population. WNNB cannot provide further input or complete review and uncertain if CEA Agency will cover full costs. WNNB requested that any documents, data or other information including research on salmon migration and associated activity be sent to them to review.
July 25, 2017	Email	ExxonMobil	Responded to the July 24 WNNB letter and included a report pertaining to potential impacts of the Project on migrating salmon indicating that further information would be provided in the EIS, cc'd all WNNB First Nations.
August 14, 2017	Email / Report	Statoil	Provided report pertaining to potential impacts of the Project on migrating salmon. In addition, the First Nation was made aware of a request to meet with WNNB regarding the report in the week of Sept 18. See WNNB summary above.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See WNNB			See table above
Madawaska Maliseet First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Madawaska First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Madawaska First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
June 26, 2017	Email	ExxonMobil	Madawaska First Nation confirmed receipt of June 15 letter.
July 14, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Left voicemail.
July 17, 2017	Phone Call	ExxonMobil	Madawaska First Nation indicated that they will be responding in a few weeks after a Tribal Council meeting.
July 24, 2017	Email and Letter	WNNB	WNNB on behalf of Madawaska First Nation indicated that a letter regarding initial interest in the Projects has been sent to CEA Agency. WNNB has requested funding from CEA Agency to review potential effects of the Projects on salmon population. WNNB cannot provide further input or complete review and uncertain if CEA Agency will cover full costs. WNNB requested that any documents, data, or other information including research on salmon migration and associated activity be sent to them to review.
July 25, 2017	Email and attached Atlantic Salmon Report	ExxonMobil	Responded to the July 24 WNNB letter and included a report pertaining to potential impacts of the Project on migrating salmon indicating that further information would be provided in the EIS.
August 14, 2017	Email/ Report	Statoil	Provided report pertaining to potential impacts of the Project on migrating salmon. In addition, the Madawaska First Nation was made aware of a request to meet with WNNB regarding the report the week of Sept 18. See WNNB summary above.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See WNNB			See table above
Oromocto First Nation			
June 13, 2017	Email / Letter	Statoil	Provided a Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Oromocto First Nation have any further questions / concerns.

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Oromocto First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 14, 2017	Phone Call	ExxonMobil	Follow-up on June 15 letter. Left voicemail.
July 24, 2017	Email / Letter	WNNB	WNNB on behalf of Oromocto First Nation stated that a letter indicating initial interest in Projects was sent to CEA Agency. WNNB has requested funding from CEA Agency to review potential effects of the Projects on salmon population. WNNB cannot provide further input or complete review and uncertain if CEA Agency will cover full costs. For further input WNNB requested that any documents, data, or other information including research on salmon migration and associated activity be sent to them to review.
July 25, 2017	Email	ExxonMobil	In response to July 24, provided report pertaining to potential impacts of the Project on migrating salmon.
August 14, 2017	Email / Report	Statoil	Provided report pertaining to potential impacts of the Project on migrating salmon. In addition, Oromocto First Nation was made aware of a request to meet with WNNB regarding the report in the week of Sept 18. See WNNB summary above.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
See WNNB			See table above
St. Mary's First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project.

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
			Provided contact information should St. Mary's First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should St. Mary's First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 14, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Left voicemail.
July 24, 2017	Email	WNNB	WNNB on behalf of St. Mary's First Nation stated that a letter indicating initial interest in the Projects has been sent to CEA Agency. WNNB has requested funding from CEA Agency to reviewing potential effects of the projects to salmon population. WNNB cannot provide further input or complete review and is uncertain if CEA Agency will cover full costs. WNNB request any documents, data or other information including research on salmon migration and associated activity be sent to them to review.
July 25, 2017	Email	ExxonMobil	In response to July 24 letter, provided report pertaining to potential impacts of the Project on migrating salmon and indicated that further information would be provided in the EIS
August 14, 2017	Email / Report	Statoil	Provided report pertaining to potential impacts of the Project on migrating salmon. In addition, St. Mary's First Nation was made aware of a request to meet with WNNB regarding the report in the week of Sept 18. See WNNB summary above.
October 24, 2017	Email	ExxonMobil Statoil	Seeking to determine if any commercial communal swordfish license activity taking place within Project Area.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick			
See WNNB			See table above
Tobique First Nation			
June 13, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Tobique First Nation have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview letter about the Project and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Tobique First Nation have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter
July 14, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Left voicemail.
July 17, 2017	Phone Call	ExxonMobil	Tobique First Nation called to request a copy of the email and letter; ExxonMobil forwarded a copy.
July 24, 2017	Email and Letter	ExxonMobil	WNNB on behalf of Tobique First Nation stated that a letter indicating initial interest in the Projects had been sent to CEA Agency. WNNB has requested funding from CEA Agency to review potential effects of the Projects on salmon population. WNNB cannot provide further input or complete review and uncertain if CEA Agency will cover full costs. WNNB requested that any documents, data or other information including research on salmon migration and associated activity be sent to them for review and input.
July 25, 2017	Email and attached Atlantic Salmon Report	ExxonMobil	In response to July 24 letter, provided report pertaining to potential impacts of the Project on migrating salmon and indicated that further information would be provided in the EIS

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

<table>
<tr><td colspan="4">New Brunswick</td></tr>
<tr><td>August 14, 2017</td><td>Email / Report</td><td>Statoil</td><td>Provided report pertaining to potential impacts of the Project on migrating salmon. In addition, Tobique First Nation was made aware of a request to meet with WNNB regarding the report in the week of Sept 18. See WNNB summary.</td></tr>
<tr><td colspan="4">Passamaquoddy of New Brunswick</td></tr>
<tr><td>August 15, 2017</td><td>Email / Letter</td><td>Statoil</td><td>Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Passamaquoddy of New Brunswick have any further questions / concerns.</td></tr>
<tr><td>August 17, 2017</td><td>Email/Letter</td><td>ExxonMobil</td><td>Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Passamaquoddy of New Brunswick have any further questions / concerns.</td></tr>
<tr><td colspan="3">Key Questions and Issues Raised</td><td>Where Addressed in the EIS and/or Follow up from the Operator</td></tr>
<tr><td colspan="3">No concerns identified to Operator</td><td>n/a</td></tr>
<tr><td colspan="4">Woodstock First Nation</td></tr>
<tr><td>Email/Letter</td><td>Statoil</td><td colspan="2">Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Woodstock First Nation have any further questions / concerns.</td></tr>
<tr><td>Letter</td><td>ExxonMobil</td><td colspan="2">Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should Woodstock First Nation have any further questions / concerns.</td></tr>
<tr><td>Email</td><td>ExxonMobil</td><td colspan="2">Follow-up to confirm receipt of June 15 letter; attached copy of letter</td></tr>
<tr><td>Email</td><td>ExxonMobil</td><td colspan="2">Woodstock First Nation confirmed receipt of June 15 letter and indicated that questions and comments would be provided in the following week.</td></tr>
</table>

Table 3.11 Engagement Activities with New Brunswick Indigenous Groups and Key Outcomes

New Brunswick		
Phone Call	ExxonMobil	Call to follow up on June 15 letter. Left voicemail.
Email/ Report	Statoil	Provided report and summary to Woodstock First Nation. Woodstock First Nation indicated they wished to be engaged directly by the Operator outside of the WNNB. A meeting date was requested for September to review the salmon report.
Phone Call	ExxonMobil Statoil	Call to request a meeting for week of September 18 and left a message.
Email	ExxonMobil Statoil	Email to Woodstock First Nation to follow up on August 2017 message to request a meeting for week of September 18.
Email	ExxonMobil Statoil	Woodstock First Nation emailed to confirm meeting date with Statoil/ExxonMobil for September 19.
Meeting	ExxonMobil Statoil	Met with Woodstock First Nation to provide an overview of the Projects and asked if there were any questions/feedback on the salmon report. Woodstock First Nation indicate they had not reviewed the report but would be meeting with Fisheries Manager to review and would provide feedback.
Email	ExxonMobil Statoil	Seeking to determine if any commercial communal swordfish license activity taking place within Project Area.

Key Questions and Issues Raised	**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator	n/a

Table 3.12 Engagement Activities with Quebec Indigenous Groups and Key Outcomes

Quebec			
Date	**Activity**	**Operator**	**Purpose and Focus**
La Première Nation des Innus de Ekuanitshit (all communication provided in the French language)			
Date	**Activity**	**Organization**	**Purpose and Focus**
June 14, 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should La Première Nation des Innus de Ekuanitshit have any further questions / concerns.

Table 3.12 Engagement Activities with Quebec Indigenous Groups and Key Outcomes

Quebec			
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact should La Première Nation des Innus de Ekuanitshit have any further questions / concerns.
June 23, 2017	Email and resent June 15, 2017 Letter	ExxonMobil	Follow-up to confirm receipt of June 15 letter; attached copy of letter.
June 26, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Left message providing English and French ExxonMobil contacts.
June 30, 2017	Phone Call	Statoil	Follow-up to June 14 letter. Council member was not aware if the letter had been received Statoil clarified contact information and resent the email.
July 6, 2017	Email	Statoil	La Première Nation des Innus de Ekuanitshit responded indicating that they would need more time to provide a response to the June 14 information.
July 10, 2017	Email	ExxonMobil	Conseil des Innus de Ekuanitshit email expressing interest but will need more time to evaluate and respond
July 18, 2017	Email / Letter	Statoil	La Première Nation des Innus de Ekuanitshit provided questions and concerns related to the Project: potential impacts of a spill on wildlife, food, subsistence and commercial fisheries; Project Area could be migratory area for commercial species; the First Nation hunts seals and migratory birds and collects eggs; environmental quality of St. Lawrence and Gulf; impacts of operational activity. Asked for salmon report, data, and studies that support low probability of uncontrolled well event, copies of proponent policies and procedures relating to spills, specific information regarding the types of ongoing drilling activity that will take place; need for capacity to hire biologist, engineer and legal advisor.

Table 3.12 Engagement Activities with Quebec Indigenous Groups and Key Outcomes

Quebec			
July 19, 2017	Email and Letter	ExxonMobil	La Première Nation des Innus de Ekuanitshit provided questions and concerns related to the Project: potential impacts of a spill on wildlife, food, subsistence, and commercial fisheries; Project Area could be migratory area for commercial species; hunts seals and migratory birds and collects eggs; environmental quality of St. Lawrence and Gulf; impacts of operational activity. Asked for salmon report, data, and studies that support low probability of uncontrolled well event, copies of proponent policies and procedures relating to spills, specific information regarding the types of ongoing drilling activity that will take place; need for capacity to hire biologist, engineer and legal advisor.
Aug 16, 2017	Email / Letter	Statoil	Responded to July 18 letter by providing salmon report summarizing research on potential migrating salmon in the Project Area and indicating that many of the issues raised in the letter will be covered in the EIS. In addition, suggested that CEA Agency funding should adequately address capacity concerns at this time.
August 31, 2017	Letter	ExxonMobil	Responded to July 18 letter by providing salmon report summarizing research on potential migrating salmon in the Project Area and indicating that many of the issues raised in the letter will be covered in the EIS. In addition, suggested that CEA Agency funding should adequately address capacity concerns at this time.

Key Questions and Issues Raised	**Where Addressed in the EIS and/or Follow up from the Operator**
Potential impact of spill on wildlife – specifically those accessed for subsistence and commercial fishing, including migratory birds and seals, eggs.	Chapter 15
Specific research information on Atlantic salmon	Section 8.3, 8.4, 12.3
Data, studies, or reports associated with the probability of an uncontrolled well event	Chapter 15
Policies and procedures regarding prevention of spill	Chapter 15
Nature of ‘ongoing operational drilling activities’ and their interaction with salmon migration	Section 8.3, 8.4, 12.3
Requested further clarification on salmon research, collaboration of EM and Statoil, cumulative effects of other industry	Section 8.3, 8.4, 12.3, Chapter 14

Table 3.12 Engagement Activities with Quebec Indigenous Groups and Key Outcomes

Quebec			
Lack of capacity to review EIS			Section 3.1
La Première Nation des Innus de Natashkuan (all communication provided in the French language)			
June 13 2017	Email / Letter	Statoil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should La Première Nation des Innus de Natashkuan have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Provided Project overview and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project Provided contact information should La Première Nation des Innus de Natashkuan have any further questions / concerns.
June 23, 2017	Email		Follow-up to confirm receipt of June 15 letter; attached copy of letter.
June 26, 2017	Phone Call	ExxonMobil	Follow-up to June 15 letter. Left message providing English and French ExxonMobil contacts.
June 29, 2017	Phone call	Statoil	Follow-up on Project Letter. Band Office indicated they would confirm receipt and respond. No response.
October 15, 2017	Email	ExxonMobil	Follow up to June 15 letter to determine if there were any questions or concerns regarding the Project, update the community on intention to submit EIS and commit to following up after submission.
October 18, 2017	Email	Statoil	Follow up to June 13 letter to determine if there were any questions or concerns regarding the Project, update the community on intention to submit EIS and commit to following up after submission.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator			n/a

Table 3.12 Engagement Activities with Quebec Indigenous Groups and Key Outcomes

Quebec			
Mi'gmawei Mawiomi Secretariat (MMS) – aggregate body for La Nation Micmac de Gespeg, Listuguj Mi'gmaq Government and Micmacs of Gesgapegiag with regard to engagement**.**			
June 14 2017	Email / Letter	Statoil	Overview letter about the Project and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should the MMS have any further questions / concerns.
June 15, 2017	Letter	ExxonMobil	Overview letter about the Project and summary information regarding salmon migration in relation to the Project. Requested feedback or information on any rights and traditional uses and how they might be affected by the Project. Provided contact information should the MMS have any further questions / concerns.
June 22, 2017	Email	ExxonMobil	Follow-up email to regarding confirmation of receipt of June 15 letter; attached copy of letter.
October 11, 2017	Email	ExxonMobil	Follow up to June 15 letter to determine if there were any questions or concerns regarding the Project, update the community on intention to submit EIS and commit to following up after submission.
October 12, 2017	Email	Statoil	Follow up to June 13 letter to determine if there were any questions or concerns regarding the Project, update the community on intention to submit EIS and commit to following up after submission.
October 13, 2017	Phone call	Statoil	Follow up call to confirm receipt of email and answer any questions, left voice mail.
Key Questions and Issues Raised			**Where Addressed in the EIS and/or Follow up from the Operator**
No concerns identified to Operator			n/a

3.4 Stakeholder Meetings and Discussions

As part of the EIS preparation, Statoil and ExxonMobil have engaged with key stakeholders and environmental non-government organizations that have historically been engaged in or have an interest in offshore oil and gas operations in Newfoundland and Labrador. These organizations include Nature Newfoundland and Labrador (NL), World Wildlife Federation (WWF), Canadian Parks and Wilderness Society (CPAWS), Protected Areas Association of Newfoundland, and Sierra Club (NL Chapter).

Fish harvesters and processors are a key stakeholder, with which the Operators have ongoing communication and engagement to keep them apprised of offshore oil and gas activity in their fishing areas and to address any concerns they may have. Fish harvesters engaged in fishing offshore Newfoundland are represented by the Fish Food and Allied Workers-Unifor (FFAW-Unifor). Fish processors include Ocean Choice International, Association of Seafood Producers, and Groundfish Enterprise Allocation Council. One Ocean is the liaison organization established by and for the fishing and petroleum industries of Newfoundland and Labrador. Its objective is to assist the fishing and petroleum industries in understanding each sector's operational activities. Members of the One Ocean Board and working group include representatives from FFAW-Unifor, fish processors, and offshore oil and gas operators.

A summary of Project-related engagement initiatives involving stakeholder groups is provided in Table 3.13.

A summary of the key questions and issues raised through the above described meetings and discussions with stakeholder groups and others is also included in Table 3.13, along with an indication of where these are addressed in the EIS.

Table 3.13 Meetings and Discussions with Stakeholder Organizations

Date	Organization	Type / Format	Operator	Purpose and Focus
March 1, 2016	One Ocean	Meeting	ExxonMobil Statoil	Working group quarterly meeting Operators update. Provided update on EA status and CEAA 2012 process.
May 19, 2016	FFAW-Unifor, One Ocean	Meeting	ExxonMobil Statoil	Project introduction and overview, EA process, opportunities for engagement during EIS preparation
May 27, 2016	Ocean Choice International	Meeting	ExxonMobil Statoil	Project introduction and overview, EA process, opportunities for engagement during EIS preparation
June 1,2016	One Ocean	Meeting	ExxonMobil Statoil	Working group quarterly meeting Operators update. Provided update on EA status and CEAA 2012 process.
November 4, 2016	One Ocean	Meeting	ExxonMobil Statoil	Working group quarterly meeting Operators update. Provided update on EA status and CEAA 2012 process.
January 19, 2017	One Ocean	Meeting	ExxonMobil Statoil	Working group quarterly meeting Operators update. Provided update on EA status and CEAA 2012 process.
March 22, 2017	FFAW-Unifor	Meeting	ExxonMobil Statoil	CEAA 2012 EA process and overview of EIS
April 6, 2017	One Ocean	Meeting	ExxonMobil Statoil	Working group quarterly meeting Operators update. Provided update on EA status and CEAA 2012 process.

Table 3.13 Meetings and Discussions with Stakeholder Organizations

July 17, 2017	One Ocean	Meeting	ExxonMobil Statoil	Working group quarterly meeting Operators update. Provided update on EA status and CEAA 2012 process.
September 21, 2017	FFAW-Unifor	Phone call	ExxonMobil Statoil	Discussion of future engagement with fish harvesters. It was decided that a meeting would be arranged once the EIS was submitted; the meeting would be focused on issues / concerns identified by the FFAW-Unifor. Questions and comments raised are summarized below.
October 2, 2017	Ocean Choice International, Association of Seafood Producers, Groundfish Enterprise Allocation Council, One Ocean	Meeting	ExxonMobil Statoil	Overview of the CEAA 2012 EA process and overview of Statoil / ExxonMobil EIS, seeking to gather feedback from the participants. Questions and comments raised are summarized below.
October 5, 2017	Nature Newfoundland and Labrador	Meeting	ExxonMobil Statoil	Overview of the CEAA 2012 EA process and overview of Statoil / ExxonMobil EIS, seeking to gather feedback from the participants. Questions and comments raised are summarized below.
September 25, 2017	Nature NL, WWF, PAAN, Sierra Club, CPAWS	Email	ExxonMobil Statoil	Invitation to meeting to provide information on proposed Projects and discuss concerns/questions. Nature NL accepted, WWF declined; no response from PAAN, Sierra Club or CPAWS.
October 5, 2017	One Ocean	Email	ExxonMobil Statoil	Working group quarterly meeting Operators update. Provided update on EA status and CEAA 2012 process.

Key Questions and Issues Raised	Where Addressed in the EIS and/or Follow up from the Operator
Re-establishment of turbot fishery and cod fishery since moratorium.	Section 7.1.8
Potential impacts of project on cod spawning areas	Section 8.3, 8.4
Timeframe for review under CEAA 2012 process as compared to the C-NLOPB EA process	Section 1.3
Information regarding annual fish harvesting statistics	Section 7.1

Table 3.13 Meetings and Discussions with Stakeholder Organizations

Recent and potential re-emergence of cod and witch flounder fisheries	Section 7.1.8
If annual EA updates/communication of upcoming activity would be continued so as to inform fishing community of planned activities for that year	Section 13.3.2, 17.5
Temporal scope of the Project and its EA	Section 1.2, 4.1, Chapter 2
Air quality identified as valued component appears inconsistent with other VC characteristics (e.g., noise is not identified as a valued component but air quality and GHG emissions are).	Operators responded that inclusion of Air Quality as a VC is Guideline requirement. Chapter 2, Section 4.1, 4.2
Availability of information for the fish species that are being fished within the 3M area	Section 7.1
Potentially having multiple drill rigs in the province at the same time (exploration drilling) may be a benefit in the case of an accidental event to provide assistance for drilling of relief wells. Operator indicated that spill prevention was paramount in this process	Chapter 2, 15
Wind effects on currents should be considered in the EIS	Section 5.5
Was it possible to only flare during the day during a flow test.	Operators responded that the test should be continuous and flaring would therefore be. Tests and flaring are only required in cases where substantial hydrocarbons are encountered.
Participants noted that met-ocean data collected by industry is of high quality and is not as readily accessible to them.	Operators indicated that all met-ocean data is provided to C-NLOPB and released to public through that mechanism. Also pointed out that changes due to Frontier and Offshore Regulatory Renewal Initiative (FORRI) propose public release of physical and environmental data.
Operators committed to providing participants with a notification of when the EIS is available for public review	Chapter 3.0

These stakeholder engagement activities have also included additional discussions and on-going information sharing through various other means (such as through letters, email, telephone conversations), the results of which have also been considered in the scope and content of the EIS as applicable.

4.0 ENVIRONMENTAL ASSESSMENT SCOPE, APPROACH, AND METHODS

This Chapter outlines the scope and focus of the EIS, as well as describing the approach and methods used to conduct the environmental effects assessment.

As both Projects and their EAs have comparable scopes and their EISs have been designed and completed using the same overall approach and methodology, the content of this chapter is common to both projects and assessments.

4.1 Scope of the Environmental Assessment and Factors Considered

This EIS has been planned, prepared, and submitted in accordance with requirements of CEAA 2012 as well as the Project-specific *Guidelines for the Preparation of an Environmental Impact Statement pursuant to the Canadian Environmental Assessment Act, 2012* issued by the Canadian Environmental Assessment Agency in December 2016 and other generic EA guidance documents issued by the Agency as cited herein.

The scope of the Project for the purposes of the EA includes each of the components and activities defined and described in Chapter 2 of this EIS and as specified in Section 3.1 of the EIS Guidelines, namely:

- *the mobilization, operation, and demobilization of Drilling Installation(s) designed for year-round operations for the drilling, testing and abandonment of…*

For the Statoil Canada Ltd. Flemish Pass Exploration Drilling Program:

... up to thirty exploration wells within exploration licences operated by Statoil Canada Ltd.

For the ExxonMobil Canada Ltd. Eastern Newfoundland Offshore Exploration Drilling Project

… up to 35 wells within exploration licences operated by ExxonMobil Canada Ltd.

…including consideration of proposed safety exclusion zones. Drilling may occur in various water depths under consideration, with various types of drilling installations, and with multiple drilling installations operating simultaneously

- *VSP surveys and in-water works (e.g., wellsite surveys) to support the specific exploration wells under consideration, but excluding surveys potentially required to support conduct of the EA (e.g., environmental baseline surveys) and surveys related to the broader delineation of resources*
- *the loading, refuelling and operation of marine support vessels (i.e., for re-supply and transfer of materials, fuel, and equipment and on-site safety during drilling activities and transport between the supply base and Drilling Installation(s) and helicopter support (i.e., for crew transport and delivery of light supplies and equipment) including transportation to the Drilling Installation*

CEAA 2012 includes the following definitions and specifications related to assessing the environmental effects of a designated project, which are relevant to the overall scope of the assessment, and which have guided the planning and development of the EIS:

> *[E] environment means the components of the Earth, and includes*
>
> *(a) land, water, and air, including all layers of the atmosphere;*
> *(b) all organic and inorganic matter and living organisms; and*
> *(c) the interacting natural systems that include components referred to in paragraphs (a) and (b)*
>
> *5 (1) For the purposes of this Act, the environmental effects that are to be taken into account in relation to an act or thing, a physical activity, a designated project, or a project are*
>
> *(a) a change that may be caused to the following components of the environment that are within the legislative authority of Parliament:*
>
> *(i) fish and fish habitat as defined in subsection 2(1) of the Fisheries Act,*
> *(ii) aquatic species as defined in subsection 2(1) of the Species at Risk Act,*
> *(iii) migratory birds as defined in subsection 2(1) of the Migratory Birds Convention Act, 1994, and*
> *(iv) any other component of the environment that is set out in Schedule 2;*
>
> *(b) a change that may be caused to the environment that would occur*
>
> *(i) on federal lands,*
> *(ii) in a province, other than the one in which the act or thing is done or where the physical activity, the designated project or the project is being carried out, or*
> *(iii) outside Canada; and*
>
> *(c) with respect to aboriginal peoples, an effect occurring in Canada of any change that may be caused to the environment on*
>
> *(i) health and socio-economic conditions,*
> *(ii) physical and cultural heritage,*
> *(iii) the current use of lands and resources for traditional purposes, or*
> *(iv) any structure, site or thing that is of historical, archaeological, paleontological, or architectural significance.*

In addition, other types of environmental effects must be considered under Section 5(2) of CEAA 2012 where the carrying out of the physical activity, the designated project or the project requires a federal authority to exercise a power or perform a duty or function conferred on it under another Act of Parliament. In the case of this Project, the Operator will require authorizations from the C-NLOPB under the Accord Acts in order for the Project to proceed. Therefore, the following environmental effects are also taken into account in the EIS:

> *(a) a change, other than those referred to in paragraphs (1)(a) and (b), that may be caused to the environment and that is directly linked or necessarily incidental to a federal authority's exercise of a power or performance of a duty or function that*

would permit the carrying out, in whole or in part, of the physical activity, the designated project, or the project; and

(b) an effect, other than those referred to in paragraph (1)(c), of any change referred to in paragraph (a) on

(i) health and socio-economic conditions,
(ii) physical and cultural heritage, or
(iii) any structure, site or thing that is of historical, archaeological, paleontological, or architectural significance.

As defined in Section 19(1) of CEAA 2012 and specified in Section 3.2 of the EIS Guidelines, the following factors are considered and addressed in the EIS:

(a) the environmental effects of the designated project, including the environmental effects of malfunctions or accidents that may occur in connection with the designated project and any cumulative environmental effects that are likely to result from the designated project in combination with other physical activities that have been or will be carried out;
(b) the significance of the effects referred to in paragraph (a);
(c) comments from the public …
(d) mitigation measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the designated project;
(e) the requirements of the follow-up program in respect of the designated project;
(f) the purpose of the designated project;
(g) alternative means of carrying out the designated project that are technically and economically feasible and the environmental effects of any such alternative means;
(h) any change to the designated project that may be caused by the environment;
(i) the results of any relevant study conducted by a committee established under section 73 or 74; and
(j) any other matter relevant to the environmental assessment that the responsible authority, or — if the environmental assessment is referred to a review panel — the Minister, requires to be taken into account.

These factors have been considered and addressed in establishing the scope, focus, and spatial and temporal boundaries of the analysis and the overall content of this EIS. The EIS has been prepared in compliance with the requirements of CEAA 2012, the EIS Guidelines, and the Accord Acts. A detailed Table of Concordance outlining these requirements and indicating where and how each item is addressed in the EIS is provided in the Executive Summary of this EIS.

4.2 Identification and Selection of Valued Components

EAs typically identify and focus on components of the environment that are of ecological or socioeconomic importance and/or which can serve as indicators of environmental change, and that have the potential to be affected in some way by the proposed project under assessment. These are known as Valued Components (VCs), and may include both biophysical and socioeconomic aspects of the environment. The VC approach is a useful, effective, and widely accepted way of ensuring that an EA focuses on components and issues that are most relevant to the Project and its potential effects.

For this EIS, the identification and selection of the VCs was an early, ongoing, and iterative process based on a number of key considerations and inputs including EIS Guidelines, regulatory guidance, and Indigenous and stakeholder engagement (Chapter 3). Specifically, commercial fisheries and fish and fish habitat VCs address the VC raised by fisheries organizations and indigenous groups related to commercial fishing. Marine fish and fish habitat, marine and migratory birds, marine mammals and sea turtles with the inclusion of species at risk address the VCs of concern raised by environmental organizations and indigenous groups from a harvesting and cultural perspective. Special Areas was also a VC of interest identified by environmental organizations. Specific details regarding feedback from stakeholders and indigenous groups and where in EIS they are addressed is provided in the tables within Sections 3.3 and 3.4. The selection of VCs was ultimately informed by consideration of the nature and characteristics of the Project, its existing environmental settings, experience and knowledge from similar offshore oil and gas projects, Indigenous concerns and the professional experience of the Operator and EA Study Team.

The following VCs are considered in this assessment:

1) Marine Fish and Fish Habitat (including Species at Risk)
2) Marine and Migratory Birds (including Species at Risk)
3) Marine Mammals and Sea Turtles (including Species at Risk)
4) Special Areas
5) Indigenous Communities and Activities
6) Commercial Fisheries and Other Ocean Users

The rationale for the selection of these VCs is further described in Table 4.1.

Table 4.1 Identified VCs and the Rationale for their Selection

Valued Component	Rationale
Marine Fish and Fish Habitat	• Fish resources are an important consideration in the EA of the proposed activities that occur within, and that may affect, the marine environment. • This VC includes relevant fish species, as well as plankton, algae, marine plants, benthos, and relevant components of their habitats (such as water and sediment), given the clear interrelationships between these environmental components • The consideration of Marine Fish and Fish Habitat within a single VC is in keeping with current and standard practice, and provides for a more comprehensive, holistic approach while at the same time reducing unnecessary repetition • The VC (description of the existing environment and effects assessment) also gives specific consideration to any particular species that have been identified by regulatory agencies, stakeholder groups or Indigenous communities. • Specifically, Indigenous Groups identified Atlantic salmon, swordfish, cod, turbot, snow crab and American eel as fish species that are important and valued for commercial and/or traditional purposes (Chapter 3).

Table 4.1 Identified VCs and the Rationale for their Selection

Valued Component	Rationale
	• Although the EIS Guidelines specify (in Section 6.3.2) “marine plants” as potential VC for the EIS, these have been considered as part of the overall Marine Fish and Fish Habitat VC, for the reasons outlined above
Marine and Migratory Birds	• A variety of avifauna species inhabit the marine environments off eastern Newfoundland at various times of the year • Birds are important from an ecological, social, and economic perspective, as they often function near the top of the food chain, and may be vulnerable to certain types of environmental disturbance • They are also an important resource for various recreational and tourism related pursuits. • Indigenous groups indicated that marine and migratory bird species and their eggs are used for traditional land and resource use activities (see Chapter 3)
Marine Mammals and Sea Turtles	• Marine mammals (including whales, dolphins, and seals) have been and remain an important element of the environmental and socio-cultural settings of the province and elsewhere in Atlantic Canada • These species are important from an ecological perspective, with a number of marine mammal species having been designated as species at risk under Canadian legislation • Some species are also important and valued due to current traditional / commercial (seal harvests) and recreational (whale watching) uses • The VC (description of the existing environment and effects assessment) also gives specific consideration to any particular species that have been identified by regulatory agencies, stakeholder groups or Indigenous communities. • Indigenous Groups identified species such as beluga, Atlantic blue and North Atlantic right whales as being important for cultural reasons, as well as noting that seals were used for traditional land and resource use activities (see Chapter 3). • Although sea turtles are generally uncommon in the region, they are also included as part of this VC given their rare and often protected status
Special Areas	• Several locations within the Canada-NL Offshore Area and beyond have been designated as special or sensitive areas due to their ecological characteristics and importance • Some of these areas are protected under provincial and/or federal legislation and others are protected under international maritime agreements
Indigenous Communities and Activities	• A number of Indigenous groups reside in Newfoundland and Labrador, and in parts of the Maritimes Provinces (Nova Scotia, New Brunswick, PEI) and Quebec • As illustrated in Chapter 7, the components and activities that comprise this Project will be located at some considerable distance from the communities, activities and other known interests associated with each of these groups. It may, however, potentially affect marine-associated species and other resources that are used by these groups, and which move through, and thus may interact with, the Project's anticipated environmental zone of influence • This VC is included in the EIS as specified in and required by the EIS Guidelines, and to address the requirements of Section 5(1)(c) of CEAA 2012

Table 4.1 Identified VCs and the Rationale for their Selection

Valued Component	Rationale
Commercial Fisheries and Other Ocean Users	• Marine commercial fisheries are key elements that have shaped the history and socioeconomic character of Newfoundland and Labrador and are important aspects of the current economic and socio-cultural fabrics of the province and other parts of Canada • Commercial fisheries in this region are extensive and diverse, and involve a range of species and gear types at various times of the year. Fishing activities are undertaken in and around the Project Area by fishing interests from Newfoundland and Labrador (including several Indigenous organizations), Canadian and international fishing enterprises • Other activities take place in parts of the Project Area and adjacent areas on either a year-round or seasonal basis, including other oil and gas related activities, general vessel traffic, research, and military exercises

Species at Risk (SAR) designated under federal and/or provincial legislation are included under the respective VC for marine fish and fish habitat, marine and migratory birds, and marine mammals and sea turtles. Within these VC Chapters, SAR are given special attention and emphasis in the identification, analysis and evaluation of potential environmental effects and required mitigation measures. Table 4.2 links each of these identified VCs to the various environmental components and issues that are specified under CEAA 2012 (Section 5). Although the EIS provides individual environmental effects assessments for each VC (Chapter 8 to 13), it is done with full consideration of the interactions and interrelationships between these environmental components through a holistic, ecosystem based approach.

Table 4.2 Identified VCs and Potential Considerations Relevant to CEAA 2012

CEAA 2012 Requirement	CEAA 2012 Section	Marine Fish and Fish Habitat	Marine and Migratory Birds	Marine Mammals and Sea Turtles	Special Areas	Indigenous Communities and Activities	Commercial Fisheries and Other Ocean Users
Fish, Fish Habitat, and Aquatic Species, including SAR	5(1)(a)(i) 5(1)(a)(ii)	●		●	○	○	○
Migratory Birds including SAR	5(1)(a)(iii)		●		○	○	
Project Activities Occurring on Federal Lands	5(1)(b)(i)	●	●	●	●	●	●
Transboundary Issues [1]	5(1)(b)(ii)						
Health and Socio-Economic Conditions for Aboriginal and Non-Aboriginal People	5(1)(c)(i) 5(2)(b)(i)	○	○	○	○	●	●

Table 4.2 Identified VCs and Potential Considerations Relevant to CEAA 2012

CEAA 2012 Requirement	CEAA 2012 Section	Marine Fish and Fish Habitat	Marine and Migratory Birds	Marine Mammals and Sea Turtles	Special Areas	Indigenous Communities and Activities	Commercial Fisheries and Other Ocean Users
Physical and Cultural Heritage, or Resources of Historical, Archaeological, Paleontological, or Architectural Significance[2]	5(1)(c)(ii) 5(1)(c)(iv) 5(2)(b)(ii) 5(2)(b)(iii)					●	
Current Use of Lands and Resources for Traditional Purposes by Aboriginal Groups [3]	5(1)(c)(iii)					●	
Other Changes to the Environment Directly Related or Necessarily Incidental to a Federal Authority's Exercise of a Power or Performance of a Duty or Function in Support of the Project	5(2)(a)						

Notes:
● Represents a direct relationship while ○ indicates a more indirect one
[1] Routine project activities are not anticipated to result in changes to the environment outside Newfoundland and Labrador, or outside the marine waters under the jurisdiction of Canada
[2] Given the location of the Project offshore, routine project activities are not anticipated to result in changes to the environment that would have an effect on physical and cultural heritage areas or resources of historical, archaeological, paleontological, or architectural significance.

In summary, the identification of the overall VCs upon which the EIS has focussed, and the consideration of and relative emphasis on each of the various sub-components that comprise each of these VCs in the effects analyses, has been informed by the specific issues and concerns raised by government agencies, stakeholder organizations, and Indigenous groups that have participated in the various engagement activities outlined in Chapter 3. In the latter case, VC selection involved the consideration of available information and perspectives from these Indigenous communities regarding their activities and interests in respect of the potentially affected environment. This includes inputs received from each group through direct engagement (Chapter 3) and/or as reflected in available information on the community and its activities.

Section 6.3.8.1 of the EIS Guidelines also lists "air quality and greenhouse gas emissions" as a potential VC that may be considered in the EIS, and specifically, the EIS Guidelines identify it as one of the "other valued components that may be affected as a result of a federal decision or due to effects on federal lands, another province or outside Canada". These components have not been considered as a specific, individual VC per se in the environmental effects assessment, but rather these aspects of the atmospheric environment were addressed as part of the overall discussion of potential Project-related environmental emissions and their management in the EIS Project

Description (Section 2.9). This includes a description of the anticipated types and levels of Project-related air emissions and their contribution to regional ambient air quality and GHG levels. This analysis has shown that the Project will make a negligible contribution to regional atmospheric emissions, and these emissions will be within applicable regulations and standards. Chapter 2 also provides a description and discussion of the various mitigations that will be put into place related to Project-related air quality and GHG emissions.

Section 6.3.8.4 of the EIS Guidelines also identify the "Human Environment" as a potential VC, and lists various associated socioeconomic components for inclusion. Although not considered a separate VC for the environmental effects assessment, relevant aspects of the human environment that are listed in this section of the EIS Guidelines and which have the potential to be affected by the Project are considered and addressed as part of the other socioeconomic VCs identified above. This includes other commercial and recreational ocean users, physical heritage items such as shipwrecks, and other components that are required to be considered in the EIS under relevant provisions of CEAA 2012 (such as, for Indigenous Peoples, those factors required under Section 5(1)(c) of the Act). Human health is considered within those VCs to the extent that it may be affected by the Project's planned activities or unplanned events, such as through direct interaction with fishing activities and equipment or through resource tainting in the event of a spill. However, given the location of most Project components and activities far offshore (and thus, at considerable distance from communities or human activities), adverse effects on other aspects of human health are not anticipated. Similarly, given the nature and location of the Project, adverse effects on other components of the human environment, such as on-land or nearshore aspects of physical and cultural heritage, rural and urban settings, and other aspects of existing socioeconomic conditions in eastern Newfoundland and beyond are not anticipated, and so these are not considered specifically as a VC in the EIS.

4.3 Environmental Effects Assessment (Planned Project Components and Activities)

The following sections describe the EA approach and methodology that is used to conduct the environmental effects assessments presented in this EIS, including each of the key stages and components. The EA structure and methods used are in keeping with current EA approaches and practice in Canada, including under CEAA 2012.

As specified in Part 1, Section 4.3 of the EIS Guidelines, the EA approach and methodology used for the EIS addresses each of the following general items:

- Identifying the activities and components of the project
- Predicting potential changes to the environment
- Predicting and evaluating the likely effects on identified VCs
- Identifying technically and economically feasible mitigation measures for significant adverse environmental effects
- Determining residual environmental effects
- Considering cumulative effects of the project in combination with other physical activities that have been or will be carried out

- Determining the potential significance of residual environmental effect following the implementation of mitigation measures

The description of the existing environment as presented in Chapters 5 to 7 of the EIS forms the environmental baseline from which Project-related environmental changes and resulting effects on the VCs are assessed and evaluated, including the corresponding identification and development of technically and economically feasible mitigation to avoid or reduce potential adverse effects. The assessment of potential environmental effects is, therefore, based on the approach of identifying and describing whether, how and to what degree the "without Project" conditions for the identified VC may change as a result of the Project.

The environmental effects assessments for each VC follow the EA methods and specific stages outlined below, with each step of the analysis completed and reported in its own individual sub-section.

4.3.1 Environmental Assessment Study Areas and Effects Evaluation Criteria

4.3.1.1 Study Areas

EA Study Areas (spatial and temporal boundaries) have been established to direct and focus the environmental effects assessment for each VC. The boundaries are informed by the nature, scale, timing and other characteristics of the Project and the existing environmental setting, and potential environmental interactions. In addition, the boundaries for the EIS include consideration of relevant CEA Agency guidance, and the results of the Operator's engagement with government departments and agencies, Indigenous and stakeholder groups.

Three types of spatial assessment boundaries are used in the EIS to reflect the various means by which the Project may interact with and potentially change the environment (Figure 4-1).

> *Project Area*: This is the overall geographic area within which all planned Project-related components and activities will take place, as described in the Project Description (Chapter 2) and based on those aspects that are considered to be within the defined scope of the Project for EA purposes (Section 2.1). The Project Area is an overall polygon that covers the various ELs off eastern Newfoundland where exploration drilling activities may be carried out as part of the Project, as well as including a surrounding area to account for potential ancillary and support activities. For example, exploration drilling will occur within the boundaries of a specific EL, but wellsite, geotechnical and or environmental surveys may occur within the EL and/or the buffer area, within the boundaries of the Project Area The assessment also considers related supply and support vessel and aircraft traffic to and from this offshore Project Area.

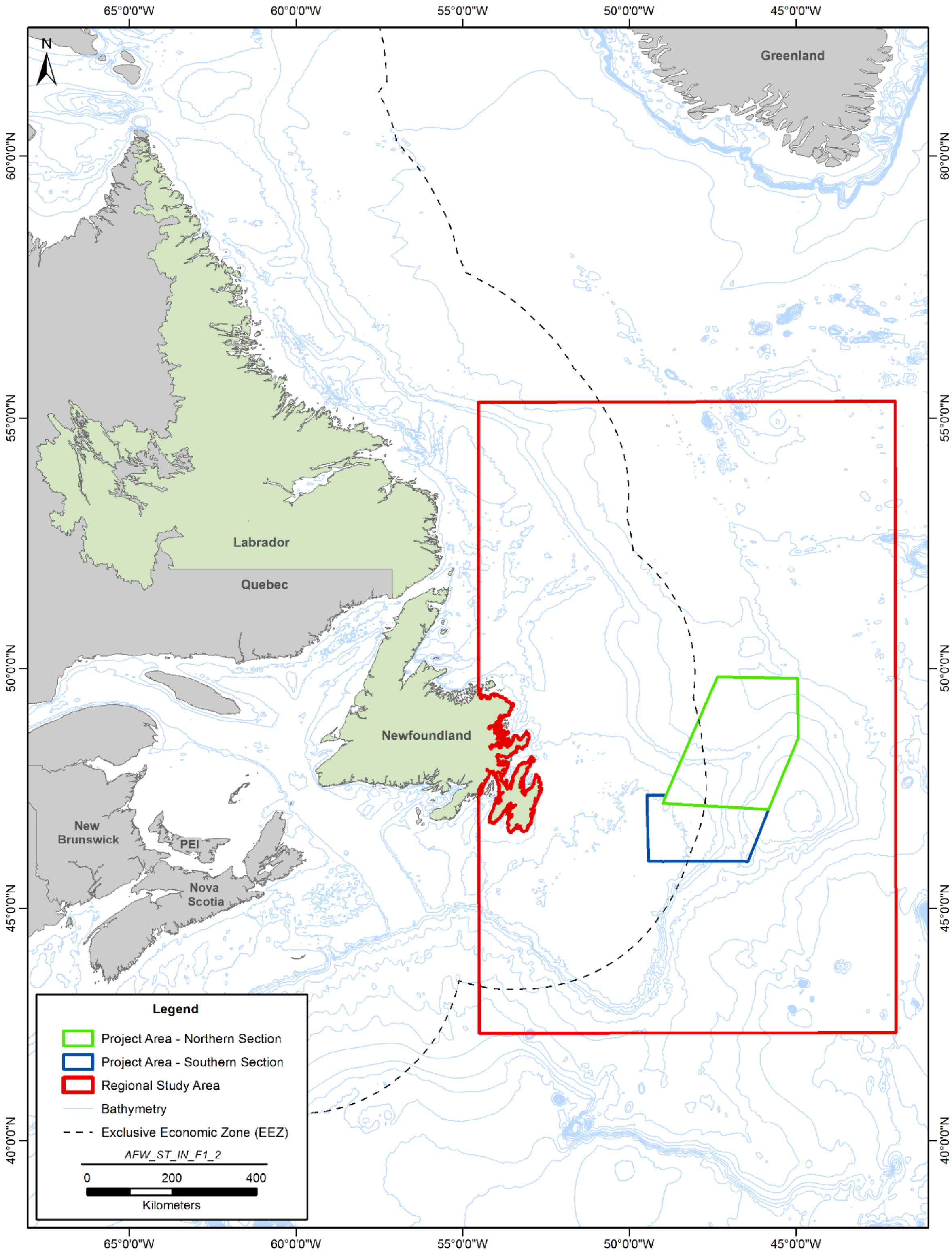


Figure 4-1 Regional Study Area

Local Study Area (LSA): These boundaries are defined on a VC-specific basis, and encompass the overall geographic area over which all planned and routine Project-related environmental interactions (including emissions and other disturbances) may occur. The LSA therefore represents the predicted environmental zone of influence of the Project's planned components and activities, within which Project-related environmental changes to the VC in question may occur and can be assessed and evaluated. For each VC, the LSA will depend on the geographic extent of an environmental disturbance or change and may vary based on its specific nature, timing, or location. Therefore, while the LSA for each VC has been defined to conservatively account for the overall zone of influence of potential Project activities at location within the Project Area, in some cases these environmental changes may occur only within a portion of the LSA itself.

Regional Study Area (RSA): In addition to planned Project environment interactions, from an ecological and socioeconomic perspective the environmental effects assessments also recognize and consider the characteristics, distributions, and movements of the individual VCs under consideration, including the larger regional areas within which they occur and function. The EA assesses potential effects to marine biota (individuals and populations) and human activities which are known or likely to occur in the LSA for the VC in question, but also considers the overall extent of affected individuals and populations during the time period at which they may be affected by planned Project components and activities. In addition to the potential environmental effects of planned Project components and activities (Chapter 2) and their emissions (see LSA definition above), the EIS also considers and assesses the potential effects of accidental events or malfunctions that may be associated with the Project, including the potential nature and geographic extent of an oil spill (see Chapter 15 and Appendix E).

Figure 4-1 illustrates the overall RSA that has been defined and used for most VCs in this EIS, which has been defined with consideration of a number of factors, as referenced above. These include, for example, the possible movement patterns of the marine fish, birds, mammals, and sea turtles that occur in the respective LSAs for each VC over the time periods and durations for which they may be affected by planned Project activities (which may, in some cases extend up to several hundred kilometres), as well as a larger distribution and geographic extent of fishing and other human activities surrounding the Project Area / LSA for regional context purposes. The RSA also encompasses the predicted zone of influence of a potential oil spill event, as summarized in Section 15.4 and modelled in detail in Appendix E, and specifically, the maximum cumulative surface oil thickness for the 95th percentile surface oil exposure case.

In doing so, the RSA extends west to the shoreline of eastern Newfoundland (thereby also covering the Project's associated vessel and aircraft traffic) and to the east to the general area for which available and validated environmental (including metocean and bathymetric) data are available, as well as reaching the eastern boundary of the various NAFO Divisions in this area.

It should be noted that this RSA has been defined and used as a general guide and area of focus for the environmental assessment, and represents the amalgamated consideration of each of the (quite diverse) VCs under consideration and the various factors noted above. The environmental effects assessment considers specific areas within this larger RSA as relevant and appropriate to the specific environmental component or interaction in question. In addition, it likewise considers and describes environmental components and potential effects that may extend outside this area where relevant, based on the nature and coverage of the environmental baseline datasets and mapping used (see discussions at the beginning of Chapters 5, 6 and 7, for example).

As described in Section 12.3, the Indigenous Communities and Activities VC considers the location and overall geographic extent of the various Indigenous communities and activities that comprise the VC, as well as the distribution and movements of the various marine-associated resources that are used for traditional purposes by these communities. For this VC, therefore, the RSA includes an overall region of Eastern Canada that generally encompasses each of the Indigenous communities and their activities throughout Newfoundland and Labrador, the Maritime Provinces and Quebec

The temporal boundaries for the effects assessment encompass the frequency and duration of Project-related activities in the Project Area, as well as the likely timing of resulting environmental effects. In conducting the assessment, special consideration is also given to the timing of VC presence within the Project and Study Areas, including important or sensitive periods.

It is within the above described spatial and temporal boundaries that the potential environmental effects on the VC resulting from planned Project components and activities and their significance are assessed and evaluated.

4.3.1.2 Significance Criteria

The determination of significance under CEAA 2012 includes considering whether the predicted residual environmental effects of the Project are adverse, significant, and likely. When a project is predicted to have adverse environmental effects, as defined in Section 5 of CEAA 2012, an EA examines whether the project is likely to cause significant adverse environmental effects after taking into account the implementation of technically and economically feasible mitigation measures. In this EIS, the definition and determination of effects significance is based on the guidance provided in the Canadian Environmental Assessment Agency's *Operational Policy Statement, Determining Whether a Designated Project is Likely to Cause Significant Adverse Environmental Effects under the Canadian Environmental Assessment Act, 2012* (Canadian Environmental Assessment Agency 2015).

Significance definitions are developed and used on a VC-specific basis within this EIS. Significant environmental effects are considered to be those adverse effects that will cause a change in the VC that will alter its status or integrity beyond an acceptable level. An environmental effect that does not meet the defined criteria is considered not significant. The development of the significance criteria used in this assessment includes consideration of (where available and relevant) applicable legislation and regulations, standards, guidelines, objectives and/or policies and management plans relevant to such determinations. For the biophysical VCs, the significance definitions include such factors as potential detectable declines in the overall abundance of marine biota or changes in their spatial and temporal distributions in the assessment areas over multiple generations, possible adverse effects to the overall abundance, distribution and health of a species at risk and its eventual recovery, and changes to the ecological and socio-cultural characteristics of special marine areas and thus to their overall integrity or value. For the socioeconomic VCs, significance is linked to the potential for, and degree and duration of, detectable effects on people and communities, including on the overall nature, location or timing of activities and their economic and cultural value, on people's health and well-being, and other relevant concepts and considerations as appropriate.

4.3.2 Potential Environmental Changes, Effects, and Associated Parameters

In order to identify and focus on key environmental issues and interactions in the EIS, the effects assessment initially identifies the various questions and issues that have been raised with regard to the Project and its potential effects on each VC. This includes those issues that have been referenced in the EIS Guidelines, through the Operator's governmental, Indigenous, and stakeholder engagement activities (as outlined in Chapter 3).

The environmental effects assessment identifies and focuses on likely environmental interactions between the Project and the VC, and then, on associated Project-induced environmental changes (such as alterations to the physical environment due to Project-related disturbances or emissions) and resulting effects of these changes on the VC. Each VC assessment identifies a number of associated parameters, which are generally defined as an important aspect or characteristic of the VC which, if changed as a result of the Project, may result in an adverse effect to the VC. For each VC, a summary of these potential interactions and associated parameters will be presented in a table.

An overview of the identified potential interactions between the VC and each of the main Project components and activities is also provided (in Table form) to focus and frame the environmental effects assessment.

4.3.3 Environmental Effects Assessment and Mitigation

The environmental effects assessment for each VC predicts and evaluates the nature and degree of changes to, and resulting effects on, the existing (baseline) environment that may potentially occur as a result of planned Project activities. The current condition of the pre-Project environment as a result of other natural and anthropogenic factors - and thus, its likely sensitivity or resiliency to further disturbance or change - has been integrally considered in the environmental effects analyses presented in this EIS. The assessment is also based on a recognition that environmental components and systems are not static, but rather are constantly changing over time both naturally and as a result of human activities and influences.

The application of mitigation measures is also considered in a fully integrated manner in the environmental effects assessment for each VC. This includes technically and economically feasible mitigation measures that are or can be incorporated into Project planning and design, as well as those that are identified as part of the effects analysis to avoid or reduce potential adverse environmental effects. Where applicable, the EIS also discusses cases where the implementation of identified mitigation may be the responsibility of parties other than the Operator as well as instances where potential mitigation measures were considered and rejected, including the rationale for these decisions. Relevant information and findings from scientific literature, results of environmental effects monitoring from similar activities, and other sources of information are used to guide and inform the assessment and evaluation of environmental effects and the identification and proposal of mitigation.

The environmental effects assessment is therefore focused on assessing and describing the likely residual environmental effects of the Project – namely, those which may occur following the implementation of mitigation measures. The effects assessment for each VC is structured to consider and address each planned Project component or activity, as follows:

- Presence and Operation of a Drilling Installation (including lights, noise, air emissions, anchoring)
- Drilling and Associated Marine Discharges
- Formation Flow Testing with Flaring
- Wellhead Decommissioning
- Geophysical / Geohazard / Wellsite / Seabed and VSP Surveys
- Geological / Geotechnical / Environmental Surveys
- Supply and Servicing

The effects assessment considers available and relevant scientific, community, stakeholder, and Indigenous knowledge in the analysis of possible Project-related environmental changes to the VC that may result through one or more mechanisms or pathways. It also recognizes and considers the interactions and interrelationships between environmental components and systems and predicted environmental effects, where relevant.

The predicted residual environmental effects of the Project are determined and described based on a number of standard and widely accepted environmental effects criteria listed and defined in Table 4.3.

Although not a specific effects "rating" per se, the current condition of an environmental component as a result of natural and/or anthropogenic factors, and thus, its resulting resiliency or sensitivity to further change (ecological / socioeconomic context) is considered integrally as part of the prediction of environmental effects, and is summarized in the effects summary tables provided for each VC. The level of confidence in each environmental effects prediction is indicated throughout, along with an associated discussion of key sources of uncertainty, data gaps, issues of reliability, sensitivity, and approaches to conservativeness in effects prediction and the identification of mitigation. Assumptions are also defined and discussed and justified where relevant.

For the biological VCs (marine fish and fish habitat, marine and migratory birds, and marine mammals and sea turtles), associated Species at Risk are addressed in a fully integrated manner within the larger VCs themselves. Each VC Chapter provides a summary discussion of the various relevant Species at Risk, including an overview of those that have the potential to interact with the Project, and a species by species summary of the Project's potential for effects on these species and associated mitigation.

The environmental effects assessment for each VC concludes with a brief summary of the predicted residual environmental effects of the Project's planned components and activities, and evaluates the significance of these based on the VC-specific significance definitions developed and presented at the beginning of the VC chapter. Key sources of uncertainty or assumptions made in defining and determining environmental effects significance are also presented and justified where relevant. If significant effects are predicted, the likelihood of their occurrence is discussed.

Table 4.3 Environmental Effects Descriptors

<table>
<tr><th>Descriptor</th><th>Definition / Ratings</th></tr>
<tr><td>Nature / Direction of the Effect</td><td>Positive, Adverse, or Neutral (as compared to baseline environment)</td></tr>
<tr><td>Magnitude</td><td>The degree of change from baseline conditions in the affected area, as defined below.
For all VCs:
Negligible: Although there is potential for a Project-VC interaction, there would be no detectable effect
For the biophysical VCs:
Low: A detectable change that is within the range of natural variability, with no associated adverse effect on the viability of the affected population.
Medium: A detectable change that is beyond the range of natural variability, but with no associated adverse effect on the viability of the affected population.
High: A detectable change that is beyond the range of natural variability, with an adverse effect on the viability of the affected population.
For the socioeconomic VCs
Low: A detectable change that is within the range of natural variability, with no associated adverse effect on the overall nature, intensity, quality / health or value of the affected component or activity.
Medium: A detectable change that is beyond the range of natural variability, but with no associated adverse effect on the overall nature, intensity, quality / health or value of the affected component or activity.
High: A detectable change that is beyond the range of natural variability, with an adverse effect on the overall nature, intensity, quality / heath or value of the affected component or activity.</td></tr>
<tr><td>Geographic Extent</td><td>The spatial area within which an environmental effect will likely occur
L Localized, In immediate vicinity of the activity
PA Within Project Area
LSA Within LSA
RSA Within RSA and/or beyond</td></tr>
<tr><td>Duration</td><td>The period of time over which an environmental effect will likely be evident
S Short term (for duration of the activity, or for duration of accidental event)
M Medium term (beyond duration of activity up to end of Project, or for duration of threshold exceedance of accidental event – weeks or months)
L Long term (beyond Project duration of activity, or beyond the duration of threshold exceedance for accidental events - years)
P Permanent (recovery to baseline conditions unlikely)</td></tr>
</table>

Table 4.3 Environmental Effects Descriptors

Descriptor	Definition / Ratings
Frequency	How often an environmental effect will likely occur (continuous, or at specific time intervals) *N* Not likely to occur *O* Occurs once *S* Occurs sporadically *R* Occurs on a regular basis *C* Occurs continuously
Reversibility	The ability of an environmental component to return to an equal or improved condition once the disturbance(s) has ended. *R* Reversible (Will eventually recover to baseline conditions) *I* Irreversible (Permanent)
Certainty	Confidence in the effects prediction *L* Low level of confidence *M* Moderate level of confidence *H* High level of confidence

Each VC Chapter also provides an overview discussion of environmental monitoring and/or follow-up programs that may be required or proposed for the VC. This includes, where applicable, a preliminary overview of its: rationale and objectives; planning and design; key areas of focus; implementation and schedule; the format, use and sharing of study results; and potential adaptive management approaches based on the results and findings of such programs.

4.4 Cumulative Environmental Effects

As required under Section 19(1) of CEAA 2012, the EIS assesses and evaluates cumulative environmental effects that are likely to result from the Project in combination with other physical activities that have been or will be carried out, as well as the significance of these potential effects. The cumulative effects assessments for all VCs are reported together in Chapter 14, which includes a detailed description of the approach and methods used (Section 14.1).

4.5 Accidental Events

The EIS also assesses and evaluates the potential environmental effects that may be associated with possible accidental events that may occur as a result of the Project. These assessments for all VCs are reported together in Chapter 15, which includes a description of the approach and methods used including the associated oil spill probability and trajectory modelling.

4.6 Effects of the Environment on the Project

As also required by the EIS Guidelines (Section 6.6.2), the EIS provides an assessment of the potential "effects of the environment on the Project", as reported in Chapter 16. This includes consideration of the manner in which local conditions and natural hazard (such as severe or extreme weather conditions and other external events) could adversely affect the Project, and how this in turn could result in effects to the environment. This analysis also includes an associated discussion of how these or other environmental conditions and factors have or will influence the design and execution of the Project (such as ice conditions, weather, geology), as well as associated planning, design and operational measures that will be taken to help protect the environment.

4.7 References

CEA (Canadian Environmental Assessment) Agency. 2015. Determining Whether a Designated Project is Likely to Cause Significant Adverse Environmental Effects under CEAA 2012. Ottawa, Ontario. Catalogue Number: En106-145/2015E-PDF

Sweeney, J. 2017. Environmental Scientist. Environmental Assessment Division., Department of Municipal Affairs and Environment, Government of Newfoundland, and Labrador. Personal communication.

5.0 EXISTING PHYSICAL ENVIRONMENT

As described in Section 2.3, the Project Area (Northern and Southern Sections) is located offshore eastern Newfoundland, and encompasses the overall geographic area within which planned Project-related activities will take place, and includes water depths ranging from approximately 100 m to as deep as 3,800 m at the northeastern corner. The EIS also considers related supply and support vessel and aircraft traffic to and from the Project Area.

The following sections provide an overview of relevant components of the physical environment within the Project Area and its surrounding environment, including aspects of its geology, bathymetry, climatology, air quality, oceanography, ambient noise, and ice conditions. The effects of climate change on the physical components is also discussed. Although the various physical components and processes that are described in this Chapter are not VCs for the purposes of the environmental effects assessment, this information is provided as background and context for the EA, and in accordance with the requirements and specifications of the EIS Guidelines. These environmental features and processes are also relevant to understanding and assessing the potential environmental disturbances, and associated environmental changes and effects pathways, that may result in an effect on the Project from the environment.

Given that the most direct relevance of the physical environment information for this EA is in assessing and evaluating the potential “effects of the environment on the Project” (Chapter 16), including the manner in which physical environmental conditions have and may eventually affect the planning and conduct of in-field Project activities, the primary focus of this section is on the Project Area itself, including both its Northern and Southern Sections, as well as the associated potential vessel and aircraft traffic routes. Where, as noted above, physical environmental conditions and processes are also relevant to the presence, distribution, and other aspects of components of the biophysical and socioeconomic VCs and potential Project-related environmental changes and effects upon them, these are also described and considered on a regional scale as part of the descriptions of the existing environment (Chapters 6 and 7) and in the VC-specific environmental effects assessments (Chapters 8 to 13).

5.1 Geology and Geomorphology

The geology of the eastern Newfoundland offshore area is complex, and the current bedrock and surficial characteristics of the region have been shaped by various natural and human factors and processes over time.

5.1.1 Bedrock Geology

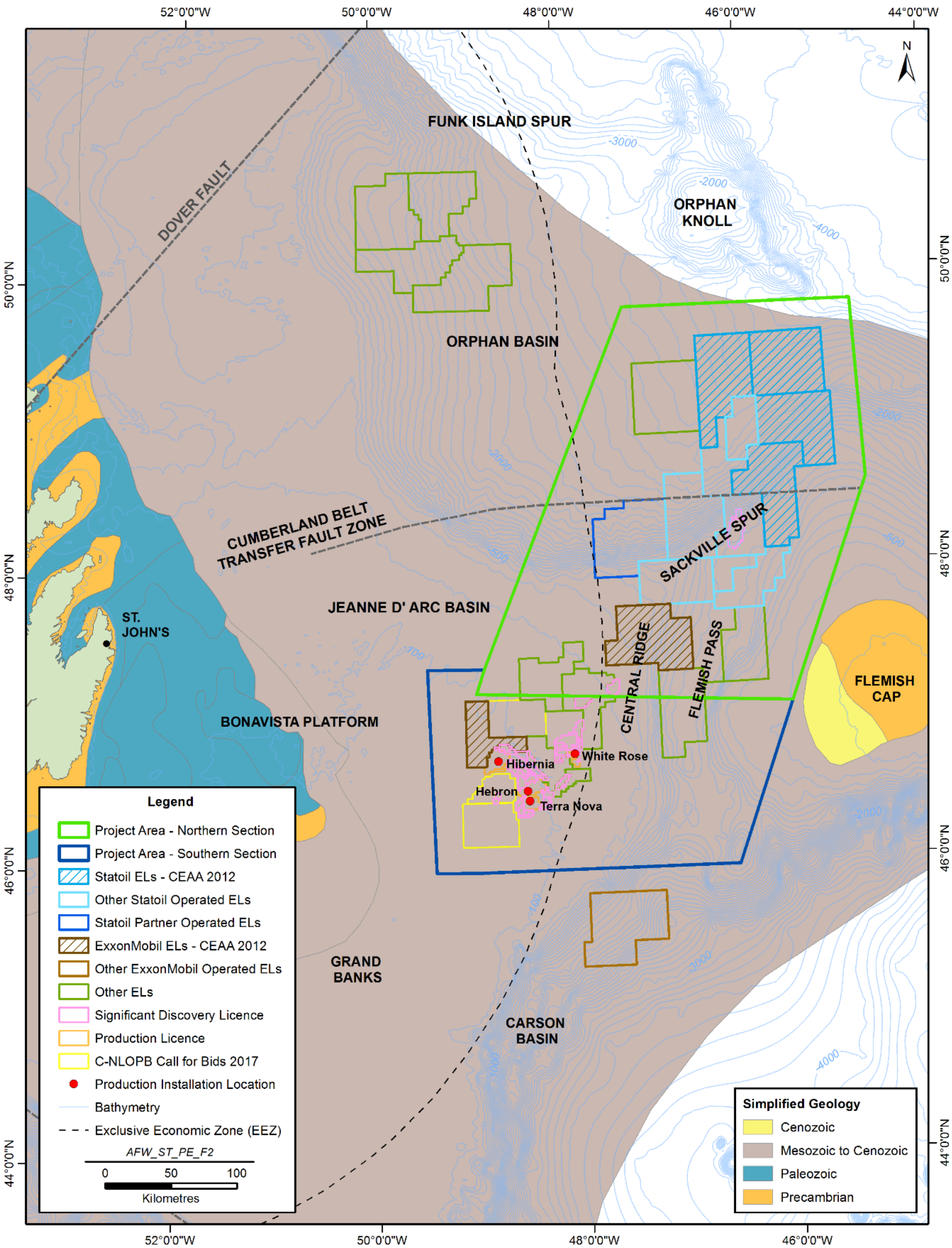
The Project Area is located on the eastern continental shelf of the offshore region of the Newfoundland continental margin and is primarily comprised of Mesozoic rock overlying pre-rift, Appalachian basement rock of Avalon terrane (Fader et al. 1989, Figure 5-1). Precambrian and Paleozoic rocks are found nearer to shore. The areas were formed by a series of three rift episodes associated with the breakup of the supercontinent Pangea and the opening of the North Atlantic Ocean during the Late Triassic to mid-Cretaceous. Rifting and seafloor spreading heated the continental crust and lithosphere and then subsided. These rifting events, combined with salt tectonics in the area, created a complex series of Mesozoic rift basins that are generally oriented northeast - southwest and are separated by basement highs along the central to outer shelf. The resulting combination of stratigraphy, structure and timing have been conducive to hydrocarbon generation and entrapment (Bell and Campbell 1990).

The main sedimentary basins in the Project Area are shown in Figure 5-1, and include two perched slope basins, the Flemish Pass, and Orphan Basin (Fader et al. 1989) and also the Jeanne d'Arc Basin. Geophysical evidence suggests that the Flemish Pass Basin forms a terraced continuation of the highly stretched and subsided East Orphan Basin, and both basins are interpreted to have had similar geologic histories, during the Late Jurassic to Early Cretaceous (Lowe et al. 2011). The primary reservoirs are located in the shallow marine and fluvial shale and sandstone deposited during the Late Jurassic and Early Cretaceous periods of the Mesozoic Era. The Late Jurassic Egret member of the Rankin Formation is a world-class source rock that is recognized as the primary source of the oil and gas discovered in the Jeanne d'Arc Basin and has also been proven to be widespread in the Flemish Pass Basin (G and G Exploration Consulting Ltd 2003).

5.1.2 Geomorphology and Surficial Geology

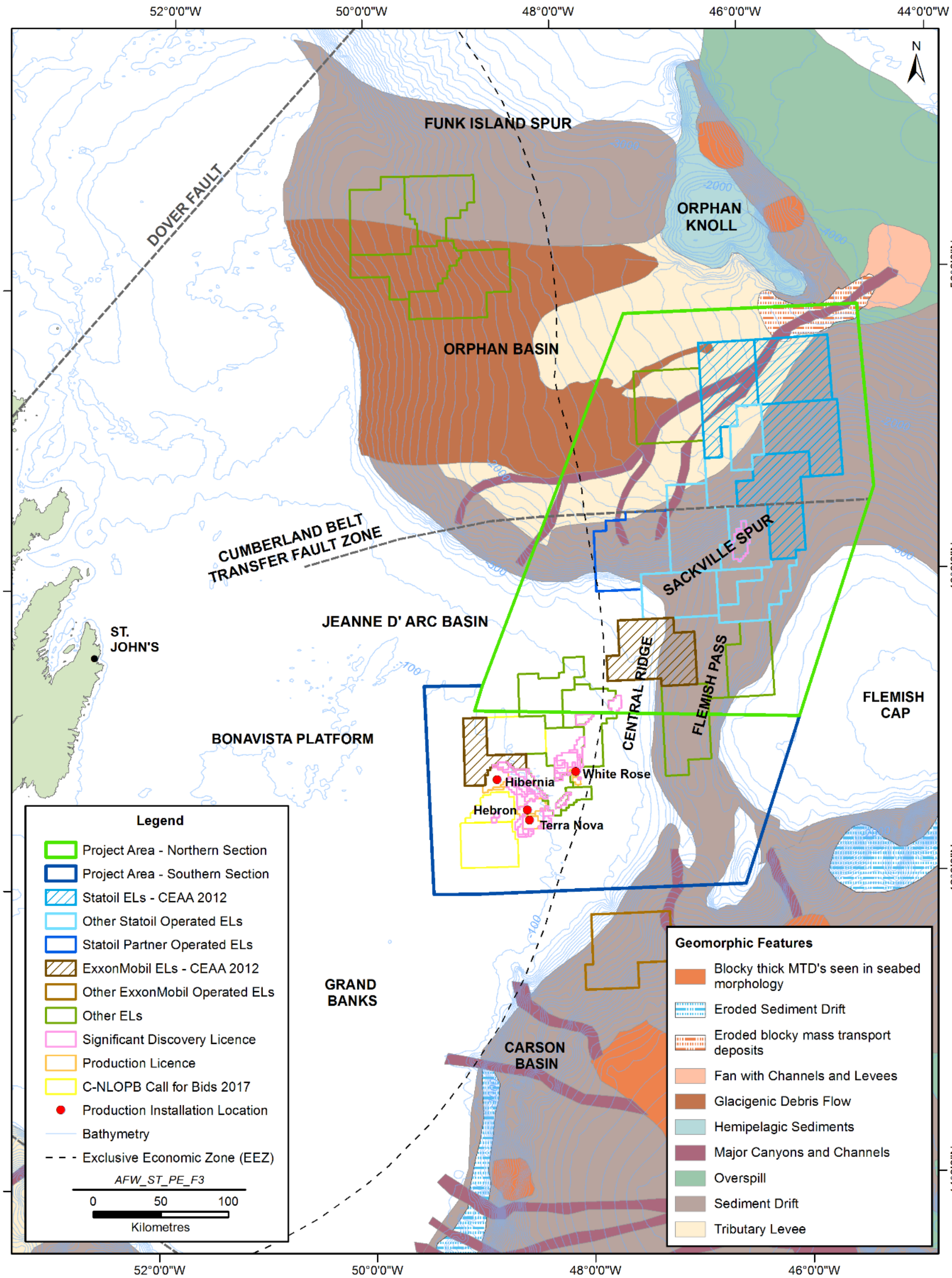
The geomorphology and surficial geology in and around the Project Area is a product of modern oceanographic processes and past glacial activity, a generalized overview of which is illustrated in Figures 5-2 and 5-3.

Some notable geomorphic features in the region overall include the Sackville Spur, the Central Ridge, and the Flemish Cap. The Sackville Spur is a prominent contourite drift which formed during the Neogene-Quaternary at the northern end of the Flemish Pass (Marshall et al. 2014) and has been incised by numerous canyons. The Central Ridge is a faulted intrabasinal high separating the Jeanne d'Arc and Flemish Pass basins (Enachescu 2012). The Flemish Cap is a large isolated continental basement high separated from the Grand Banks by the Flemish Pass and represents the most easterly extension of North American continental crust (King and Fader 1985). It is underlain by Avalon terrane bedrock and consists of a central core of Hadrynian rocks, including granodiorites, granites, dacites, and an onlapping sequence of Mesozoic to Cenozoic aged sediments (King et al. 1986). Locally, it is covered by a veneer of sand up to several metres thick (Weitzman et al. 2014). The Bonavista Platform is located between the shore and the Project Area. Seabed features in the area include iceberg scouring and to a lesser extent, seabed depressions of unknown origin (Cameron and Best 1985).



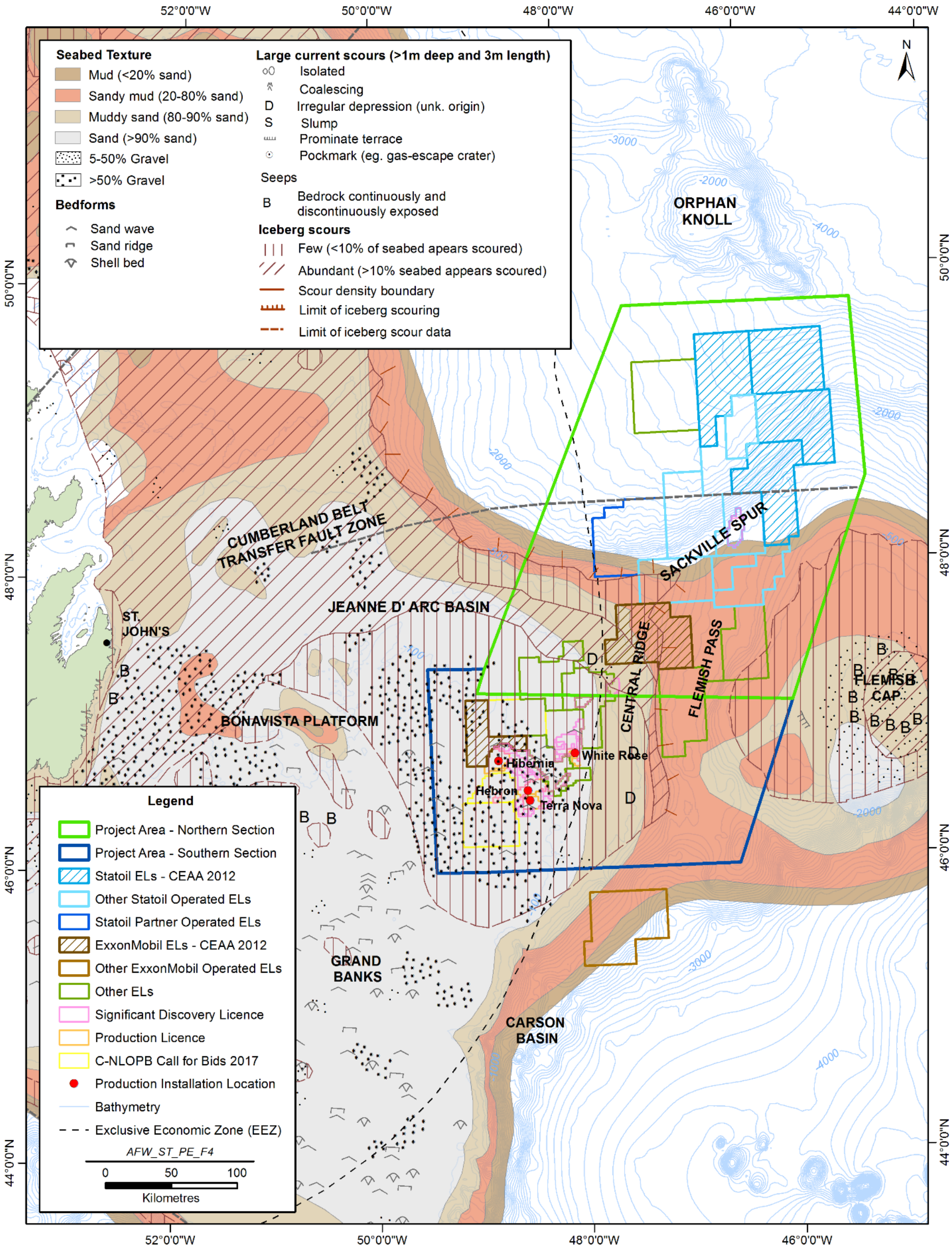
Source: Fader et al. (1989); Enachescu and Fagan (2005)

Figure 5-1 Geological Overview (Bedrock)



Source: Rudolph et al. (2016)

Figure 5-2 Geomorphic Features



Source: Cameron and Best (1985)

Figure 5-3 Seabed Features

The surficial geology of the region is also highly variable, but generally in water depths less than 600 m, the shallow geology consists of glacial till with a veneer of sand and gravel up to several metres thick. In deeper water, such as the slope of the Flemish Pass, the seabed generally consists of Holocene silty clay. On parts of the floor of the Flemish Pass, winnowed sands are present (Murillo et al. 2016). The coarser-grained sediments are found through the center and western side of the Flemish Pass while the finer-grained sediments are concentrated predominately on the eastern side of the Pass, including the terrace (Marshall et al. 2014). There is also potential for gravel and ice-rafted cobbles and/or boulders on the seafloor and in the shallow subsurface (Fugro 2017).

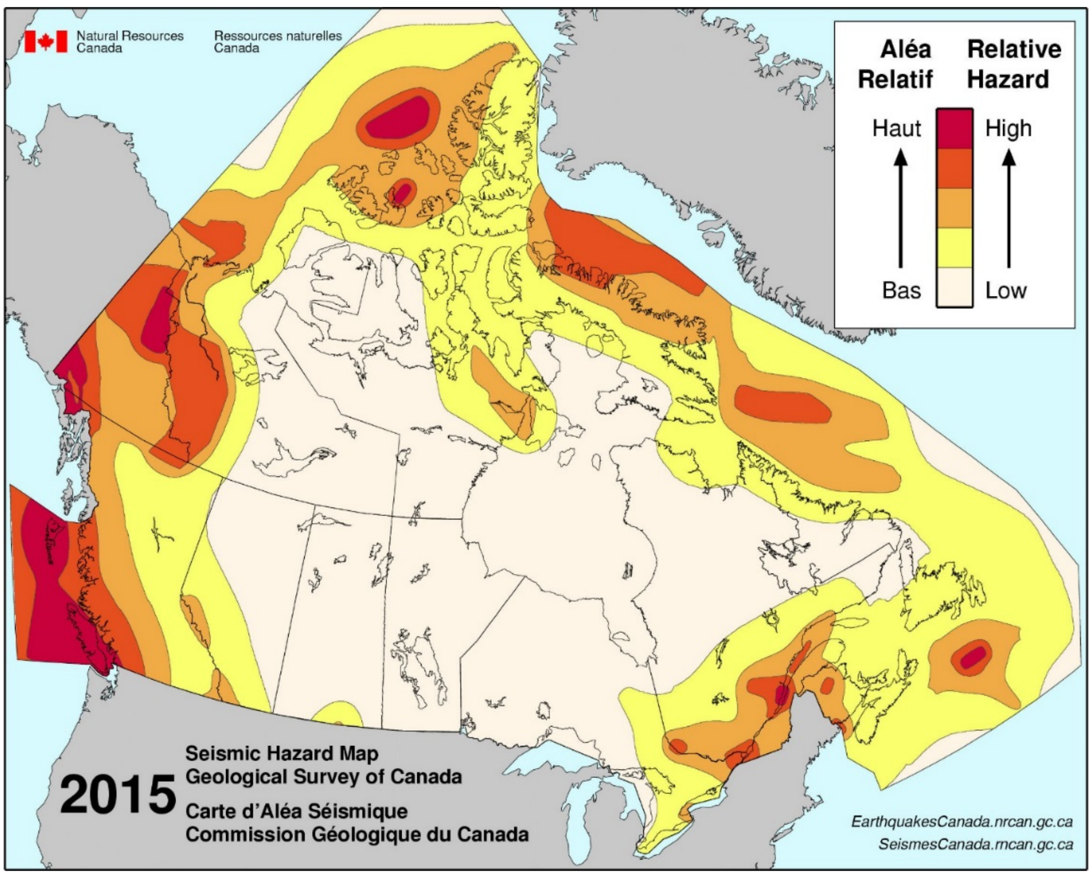
Quaternary sediments in the Project Area - Northern Section include turbidite sands and muds and proglacial muds derived from the Grand Banks of Newfoundland, ice-rafted and proglacial plume deposits transported southward in the Labrador Current, and debris-flow deposits. These sediments have been described as follows by Piper and Campbell (2005). In the northern Flemish Pass, deposits up to 120 m thick have been recognized and are interpreted as debris-flow deposits that are thought to be derived from sediment failures that have left scarps both on the southeast side of Sackville Spur and on the north-west side of the Flemish Cap. Sediments recovered from this area are generally lean silt to lean clay and are considered to be normally consolidated. The western slopes of the Flemish Pass are comprised mainly of muds with some coarse-grained ice-rafted detritus. Interbedded sandy turbidites are most abundant between 2 and 3.5 metres below sea floor. On the floor of the central part of the Flemish Pass, successions of silty muds with ice-rafted detritus, thin sand, and mud turbidites overlie thick bedded sand turbidites. On the eastern slopes of the Flemish Pass, sediment consists primarily of mud with sparse ice-rafted detritus. On the Sackville Spur, eight metres of sandy gravelly mud has been locally observed overlying 4.5 m of grey mud and then a further 12 m of gravelly sandy mud. Quaternary deposits in the southern Orphan Basin include complex mass transport deposits (MTD) comprising both glaciogenic debris flow and blocky MTD.

Three main seabed formations have been recognized within the Grand Banks region of the Project Area - Southern Section, including the Grand Banks Drift, Adolphus Sand and the Grand Banks Sand and Gravel. The Grand Banks Drift is a till comprised of poorly sorted, gravelly, and sandy mud with frequent cobbles and boulders. This unit was formed directly beneath the grounded ice, conformably overlies the bedrock surface, and generally occurs as a continuous till blanket of variable thickness and morainal ridges (Sonnichsen et al. 2005). Overlying the Grand Banks Drift is a patchy silty sand veneer of the Adolphus Sand. It generally comprises compact to loose, olive-grey, fine to medium sand, often with silt, shells and fine gravel and rarely exceeds two to three meters in thickness (Sonnichsen et al. 2005). It typically occurs in the peripheral areas of the Banks and in the adjacent saddles. The youngest formation is the Grand Banks Sand and Gravel which is a basal transgressive deposit. It was formed by coastal and shallow water processes during the last shoreline transgression, and occurs typically at waters less than 100 m deep. This formation is a clean, free-draining, well-sorted material ranging from uniform fine sand to gravel size components (Sonnichsen et al. 2005). Deeper basins such as the Flemish Pass are generally silt or clay-filled.

In general, sediments in the Project Area - Northern Section include turbidite sands and muds and proglacial muds derived from the Grand Banks of Newfoundland, ice-rafted and proglacial plume deposits transported southward in the Labrador Current, and debris-flow deposits. In the Project Area - Southern Section, the three main seabed formations include the Grand Banks Drift, Adolphus Sand and the Grand Banks Sand and Gravel.

5.1.3 Seismicity

Canada's eastern continental margin is tectonically passive and seismicity is relatively rare throughout much of the region. Natural Resources Canada (NRCan) estimates that approximately 450 earthquakes occur each year in Eastern Canada (NRCan 2017a). Seismicity generally occurs randomly along the Grand Banks margin. The most recent edition of the Seismic Hazard Map prepared by NRCan (Figure 5-4), which illustrates the probability of earthquake occurrences across Canada, indicates that the Project Area has been classified as having a relatively low seismic hazard.



Source: Natural Resources Canada (2017b)

Figure 5-4 Seismic Hazard Map

According to the National Earthquake Database (NRCan 2017c) there have been two seismic events recorded within the boundaries of the Project Area - Northern Section and seven seismic events recorded within the Project Area - Southern Section during the 1985-2017 period (Figure 5-5). In the Project Area - Northern Section, the magnitudes of these events have been fairly low, ranging from 4.3 to 4.5 with an average magnitude of 4.4 and a median magnitude of 4.4. For the events in the Project Area - Northern Section, the epicentres occurred in the southwest corner, and are possibly related to the various tectonic lineaments in the area. Similarly, in the Project Area - Southern Section, the magnitudes of these events have also been low, ranging from 3.0 to 4.5 with an average magnitude of 3.9 and a median magnitude of 4.0. The majority of these recorded events have epicentres in the northwest corner of Project Area - Southern Section, and are possibly related to the various tectonic lineaments in the area.

5.1.4 Geohazards

Common offshore geohazards may include slope instability, seismicity, sediment loading, venting of shallow gas, gas hydrates, seabed instabilities and ice scour. Sediment failure is essentially a consequence of gradient, magnitude of seismic acceleration and sediment strength. Most continental margin sediments, except on slopes of more than a few degrees, are relatively stable and would require seismic accelerations associated with a large earthquake (magnitude of five or greater) to fail (Nadim et al. 2005). The discussion that follows is, based on the existing information sources used, necessarily regional in scope, although any known features and processes that are specific to parts of the Project Area are highlighted where relevant. In addition, as discussed in Chapter 2, the Operator may collect additional geohazard data in the area of each well prior to drilling, in accordance with relevant regulatory requirements.

NRCan analysis indicates that in the area offshore Eastern Canada, there is a risk of landslide every 20,000 years and a minor one every few thousand years. Most of the large failures on the seabed date back more than 10,000 years during periods of glaciations when large amounts of sediment were deposited directly onto the slope of the continental shelf (NRCan 2010). Synchronous failures in multiple drainage systems suggests that most failures are earthquake triggered, with some seismicity induced by glacio-isostasy (Piper 2005). The mean recurrence interval of earthquakes with magnitudes of seven at any point on the margin is estimated at 30,000 years from seismological models and 40,000 years from the sediment failure record (Piper et al. 2011).

Potential offshore geohazards in and around the Project Area comprise a number of geological phenomena including, but not necessarily limited to, submarine slides, shallow gas and dissociation of gas hydrates and seismic events. Shallow gas can lead to excess pore pressure in permeable strata such as silts and can be a preconditioning factor for submarine landsliding. Migration of fluids from deep in the Orphan Basin along the Cumberland Fault Zone has likely preconditioned the region for failure. However older landslides on the northwest flank of the Flemish Cap have permitted much of the excess pore pressure in permeable beds to drain so that those areas are now more stable (Cameron et al. 2014).

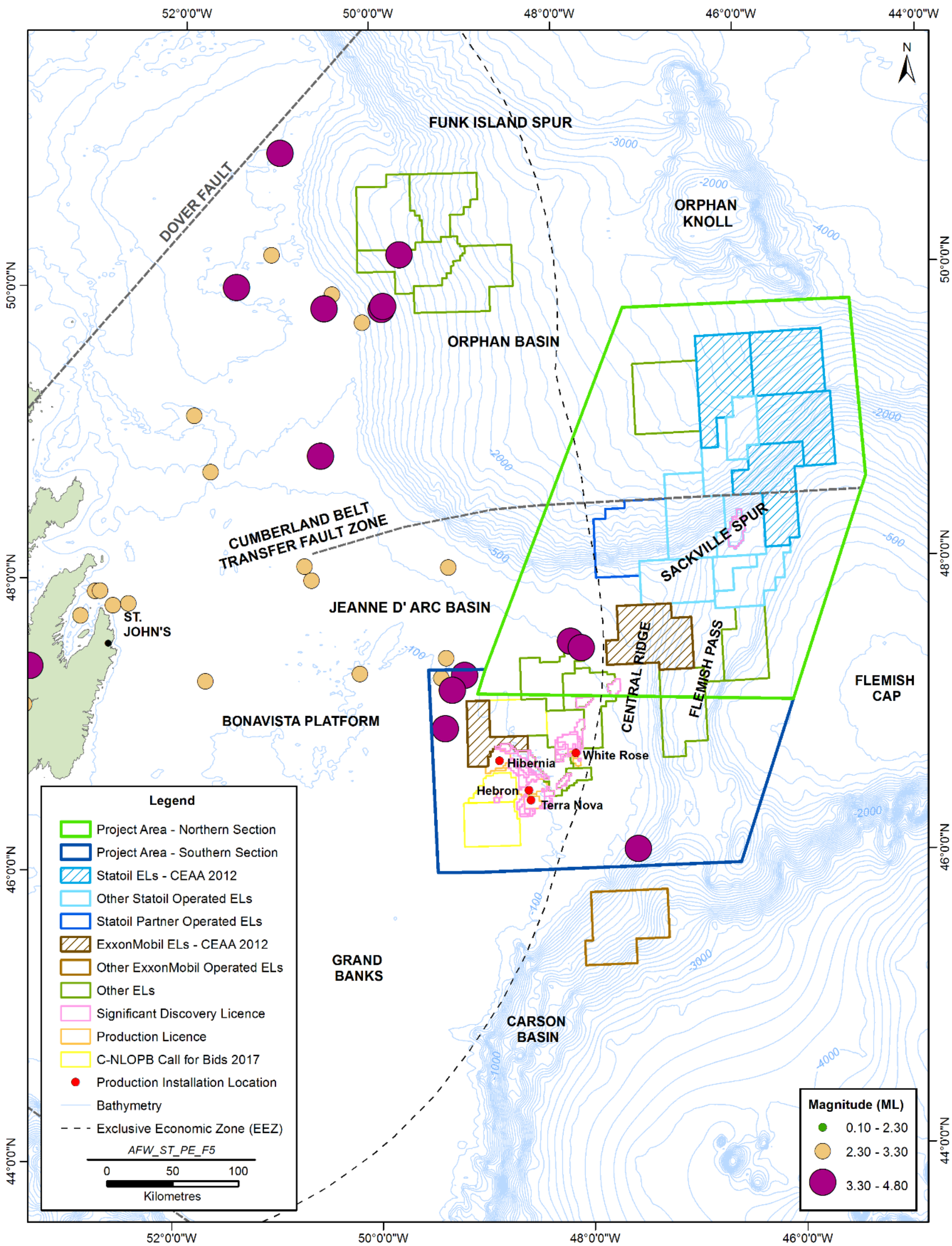


Figure 5-5 Earthquake Epicentres (1985-2017) and Seismotechtonic Setting

Three prominent MTD complexes dominate the upper portion of the Flemish Pass stratigraphy in the Project Area – Northern Section. The youngest of these three are the Sackville Slide which is believed to have occurred approximately 250 to 350 thousand years ago and is interpreted as a single event triggered by an earthquake (Fugro 2017). Previous investigations also show that there are younger and smaller complex landslides along a 65 km length of the northwest flank of the Flemish Pass and approximately 20 km downslope with four deep arcuate slide scars found at its centre. Failed sediments have run out as far as 20 km onto the floor of the Flemish Pass, forming mass transport deposits typically 50 m thick (Cameron et al. 2014). These major sediment failures occurred approximately 27,000 and 20,500 years ago, and are believed to have been a result of earthquake triggers (Cameron et al. 2014). Piper and Campbell (2005) presented a brief regional geohazard assessment of the Flemish Pass area and suggest that most large debris flow deposits in the area are the result of earthquake triggered slumps on both flanks of the Flemish Pass. Geotechnical studies from piston cores show that these failed sediments are silty and have potential for liquefaction during cyclic loading (Piper 2014).

Piper and Campbell (2005) also indicate that gas hydrates may also act as a trigger for failure in the Flemish Pass as observed by a pattern of younger debris-flow deposits in the central region of the area. Bottom water temperature in the Flemish Pass is buffered by the supply of cold arctic water through the Labrador Current, so that times of gas hydrate melting are likely restricted to periods of falling sea level between interglacial and glacial maximum conditions. Falling sea level results in less hydrostatic pressure in seabed sediments and consequently a melting of gas hydrate.

Evidence of past instability within the Orphan Basin includes thick, stacked MTDs on the basin floor and seabed failure scars on the continental slope (Campbell 2005). MTDs may be unstable in areas based on the presence of diapiric features and can provide weak layers for the development of seabed creep (Campbell 2005). Within the Orphan Basin, slopes steeper than three degrees show widespread failure except where underlain by glacial till (Piper et al. 2011). Failures in the Orphan Basin represent earthquakes with magnitudes ranging from 5.6 to 7.6 (Piper et al. 2011).

The natural risk of large slope failure appears low, with a recurrence interval of 100,000 years. It is likely preconditioned by high pore pressure and triggered by earthquakes. In the northern Flemish Pass and southern Orphan Basin, the steep slopes, abundant shallow gas, and possibly greater seismicity make large landslides more frequent, with a recurrence interval of 10,000 years. This translates to a 1 in 500 risk of a landslide occurring over an approximately 20 year period in the northern Flemish Pass (Cameron et al. 2014).

Tsunami hazard along the Atlantic coast of Canada is relatively low, with few tsunamis recorded in historical time. There are no active plate boundaries nearby to generate tsunamis by displacement of the seafloor, but submarine landslides triggered by earthquakes can produce a tsunami. In a preliminary tsunami hazard assessment of the Canadian coastline, Leonard et al. (2010) use a tsunami runup threshold of 1.5 m for potentially damaging coastal waves and a tsunami runup threshold of 3.0 m for significant damage potential. Their assessment of the outer Atlantic coastline indicates an expected recurrence of runup exceeding 1.5 m approximately every 300 to 1,700 years. For larger runup (over 3.0 m), the estimated recurrence interval is approximately 600 to 4,000 years.

Leonard et al. (2010) assume that a mean local runup of over 1.5 m could result from failures with an along-slope extent greater than 50 km, and a mean local runup over 3.0 m may be produced from failures greater than 70 km in length. In the Orphan Basin, for example, the expected recurrence interval of landslides with an extent over 50 km is approximately 10,000 years. In the Flemish Pass, such threshold landslides are expected to occur with an average recurrence interval of approximately 21,000 years. Continental slope failures with extents over 70 km are expected approximately every 11,500 years in the Orphan Basin and approximately every 45,000 years in the Flemish Pass.

5.2 Bathymetry

The bathymetry in the Project Area and surrounding regions is generally well known (Figure 5-6). Overall, depths range from approximately 100 m at the southwest corner to as deep as 3,800 m at the northeastern corner of the Project Area. Some of the key bathymetry features are shown in Figure 5-6. The Jeanne d'Arc Basin of the Grand Banks, Flemish Pass and Flemish Cap are common to both the Northern and Southern sections of the Project Area.

The potential vessel and aircraft traffic routes and western portions of the Project Area cross the Grand Banks, a region with average depths of approximately 75 m, which extend to approximately 350 km east of St. John's to the 200 m depth contour and then a further 50 km east to the 1,000 m depth contour. To the east of the Grand Banks lies the Flemish Pass, with depths of almost 1,300 m. On the eastern side of the Flemish Pass, water depths rise again to the Flemish Cap, a large bathymetric feature of approximately 50,000 km^2 with depths rising back up to approximately 130 m. The Sackville Spur, located in the central portion of the Project Area – Northern Section, extends the nose of the Grand Banks at depths of up to 1,000 m. This area lies approximately 250 km east-northeast from the western boundary of the Project Area – Northern Section. Northeast of the Sackville Spur depths quickly reach 2,000 m and farther out reach 3,300 m in the northeastern corner.

The Grand Banks extend north to the Northeast Newfoundland Shelf, with depths generally between 200 to 300 m. To the northeast of the Grand Banks shelf lies the Orphan Basin. This includes much of the northern portion of the Project Area – Northern Section. In the Orphan Basin water depths range from approximately 1,200 m at the edge of the continental shelf to as deep at 3,300 m south of the Orphan Knoll. The Orphan Knoll lies north of the Project Area, in water depths of around 2,000 m, and is a bathymetric high in the centre of the Orphan Basin. The Labrador Basin and deep ocean lie farther offshore to the north and east of the Orphan Basin and Flemish Cap, with depths from approximately 3,000 m to greater than 4,000 m.

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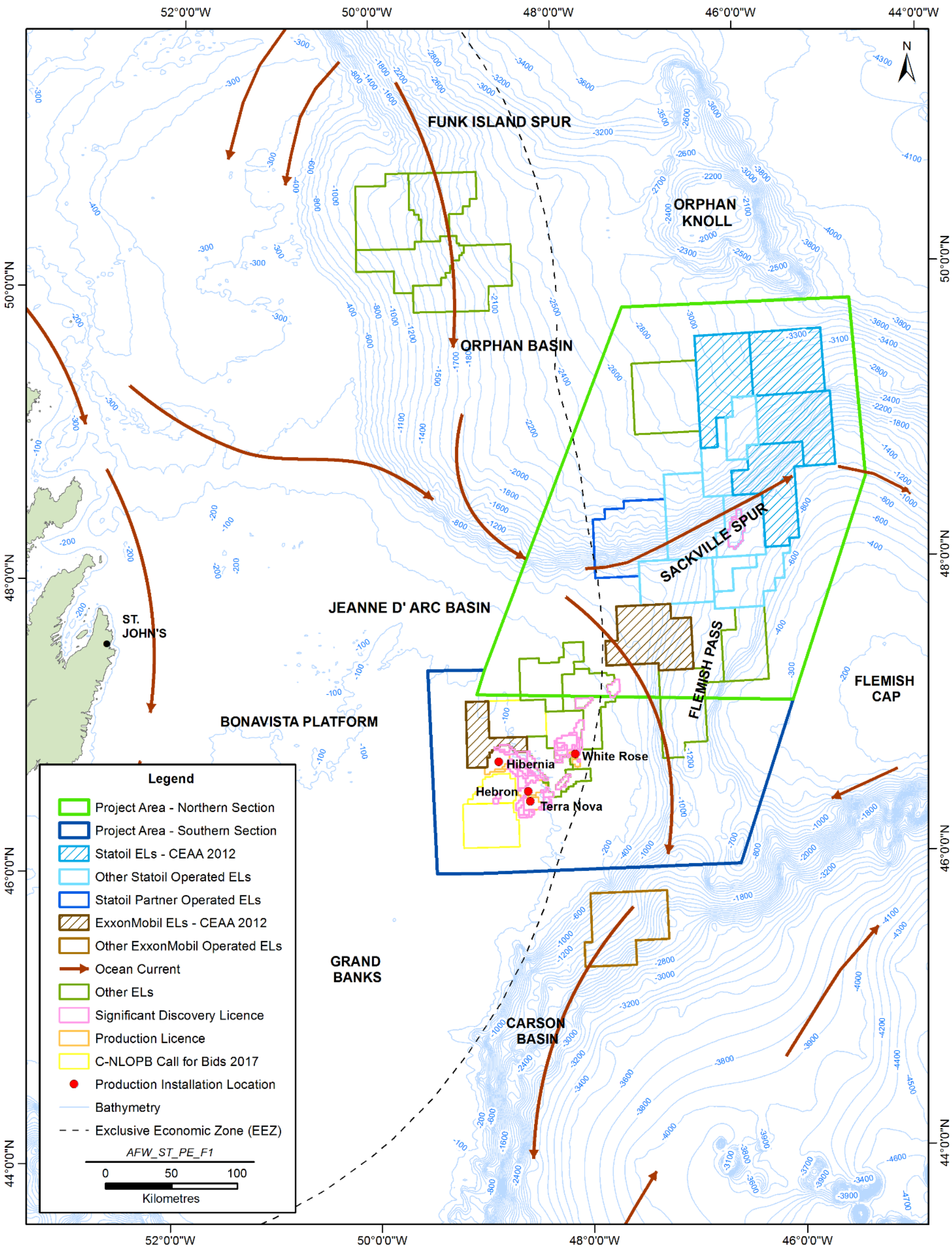


Figure 5-6 General Bathymetry and Ocean Current Circulation

5.3 Climatology

This section provides an overview of key climatological conditions and characteristics of the Project Area, including wind, air temperature, precipitation, fog, and visibility. Additional detail on these environmental characteristics for the Project Area and the larger Eastern Newfoundland offshore area is provided in the Eastern Newfoundland SEA, Section 4.1 (Amec 2014).

5.3.1 Wind Speed and Direction

A primary characterization of the wind climatology of the Project Area is provided with statistics derived from the MSC50 wind and wave hindcast. Additional information is presented from historical drilling campaigns and the weather observations prepared, recorded, and distributed in Manual of Marine Observations (MANMAR) format by offshore-based observers as a requirement of the Physical Environmental Monitoring Guidelines (NEB et al. 2008). The reports are typically sent to shore-based forecasters every three hours on a 24/7 basis. The basis for marine weather observing in Canada is the MANMAR (Environment and Climate Change Canada 2017).

The MSC50 dataset includes hourly wind and wave parameters of the North Atlantic Ocean (Swail et al. 2006). The hindcast data were produced through the kinematic reanalysis of all significant tropical and extra-tropical storms in the North Atlantic. The dataset covers hourly wind and wave parameters, from 1954 to 2015, for the North Atlantic Ocean and includes consideration of periods with sea ice coverage. Ice concentration data that were considered are mean monthly values through 1961 inclusive and then Canadian Ice Service (CIS) mean weekly ice concentrations for 1962 onwards. That is, ice is applied for an entire calendar week (e.g., one would see something like the 1st to 7th of the month is ice, then 8th to 14th isn't). Subsequently, given the poorer resolution of ice information, the 1954-1961 period of the MSC50 dataset was excluded from the present analysis. The 1962-2015 periods are considered for wave and, for consistency, wind.

The overall resolution of MSC50 hindcast data grid points (nodes) is high, with one point every 0.1° latitude by 0.1° longitude (approximately 7.6 km east-west and 11.2 km north-south near 47°N). To provide a characterization over the Project Area, five sample locations were selected to cover a range of depths and distance offshore which can influence wave conditions. Three grid point nodes were selected for the Project Area – Northern Section, while two nodes were selected for the Project Area – Southern Section. The nodes are shown in Figure 5-7 and listed in Table 5.1.

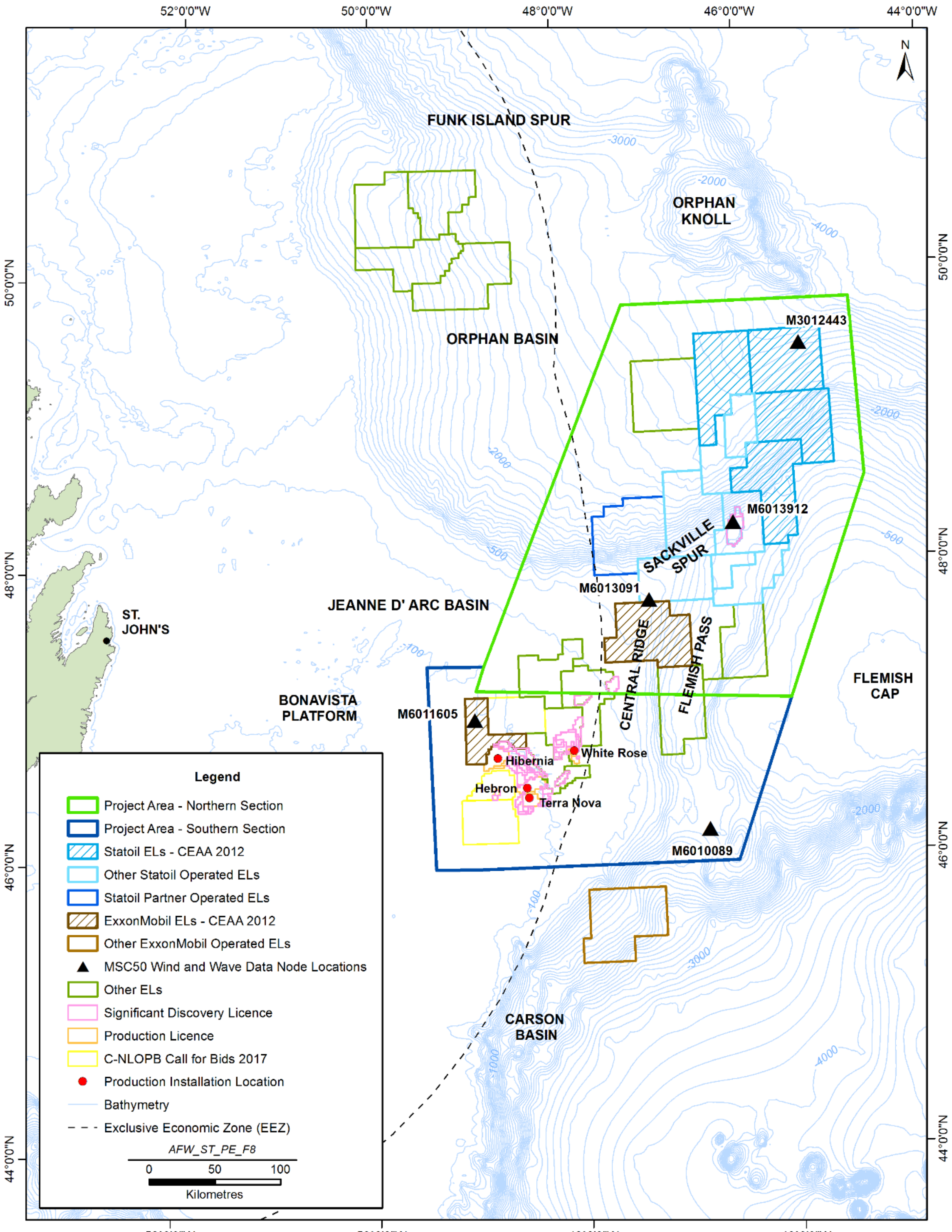


Figure 5-7 Location of the MSC50 Nodes Selected to Describe Wind and Wave Conditions

Table 5.1 Location of the MSC50 Nodes Selected to Describe Wind and Wave Conditions

MSC50 Node	Latitude (N)	Longitude (W)	Water Depth (m)
Project Area – Northern Section			
M3012443	49.5°	45.5°	2,990
M6013912	48.3°	46.3°	1,038
M6013091	47.8°	47.2°	390
Project Area – Southern Section			
M6011605	47.0°	49.0°	89
M6010089	46.2°	46.7°	1,033

The MSC50 wind speeds are 1-hour average wind speeds for a height of 10 m above sea level. Wind speed measurements are frequently averaged over shorter durations (e.g., 10 minutes for marine reports and two minutes for aviation, and a one minute average is used for the categorization of tropical cyclones). Wind gusts are typically for one, two or five second durations. Several formulas (e.g., ISO/DIS 19901-1 (2005)), can be used to scale winds to averaging times less than 1 h and for different reference elevations (e.g., between 10 m and drilling installation anemometer height or vice versa), and are frequently applied in design criteria studies applying measured and hindcast data sets.

Wind conditions are summarized with monthly and annual statistics presented in Table 5.2, which lists from north to south all five MSC50 grid point nodes for the Project Area.

Table 5.2 Wind Statistics

Location	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Mean Wind Speed (m/s)													
M3012443	12.1	11.7	10.6	9.0	7.9	7.2	6.7	7.0	8.4	9.7	10.5	11.5	9.3
M6013912	12.0	11.7	10.5	8.7	7.6	7.0	6.4	6.8	8.1	9.6	10.3	11.4	9.2
M6013091	11.6	11.4	10.2	8.5	7.3	6.8	6.3	6.6	7.8	9.2	9.9	11.1	8.9
M6011605	11.1	11.0	9.9	8.3	7.1	6.7	6.3	6.6	7.7	8.9	9.7	10.7	8.6
M6010089	11.3	11.2	10.0	8.4	7.1	6.7	6.0	6.4	7.6	9.0	9.6	10.9	8.7
Most Frequent Direction (from)													
M3012443	W	W	W	SW	SW	SW	SW	SW	SW	W	W	W	SW
M6013912	W	W	W	W	SW	SW	SW	SW	SW	W	W	W	W
M6013091	W	W	W	SW	SW	SW	SW	SW	SW	W	W	W	SW
M6011605	W	W	W	SW	SW	SW	SW	SW	SW	W	W	W	SW
M6010089	W	W	W	W	SW	SW	SW	SW	W	W	W	W	W

Table 5.2 Wind Statistics

Location	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Maximum Speed (m/s)													
M3012443	29.8	30.4	29.2	24.8	24.2	20.8	17.2	28.9	26.6	26.8	26.2	30.4	30.4
M6013912	29.6	31.1	30.7	25.7	25.4	23.1	19.9	28.4	28.7	27.8	27.0	31.0	31.1
M6013091	28.9	31.2	28.8	25.1	24.8	23.5	18.1	29.8	28.6	26.9	26.6	29.5	31.2
M6011605	29.2	32.4	27.8	25.2	22.3	23.5	19.1	27.0	29.0	31.6	27.4	28.3	32.4
M6010089	31.2	30.3	29.0	27.4	23.3	23.2	21.3	28.2	25.1	26.8	29.1	30.1	31.2
Direction of Maximum Wind Speed (from)													
M3012443	W	W	W	N	NW	NW	W	S	SE	SE	SW	NW	NW
M6013912	W	S	W	S	NW	NW	S	S	SE	NW	W	NW	S
M6013091	W	SW	W	S	NW	NW	S	S	SW	NW	NW	SW	SW
M6011605	W	NW	W	N	NW	NW	SW	S	SW	S	NW	SW	NW
M6010089	W	W	W	NW	NW	W	SW	S	S	W	W	SW	W
MSC50 data for the period 1962-2015. Project Area – Northern Section: grid point nodes M3012443, M6013912, M6013091. Project Area – Southern Section: grid point nodes M6011605, M6010089													

5.3.1.1 Project Area – Northern Section

Mean hourly wind speeds for the Project Area – Northern Section range from approximately 6 to 7 m/s in July to 12 m/s in January, while the strongest winds of 31 m/s occur in February and December. The maximum wind speeds indicate that gale force winds, in the range from 17.5 to 24.2 m/s, occur in June and July, while storm force winds, in the range from 24.7 to 32.4 m/s, can occur during the rest of the year.

Inspection of both wind and wave statistics (discussed in Sections 5.3 and 5.5) and directional roses for the three MSC50 nodes examined for the Project Area – Northern Section indicates that there is little variation in wind and wave conditions between the three locations. Given conditions are comparable, one grid point node M6012443 (the deepest node location and farthest from shore) is selected to illustrate regional conditions over the Project Area – Northern Section. Monthly and annual directional wind distributions are shown in Figures 5-8 and 5-9, respectively. The wind roses for the other two node locations are similar.

Environmental monitoring data collected as part of recent drilling campaigns includes that from nine Statoil wells from 2013 to 2016 in the Project Area – Northern Section. These well locations are illustrated in Figure 5-10 and the associated timeline history is presented in Figure 5-11. It is noted that approximately 80 percent of these MANMAR observations were made during daytime hours only (i.e., at 09, 12, 15, and 18 h).

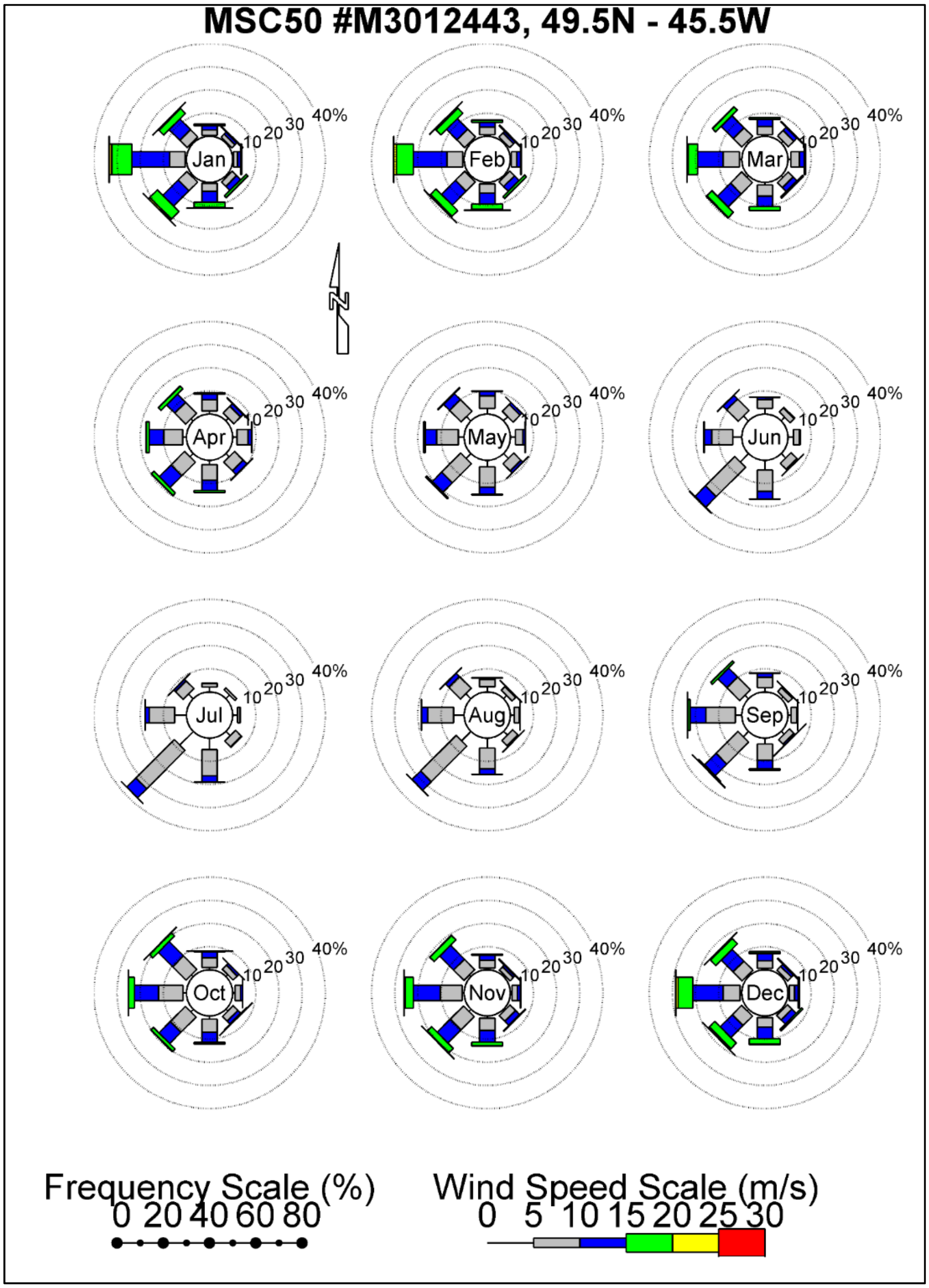


Figure 5-8 **Monthly Wind Roses, MSC50 Node M3012443 (1962–2015), Project Area – Northern Section**

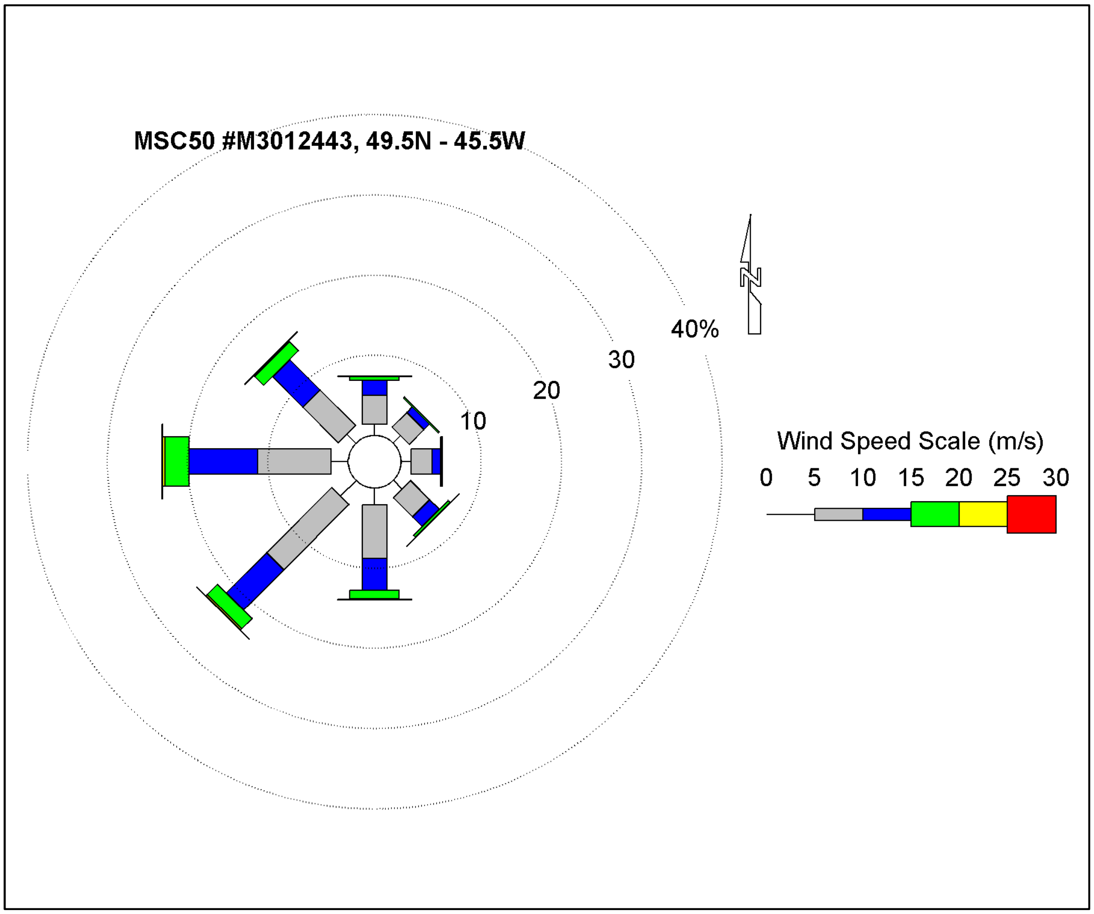


Figure 5-9 Annual Wind Rose, MSC50 Node M3012443 (1962–2015), Project Area – Northern Section

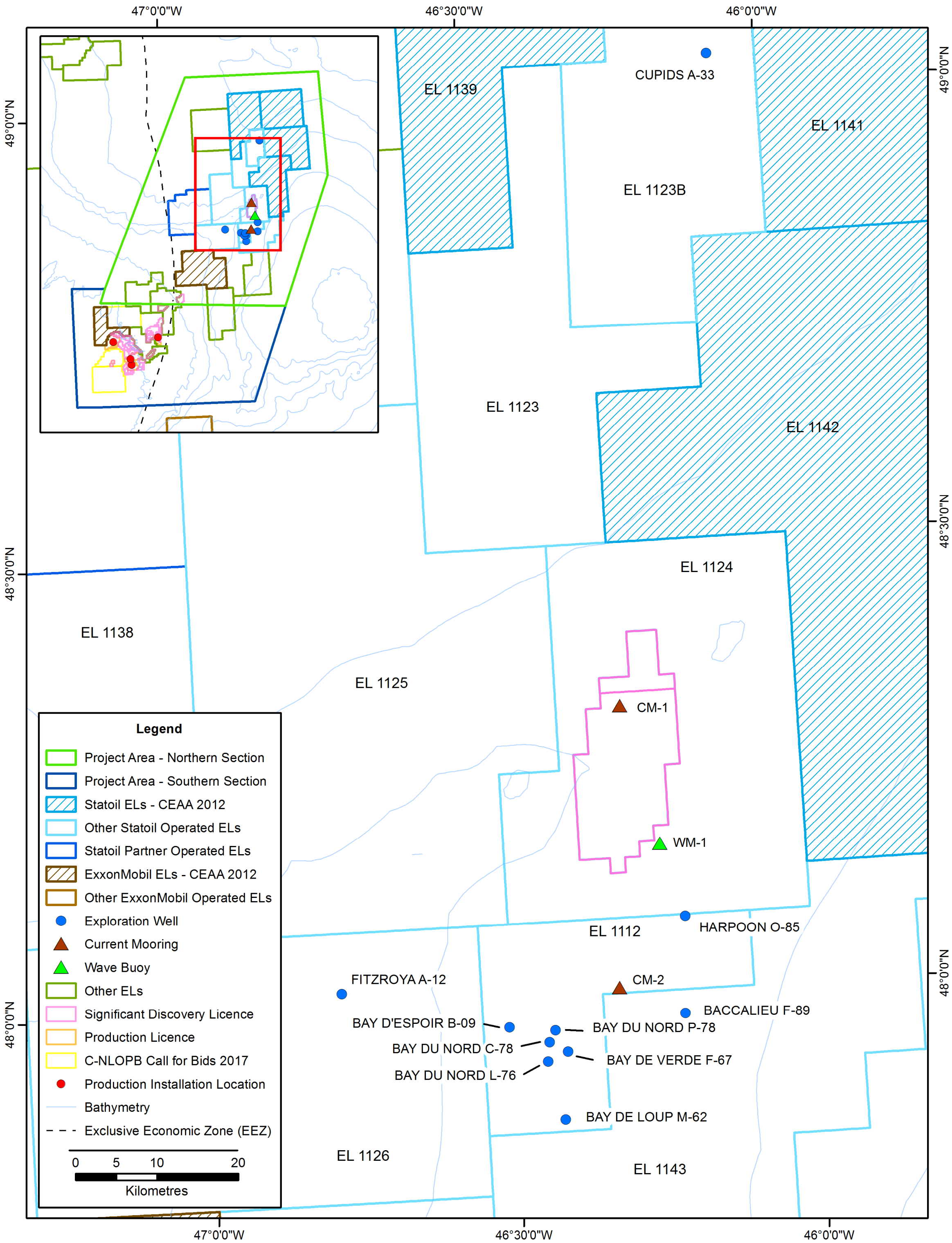


Figure 5-10 Statoil Exploration Wells, Project Area – Northern Section, 2013-2017

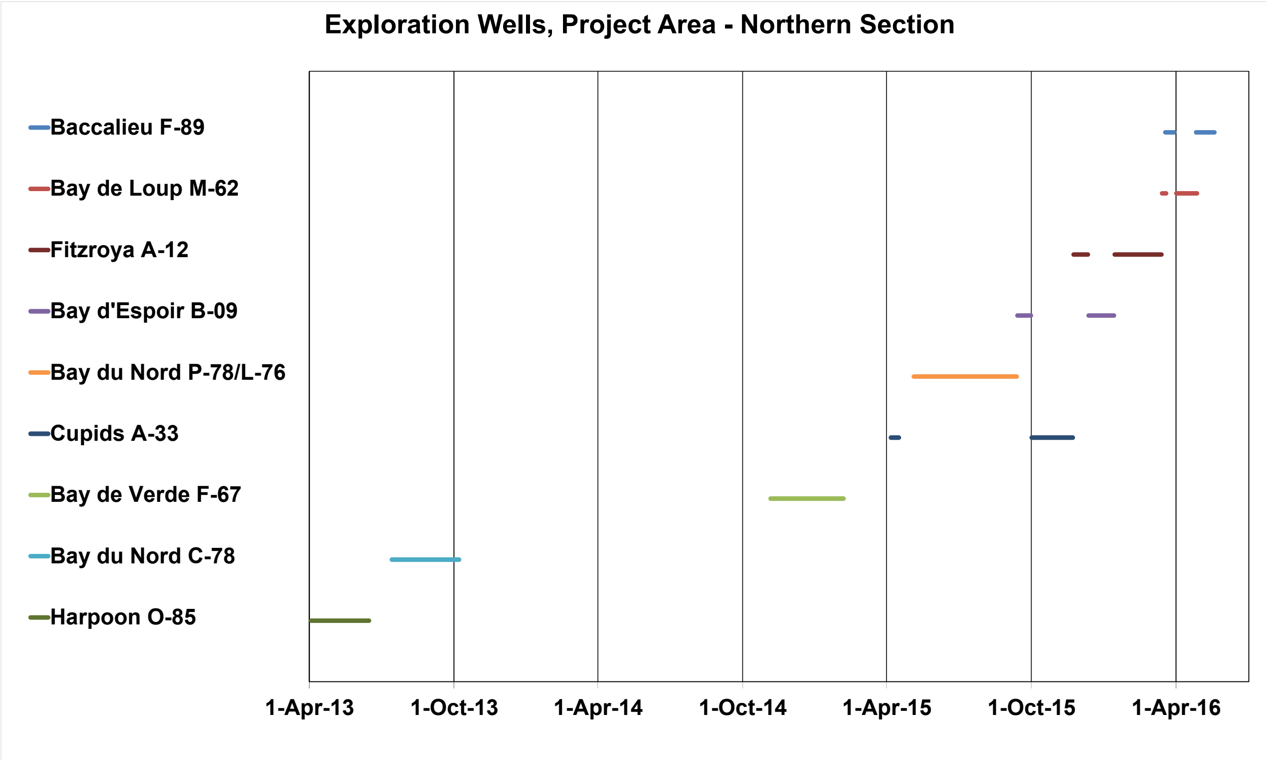


Figure 5-11 Statoil Exploration Wells, Project Area – Northern Section, 2013-2016, Drilling Installation History

Wind statistics from these Project Area – Northern Section exploration wells are presented in Table 5.3. Whereas the winds for MSC50 are representative of a 10 m elevation, these drilling installation winds are from an elevation of 107 m. Mean hourly wind speeds from these well programs range from 9 to 10 m/s in the summer to 14 or 15 m/s in November, January, and February. Winds are most frequent from the west or southwest in all months. Maximum wind speeds range from 20.1 m/s in August to 31.4 m/s in January through March with the largest wind speed of 38.6 m/s measured on 17 April 2015 at Bay du Nord L-76.

Table 5.3 Wind Statistics, Statoil Exploration Wells, 2013-2016

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Mean Wind Speed (m/s)												
15.0	13.8	13.4	13.3	10.6	9.6	9.4	9.9	10.1	12.7	13.9	12.2	12.2
Most Frequent Direction (from)												
W	SW	W	W	SW	W	SW	SW	W	W	W	W	SW
Maximum Speed (m/s)												
31.4	31.4	31.4	38.6	30.3	26.2	22.6	20.1	23.7	26.7	34.5	25.7	38.6
Direction of Maximum Wind Speed (from)												
SW	S	SW	NW	NW	SW	SW	S	W	W	S	W	NW

5.3.1.2 Project Area – Southern Section

Mean hourly wind speeds for the Project Area – Southern Section range from 6 m/s in July to 11.3 m/s in January, while the strongest winds of 32.4 m/s occur in February (Table 5.2). The maximum wind speeds indicate that gale force winds, in the range from 17.5 to 24.2 m/s, occur in May, June, and July, while storm force winds, in the range from 24.7 to 32.4 m/s, can occur during the rest of the year.

Inspection of both wind and wave statistics (discussed in Sections 5.3 and 5.5) and directional roses for the two MSC50 nodes examined for the Project Area – Southern Section indicates there is little variation in wind and wave conditions between the two locations. Given conditions are comparable, one grid point node M6010089 is selected to illustrate regional conditions over the Project Area – Southern Section. Monthly and annual directional wind distributions for this gridpoint are shown in Figures 5-12 and 5-13, respectively. The wind roses for the other node location are similar.

The most complete and best-maintained MANMAR observation record for the Project Area – Southern Section is likely that from the Hibernia Platform on the Grand Banks dating back to 1997. This data set (48,542 observations for wind) was selected for derivation of additional wind and wave statistics to augment the primary source of MSC50 and air temperature statistics (see Section 5.3.2.2) to complement that reported based on the ICOADS.

Wind statistics, from 30 May 1997 to 7 July 2017, from the Hibernia Platform are presented in Table 5.4. Whereas the winds for MSC50 are representative of a 10 m elevation, the Hibernia winds are at a platform elevation of 139 m. Mean hourly wind speeds for the Hibernia Platform range from approximately 10.5 m/s in August to 16.0 m/s in January. The maximum wind speeds indicate that hurricane force winds of 32.8 m/s or above – at platform elevation, can occur in October through April.

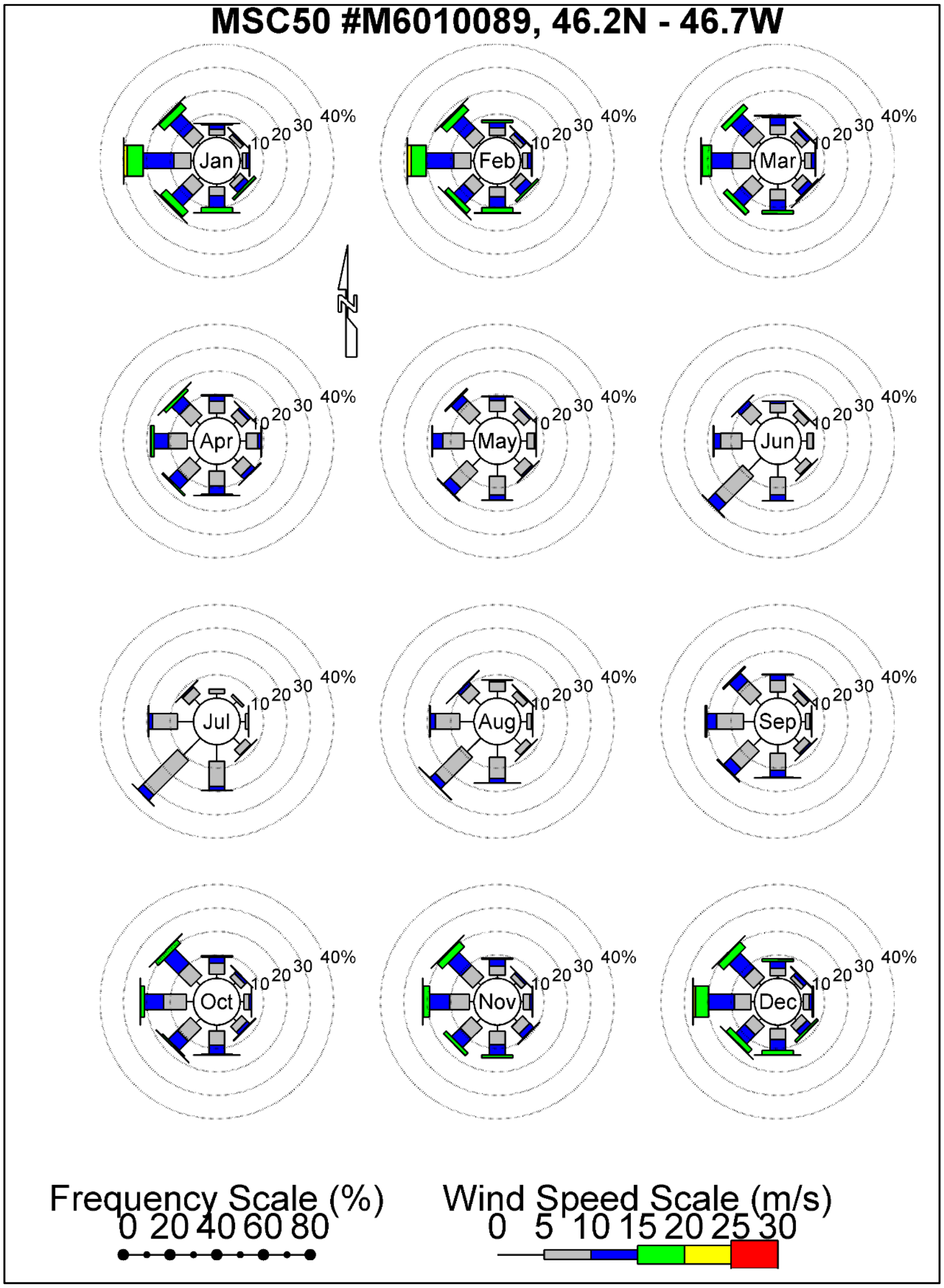


Figure 5-12 Monthly Wind Roses, MSC50 Node M6010089 (1962–2015), Project Area – Southern Section

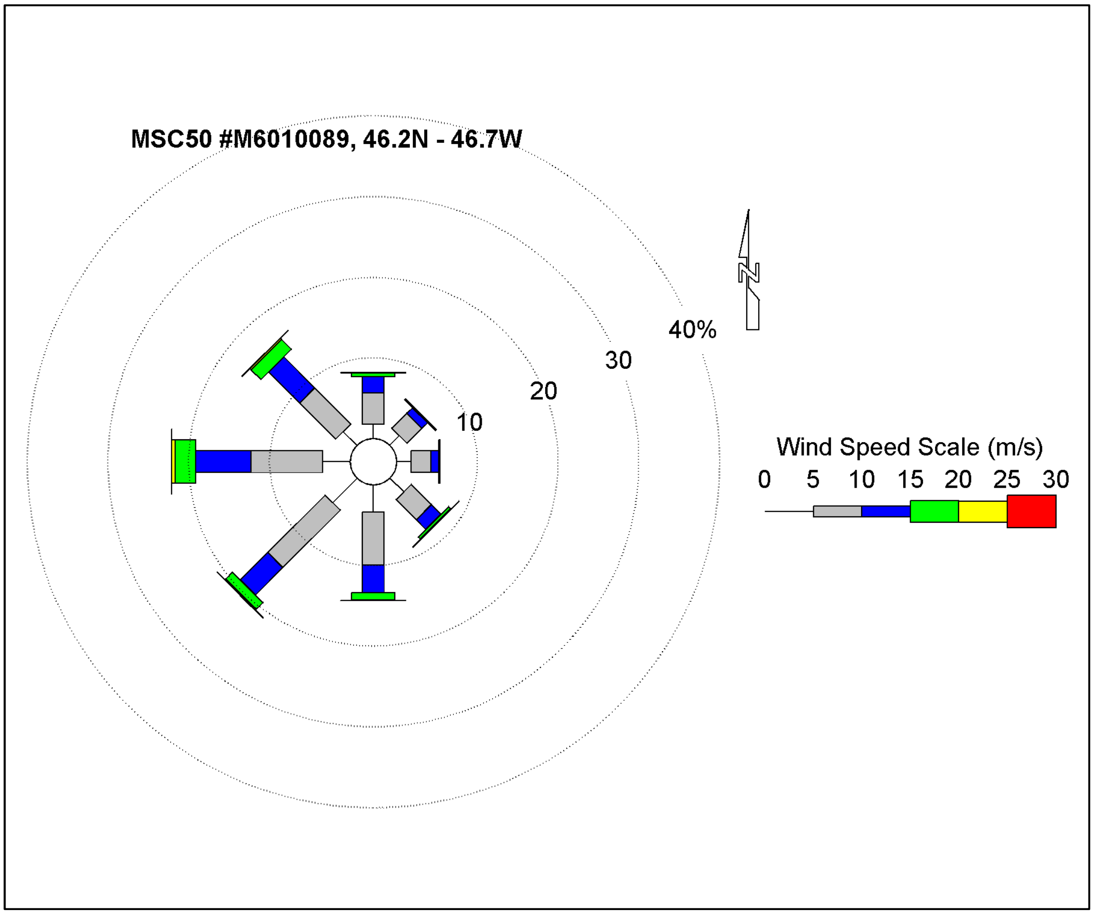


Figure 5-13 Annual Wind Rose, MSC50 Node M6010089 (1962 – 2015), Project Area – Southern Section

Table 5.4 Wind Statistics: Hibernia Platform

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Mean Wind Speed (m/s)												
16.0	15.6	14.8	13.9	12.4	11.6	11.6	10.5	11.6	13.2	13.9	15.9	13.4
Most Frequent Direction (from)												
W	W	W	S	SW	SW	W	SW	SW	W	W	W	W
Maximum Speed (m/s)												
38.6	37.6	36.5	35.0	30.9	29.3	29.8	27.8	30.3	33.4	34.5	37.0	38.6
Direction of Max Wind Speed (from)												
NW	SE	W	S	S	S	SW	S	SW	W	S	S	NW

5.3.1.3 Potential Vessel and Aircraft Traffic Routes

The range of wind conditions experienced along the potential vessel and aircraft traffic routes from St. John's to the Project Area are likely to be quite close to those experienced farther offshore. During fall and winter months, average wind speeds farther offshore can be expected to be 1 to 2 m/s higher than near St. John's; maximum wind speeds can be expected to be at least 2 to 3 m/s higher. Further information on the regional wind environment in this area is provided in the Eastern Newfoundland SEA (Amec 2014), Section 4.1.3.

5.3.2 Air Temperature

Atmospheric properties over the ocean surface, including air temperature, precipitation and visibility have been characterized using the International Comprehensive Ocean-Atmosphere Data Set (ICOADS). ICOADS represents the most extensive available database of observations of atmospheric and sea conditions. The dataset consists of global marine observations recorded from 1662 to the present, compiled by the United States National Centre for Atmospheric Research (Freeman et al. 2017). Conditions for the Project Area – Northern Section and Project Area – Southern Section have been characterized by selecting all ICOADS observations within the Project Area for the period January 1960 to February 2017, inclusive (Research Data Archive et al. 2017).

A secondary data source includes weather observations from historical drilling campaigns as described above for winds. These are presented for recent Statoil drilling programs for the Project Area – Northern Section and from production operations at the Hibernia Platform for the Project Area – Southern Section.

5.3.2.1 Project Area – Northern Section

Monthly air temperature statistics for the Project Area – Northern Section are presented in Table 5.5. Air temperature exhibits strong seasonal variations, with mean temperatures ranging from -0.4°C in January to 13.0°C in August. The coldest observed air temperature on record (-13.5°C) was in February, while during the summer months the coldest observed temperatures range from -1.8°C in June to 3°C in August. The highest observed temperatures during winter months are approximately 22°C, while in summer the values reach as high as 24.5°C. Throughout the year the mean daily minimum and maximum temperatures generally stay within approximately 3°C of the mean temperature (Figure 5-14).

Table 5.5 Monthly Air Temperature (°C) Statistics, Project Area – Northern Section

Month	Mean	Max	Min	SD	Mean Daily Min	Mean Daily Max
Jan	0.4	22.0	-13.0	4.0	-1.2	3.7
Feb	0.5	21.0	-13.5	4.0	-1.7	3.7
Mar	1.6	17.0	-12.0	3.7	-0.7	4.7
Apr	3.1	18.0	-6.8	3.1	0.9	6.1
May	4.9	18.7	-4.1	2.9	2.9	7.8
Jun	7.0	21.1	-1.8	3.0	5.3	9.7

Table 5.5 Monthly Air Temperature (°C) Statistics, Project Area – Northern Section

Month	Mean	Max	Min	SD	Mean Daily Min	Mean Daily Max
Jul	10.8	23.5	1.5	3.0	9.2	13.2
Aug	13.0	24.0	3.0	2.6	11.5	14.9
Sep	11.9	24.5	1.0	2.9	10.1	14.0
Oct	8.5	22.8	-1.5	2.9	6.8	10.6
Nov	5.6	20.6	-5.8	3.4	3.8	8.0
Dec	3.2	22.0	-9.5	3.8	1.3	5.8

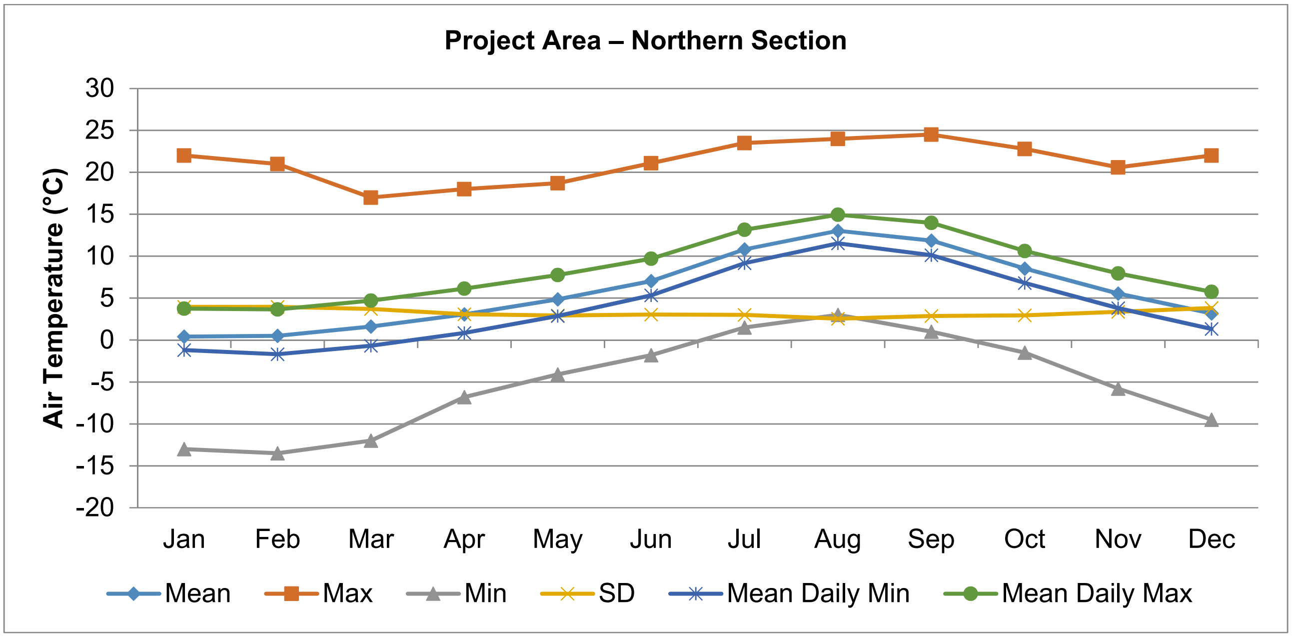


Figure 5-14 Air Temperature, Project Area – Northern Section

Air temperature statistics from the Statoil exploration drilling programs located in the Project Area – Northern Section are presented in Table 5.6. Mean air temperatures range from -1.0°C in March to 12.4°C in August. The coldest temperature reported is -9.5°C from 13 March 2015 at Bay du Nord P-78 (all air temperatures on that date where in the range of -9.5°C to -8.4°C); the warmest temperature reported is 16.4°C from 2 September 2015 at Bay du Nord L-76.

Table 5.6 Monthly Air Temperature (°C) Statistics, Statoil Exploration Wells, 2013-2016

Month	Mean	Max	Min	SD
Jan	0.6	8.4	-5.6	2.8
Feb	0.5	7.7	-6.2	2.9
Mar	-1.0	7.4	-9.5	3.4
Apr	2.0	9.0	-4.9	2.7
May	3.4	10.4	-1.3	2.4
Jun	5.5	10.9	0.7	2.0

Table 5.6 Monthly Air Temperature (°C) Statistics, Statoil Exploration Wells, 2013-2016

Month	Mean	Max	Min	SD
Jul	8.9	14.2	5.7	2.0
Aug	12.4	15.7	8.9	1.3
Sep	11.2	16.4	5.4	2.1
Oct	8.6	13.6	0.9	2.5
Nov	5.0	12.4	-2.2	2.5
Dec	2.7	10.9	-5.7	3.5
Annual	3.9	16.4	-9.5	4.8

5.3.2.2 Project Area – Southern Section

Monthly air temperature statistics for the Project Area – Southern Section are presented in Table 5.7. Air temperature exhibits strong seasonal variations, with mean temperatures ranging from -0.1°C in January to 14.4°C in August. The coldest observed air temperature on record (-13.6°C) was in February, while during the summer months the coldest observed temperatures ranged from -1.2°C to 3°C in June and August. The highest observed temperatures during winter months are approximately 19.5°C, while in summer the values reach as high as 24°C. Throughout the year the mean daily minimum and maximum temperatures generally stay within approximately 3°C of the mean temperature (Figure 5-15).

Table 5.7 Monthly Air Temperature (°C) Statistics, Project Area – Southern Section

Month	Mean	Max	Min	SD	Mean Daily Min	Mean Daily Max
Jan	0.4	18.0	-12.8	3.2	-1.7	3.6
Feb	-0.1	17.5	-13.6	3.2	-2.2	3.1
Mar	0.6	17.0	-11.0	3.0	-1.3	4.1
Apr	2.2	16.7	-6.5	2.6	0.5	5.2
May	4.3	18.0	-5.0	2.6	2.5	7.2
Jun	7.4	20.5	-1.2	2.7	5.7	10.2
Jul	12.0	23.5	1.2	2.7	10.0	14.2
Aug	14.4	24.0	3.0	2.3	12.4	16.4
Sep	12.9	23.5	1.0	2.6	10.8	15.0
Oct	9.2	22.5	-1.2	3.0	7.3	11.7
Nov	5.5	20.5	-5.0	3.1	3.7	8.2
Dec	2.3	19.5	-10.2	3.4	0.5	5.2

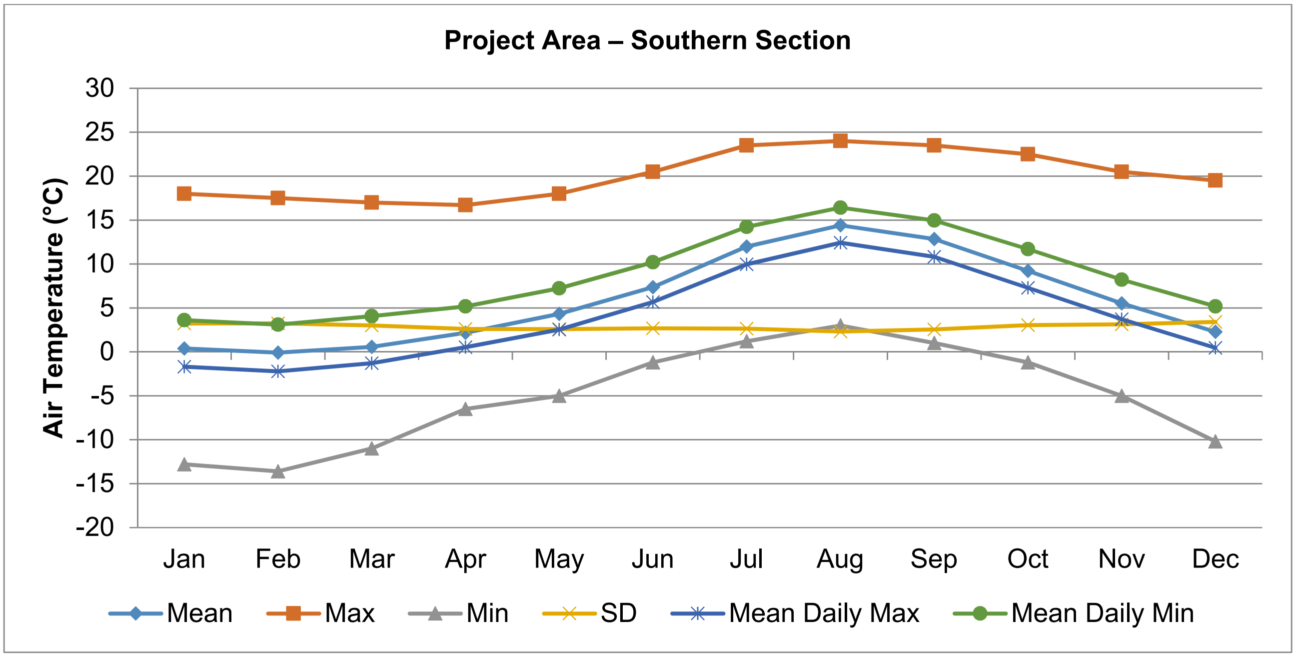


Figure 5-15 Air Temperature, Project Area – Southern Section

Air temperature statistics from the Hibernia Platform located in the Project Area – Southern Section are presented in Table 5.8. Mean air temperatures for the Hibernia Platform range from -0.5°C in February to -14.8°C in August. The coldest temperature reported is -13.8°C from 31 January 2002; the warmest temperature reported is 20.4°C from 24 August 2009.

Table 5.8 Monthly Air Temperature (°C) Statistics, Hibernia Platform

Month	Mean	Max	Min	SD
Jan	0.1	11.3	-13.8	3.4
Feb	-0.5	10.4	-13.5	3.4
Mar	0.1	11.2	-10.2	3.1
Apr	2.0	12.0	-5.6	2.9
May	4.4	13.9	-3.2	2.9
Jun	7.7	15.8	0.0	2.9
Jul	12.5	19.6	3.9	2.5
Aug	14.8	20.4	8.5	2.0
Sep	13.1	19.6	4.9	2.6
Oct	9.2	17.4	-0.7	3.0
Nov	5.8	16.4	-3.7	3.5
Dec	1.8	12.2	-8.6	3.5
Annual	6.0	20.4	-13.8	6.0

5.3.2.3 Potential Vessel and Aircraft Traffic Routes

Air temperatures at sea will be strongly influenced by moderating effects of sea temperature, with daily and seasonal variations much smaller than on land. Once offshore, over the existing and potential supply vessel and aircraft traffic routes, conditions are on average fairly consistent with mean values of approximately 0°C in February and approximately 15°C in August (Bowyer 1995). Temperature are slightly warmer by a couple of degrees in winter for the farthest east portions of the transit routes with the influence of warmer Gulf Stream waters. Further information on regional air temperature conditions in this area is provided in the Eastern Newfoundland SEA (Amec 2014, Section 4.1.3).

5.3.3 Precipitation

The ICOADS database contains observations of several precipitation types and thunderstorm occurrence. The weather state is recorded and categorized as an event based on the type (but not the amount) of precipitation during that event. The frequency of occurrence of the different precipitation types and thunderstorms have been calculated as a percentage of the total monthly and annual weather observations for the same data set described in Section 5.3.2 for air temperature, with observations spanning 1960 to February 2017 and including both the Northern and Southern Sections of the Project Area.

A considerable degree of variability of precipitation patterns within localized regions of the Project Area is expected. The statistics shown below are the percentage of a certain distinct weather state (e.g., rain, thunderstorms, hail) for all weather reports available on record for that month. The weather states have been consolidated from 50 different ICOADS classifications, separating (without overlap) rain from freezing rain and snow (although some overlap may exist between these states and mixed rain/snow, hail, and thunderstorm, which represent a small percentage of the data). The frequency of occurrence – or, the percent of time the given condition(s) occurs in a given month (or annually) - can most closely be characterized as representing unspecified periods of time, for a percentage of all days.

5.3.3.1 Project Area – Northern Section

For the Project Area - Northern Section, the data indicate that most of the observed precipitation events are in the form of rain, snow, and drizzle, while other precipitation types, such as mixed rain, freezing rain, and hail, occur far less frequently. Rain occurs approximately 9 to 13 percent all months of the year, while snow is most likely to occur in December, January, and February (Table 5.9, Figure 5-16). Freezing rain is relatively infrequent in this area, occurring less than one percent of the time during a given month, and does not occur at all between July and October. Thunderstorms are the main generating mechanism of hail, and therefore the observation of hail is expected during thunderstorms. Figure 5-17 shows that hail and thunderstorms indeed occur with similarly low frequencies. There is a year-round potential for thunderstorms and hail, but the frequency of occurrence is less than one percent.

Table 5.9 Frequency of Occurrence (Percent) of Precipitation and Thunderstorms, Project Area – Northern Section

Month	Rain / Drizzle	Freezing Rain / Drizzle	Rain / Snow Mixed	Snow	Hail	Thunderstorm
Jan	9.9	0.4	1.7	13.9	0.6	0.0
Feb	9.0	0.2	1.0	14.6	0.4	0.0
Mar	8.9	0.1	1.0	8.2	0.3	0.0
Apr	8.4	0.1	0.6	4.1	0.2	0.0
May	9.7	0.0	0.2	1.2	0.1	0.0
Jun	8.9	0.1	0.1	0.2	0.1	0.1
Jul	8.9	0.0	0.1	0.1	0.2	0.2
Aug	8.9	0.0	0.2	0.2	0.1	0.1
Sep	9.5	0.0	0.0	0.1	0.0	0.0
Oct	12.4	0.0	0.1	0.5	0.1	0.0
Nov	12.4	0.1	0.6	2.5	0.3	0.0
Dec	11.3	0.1	1.6	7.6	0.8	0.1
Annual	9.7	0.1	0.6	4.6	0.2	0.1

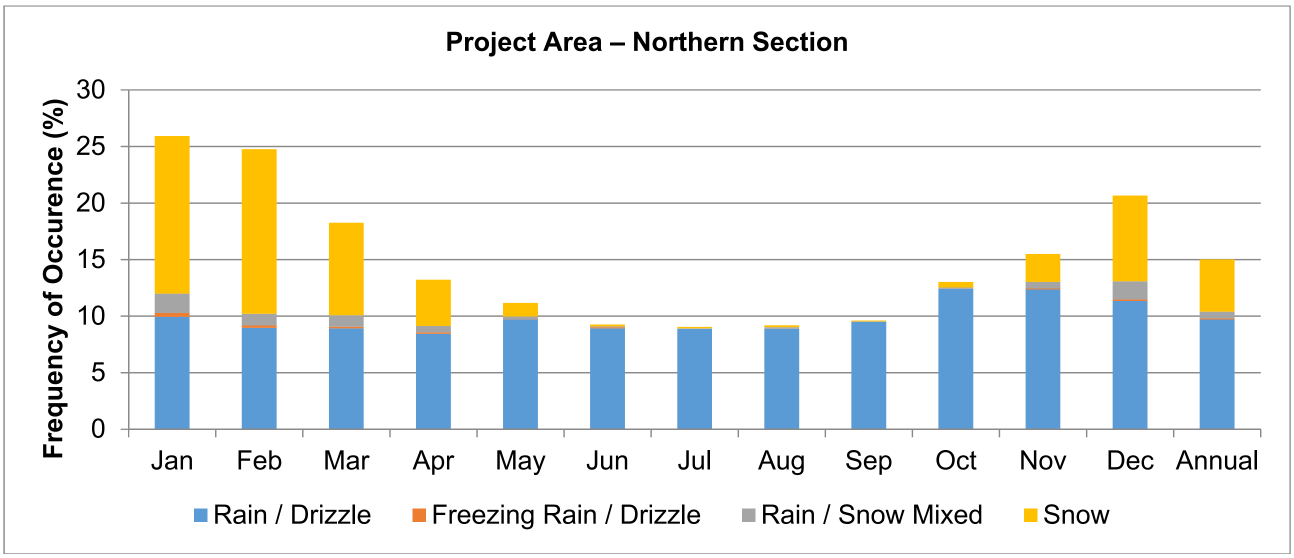


Figure 5-16 Frequency of Occurrence (Percent) of Precipitation by Type, Project Area – Northern Section

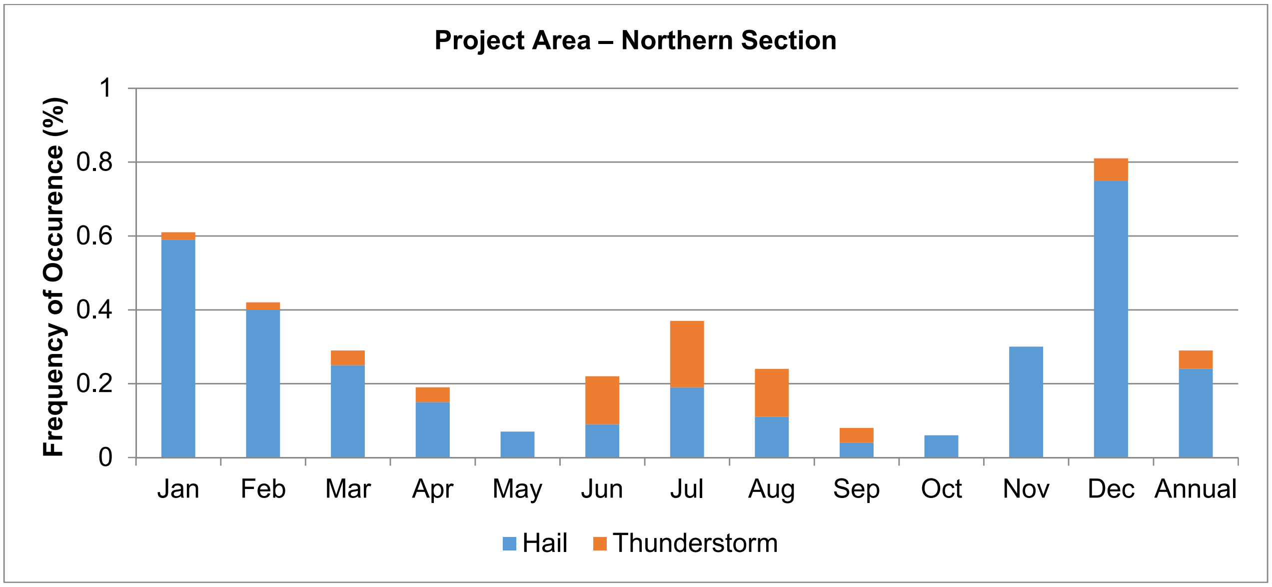


Figure 5-17 Frequency of Occurrence (Percent) of Thunderstorm and Hail, Project Area – Northern Section

5.3.3.2 Project Area – Southern Section

For the Project Area - Southern Section, the data indicate that most of the observed precipitation events are in the form of rain, snow, and drizzle, while other precipitation types, such as mixed rain, freezing rain, and hail, occur far less frequently. Rain occurs approximately nine to 16 percent all months of the year, while snow is most likely to occur in December, January, February, and March (Table 5.10, Figure 5-18). Freezing rain is relatively infrequent in this area, occurring less than one percent of the time during a given month, and does not occur at all between June and October. Thunderstorms are the main generating mechanism of hail, and therefore the observation of hail is expected during thunderstorms. Figure 5-19 shows that hail and thunderstorms indeed occur with similarly low frequencies. There is a year-round potential for thunderstorms and hail, but the frequency of occurrence is less than one percent.

Table 5.10 Frequency of Occurrence (Percent) of Precipitation and Thunderstorms, Project Area – Southern Section

Month	Rain / Drizzle	Freezing Rain / Drizzle	Rain / Snow Mixed	Snow	Hail	Thunderstorm
Jan	11.1	0.4	0.4	15.0	0.5	0.0
Feb	9.2	0.8	0.3	14.9	0.3	0.0
Mar	9.7	0.9	0.3	9.8	0.2	0.0
Apr	11.2	0.4	0.2	3.6	0.1	0.0
May	11.5	0.1	0.1	0.8	0.1	0.0
Jun	11.5	0.0	0.0	0.1	0.0	0.0
Jul	9.5	0.0	0.1	0.1	0.1	0.1
Aug	10.4	0.0	0.1	0.1	0.0	0.1
Sep	11.1	0.0	0.1	0.1	0.0	0.0
Oct	15.0	0.0	0.0	0.3	0.2	0.1
Nov	15.3	0.1	0.3	2.7	0.4	0.1
Dec	12.5	0.2	0.4	9.4	0.4	0.0
Annual	11.5	0.2	0.2	4.7	0.2	0.0

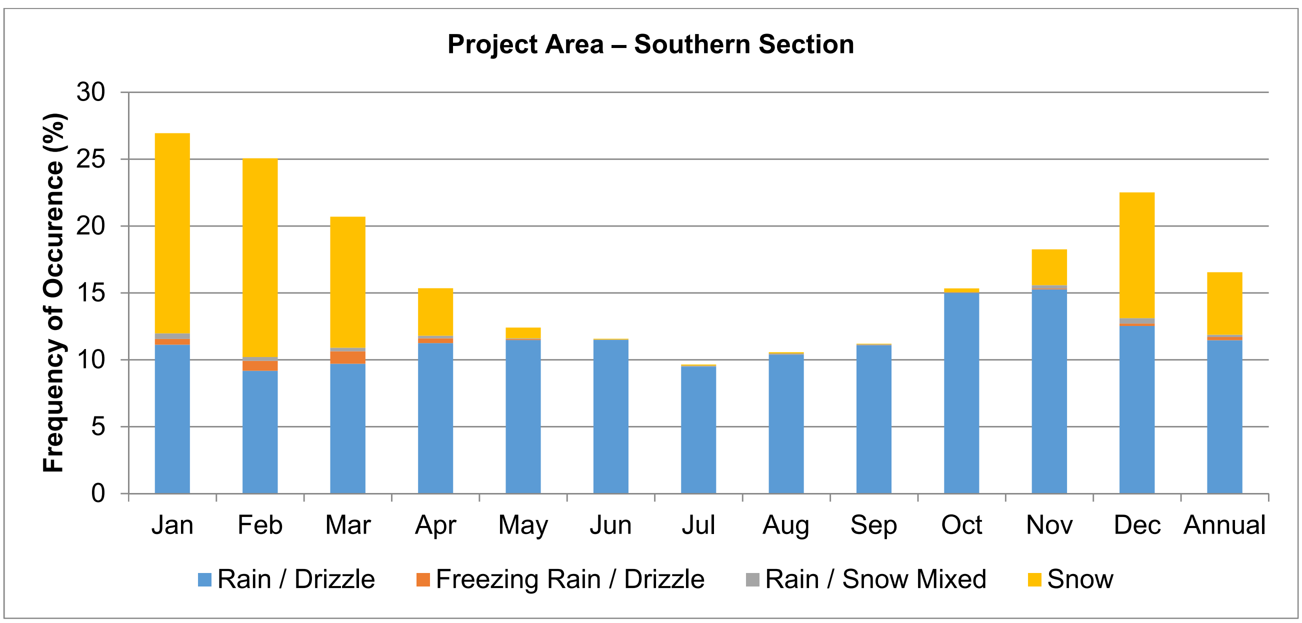


Figure 5-18 Frequency of Occurrence (Percent) of Precipitation by Type Project Area – Southern Section

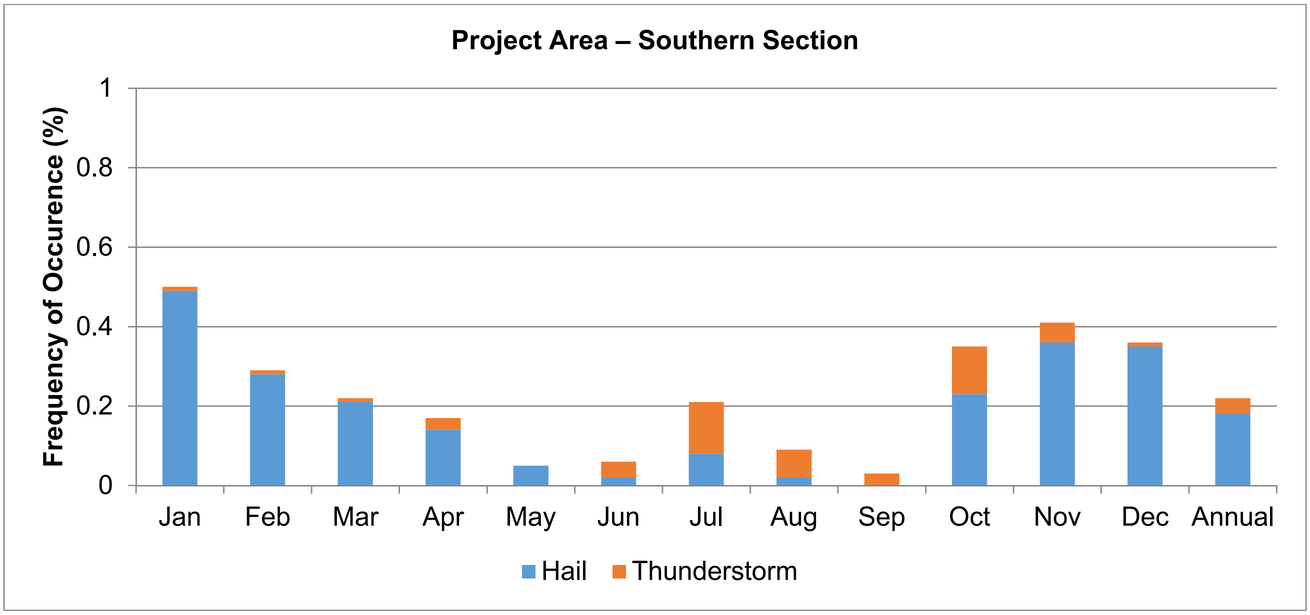


Figure 5-19 Frequency of Occurrence (Percent) of Thunderstorm and Hail, Project Area – Southern Section

5.3.3.3 Potential Vessel and Aircraft Traffic Routes

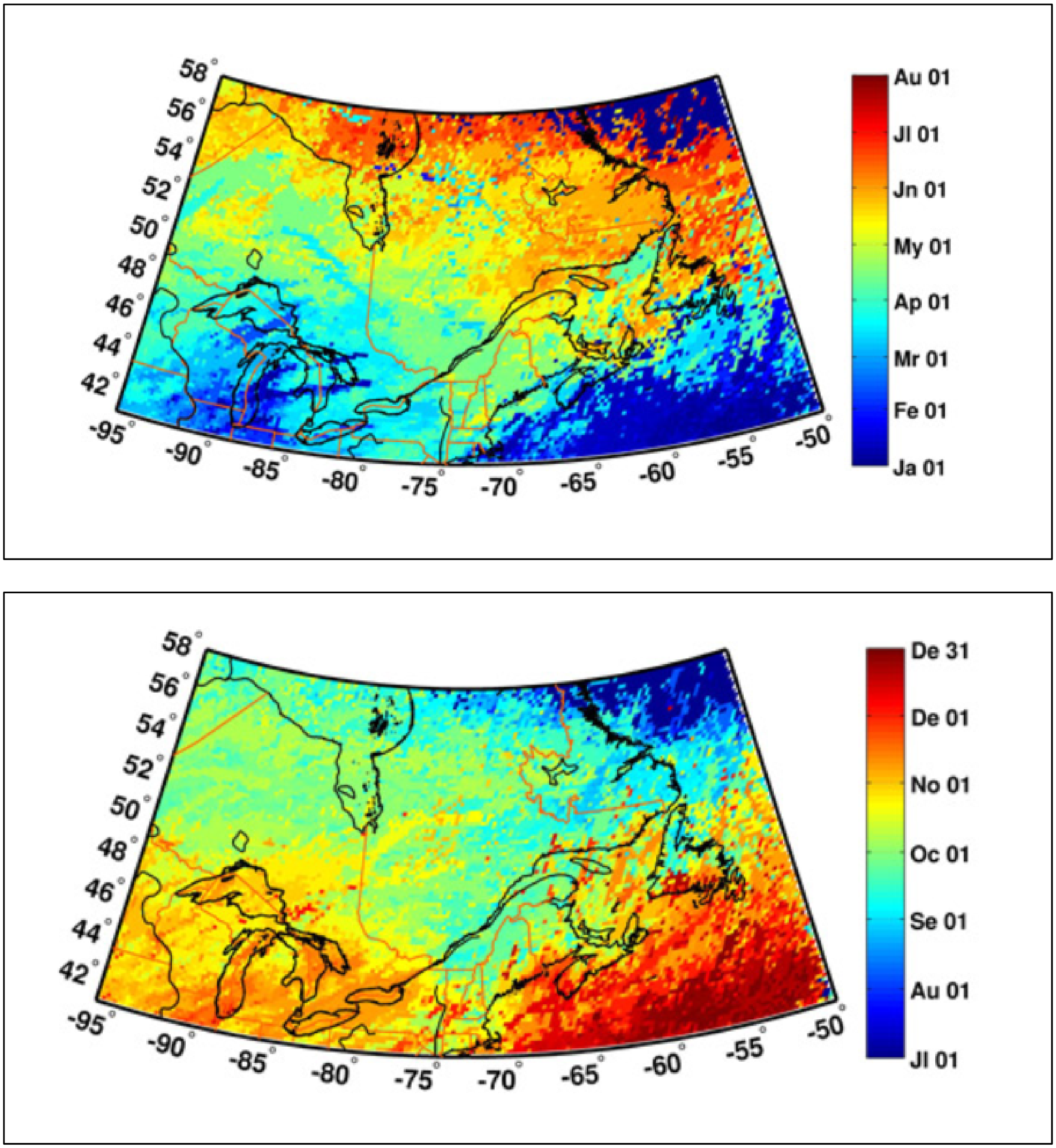
Precipitation along the potential vessel and aircraft traffic routes can be experienced throughout the year, with it being three to four times more likely in winter than in summer. Further information on the regional precipitation characteristics of this area is provided in the Eastern Newfoundland SEA (Amec 2014), Section 4.1.3.

5.3.3.4 Lightning

Lightning is an electrical discharge most commonly produced in thunderstorms, usually accompanied by thunder. It occurs in clouds with vigorous convection where enough electrical charge is separated through the movement of cloud droplets and precipitation particles. By its nature, lightning is a localized phenomenon and, as a result, it is one which is difficult to accurately represent in numerical models. Measurements are available from the Canadian Lightning Detection Network; however, this is a land based network, with coverage just to eastern Newfoundland (i.e., the Grand Banks are on the far eastern edge of the network).

Nevertheless, the available lightning statistics from Environment and Climate Change Canada for Eastern Canada do provide some indication of conditions over portions of the potential vessel and aircraft traffic routes and western portions of the Project Area. This includes average dates for the beginning and ending of lightning season for Eastern Canada as shown in Figure 5-20.

Lightning occurs virtually year-round offshore Newfoundland. During winter, stronger strikes are possible and may be an issue for helicopters flying to the offshore platforms.



Source: Environment and Climate Change Canada (2016a)

Figure 5-20 Average Start (top) and End (bottom) Dates of the Lightning Season for Eastern Canada (1999-2013)

5.3.4 Fog and Visibility

The Project Area and surrounding areas have some of the highest occurrence rates of marine fog in North America, which in these regions is often of the advection type. Advection fog is formed when warm moist air flows over a cold surface such as the cold Northwest Atlantic Ocean, and can persist for days or weeks. This type of fog is most prevalent in spring and summer. Visibility is affected by the presence of fog, the number of daylight hours, as well as frequency and type of precipitation. For this characterization, visibility from the ICOADS dataset (observations span 1960 to February 2017, for the entire Project Area) has been classified as very poor (less than 0.5 km), poor (0.5 to 1 km), fair (1 to 10 km) or good (greater than 10 km). For offshore flying, helicopters need visual confirmation at 0.25 nautical miles (nm) (approximately 500 m) out and need a visibility of 0.5 nm or 1 km, or greater, to land.

The monthly and annual frequencies of occurrence of each state are shown in the figures and tables in the following sections. Fog and visibility conditions and seasonal variability are expected to vary considerably across the Project Area, along with air temperatures and precipitation rates. Therefore, site-specific conditions and the possible implications of these would have to be characterized from local visibility datasets for Project- and activity-specific planning and analysis.

5.3.4.1 Project Area – Northern Section

As shown in Table 5.11 and Figure 5-21, visibility within the Project Area - Northern Section varies considerably throughout the year. Good or fair visibility combined occur approximately 82 percent of the time annually. Good visibility (greater than 10 km) is most frequent during the fall, and least frequent in spring and summer. Visibility is poorest in July with conditions being very poor or poor almost half the time (43 percent). Annually, visibility is very poor 11.7 percent of time, poor 6 percent of the time, fair 18.1 percent of the time, and good 64.1 percent of the time.

Table 5.11 Monthly and Annual Frequencies (Percent) of Occurrence of Visibility, Project Area – Northern Section

Month	Very Poor (<0.5 km)	Poor (0.5 – 1 km)	Fair (1 – 10 km)	Good (>10 km)
Jan	3.5	3.8	22.4	70.3
Feb`	4.7	4.5	23.1	67.8
Mar	6.7	6.0	20.5	66.7
Apr	10.8	8.1	19.7	61.4
May	14.3	7.9	17.2	60.6
Jun	20.6	7.9	16.7	54.9
Jul	32.6	10.6	15.8	41.0
Aug	20.9	6.1	15.5	57.5
Sep	9.5	4.0	13.3	73.3
Oct	5.7	3.1	14.8	76.4
Nov	6.6	3.8	15.5	74.2

Table 5.11 Monthly and Annual Frequencies (Percent) of Occurrence of Visibility, Project Area – Northern Section

Month	Very Poor (<0.5 km)	Poor (0.5 – 1 km)	Fair (1 – 10 km)	Good (>10 km)
Dec	5.0	4.0	20.4	70.5
Annual	11.7	6.0	18.1	64.1

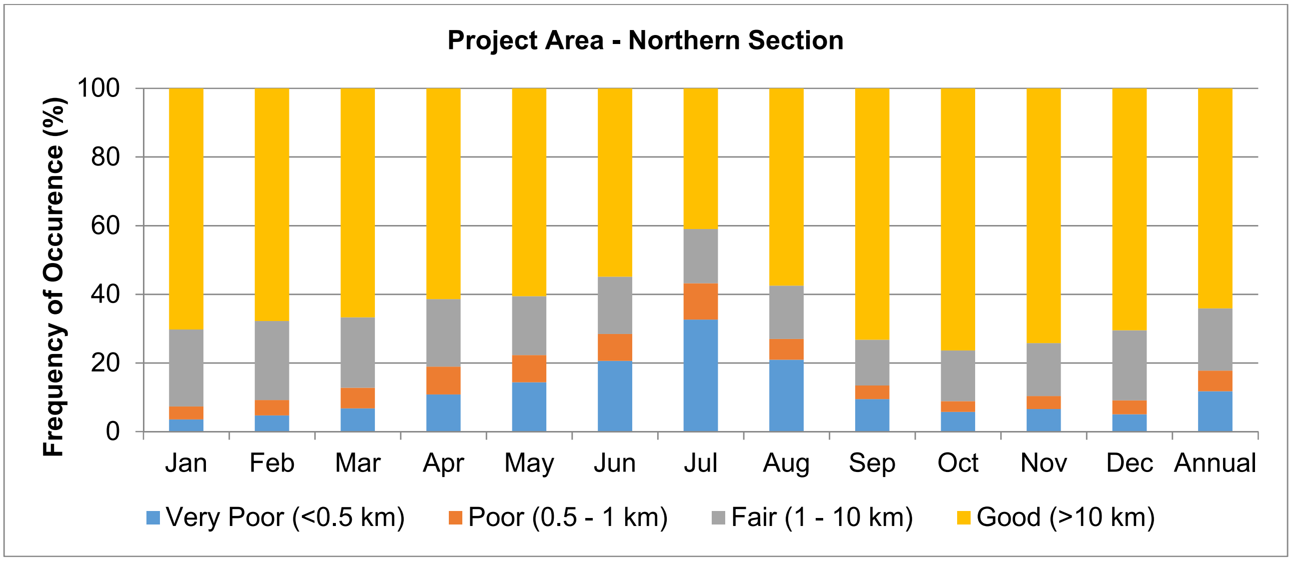


Figure 5-21 Frequency of Occurrence of Visibility, Project Area – Northern Section

Visibility class statistics from the Statoil exploration drilling programs noted above, located in the Project Area – Northern Section, are presented in Table 5.12 and shown in Figure 5-22. Conditions are comparable with those from the ICOADS analysis above (Table 5.11 and Figure 5-21). For example, visibility is very poor or poor 17.7 percent of the time annually for the entire Project Area – Northern Section region based on ICOADS compared with 15.4 percent of the time from the Statoil exploration drilling programs data. Visibility is fair 18.1 percent of the time annually for the ICOADS region compared with 18.4 percent of the time for the drilling campaign locations. Visibility is good 64.1 percent of the time annually for the ICOADS region compared with 66.3 percent of the time for the drilling campaign locations.

Table 5.12 Monthly and Annual Frequencies (Percent) of Occurrence of Visibility, Statoil Exploration Wells, 2013-2016

Month	Very Poor (<0.5 km)	Poor (0.5 – 1 km)	Fair (1 – 10 km)	Good (>10 km)
Jan	4.0	1.4	20.9	73.7
Feb`	9.5	1.6	24.9	64.0
Mar	5.5	1.2	18.4	74.9
Apr	15.5	1.1	20.8	62.6
May	22.5	3.6	17.5	56.5

Table 5.12 Monthly and Annual Frequencies (Percent) of Occurrence of Visibility, Statoil Exploration Wells, 2013-2016

Month	Very Poor (<0.5 km)	Poor (0.5 – 1 km)	Fair (1 – 10 km)	Good (>10 km)
Jun	16.3	3.3	20.6	59.8
Jul	26.9	2.4	19.7	51.0
Aug	24.6	2.0	16.6	56.8
Sep	17.7	2.0	10.3	70.0
Oct	9.2	0.0	14.9	75.9
Nov	4.5	0.0	14.5	80.9
Dec	9.8	0.4	13.8	76.0
Annual	13.7	1.7	18.4	66.3

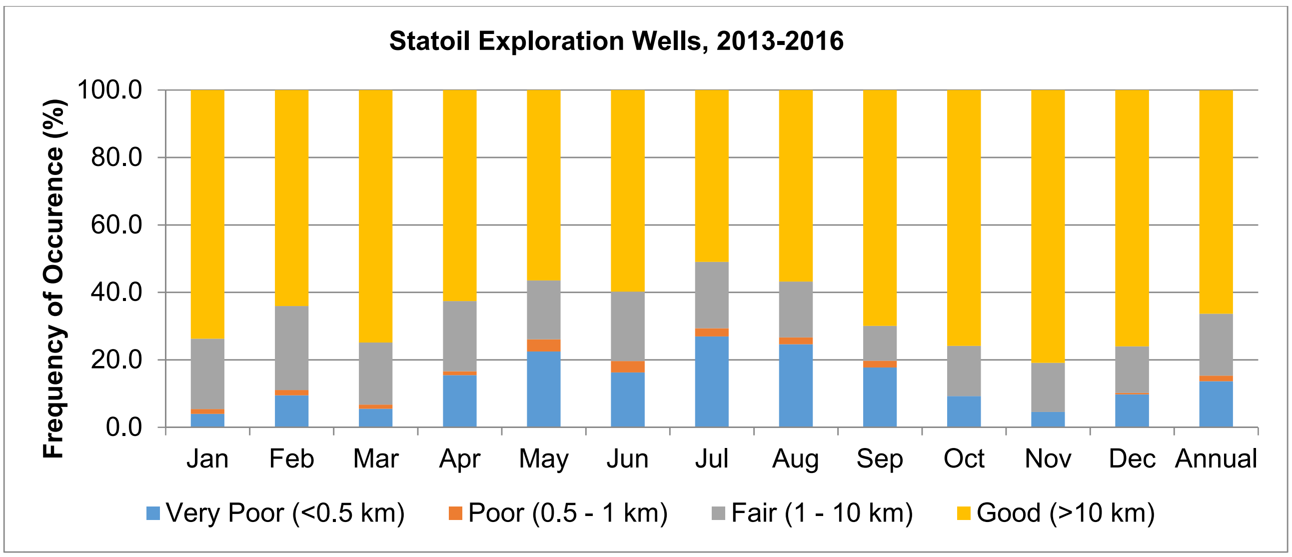


Figure 5-22 Frequency of Occurrence of Visibility, Statoil Exploration Wells, 2013-2016

A simple comparison of these visibility statistics for the Project Area – Northern Section indicates noticeably less frequent conditions of very poor or poor visibility has been encountered during the drilling campaigns during several months, June and July, compared with the ICOADS climatology. March and November also experienced better conditions than the ICOADS climatology. Conversely in May and September visibility conditions experienced were less favourable than the ICOADS climatology would suggest.

5.3.4.2 Project Area – Southern Section

As shown in Table 5.13 and Figure 5-23, visibility within the Project Area - Southern Section varies considerably throughout the year. Good or fair visibility combined occur approximately 79 percent of the time annually. Good visibility (greater than 10 km) is most frequent during the fall, and least frequent in spring and summer. Visibility is poorest in July with conditions being very poor or poor half the time (50.3 percent). Annually, visibility is very poor 17.2 percent of time, poor 3.6 percent of the time, fair 17.2 percent of the time, and good 62 percent of the time.

Table 5.13 Monthly and Annual Frequencies (Percent) of Occurrence of Visibility, Project Area – Southern Section

Month	Very Poor (<0.5 km)	Poor (0.5 – 1 km)	Fair (1 – 10 km)	Good (>10 km)
Jan	6.5	2.5	19.3	71.7
Feb`	8.3	3.1	20.8	67.8
Mar	9.6	3.2	20.1	67.1
Apr	18.9	4.3	19.0	57.9
May	25.1	5.3	17.4	52.3
Jun	32.6	6.0	17.6	43.9
Jul	44.3	6.0	14.7	35.0
Aug	22.9	3.9	15.4	57.8
Sep	11.4	2.3	13.7	72.6
Oct	8.6	1.8	14.1	75.5
Nov	9.3	2.4	16.1	72.3
Dec	7.2	2.0	18.4	72.5
Annual	17.2	3.6	17.2	62.0

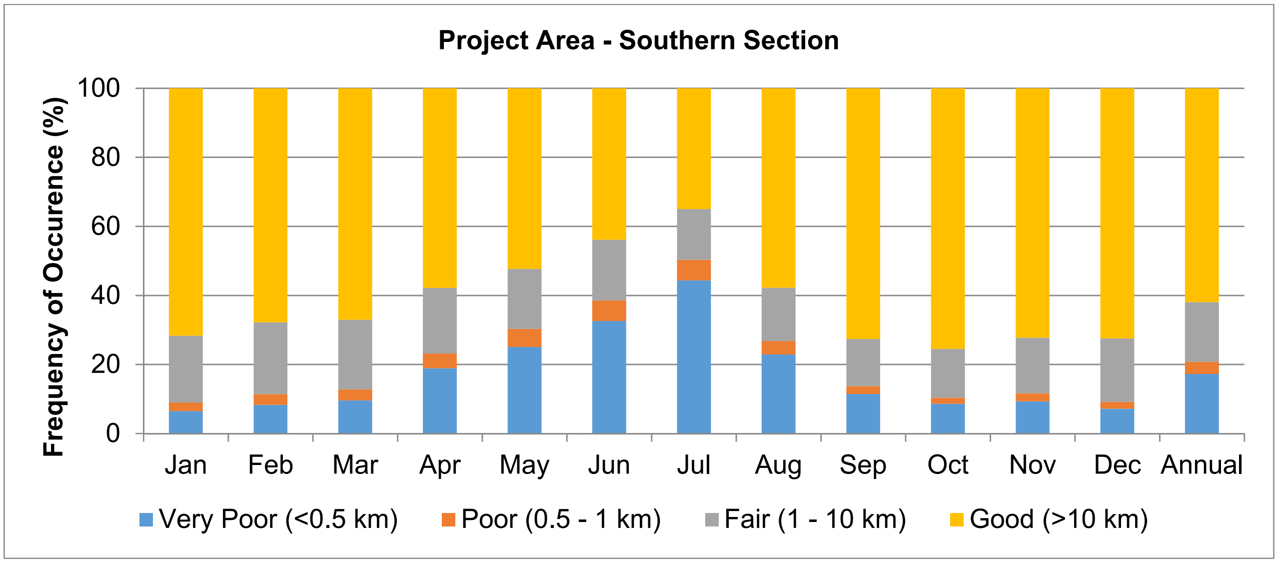


Figure 5-23 Frequency of Occurrence of Visibility Types, Project Area – Southern Section

Visibility class statistics from the Hibernia Platform located in the Project Area – Southern Section are presented in Table 5.14 and Figure 5-24. Conditions are least favourable in July with visibility less than 0.5 km for 43 percent of the time and good conditions, greater than 10 km just 38 percent of the time. By contrast, visibility is most favourable in December: greater than 10 km 75 percent of the time, and poor or very poor just eight percent of the time. Annually, one might expect very poor or poor visibility 21 percent of the time, fair visibility 17 percent of the time and good visibility 62 percent (almost two thirds) of the time.

Table 5.14 Monthly and Annual Frequencies (Percent) of Occurrence of Visibility, Hibernia Platform

Month	Very Poor (<0.5 km)	Poor (0.5 – 1 km)	Fair (1 – 10 km)	Good (>10 km)
Jan	7.5	1.6	19.2	71.7
Feb`	9.0	1.8	20.5	68.8
Mar	11.8	2.3	19.1	66.8
Apr	21.0	3.1	18.8	57.0
May	26.7	3.5	16.3	53.5
Jun	35.7	4.0	16.0	44.2
Jul	43.4	3.2	15.0	38.4
Aug	25.0	2.8	14.7	57.5
Sep	11.6	1.9	12.9	73.6
Oct	9.6	1.2	14.0	75.2
Nov	10.9	2.1	15.6	71.4
Dec	6.7	1.3	17.9	74.1
Annual	18.6	2.4	16.6	62.4

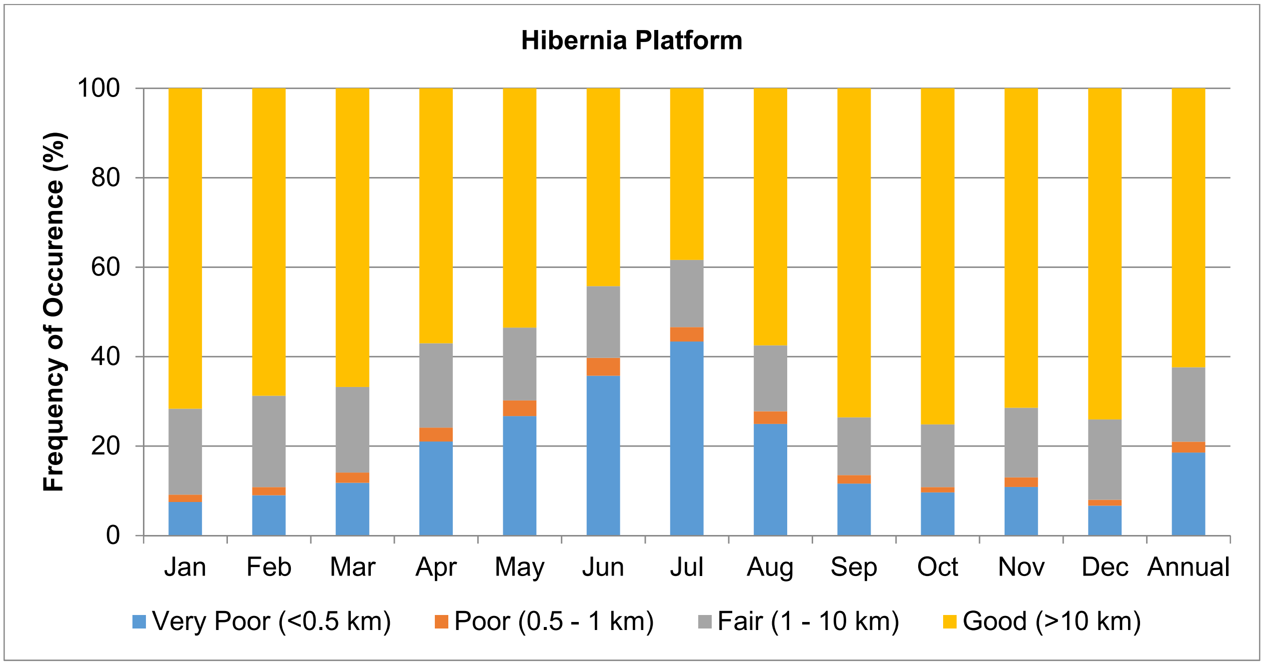


Figure 5-24 Frequency of Occurrence of Visibility, Hibernia Platform

5.3.4.3 Potential Vessel and Aircraft Traffic Routes

Fog, while more common over the Grand Banks, can be found along the potential vessel and aircraft traffic routes, and is most common in late spring and early summer. Further information on regional fog and visibility conditions is provided in the Eastern Newfoundland SEA (Amec 2014), Section 4.1.3.

5.4 Air Quality

The existing ambient air quality within the Project Area can be generally categorized as good, and is occasionally and locally influenced by exhaust emissions from marine vessel and helicopter traffic and from the operations of the existing oil production platforms (Hibernia, White Rose, and Terra Nova).

To characterize the existing ambient air quality surrounding the Project Area, data was acquired from the National Pollutant Release Inventory (NPRI) Reporting program for criteria air contaminants (i.e., carbon monoxide (CO), nitrogen dioxide (NO_2), sulphur dioxide (SO_2), total particulate matter (TPM), particulate matter less than 10 and 2.5 microns in diameter ($PM_{2.5}$, PM_{10}), and volatile organic compounds (VOCs)). The NPRI program is legislated under the *Canadian Environmental Protection Act* (CEPA), and requires each facility meeting specified reporting triggers, to report their emissions to Environment and Climate Change Canada (ECCC) on an annual basis. An overview of the emissions reported from the operation of Hibernia, White Rose, and Terra Nova for the 2015 reporting year (the most recent such data available) are provided in Table 5.15.

Table 5.15 2015 Facility Reported CAC Emissions (NPRI Reporting) – NL Offshore Area Production Platforms

Facility	Air Emissions (tonnes/year)					
	CO	NO_2	TPM	PM_{10}	$PM_{2.5}$	VOC
Terra Nova	566	2,065	160	154	154	644
Hibernia	841	2,676	253	253	253	254
White Rose	657	958	161	161	160	451
Source: Environment and Climate Change Canada (2016b)						

As the Jeanne d'Arc Basin is not known to contain sour gas, emissions of sulphur dioxide and hydrogen sulphide have not been reported.

Emissions of GHGs from the operation of the existing offshore oil production platforms are also reported on an annual basis to ECCC, through the Greenhouse Gas Emissions Reporting Program. An overview of the 2015 reported emissions for each of the existing production platforms are provided in Table 5.16.

Table 5.16 2015 Facility Reported GHG Emissions – NL Offshore Area Production Platforms

Facility	GHG Emissions (tonnesCO_{2eq}/year)			
	CO_2	CH_4	N_2O	Total
Terra Nova	513,275	25,879	9,275	548,428
Hibernia	471,863	39,523	3,785	515,170
White Rose	483,436	39,837	11,981	535,253
Source: Environment and Climate Change Canada (2017)				

As mentioned above, occasional influences from marine vessel traffic in the Project Area would also affect the air quality at the Project site. Such emissions however are regulated by the International Maritime Organization (IMO) through MARPOL.

5.5 Oceanography

This section provides an overview of the primary oceanographic conditions and characteristics of the Project Area. This includes waves, ocean currents, seawater properties (temperature, salinity), and extreme winds and waves.

5.5.1 Waves

For this EIS, the wave climate within the Project Area has been characterized by descriptive statistics derived from the aforementioned MSC50 wind and wave hindcast dataset. The wave hindcast was conducted by using the wind field reanalysis to force a third generation wave model (Swail et al. 2006) over the North Atlantic Ocean. The model used was Oceanweather's OWI-3G, adopted onto a 0.5 degree grid on a basin-wide scale. Inscribed in the 0.5 degree model was a further refined

0.1 degree shallow water implementation of the OWI-3G model, which allowed for shallow water effects to be accounted for in the maritime region. The MSC50 methodology and results have been extensively documented and validated (Swail and Cox 2000; Woolf et al. 2002; Caires et al. 2004).

As presented earlier for wind conditions, three MSC50 grid point locations were selected to provide a representative illustration of sub-regions and associated conditions over the Project Area – Northern Section, and two nodes were selected as representative of the Project Area – Southern Section. This is consistent with a regional overview for general illustration and EA purposes, rather than detailed oceanographic information for design or operational purposes.

The wave climate is described in terms of the significant wave height (Hs, defined as four times the square root of the total variance of the wave energy spectrum), and the peak wave spectral period (Tp, defined as the period of waves with the highest contribution to the energy spectrum). Ocean waves are due to the effects of wind on the air/water interface. The winds are due to the dominant local and regional weather systems encountered and exhibit a pronounced seasonal variability. Wind waves (or sea) will be generated in the immediate area of wind, developing quickly within an hour. Swells are what remains of the wind waves after they propagate away from where they were generated. Swells are long waves that contain a lot of wave energy, and can take days to subside. The range of wave periods for wind waves and swells overlap considerably with wind waves having periods up to 15 s for large winds speeds, while swells of only a few seconds are possible.

Inspection of the statistics and directional roses indicates waves conditions are comparable and vary little between the three locations for the Project Area – Northern Section. Similarly, inspection of the two nodes for the Project Area – Southern Section indicates wave conditions there are also comparable. Table 5.17 presents monthly wave height and wave period statistics for all five nodes, listed from north to south.

5.5.1.1 Project Area – Northern Section

Monthly wave roses are presented in Figure 5-25 for the Project Area – Northern Section, where mean wave heights range from approximately 1.8 m in July to 4.6 m in January. An annual wave rose is also provided in Figure 5-26. Table 5.17 indicates that the most severe sea states at Node M3012443 occur in December and January, when maximum significant wave heights of up to 13.8 m from the northwest, west, and southwest respectively, are possible, with associated peak periods of 15-16 s. In contrast, the maximum significant wave height is lowest (6 m) in July, with an associated peak period of 11 s.

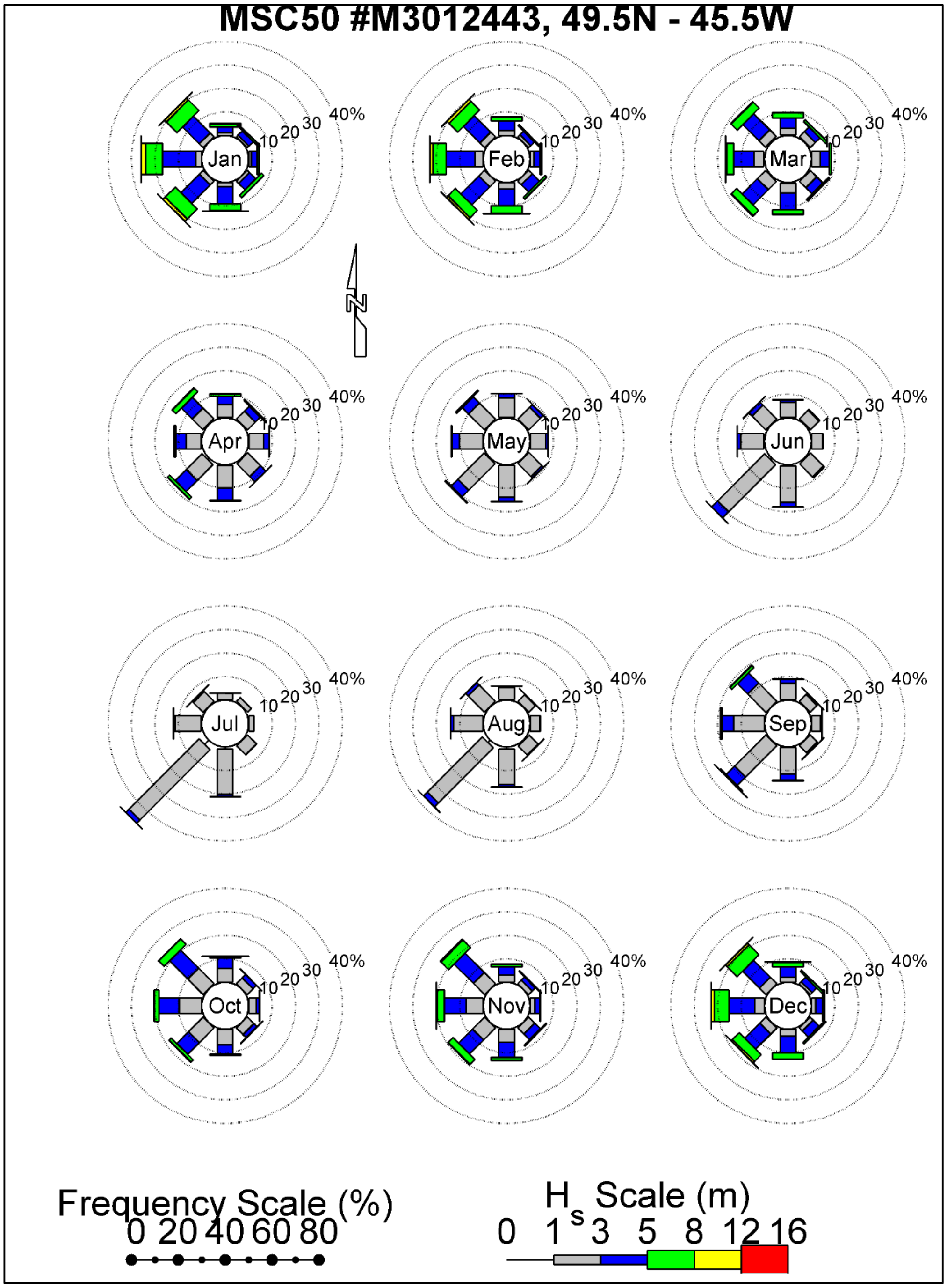


Figure 5-25 Monthly Wave Roses, MSC50 Node M3012443 (1962 – 2015), Project Area – Northern Section

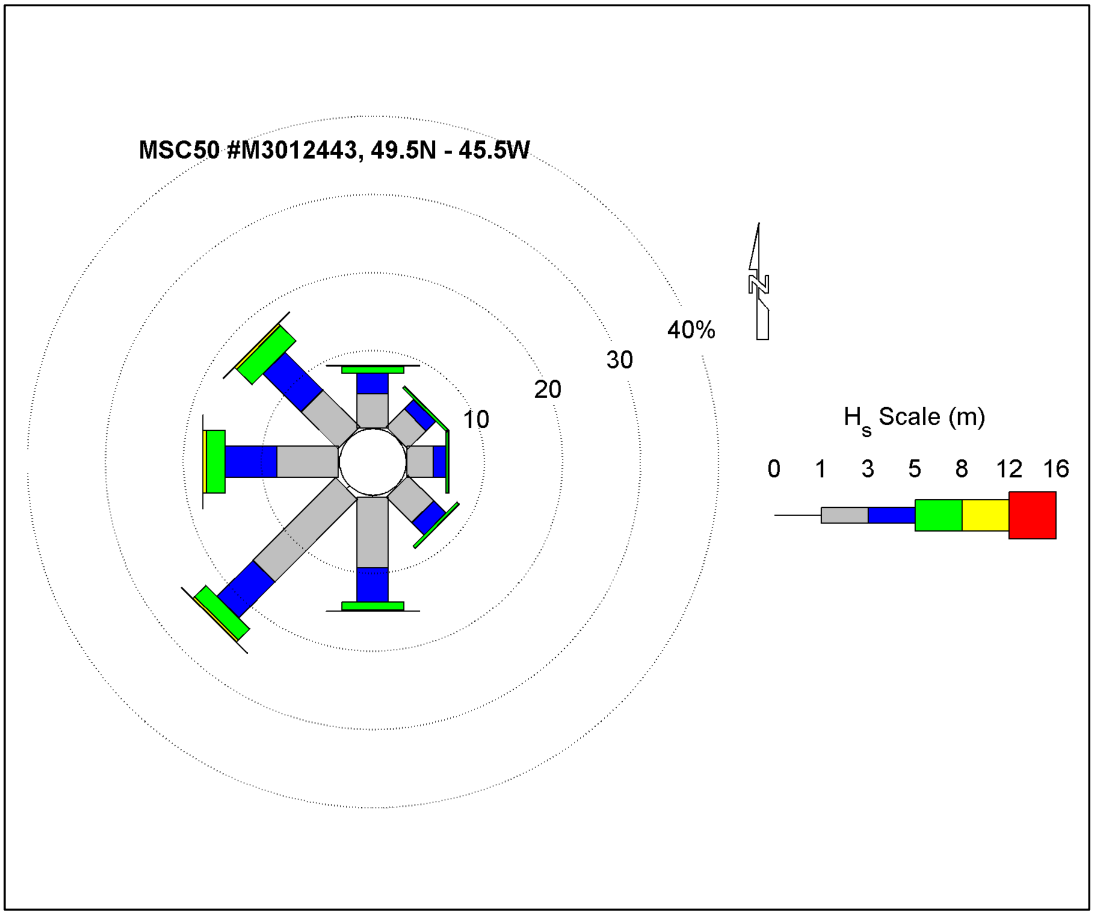


Figure 5-26 Annual Wave Rose, MSC50 Node M3012443 (1962 – 2015), Project Area – Northern Section

Table 5.17 Wave Statistics

Location	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Mean Hs (m)													
M3012443	4.6	4.4	3.8	3.0	2.4	2.0	1.8	1.9	2.6	3.2	3.7	4.3	3.1
M6013912	4.6	4.2	3.6	3.0	2.3	2.0	1.8	1.9	2.6	3.2	3.6	4.3	3.1
M6013091	4.4	3.8	3.0	2.8	2.3	2.0	1.8	1.9	2.5	3.1	3.5	4.2	2.9
M6011605	4.1	3.6	3.0	2.6	2.2	1.9	1.7	1.8	2.4	2.9	3.3	3.9	2.8
M6010089	4.4	4.1	3.4	2.9	2.2	2.0	1.7	1.8	2.4	3.1	3.5	4.1	3.0
Mean Tp (s)													
M3012443	10.7	10.4	10.0	9.3	8.5	8.0	7.7	7.8	8.8	9.5	9.8	10.5	9.2
M6013912	10.7	10.3	9.8	9.5	8.6	8.1	7.8	7.9	8.9	9.5	9.9	10.5	9.3
M6013091	10.5	9.4	8.6	9.0	8.6	8.1	7.8	7.9	8.9	9.5	9.9	10.5	9.1
M6011605	10.3	9.5	8.9	8.7	8.5	7.9	7.7	7.7	8.8	9.3	9.7	10.3	8.9
M6010089	10.7	10.4	9.6	9.4	8.6	8.0	7.8	7.9	8.9	9.5	9.9	10.5	9.3

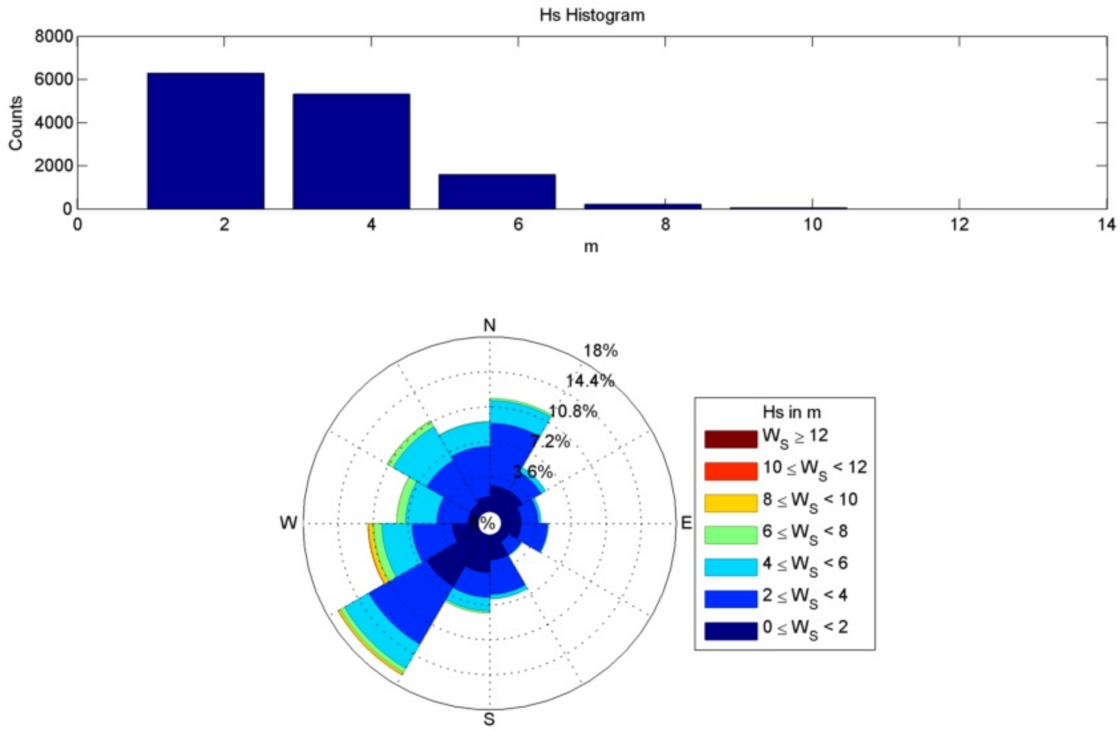
Table 5.17 Wave Statistics

Location	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Most Frequent Direction (from)													
M3012443	W	W	NW	SW	SW	SW	SW	SW	SW	NW	NW	W	SW
M6013912	W	W	NW	SW	SW	SW	SW	SW	SW	NW	NW	NW	SW
M6013091	W	W	SW	SW	SW	SW	SW	SW	SW	NW	NW	NW	SW
M6011605	W	SW	SW	SW	SW	SW	SW	SW	SW	SW	NW	W	SW
M6010089	W	W	W	SW	SW	SW	SW	SW	SW	NW	NW	W	SW
Maximum Hs (m)													
M3012443	13.8	13.3	13.2	12.0	10.4	9.0	6.0	7.0	12.1	12.1	12.3	13.8	13.8
M6013912	14.2	15.3	13.1	11.0	11.7	10.5	7.1	8.2	13.3	12.5	13.2	15.3	15.3
M6013091	14.2	15.5	11.8	11.0	11.5	10.6	6.4	8.6	13.5	12.3	12.5	14.3	15.5
M6011605	12.0	14.1	10.7	10.6	9.9	9.7	6.1	8.3	12.7	11.5	11.0	12.7	14.1
M6010089	14.2	13.6	12.1	10.9	10.8	10.5	6.9	10.1	11.1	13.1	12.8	14.0	14.2
Tp of Maximum Hs (s)													
M3012443	15.9	15.2	14.7	14.3	13.3	12.2	11.0	11.6	14.4	14.8	14.4	15.7	15.7
M6013912	16.0	16.2	14.4	13.9	13.9	13.5	12.1	11.8	15.7	14.6	15.4	16.2	16.2
M6013091	14.7	16.9	13.3	13.8	14.0	13.8	11.9	11.8	15.4	14.7	14.4	15.9	16.9
M6011605	17.2	16.2	17.6	16.4	17.3	14.4	17.2	17.3	17.3	17.7	15.9	17.3	17.7
M6010089	15.7	15.8	15.3	13.0	14.2	13.7	11.8	13.5	14.2	15.0	14.4	16.0	15.7
Maximum Tp (s)													
M3012443	16.5	15.8	17.0	15.6	17.3	21.0	20.6	17.4	17.1	17.2	15.4	16.2	21.0
M6013912	17.3	17.0	17.4	16.9	17.3	21.0	17.3	17.4	17.5	17.4	16.0	17.3	21.0
M6013091	17.3	16.9	17.7	17.1	17.4	20.9	17.5	18.5	17.6	17.5	16.0	17.3	20.9
M6011605	17.2	16.2	17.6	16.4	17.3	14.4	17.2	17.3	17.3	17.7	15.9	17.3	17.7
M6010089	17.3	16.9	18.5	15.8	17.4	20.9	17.4	17.9	17.3	17.5	17.1	17.3	20.9
Direction of Maximum Hs (from)													
M3012443	W	SW	W	W	NW	NW	SW	NW	SW	N	W	NW	NW
M6013912	W	SW	NW	S	NW	NW	S	SW	SW	SW	W	NW	NW
M6013091	NW	SW	NW	NW	NW	NW	S	SW	SW	SW	W	NW	SW
M6011605	SW	SW	SW	N	NW	NW	NW	SW	SW	S	N	N	SW
M6010089	W	SW	SW	N	NW	NW	S	SW	W	W	W	NW	W
MSC50 data for the period 1962-2015. Project Area – Northern Section: grid point nodes M3012443, M6013912, M6013091. Project Area – Southern Section: grid point nodes M6011605, M6010089													

Wave information is also available from a directional waverider deployed at location WM-1 (see Figure 5-10) during a Statoil met-ocean monitoring program in 2014-2015 (including two current moorings CM-1 and CM-2 (see Figure 5-10) in the northern Flemish Pass (Amec Foster Wheeler 2015a). Summary wave analysis from this program is presented in Figure 5-27, which includes a wave rose (indicating waves most frequently from the southwest), histogram of Hs, and statistics of Hs, Tp and wave direction for the overall program duration.

Project: Statoil Current Monitoring
Start: 02-Jun-2014 16:15:59 UTC
Number of data points: 13503

Location: WM-1, Lat: 48.163 N, Lon: -46.240 W
End: 10-Mar-2015 23:16:00 UTC
Sampling interval: 30 Minutes



	Min	Max	Mean	STD	Mode	# of Points
Hs (m)	0.8000	12.6000	3.1000	1.5000	1.2000	13503
Direction (deg T)	0.1000	360	199.6000	105.4000	168.6000	13503
Tp (s)	3.8000	20	10.3000	2.4000	10	13503

Figure 5-27 Wave Monitoring Summary Plot, Statoil Flemish Pass MetOcean Program

5.5.1.2 Project Area – Southern Section

For the Project Area – Southern Section, mean wave heights range from approximately 1.7 m in July to 3.4 m in January. Table 5.17 indicates that the most severe sea states occur in December and January, when maximum significant wave heights at Node M6010089 of up to 14.2 m from the west are possible, with associated peak periods of 15-16 s. In contrast, the maximum significant wave height is lowest (6.9 m) in July, with an associated peak period of 11.8 s. Monthly and annual wave roses for this area are presented in Figures 5-28 and 5-29, respectively.

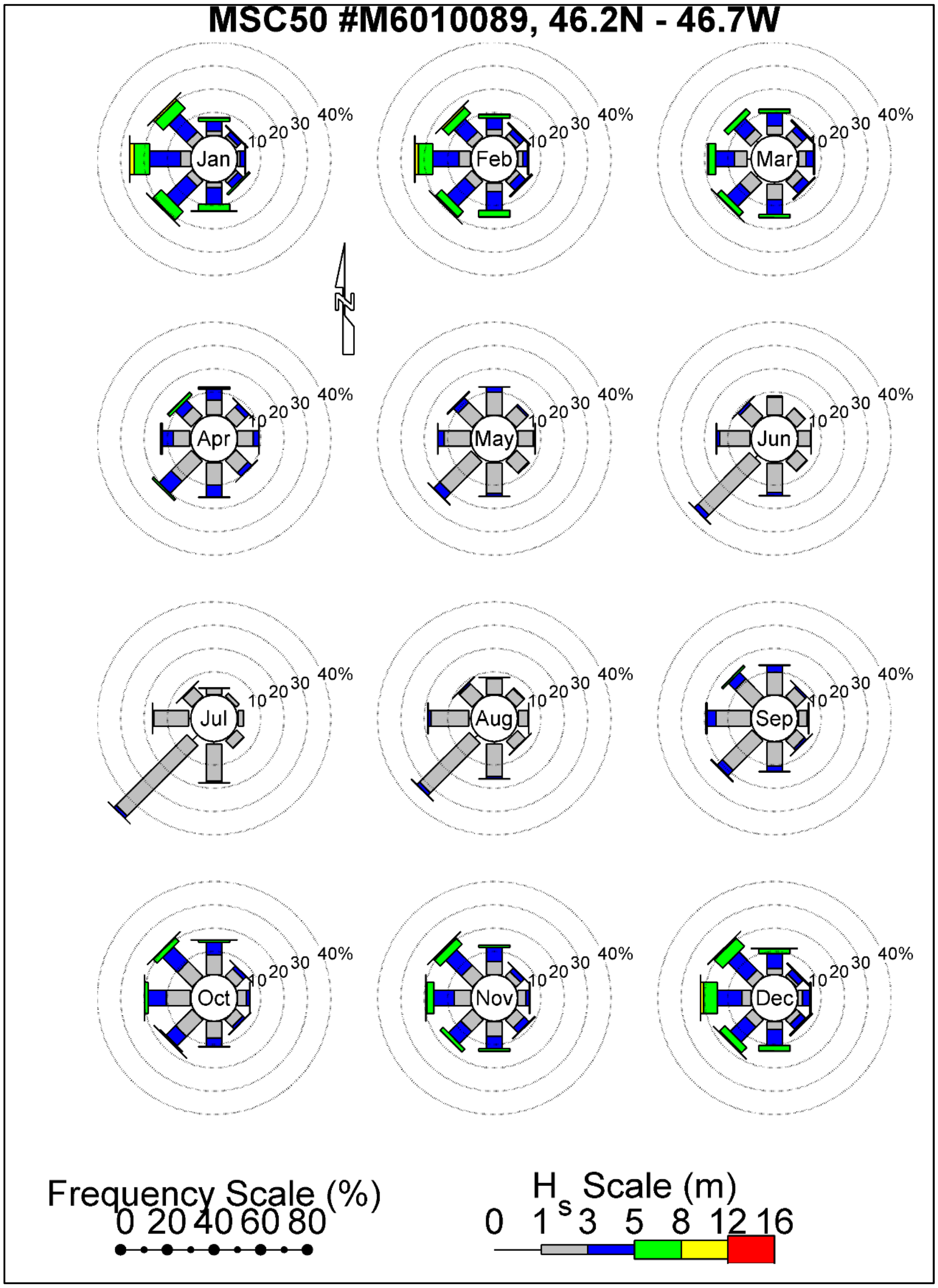


Figure 5-28 Monthly Wave Roses, MSC50 Node M6010089 (1962 – 2015), Project Area – Southern Section

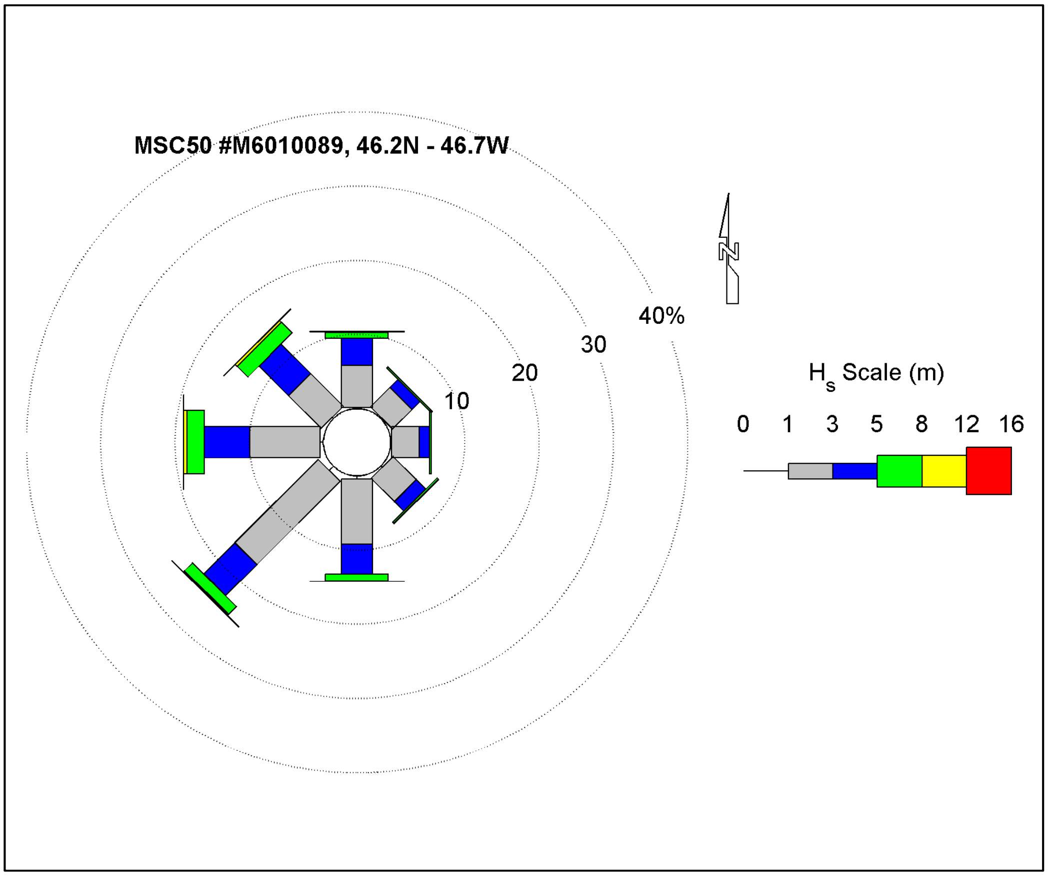


Figure 5-29 Annual Wave Rose, MSC50 Node M6010089 (1962 – 2015), Project Area – Southern Section

Wave statistics, from 30 May 1997 to 7 July 2017, from the Hibernia Platform located in the Project Area – Southern Section, are presented in Table 5.18. A simple comparison of mean and maximum Hs values for the Hibernia Platform and nearby MSC50 grid point node M6011605 (approximately 32 km to the northwest of Hibernia) is shown in Figure 5-30. Mean values are almost identical; maximum values are less consistent and for several months hindcast values are noticeably larger (February, May and June are over 3 m greater) for the hindcast. However, this is not unreasonable given the longer record for the hindcast (54 years compared with 20 years from Hibernia).

Table 5.18 Wave Statistics: Hibernia Platform

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Mean Hs (m)												
4.0	3.7	3.3	2.7	2.1	1.8	1.7	1.7	2.3	3.1	3.1	3.8	2.8
Mean Tp (s)												
8.6	8.3	8.0	7.6	7.0	6.5	6.3	6.6	7.3	7.7	8.1	8.4	7.5
Maximum Hs (m)												
12.5	10.5	10.0	9.2	6.7	6.5	6.0	8.0	11.3	11.2	12.0	12.0	12.5

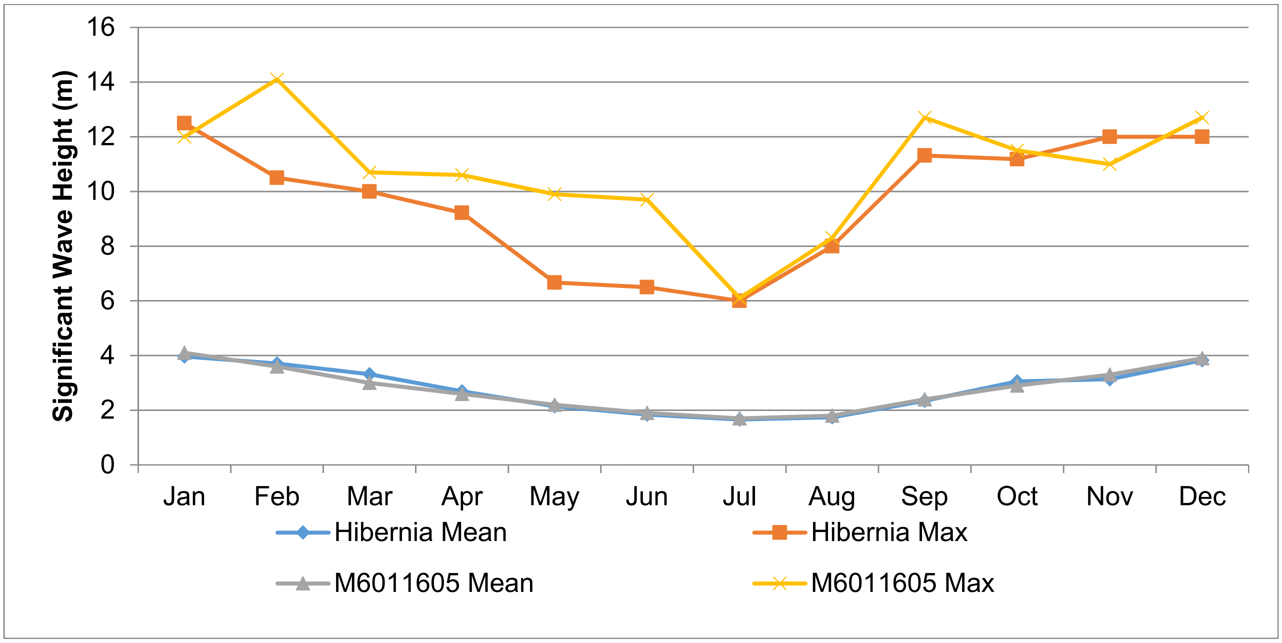


Figure 5-30 Comparison of Significant Wave Height: Hibernia and MSC50 Node M6011605

5.5.1.3 Potential Vessel and Aircraft Traffic Routes

The range of wave conditions experienced along the potential vessel and aircraft traffic routes from St. John's to the Project Area will be quite close to those experienced farther offshore, although with wave heights expected to be somewhat lower closer to shore; annually, mean wave heights are approximately 2 m near St. John's compared with 3 to 3.5 m near the eastern portions of the Project Area. During fall and winter months, average wave heights can be expected to be 1.5 m higher than near St. John's; maximum wind speeds can be expected to be at least 2 m higher. Further information on the regional wave environment in this area is provided in the Eastern Newfoundland SEA (Amec 2014), Section 4.1.4.

5.5.2 Ocean Currents

The cold Labrador Current dominates the general circulation over the Canada-NL Offshore Area. The Labrador Current is divided into two streams: 1) an inshore branch that flows along the coast on the continental shelf; and 2) an offshore branch that flows along the outer edge of the Grand Banks (see Figure 5-6).

The Labrador Current's inshore branch tends to flow mainly in the Avalon Channel closely along the coast of the Avalon Peninsula but may sometimes also spread farther out on the Grand Banks. The offshore branch flows over the upper Continental Slope at depth, and through the Flemish Pass with depths almost to 1,300 m.

The offshore Labrador Current (which remains bathymetrically trapped over the upper Continental Slope) has average speeds of approximately 40 cm/s carrying approximately 85 percent of the total transport, mainly between the 400 and 1,200 m isobaths (Lazier and Wright 1993). Over areas of the

Grand Banks with water depths less than 100 m, the mean currents are generally weak (less than 10 cm/s) and flow southward, dominated by wind-induced and tidal current variability (Seaconsult Ltd. 1988).

Through the Project Area in the vicinity of the Flemish Pass, the Labrador Current bifurcates, with the main branch flowing southwards as Slope Water Current and the side branch flows clock-wise around the Flemish Cap. The cores of the currents are located at an average depth of 100 m.

For the purposes of this overview, current statistics for all current meter data around the Project Area are reported. A further breakdown by Northern and Southern Project Area is presented. The primary data source is the Bedford Institute of Oceanography (BIO) Ocean Data Inventory (ODI) (Gregory 2004). The database was queried for the area extending from 45.8°N to 50°N, 44.7°W to 49.7°W (DFO 2017a).

A total of 1,245 monthly current statistic records were returned for the Project Area, from 371 mooring stations at different depths, as reported in Table 5.19. These provide good representation of currents in the western part of the Project Area – Southern Section, together with dedicated DFO mooring programs in the Flemish Pass and Orphan Basin; however, there is generally limited measurement coverage elsewhere (Figure 5-31). The database consists of all current meter records that have a record length of at least five days within a given month.

Table 5.19 Number of ODI Ocean Current Records

Depth	Project Area – Northern Southern Number of Records	Project Area – Southern Section Number of Records
0 to 100 m	122	727
100 to 200 m	91	84
200 to 500 m	40	34
500 to 1,000 m	83	11
Greater than 1,000 m	53	0
Total	389	856

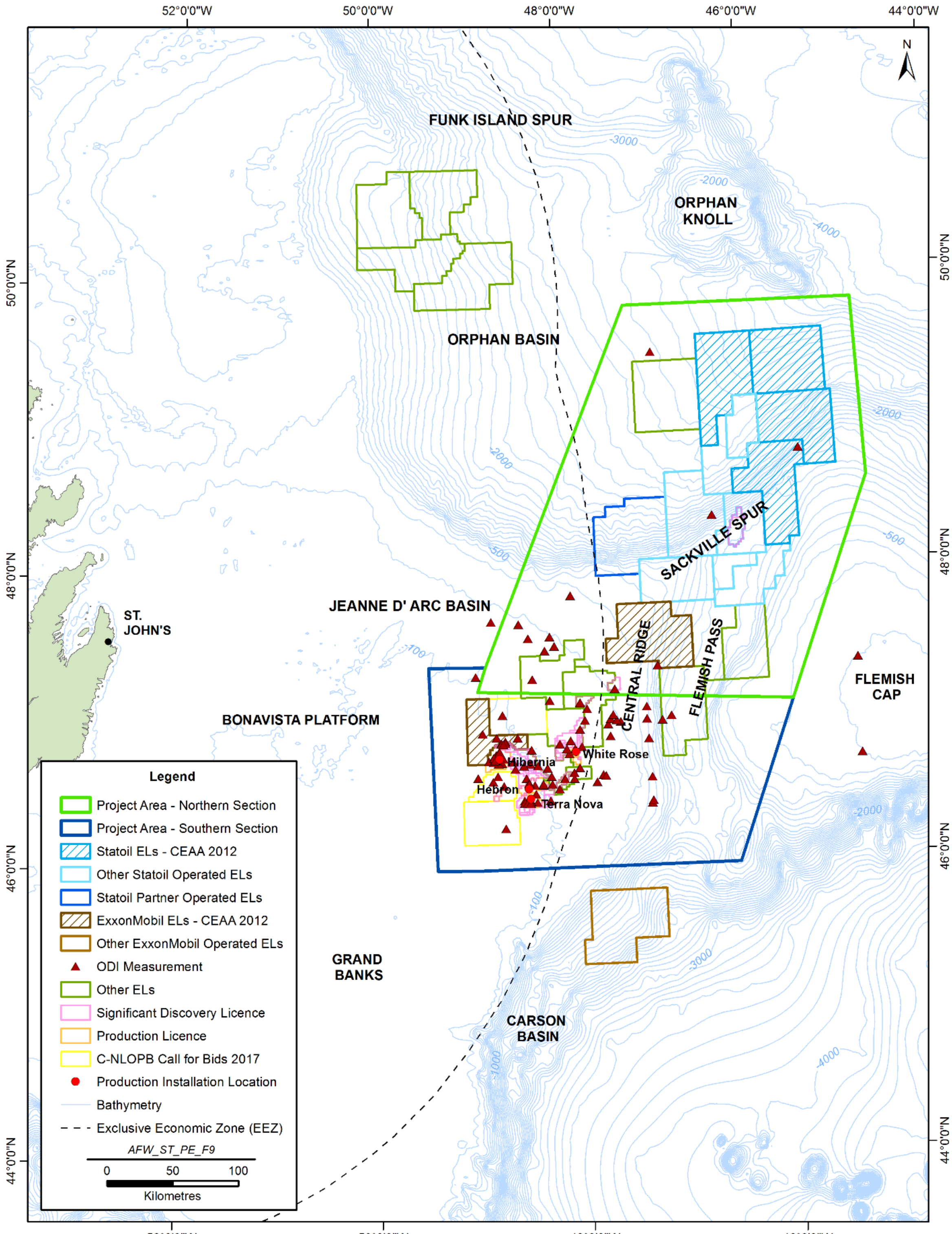


Figure 5-31 Location of ODI Current Measurements

A summary of mean and maximum currents for both the Northern and Southern sections of the Project Area is presented in Figure 5-32.

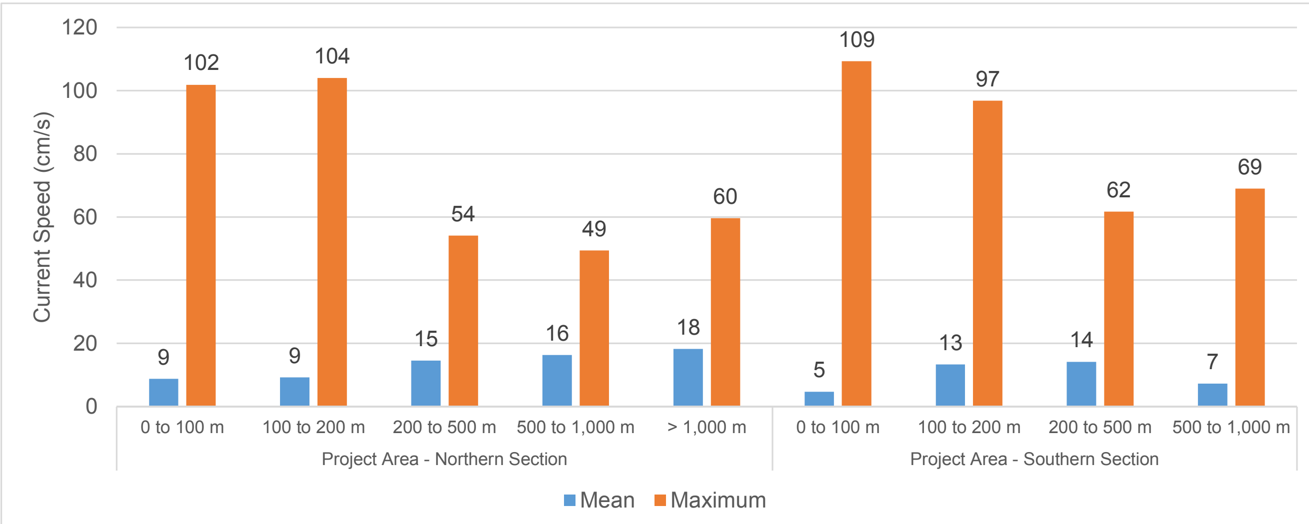


Figure 5-32 Mean and Maximum Ocean Currents

5.5.2.1 Project Area – Northern Section

The mean and maximum current speeds by instrument depth for the Project Area – Northern Section are presented in Figure 5-33. Mean current speeds typically range between approximately 5 and 20 cm/s. Maximum current speeds typically range between approximately 30 and 70 cm/s, with maximum speeds of 102 and 104 cm/s measured at instrument depths of 5 and 167 m respectively. For depths greater than 300 m, the largest current speed of 59.6 cm/s was recorded on 6 January 2014, at 48.36269°N, 46.531470°W, at a depth of 1,350 m (where the sounding depth is 1,400 m).

Ocean current measurements are also available from two current moorings equipped with Acoustic Doppler Current Profiler (ADCP) and Recording Current Meter (RCM) instruments. These were deployed at locations CM-1 and CM-2 during a Statoil met-ocean monitoring program in 2014-2015 in the northern Flemish Pass in water depths of 1,028 and 1,120 m (Amec Foster Wheeler 2015b, 2015c).

Summary current statistics from these two deployments are presented in Tables 5.20 and 5.21, which include selected depths near-surface, mid-depth, and near-bottom. Numerous other analyses were completed in compiling the monitoring program reports (Amec Foster Wheeler 2015b, 2015c). Progressive vector plots – which show the net displacement of a particle subjected to the current velocity - for a near-surface depth for the second CM-1 deployment and for the CM-2 deployment are shown in Figures 5-34 and 5-35, respectively. At CM-1 to the north the flow is directly to the east, whereas at CM-2 the flow is directly to the south and south-southwest.

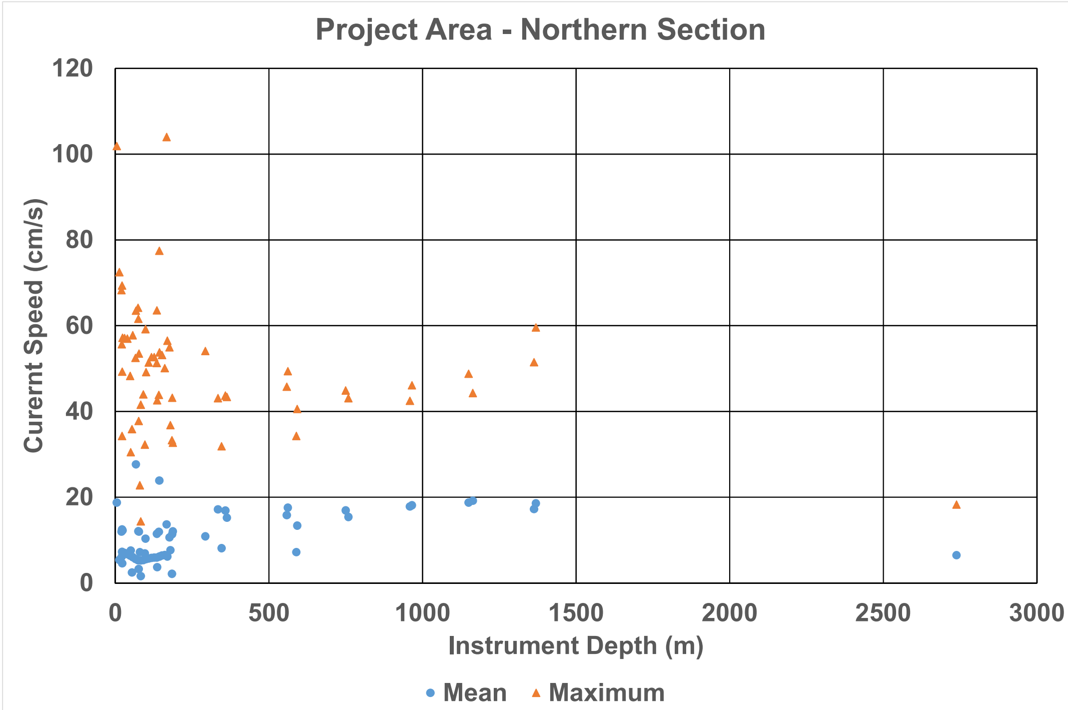


Figure 5-33 Mean and Maximum Current Speeds, Project Area – Northern Section

Table 5.20 Flemish Pass Statoil Current Monitoring, CM-1, Current Statistics

Depth (m)	Mean Current Speed (cm/s)	Mean Current Direction (°T) (to)	Maximum Current Speed (cm/s)	Direction of Maximum Current (°T) (to)
	1 Jun to 18 Jul 2014			
65	13.5	121	47.3	179
434	5.6	104	16.5	141
984	-	-	-	-
	2 Nov 2014 to 21 Mar 2015			
66	13.4	86	45.6	118
441	7.3	83	26.8	93
945	7.0	104	22.1	217
CM-1 located (both deployments) at ~48° 19.1'N, 46° 17.5'W, water depth=1,028 m. Three upward-looking ADCPs at 90 m (8 m current bins), 500 m and 1,000 m (both with 32 m current bins)				

Table 5.21 Flemish Pass Statoil Current Monitoring, CM-2, Current Statistics

Depth (m)	Mean Current Speed (cm/s)	Mean Current Direction (°T) (to)	Maximum Current Speed (cm/s)	Direction of Maximum Current (°T) (to)
	2 Jun 2014 to 25 Jan 2015			
65	12.4	194	51.6	159
499	7.7	204	21.8	209
984	7.8	203	35.4	210
CM-2 located at 48° 0.364’N, 46° 19.241’W, water depth=1,171 m. Three upward-looking ADCPs at 80 m (8 m current bins), 570 m and 1,120 m (both with 32 m current bins)				

Figure 5-34 Flemish Pass Statoil Current Monitoring, CM-1, Progressive Vector Plot, 66 m

Project: Statoil Current Monitoring
Start: 02-Jun-2014 23:10:00 UTC
Number of data points: 34061
Depth: 65 m

Location: CM-2, Lat: 48° 00.364'N, Lon: 46° 19.241'W
End: 25-Jan-2015 11:49:59 UTC
Sampling interval: 10 Minutes

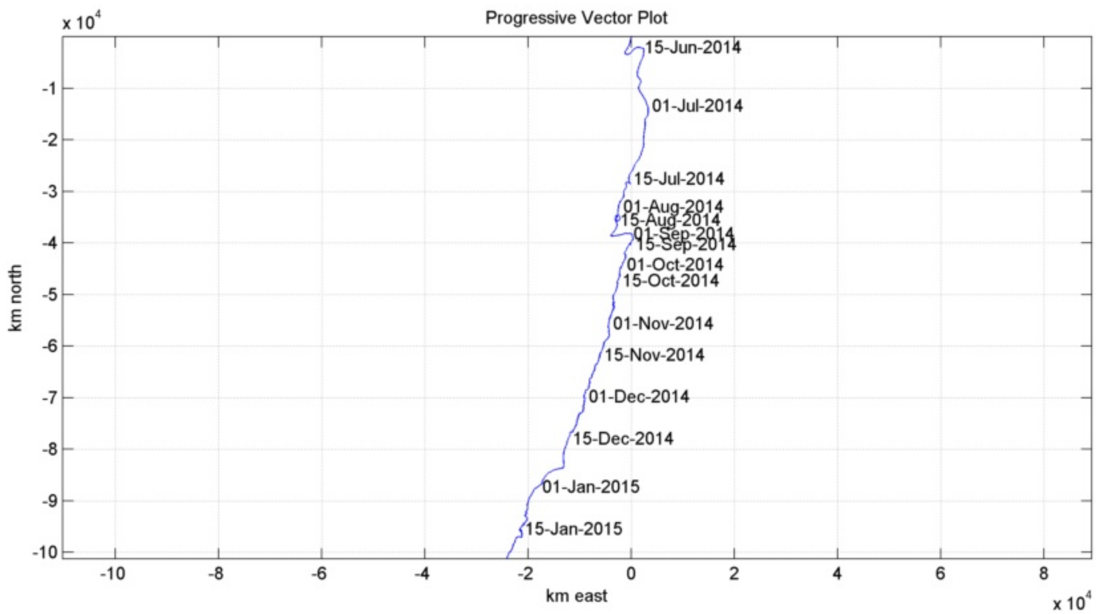


Figure 5-35 Flemish Pass Statoil Current Monitoring, CM-2, Progressive Vector Plot, 65 m

5.5.2.2 Project Area – Southern Section

For the Project Area – Southern Section, the average (for each of the various depth ranges shown in Figure 5-36) mean current speeds range from approximately 5 to 14 cm/s. The average of the monthly mean current speeds measured for all instrument depths are shown in Figure 5-36. This shows that mean speeds generally range from less than 2 to 5 cm/s up to 22 to 27 cm/s at numerous instrument depths with the largest mean speed being 42 cm/s at an instrument depth of 112 m. Maximum current speeds, also shown in Figure 5-36, typically range from approximately 20 to 80 cm/s (up to 60 cm/s for instrument depths in the 200 to 400 m range), with the largest maximum speed being 109 cm/s at an instrument depth of 25 m. There are eight maximum current speeds measured above 80 cm/s at instrument depths between 18 and 112 m.

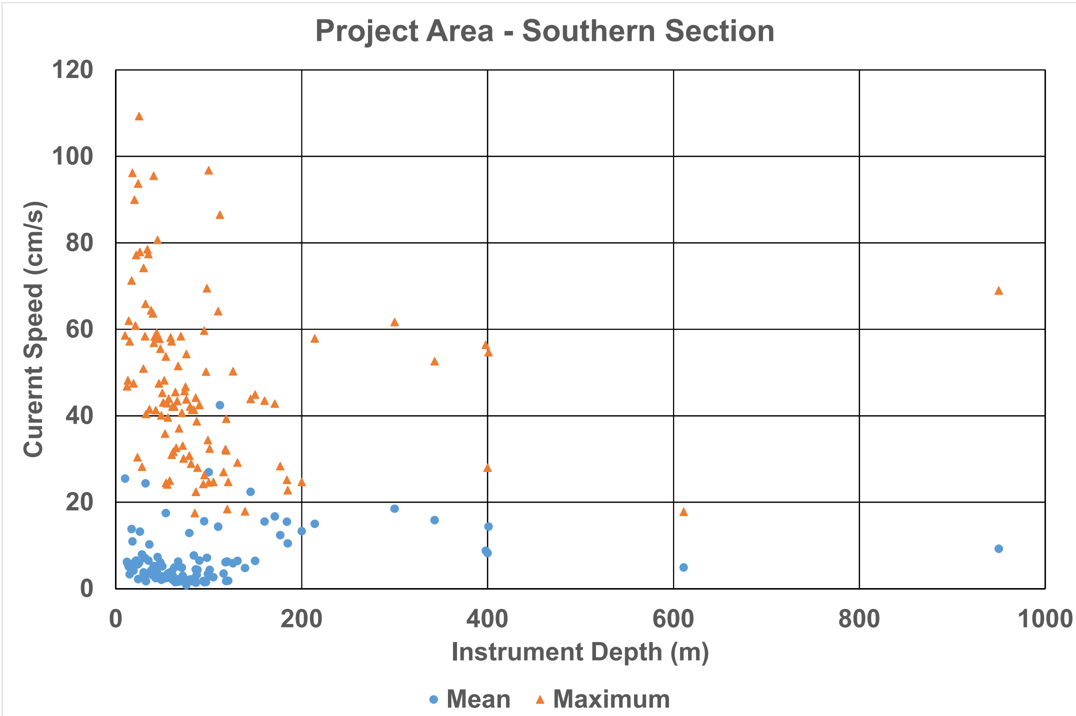


Figure 5-36 Mean and Maximum Current Speeds, Project Area – Southern Section

While the ODI database reported above includes many of the historical drilling campaign measurements, recent measurements from near Hibernia and Hibernia South production drilling are presented here to provide an additional characterization of currents for the Project Area – Southern Section.

A bottom-mounted upward-looking Acoustic Doppler Current Profiler (ADCP) has been deployed to support drilling at Hibernia P-02 since May 2014 and is located approximately 8.5 km west-northwest of the West Aquarius drilling installation and 7.5 km south-southwest of the Hibernia Platform, as part of fulfilling the Physical Environmental Monitoring Guidelines. Based on measurements from two recent deployments a year-long record of currents was assembled for drill cuttings dispersion modelling which characterizes near-surface (approximately 28 m), mid-depth (approximately 44 m) and near-bottom (approximately 68 m) conditions.

Monthly near-surface mean current speeds range from 13 cm/s in June to 23 cm/s in winter, with maximum values ranging from 36 cm/s in May to 93 cm/s in September (Table 5.22). At mid-depth, monthly mean currents range from 11 cm/s in June to 20 cm/s in September. Maximum current speeds at mid-depth reach 83 cm/s in September. Near-bottom mean current speeds are 12 to 15 cm/s for most months, and maximum speeds range from 30 cm/s in June and July to 58 cm/s in September.

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Table 5.22 Monthly Current Statistics, Hibernia, 2015-2016

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Near-Surface	Min (cm/s)	1	1	1	0	1	0	0	1	0	1	1	0
	Mean (cm/s)	21	23	16	14	14	13	14	19	17	19	17	15
	Max (cm/s)	77	71	57	47	36	39	44	58	93	64	59	49
Mid-Depth	Min (cm/s)	1	1	0	0	1	1	1	0	0	1	1	0
	Mean (cm/s)	16	17	15	13	12	11	12	14	20	17	16	15
	Max (cm/s)	44	52	51	42	26	36	37	48	83	61	41	48
Near-Bottom	Min (cm/s)	0	1	0	1	1	1	1	0	1	0	1	0
	Mean (cm/s)	15	15	14	13	12	12	12	13	16	15	13	12
	Max (cm/s)	38	42	46	41	31	30	30	47	51	58	36	29

Monthly current roses for the three depths are shown in Figures 5-37 to 5-39. The current roses illustrate, for each month, the percent frequency of distribution of current direction and current speed, as well as the distribution of current speed within each directional sector or bar. Bars represent the total percent frequency of currents observed flowing to each direction. Each circle equals 5 percent and the total bar length represents the total percent occurrence of currents in that direction (e.g., just over 20 percent of currents are to the northeast in February, and 15 percent of near-surface currents are to the east in March) (Figure 5-37). Each section of a current rose bar corresponds to currents of a given speed range or bin, with bins being the noted 10, 20, …, 80 cm/s in size (e.g., the currents to the northeast in February exceed 60 cm/s) (reach 71 cm/s as shown in Table 5.22), although as indicated by the narrow red bar section this is for less than 1 percent of the time.

Longshore drift processes deal with transport of pebbles and sand along coastlines. As indicated in Figure 5-3, the seabed near the Avalon Peninsula is generally made of two textures. Immediately nearshore the seabed is muddy sand (80 to 90 percent sand). Slightly farther offshore the seabed is sand (greater than 90 percent sand) with patchy outcrops of greater than 50 percent gravel. Together, these conditions indicate that some erosion and deposition are possible along the shoreline.

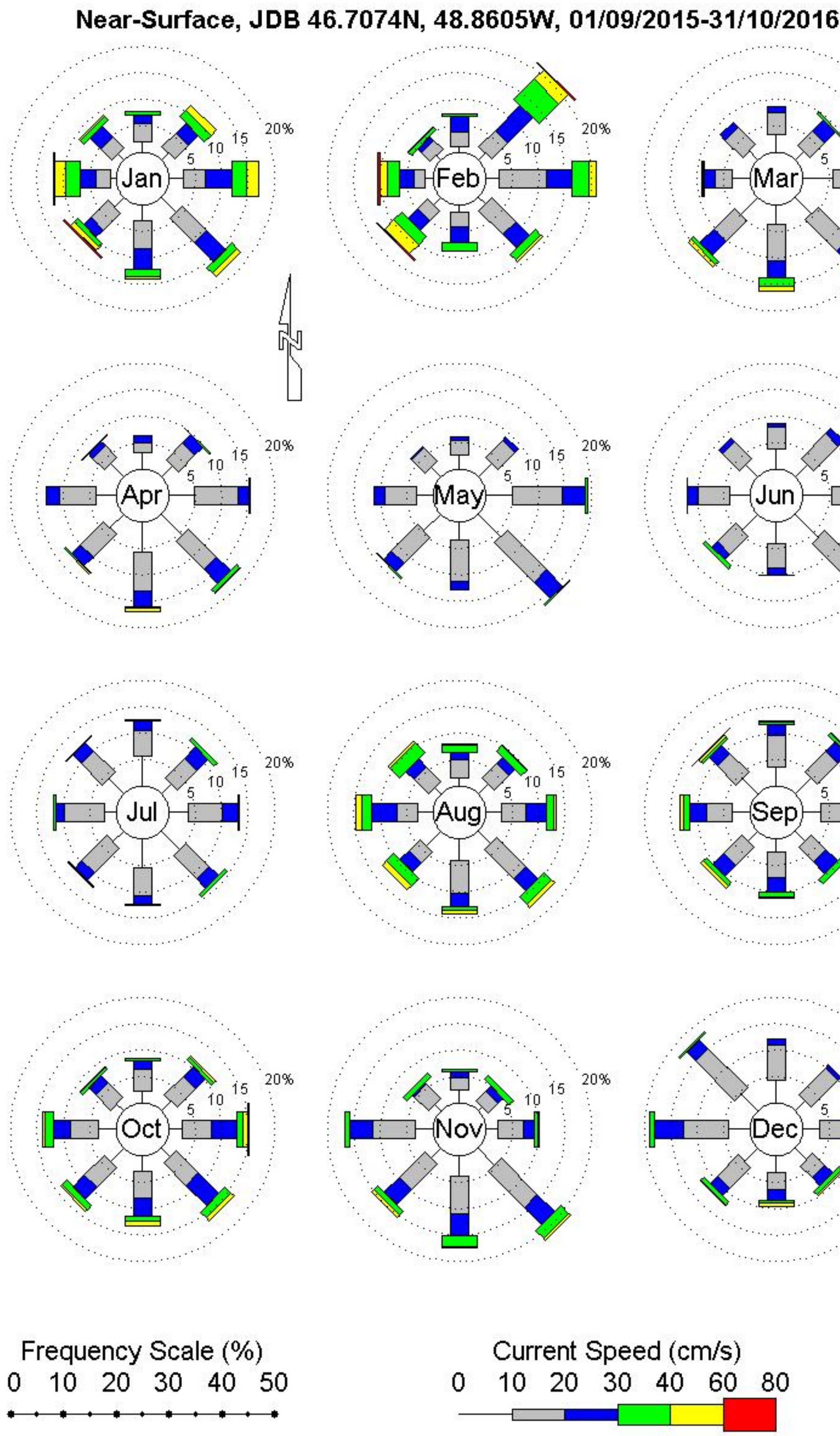


Figure 5-37 Monthly Current Roses, Near-Surface, Hibernia, Sep 2015 to Oct 2016

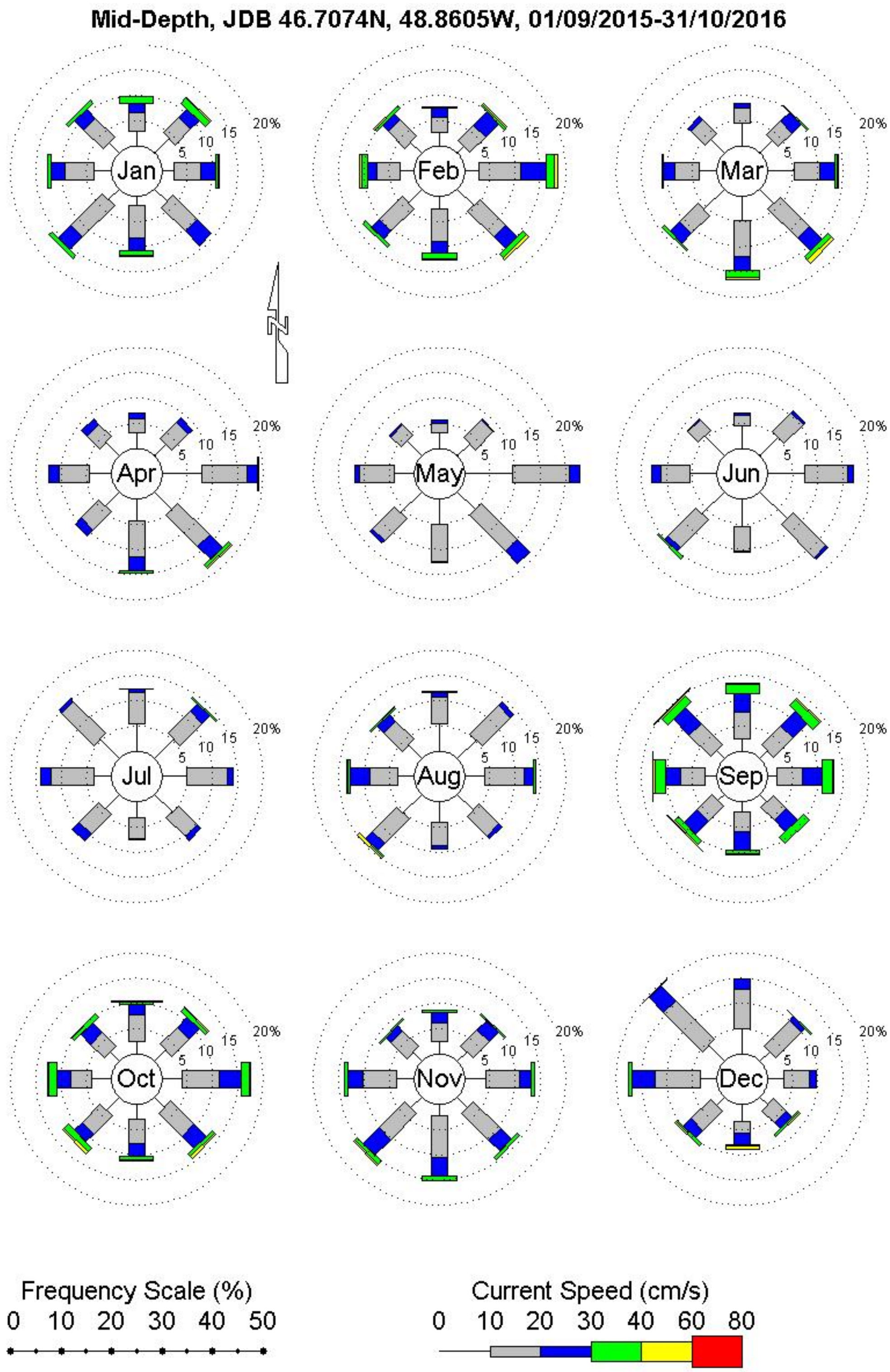


Figure 5-38 Monthly Current Roses, Mid-Depth, Hibernia, Sep 2015 to Oct 2016

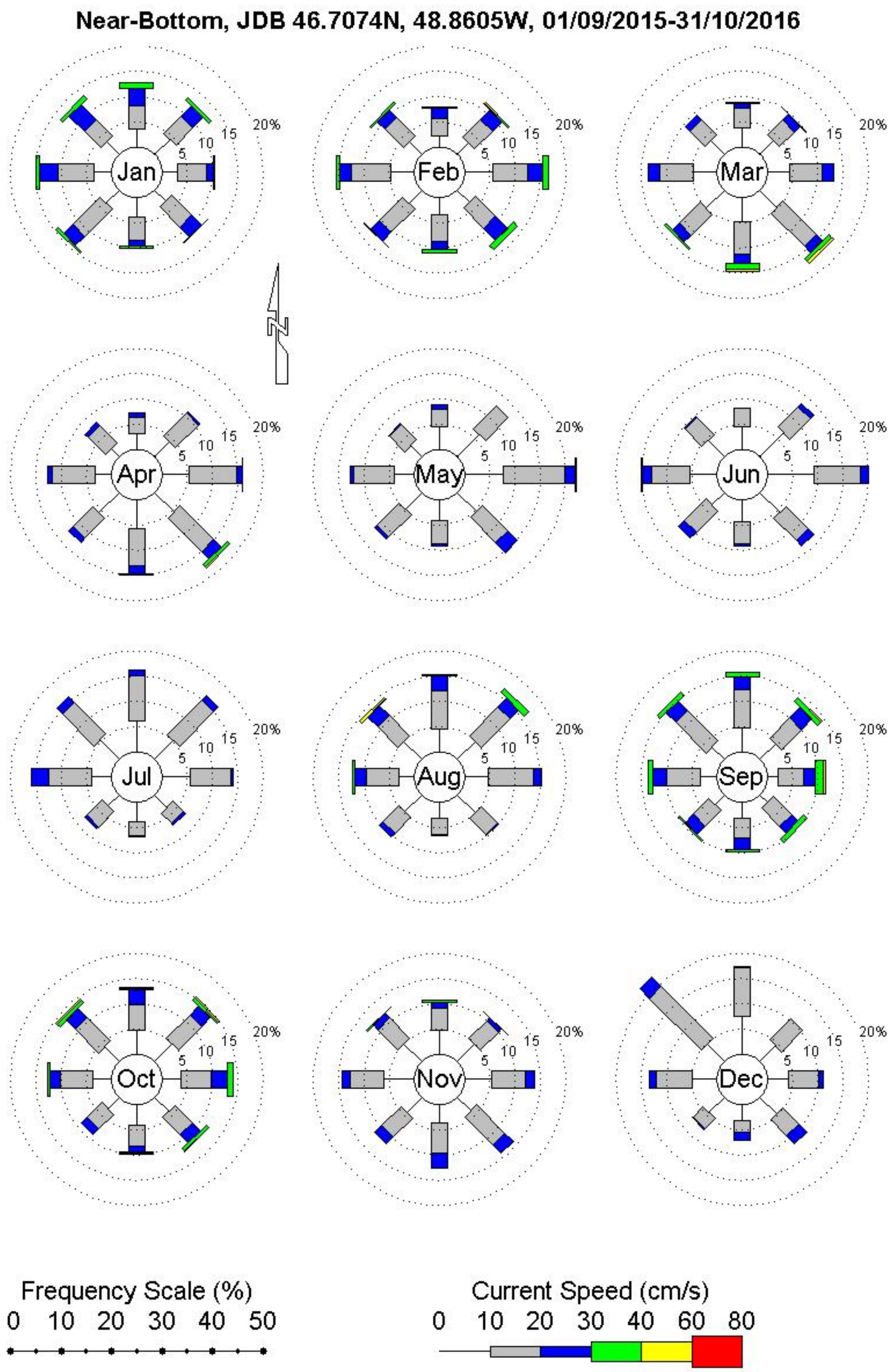


Figure 5-39 Monthly Current Roses, Near-Bottom, Hibernia, Sep 2015 to Oct 2016

5.5.2.3 Potential Vessel and Aircraft Traffic Routes

The ocean current conditions encountered along the potential vessel routes from St. John's to the Project Area will vary depending on distance offshore. Close to the Avalon Peninsula circulation will be dominated by the inshore branch of the Labrador Current flowing south with average speeds of about 15 cm/s. This inshore branch sometimes also spreads out farther out onto the Grand Banks where currents are generally weak (less than 10 cm/s) and southwards and dominated by wind-induced and tidal current variability. Toward the end of the southeastern vessel route, conditions will be similar to those characterized above for near Hibernia and the Project Area – Southern Section. Along the northern potential vessel routes once the Grand Bank is traversed, the offshore branch of the Labrador Current that flows along the outer edge of the Grand Banks will be encountered. The flow here is stronger than inshore with average speeds of approximately 40 cm/s – and conditions will be those characterized above for the Project Area – Northern Section. Further information on the ocean current environment in this area is provided in the Eastern Newfoundland SEA (Amec 2014), Section 4.1.4.

5.5.3 Extreme Events

To estimate extreme wind and wave conditions, extremal analysis was performed to determine the highest expected values for wind speed, and significant wave height. The analysis was based on the Gumbel distribution to which the data were fitted using the maximum likelihood method. The analysis includes both tropical and extra-tropical storms over the entire period. The Gumbel fit is done using the maximum likelihood method. Lower and upper 95 percent confidence intervals are calculated. The confidence intervals on the extreme values are derived from the standard deviations on the maximum likelihood estimates under the assumption that they are normally distributed. These are derived from the covariance of the estimates of the maximum likelihood parameters of the Gumbel distribution (its mean and standard deviation). The covariance matrix of these two parameters is calculated from the data as the inverse of the observed Fisher information matrix (a measure of the curvature of the log-likelihood surface at the maximum likelihood estimate).

Extreme values were computed for four different return periods: 1, 10, 50 and 100 years (Tables 5.23 and 5.24). In the Proiect Area - Northern Section, extreme winds range from 24.6 m/s to 34.0 m/s for the 1-year and 100-year return periods respectively, while extreme waves range from 11.3 m to 15.6 m. For the Project Area - Southern Section, extreme winds are slightly higher, ranging from 25.2 to 34.6 m/s, while the extreme waves are also higher, ranging from 11.3 m to 17.2 m.

Table 5.23 Extreme Wind and Wave Estimates, MSC50 Node M3012443 (1962–2015), Project Area – Northern Section

Return Period (years)	1	10	50	100
Significant Wave Height (m)	11.3 +/- 0.1	13.3 +/- 0.4	15.0 +/- 0.5	15.6 +/- 0.6
Wind Speed (m/s)	24.6 +/- 0.3	29.0 +/- 1.2	32.5 +/- 1.9	34.0 +/- 2.1

Table 5.24 Extreme Wind and Wave Estimates, MSC50 Node M6010089 (1962–2015), Project Area – Southern Section

Return Period (years)	1	10	50	100
Significant Wave Height (m)	11.3 +/- 0.2	14.1 +/- 0.8	16.3 +/- 1.2	17.2 +/- 1.4
Wind Speed (m/s)	25.2 +/- 0.3	29.6 +/- 1.3	33.1 +/- 1.9	34.6 +/- 2.2

5.5.4 Seawater Properties (Temperature, Salinity, pH, Turbidity)

Statistical summaries of sea temperature and salinity were derived from the Hydrographic Database of the Ocean Data Inventory (ODI) of the Bedford Institute of Oceanography (DFO 2017b) for a rectangular area surrounding the Project Area, querying the period 1900 to 2017 for depths down to 3,000 m.

5.5.4.1 Project Area – Northern Section

Table 5.25 presents monthly depth profile statistics of mean, minimum and maximum sea temperature for the Project Area – Northern Section together with a count of the number of months for which there are data for the given month and depth range.

Mean sea surface temperatures range from 1.6°C in March to 5.2°C in August. Minimum temperatures at the surface range from -1.8°C in January to 1.1°C in August and September. Maximum sea surface temperatures range from 4.0°C in March to 11.8°C in August. This seasonal temperature cycle is observed down to 250 m, where temperatures are higher in the summer than in winter. For depths greater than 250 m however, sea temperature is only slightly variable by depth with monthly mean temperatures ranging from 2.9°C to 3.9°C and averaging 3.4°C down to 2,000 m. From 2,000 to 3,000 m temperatures are approximately one degree colder ranging from 2.0°C to 3.0°C and averaging 2.5°C.

As a companion to the above sea temperature data, Table 5.26 presents monthly depth profile statistics of mean, and minimum and maximum salinity for the Project Area – Northern Section. Sea surface salinities range from a minimum of 32.1 in November to a maximum of 34.9 in April with monthly averages that range by less than 1, from 33.3 in September to 34.1 in February and March. For 250 m, the variability in salinity is even less, with mean values ranging from 34.4 to 34.7 and average 34.6. For depths below 250 m, the range in salinity is even less with all measurements from 500 to 3,000 m variable being between 34.8 and 35.0.

These temperature and salinity statistics represent the normal conditions across the Project Area – Northern Section. Local seawater properties may exhibit some spatial variability (both across the Project Area and by depth) and temporal variability. In addition, not all months or depths are well-sampled. For example, while there are 612 data months for depths 0 to 500 m, there are 16 data months in winter below 1,000 m, and just 23 data months over the entire year for depths below 2,000 m.

Table 5.25 Monthly Sea Temperature Profile Statistics, Project Area – Northern Section

Mean Sea Temperature (°C)

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	2.3	2.3	1.6	2.0	2.1	2.9	4.4	5.2	4.6	5.3	3.5	2.9
250	3.2	3.7	3.3	3.1	2.6	2.8	3.7	3.1	2.0	3.1	2.8	3.2
500	3.8	3.9	3.7	3.6	3.6	3.5	3.7	3.6	3.9	3.6	3.8	3.9
750	3.7	3.7	3.6	3.5	3.5	3.5	3.5	3.6	3.7	3.5	3.6	3.6
1000	3.5	3.6	3.5	3.5	3.4	3.4	3.5	3.6	3.6	3.4	3.4	3.4
1250	3.4		3.2	3.3	3.4	3.4	3.5	3.3	3.5	3.4	3.4	3.3
1500	3.4		3.3	3.3	3.3	3.4	3.3	3.4	3.4	3.4	3.5	3.2
1750	3.3			3.2	3.1				3.1		3.4	
2000	3.1			3.0	3.0		3.1		2.9		3.2	
2250				2.8	2.6						3.0	
2500				2.4	2.4						2.8	
2750				2.1	2.4						2.5	
3000				2.0	2.2						2.2	

Minimum Sea Temperature (°C)

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	-1.8	-0.7	-1.7	-1.6	-1.5	-1.4	-0.5	1.1	1.1	0.6	0.1	-0.6
250	-0.2	1.5	-0.7	-0.3	-1.3	-1.2	1.9	-0.3	-0.9	-0.5	-1.0	-0.9
500	3.4	2.6	2.8	2.6	2.7	2.7	2.9	3.2	3.4	3.3	3.2	3.3
750	3.3	3.3	3.1	3.3	3.1	2.9	3.1	3.4	3.4	3.2	3.2	3.2
1000	3.3	3.5	3.0	3.3	3.2	3.0	3.4	3.4	3.4	3.1	3.0	3.0
1250	3.3		2.9	3.2	3.1	3.2	3.4	3.3	3.4	3.1	2.9	3.0
1500	3.3		2.9	3.1	3.1	3.2	2.9	3.4	3.3	3.4	3.3	3.2
1750	3.1			3.1	3.0				3.1		3.4	
2000	3.0			2.9	2.8		3.1		2.9		3.2	
2250				2.7	2.4						3.0	
2500				2.3	2.3						2.8	
2750				2.1	2.2						2.5	
3000				2.0	2.2						2.2	

Maximum Sea Temperature (°C)

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	5.9	5.2	4.0	6.6	8.5	9.0	10.9	11.8	8.3	8.8	9.3	5.8
250	4.6	4.6	4.8	4.9	5.8	4.5	4.9	4.5	4.4	5.8	4.8	4.7
500	4.3	4.2	4.4	4.3	4.6	4.4	4.5	4.0	4.3	4.2	4.6	4.6
750	4.1	3.8	4.0	3.9	4.0	4.0	3.9	3.8	3.9	3.9	4.3	4.1
1000	3.7	3.6	3.8	3.7	3.9	3.7	3.7	3.7	3.7	3.9	3.9	3.8
1250	3.5		3.5	3.5	3.6	3.5	3.6	3.3	3.6	3.7	3.7	3.6
1500	3.4		3.5	3.5	3.5	3.5	3.5	3.4	3.5	3.6	3.6	3.2
1750	3.4			3.2	3.2				3.1		3.4	
2000	3.3			3.0	3.2		3.1		2.9		3.2	
2250				2.9	2.8						3.0	
2500				2.5	2.6						2.8	
2750				2.2	2.6						2.5	
3000				2.0	2.3						2.2	

Number of Data Months

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	10	7	10	19	38	37	22	15	12	11	24	15
250	10	8	10	19	36	35	19	16	11	11	24	14
500	9	7	9	16	27	34	18	10	4	9	23	13
750	5	5	7	11	20	27	8	7	4	9	18	8
1000	3	2	5	9	17	20	7	4	4	7	8	7
1250	2		2	5	9	4	3	1	2	4	6	7
1500	2		3	8	13	7	3	1	2	3	4	3
1750	1			2	3				1		1	
2000	1			2	4		1		1		1	
2250				2	4						1	
2500				2	4						1	
2750				2	2						1	
3000				1	2						1	

Table 5.26 Monthly Salinity Profile Statistics, Project Area – Northern Section

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Salinity (psu)												
0	33.8	34.1	34.1	33.9	33.7	33.6	33.8	33.6	33.3	33.9	33.6	33.7
250	34.6	34.7	34.7	34.6	34.5	34.5	34.7	34.6	34.4	34.7	34.5	34.6
500	34.8	34.9	34.9	34.9	34.8	34.8	34.9	34.9	34.9	34.9	34.8	34.9
750	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
1000	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
1250	34.9		34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
1500	34.9		34.9	34.9	34.9	34.9	34.9	34.9	34.9	35.0	34.9	34.9
1750	35.0			35.0	34.9				34.9		34.9	
2000	35.0			35.0	34.9		34.9		34.9		34.9	
2250				35.0	34.9						34.9	
2500				35.0	34.9						34.9	
2750				34.9	34.9						34.9	
3000				34.9	34.9						34.9	
Minimum Salinity (psu)												
0	32.8	33.3	32.8	32.5	32.4	32.3	32.4	32.4	32.3	32.5	32.1	32.5
250	33.5	34.2	33.3	33.4	33.3	33.1	34.5	33.4	33.5	33.5	33.4	33.3
500	34.7	34.5	34.8	34.7	34.6	34.3	34.7	34.8	34.8	34.7	34.7	34.8
750	34.8	34.8	34.8	34.8	34.8	34.4	34.8	34.9	34.9	34.8	34.7	34.8
1000	34.8	34.9	34.8	34.8	34.8	34.8	34.8	34.9	34.9	34.7	34.7	34.8
1250	34.9		34.8	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.8	34.8
1500	34.9		34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.8
1750	34.9			34.9	34.9				34.9		34.9	
2000	34.9			34.9	34.9		34.9		34.9		34.9	
2250				34.9	34.9						34.9	
2500				34.9	34.9						34.9	
2750				34.9	34.9						34.9	
3000				34.9	34.9						34.9	
Maximum Salinity (psu)												
0	34.6	34.6	34.8	34.9	34.8	34.7	34.5	34.5	34.7	34.6	34.6	34.5
250	35.0	34.9	34.9	35.0	34.9	34.9	34.9	34.9	34.9	35.0	34.9	34.9
500	35.0	34.9	34.9	35.0	34.9	35.0	34.9	34.9	34.9	35.0	34.9	35.0
750	35.0	34.9	34.9	34.9	34.9	35.0	34.9	34.9	34.9	35.0	34.9	34.9
1000	35.0	34.9	34.9	34.9	35.0	34.9	35.0	34.9	35.0	35.1	34.9	34.9
1250	34.9		34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9
1500	35.0		34.9	35.0	35.0	34.9	35.0	34.9	34.9	35.1	34.9	34.9
1750	35.0			35.0	34.9				34.9		34.9	
2000	35.0			35.0	34.9		34.9		34.9		34.9	
2250				35.0	34.9						34.9	
2500				35.0	34.9						34.9	
2750				35.0	34.9						34.9	
3000				34.9	34.9						34.9	

5.5.4.2 Project Area – Southern Section

Table 5.27 presents monthly depth profile statistics of mean, minimum and maximum sea temperature for the Project Area – Southern Section together with a count of the number of months for which there are data for the given month and depth range.

Mean sea surface temperatures range from 0.6°C in April to 10.9°C in September. Minimum temperatures at the surface range from -1.8°C in April to 4.9°C in September. Maximum sea surface temperatures range from 5.8°C in February to 19.6°C in September. This seasonal temperature cycle is observed down to 300 m, where temperatures are higher in the summer than in winter. For depths greater than 300 m however, sea temperature is only slightly variable by depth with monthly mean temperatures ranging from 3.2°C to 3.6°C.

As a companion to the sea temperature data, Table 5.28 presents monthly depth profile statistics of mean, and minimum and maximum salinity for the Project Area – Southern Section. Sea surface salinities range from a minimum of 32.0 in August to a maximum of 33.7 in March. Above 300 m, the variability in salinity is low with mean values ranging from 32.0 to 34.7. For depths below 300 m, the range in salinity is even less with all measurements from 300 to 1,000 m variable being between 34.6 and 34.9.

These temperature and salinity statistics represent the normal conditions across this part of the Project Area. Local seawater properties may exhibit some spatial variability (both across the Project Area and by depth) and temporal variability. In addition, not all months or depths are well-sampled. For example, while there are over 35,000 data months for depths 0 to 300 m, there are only approximately 3,500 data months below 300 m.

5.5.4.3 pH and Turbidity

As pH data for the Project Area are scarce and limited in both temporal and spatial resolution, the description provided herein is based on data collected from the World Ocean Circulation Experiment (WOCE) database for the entirety of the Atlantic Ocean (data available at http://cdiac.ornl.gov/oceans/CDIACmap.html). Figure 5-40 shows that surface waters in the Atlantic Ocean have a pH (adjusted to 25°C temperature) range of 8.0 to 8.1, which decreases to approximately 7.7 at 1,000 m depth, then remaining stable to the ocean floor. An example CTD profile of surface waters (0-80 m) from the Hibernia Effects Monitoring (EEM) Program in 2015 is shown in Figure 5-41, which agrees with surface waters on the Grand Banks having a pH of approximately 8.1.

Turbidity data are similarly scarce for the Project Area. Data are available from NOAA, from a cruise in March of 2011 in an area north of Flemish Pass (Ullman et al. 2013). From this cruise, it can be seen that turbidity is approximately 0.2 to 0.3 NTU in near-surface waters and steadily decreases to below 0.01 at 200 m and deeper. It should be noted that there is some potential for seasonal variability associated with biogenic fallout.

Table 5.27 Monthly Sea Temperature Profile Statistics, Project Area – Southern Section

Mean Sea Temperature (°C)

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	2.4	0.8	2.1	0.6	2.7	4.7	9.4	7.7	10.9	8.3	5.4	4.0
20	2.4	0.8	2.1	0.4	2.2	3.7	7.2	3.7	8.5	7.3	5.0	3.9
40	2.0	0.9	1.0	0.1	1.1	1.8	3.4	0.0	2.9	4.1	3.3	3.3
60	2.0	1.0	1.0	0.0	0.4	0.5	0.9	-0.9	-0.2	1.3	1.6	2.5
80	2.0	1.1	2.0	0.0	0.1	0.2	0.6	-0.6	-0.7	0.6	0.8	1.9
100	2.1	1.4	2.4	0.4	0.1	0.1	0.8	-0.6	-0.7	1.2	0.7	2.0
200	3.2	2.5	3.7	2.7	2.2	2.3	3.2	2.8	1.6	3.4	2.5	3.6
300	3.6	3.1	3.8	3.4	3.1	3.2	3.7	3.7	3.9	3.7	3.4	3.9
400	3.8	3.4	3.8	3.6	3.5	3.5	3.7	3.7	3.9	3.8	3.8	3.8
500	3.8	3.7	3.8	3.6	3.5	3.6	3.7	3.7	3.8	3.7	3.8	3.7
600	3.8	3.8	3.6	3.7	3.6	3.6	3.7	3.7		3.6	3.8	3.6
700	3.7	3.6	3.4	3.6	3.4	3.6	3.6	3.7		3.6	3.6	3.5
800	3.6	3.5	3.6	3.6	3.5	3.5	3.6	3.6		3.5	3.6	3.5
900	3.5	3.6	3.2	3.5	3.4	3.6	3.5	3.6		3.5	3.6	3.4
1000	3.5		3.4	3.5	3.5	3.5	3.4	3.5		3.4	3.4	3.3

Minimum Sea Temperature (°C)

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	-1.4	-1.8	-1.8	-1.5	-1.1	0.0	1.7	1.4	4.9	1.2	0.3	0.5
20	-1.3	-1.8	-1.8	-1.6	-1.1	-0.6	0.2	0.0	3.0	-0.7	0.5	0.5
40	-1.3	-1.8	-1.8	-1.7	-1.7	-1.5	-1.3	-1.6	-1.5	-1.3	-1.4	-0.1
60	-1.2	-1.7	-1.8	-1.8	-1.7	-1.7	-1.7	-1.7	-1.7	-1.5	-1.3	-1.2
80	-1.1	-1.7	-1.7	-1.8	-1.7	-1.7	-1.8	-1.7	-1.7	-1.6	-1.4	-1.3
100	-0.9	-1.7	-1.7	-1.8	-1.6	-1.7	-1.7	-1.7	-1.6	-1.5	-1.4	-1.3
200	-0.7	-0.8	-1.2	-0.7	-1.0	-1.0	0.0	-0.8	-0.4	0.8	-0.9	-0.8
300	1.4	1.7	2.2	0.4	0.8	0.8	2.3	1.5	3.5	1.4	0.6	1.1
400	1.6	2.1	2.5	2.3	1.8	2.0	3.0	1.9	3.5	3.1	2.2	3.4
500	3.5	2.7	3.0	3.1	2.9	3.2	3.0	3.0	3.8	3.3	3.1	3.3
600	3.5	3.3	3.4	3.2	3.1	3.2	3.1	3.1		3.2	3.2	3.2
700	3.5	3.5	3.2	3.2	3.2	3.3	3.1	3.2		3.2	3.1	3.1
800	3.4	3.3	3.0	3.3	3.2	3.2	3.1	3.3		3.1	3.3	3.2
900	3.4	3.3	3.1	3.2	3.2	3.3	3.1	3.3		3.1	3.4	3.1
1000	3.4		3.0	3.1	3.1	3.1	3.1	3.3		3.0	3.3	3.1

Maximum Sea Temperature (°C)

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	8.2	5.8	6.6	6.6	10.3	10.4	15.1	17.0	19.6	14.4	11.1	10.6
20	8.2	5.8	6.6	6.6	10.1	9.6	12.5	13.1	19.6	13.1	11.0	10.5
40	8.2	5.8	4.6	6.8	9.6	8.6	9.8	11.9	8.7	10.5	9.7	8.3
60	8.3	5.8	4.5	7.1	8.7	6.7	7.8	5.4	5.8	8.6	8.4	7.2
80	8.7	5.9	6.7	7.3	8.4	6.7	7.9	5.5	3.7	6.1	8.2	6.9
100	8.7	5.9	6.7	7.7	8.1	6.5	8.2	5.3	4.1	6.4	7.1	7.1
200	6.9	5.2	8.1	6.3	6.8	5.3	6.5	5.1	4.8	6.0	4.9	5.6
300	4.9	5.0	5.7	4.8	5.6	5.2	5.0	5.0	4.4	5.0	4.8	5.3
400	4.7	4.9	4.5	5.2	4.8	4.7	5.5	4.8	4.1	4.6	4.8	4.9
500	4.3	4.4	5.1	4.2	4.0	4.1	4.6	4.4	3.8	4.8	4.7	4.5
600	4.3	4.3	4.3	4.1	3.9	4.0	4.3	4.4		4.6	4.6	4.6
700	4.2	3.9	4.1	4.1	3.8	3.9	4.2	4.2		4.0	4.0	4.1
800	4.1	3.8	4.0	4.0	3.8	3.8	4.1	4.1		3.9	3.9	4.0
900	3.9	3.8	3.6	4.0	3.6	3.7	4.0	4.0		3.8	3.8	4.0
1000	3.8		3.7	4.0	3.6	3.7	3.9	3.9		3.7	3.5	3.8

Number of Data Months

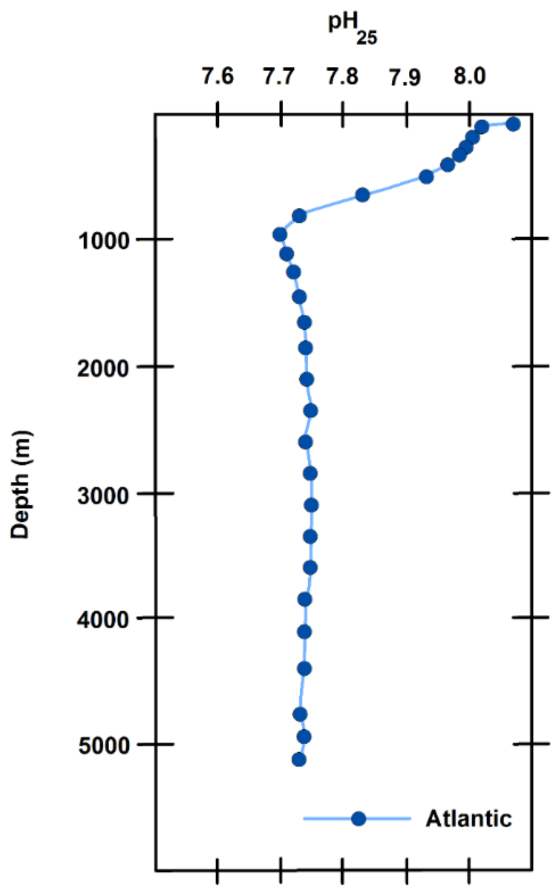
Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	119	85	114	614	537	1137	673	900	158	574	750	268
20	120	86	116	630	538	1143	674	902	159	579	752	272
40	80	77	81	611	491	1121	675	901	147	579	752	270
60	86	77	82	617	501	1125	673	694	147	579	750	272
80	87	75	115	614	490	1110	671	441	144	566	734	271
100	82	75	103	459	347	687	576	401	99	396	516	232
200	68	58	72	181	156	313	250	92	23	208	256	148
300	57	47	49	109	115	222	197	69	6	181	174	130
400	41	37	50	66	74	136	112	53	3	108	107	109
500	36	40	44	48	48	75	95	45	1	98	51	97
600	27	15	25	36	41	70	59	44		97	49	95
700	23	8	16	25	16	27	36	36		81	12	85
800	23	9	47	26	21	25	38	32		81	4	81
900	15	3	10	19	11	13	29	24		61	5	71
1000	13		18	20	11	9	18	26		52	2	56

Table 5.28 Monthly Salinity Profile Statistics, Project Area – Southern Section

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Salinity (psu)												
0	33.5	33.4	33.7	33.0	32.9	32.7	32.6	32.0	32.1	32.5	32.5	33.1
20	33.5	33.4	33.7	33.0	32.9	32.7	32.8	32.5	32.3	32.6	32.6	33.1
40	33.6	33.6	33.6	33.1	33.0	32.9	33.0	32.9	32.7	32.9	32.9	33.3
60	33.7	33.7	33.6	33.2	33.1	33.0	33.3	33.1	33.1	33.3	33.2	33.5
80	33.8	33.7	33.9	33.3	33.3	33.1	33.5	33.4	33.2	33.5	33.4	33.7
100	34.0	33.8	34.1	33.5	33.5	33.4	33.7	33.5	33.4	33.8	33.7	34.0
200	34.5	34.4	34.6	34.5	34.3	34.3	34.6	34.5	34.3	34.6	34.4	34.7
300	34.7	34.6	34.8	34.7	34.7	34.7	34.8	34.8	34.9	34.7	34.6	34.8
400	34.8	34.7	34.8	34.8	34.8	34.8	34.8	34.8	34.9	34.8	34.7	34.8
500	34.9	34.8	34.9	34.8	34.8	34.8	34.8	34.8	34.9	34.9	34.8	34.9
600	34.9	34.9	34.9	34.9	34.9	34.8	34.9	34.9		34.9	34.8	34.9
700	34.8	34.9	34.8	34.9	34.9	34.9	34.9	34.9		34.9	34.8	34.9
800	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9		34.9	34.9	34.9
900	34.9	34.9	34.9	34.9	34.9	34.9	34.9	34.9		34.9	34.9	34.9
1000	34.9		34.9	34.9	34.9	34.9	34.9	34.9		34.9	34.9	34.9
Minimum Salinity (psu)												
0	32.3	32.4	32.5	32.1	32.2	32.0	31.4	30.7	31.3	31.3	31.0	31.9
20	32.3	32.4	32.6	32.1	32.2	32.2	31.8	31.8	31.6	31.7	31.6	31.9
40	32.6	32.4	32.7	32.4	32.3	32.2	32.1	32.4	32.0	32.0	31.9	32.2
60	32.6	32.5	32.8	32.5	32.3	32.3	32.5	32.6	32.5	32.4	32.0	32.5
80	32.6	32.6	32.8	32.5	32.3	32.3	32.6	32.8	32.7	32.7	32.1	32.7
100	32.8	32.6	32.8	32.6	32.7	32.6	32.7	32.9	32.8	32.9	32.7	32.9
200	33.2	33.5	33.2	33.6	33.3	33.3	33.6	33.6	33.8	33.9	33.6	33.3
300	34.1	34.3	34.3	33.9	34.0	34.0	34.4	34.4	34.8	34.2	33.7	34.2
400	34.4	34.4	34.4	34.5	34.3	34.3	34.7	34.5	34.8	34.7	34.0	34.7
500	34.8	34.5	34.5	34.6	34.7	34.7	34.7	34.7	34.9	34.8	34.2	34.8
600	34.8	34.7	34.6	34.8	34.8	34.8	34.7	34.7		34.8	34.3	34.8
700	34.6	34.8	34.6	34.8	34.8	34.8	34.7	34.8		34.8	34.8	34.8
800	34.8	34.9	34.6	34.8	34.8	34.8	34.8	34.7		34.8	34.8	34.8
900	34.8	34.9	34.9	34.8	34.8	34.9	34.8	34.8		34.8	34.9	34.8
1000	34.8		34.8	34.8	34.9	34.8	34.9	34.9		34.8	34.8	34.8
Maximum Salinity (psu)												
0	34.5	34.2	34.6	34.7	34.7	34.5	34.5	34.1	33.3	34.2	34.4	34.3
20	34.5	34.2	34.6	34.7	34.7	34.5	34.5	34.3	33.4	34.2	34.4	34.3
40	34.5	34.3	34.6	34.6	34.8	34.5	34.6	34.5	33.9	34.2	34.4	34.3
60	34.5	34.4	34.6	34.9	34.8	34.6	34.7	34.6	34.3	34.6	34.5	34.4
80	34.5	34.7	34.6	35.0	35.2	34.7	34.8	34.7	34.4	34.8	34.9	34.6

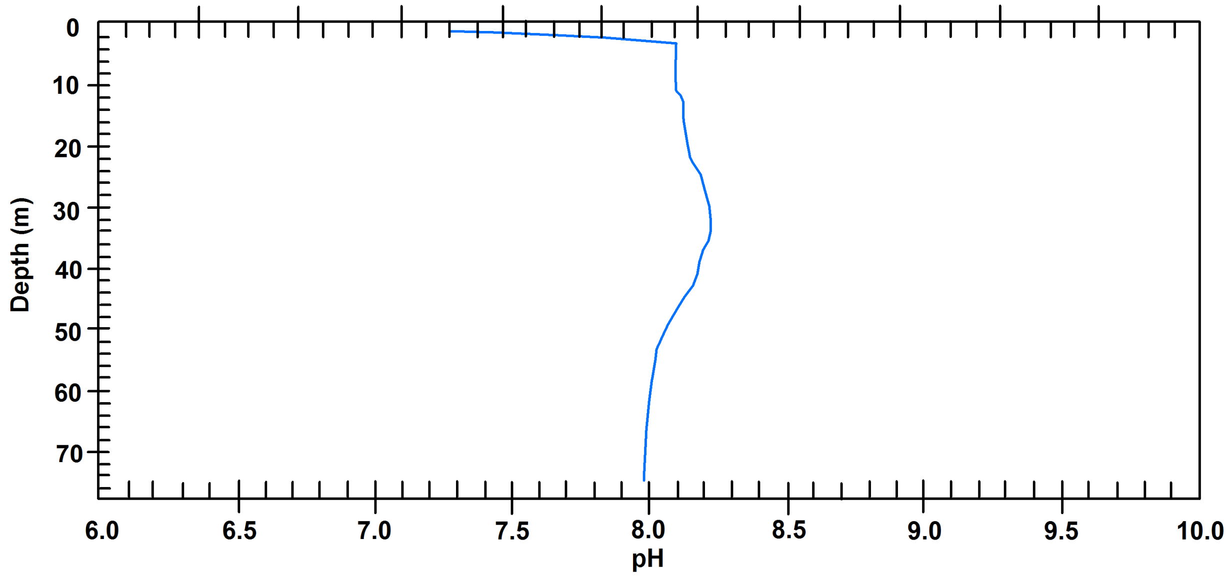
Table 5.28 Monthly Salinity Profile Statistics, Project Area – Southern Section

Depth (m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
100	34.6	34.8	34.7	34.8	34.8	34.8	34.9	34.8	34.5	34.9	34.9	34.7
200	35.0	34.9	35.1	35.0	34.9	34.9	35.1	34.9	34.9	35.0	35.0	34.9
300	35.0	34.9	35.0	35.0	35.0	35.0	35.1	34.9	34.9	35.0	34.9	35.0
400	35.1	35.0	34.9	34.9	35.0	35.1	35.1	35.0	34.9	35.0	34.9	35.0
500	35.1	34.9	35.0	34.9	34.9	34.9	35.1	34.9	34.9	35.0	34.9	35.0
600	35.0	34.9	35.0	35.0	34.9	34.9	35.1	34.9		35.0	35.0	35.0
700	34.9	34.9	34.9	34.9	34.9	35.1	35.0	34.9		35.0	34.9	35.0
800	35.0	34.9	35.0	34.9	35.0	34.9	35.0	34.9		35.0	34.9	35.0
900	34.9	34.9	34.9	34.9	35.6	34.9	34.9	34.9		35.0	34.9	34.9
1000	34.9		34.9	34.9	34.9	34.9	34.9	34.9		35.1	34.9	35.0



Source: Wallace (1997)

Figure 5-40 Overview of pH for the Atlantic Ocean from the WOCE



Source: Stantec Consulting (2014)

Figure 5-41 Surface pH data from Hibernia EEM Program, December 9, 2015

5.5.5 Tides

Water level variations due to tides in the Project Area are generally quite predictable. Several models are available for the prediction of water levels at specific locations where the tidal constituents are known or can be extrapolated from other locations.

Using the WebTide model (Dupont et al. 2002), based on tidal modeling studies conducted by DFO, tidal water levels are computed for both sections of the Project Area at the same locations of the referenced MSC50 nodes (used for wind and wave analysis). These results are presented in Table 5.29.

Table 5.29 Tidal Predictions

Project Area	Tidal Constituent	Constituent Amplitude (cm)	Phase (deg GMT)	Total Amplitude (cm)
Northern Section (49.5°N, 45.5°W)	M_2	13.2	303.4	36.9
	K_1	8.7	157.6	
	N_2	2.5	293.3	
	S_2	7.1	343.3	
	O_1	5.4	126.5	
Southern Section (46.2°N, 46.7°W)	M_2	15.2	339.8	37.7
	K_1	7.2	153.4	
	N_2	3.0	317.9	
	S_2	7.4	16.5	
	O_1	4.9	144.7	

The contribution of each tidal constituent to the observed tidal range during a full tidal cycle is twice its amplitude. The largest contribution comes from M2, the principal lunar semidiurnal constituent, followed by S2, the solar semidiurnal constituent. The other components have a relatively smaller contribution toward the observed tides. Overall, the water levels exhibit two high tides and two low tides per day, with one set of tides having a higher tidal range than the other.

5.5.6 Storm Surge

Storm surge is the abnormal rise in seawater level during a storm, measured as the height of the water above the normal predicted astronomical tide. Storm surge amplitudes can be high in coastal areas, but surges with comparatively smaller amplitudes can also occur offshore, away from the coastline. A hazard from storm surges is elevated mean water levels, specifically when they occur at high tide. A study by Bernier et al. (2006), which used a hindcast of water levels over 40 years, calculated a potential storm surge of 70 cm in the Northwest Atlantic. The Bernier model agrees well with observations recorded by Seaconsult (1988), which indicated that the expected storm surge levels at Terra Nova range between 50 cm (1 year return period) and 73 cm (100 year return period).

5.6 Ambient Noise

The existing noise environment or sound-scape of the Project Area is characterized by a degree of existing atmospheric and underwater noise, resulting from natural conditions and processes, such as weather and wave action, marine mammals, as well as from other human activities that occur in parts of the Project Area on either a continuous basis (i.e., existing petroleum production platforms in the Project Area - Southern Section) or those which are more intermittent and transient in nature, such as fishing activity, other oil and exploration programs, and marine transportation.

As part of its analysis of underwater sound generation and its potential effects for this EIS, the Operators commissioned a study (Quijano et al. 2017; Appendix C) on existing underwater sound levels in and around the Project Area, as well as an analysis of potential sound types and levels that may be generated by planned Project activities and their possible propagation. This report is provided as Appendix C of this EIS, with its results used extensively in the associated environmental effects assessments (Chapters 8 to 13). Statoil also commissioned JASCO to analyze ambient acoustic data collected in 2014 and 2015 by a recorder secured to an oceanographic mooring in the northern sections of the Flemish Pass, near the Statoil 2014-16 exploratory drilling program (Maxner et al. 2017, Appendix D).

Section 5.6.1 describes the soundscape collected near the exploratory drilling program. Section 5.6.2 provides a brief overview of ambient noise levels, as described Appendix C. Section 5.6.4 provides a summary of the sources of underwater sound in the Project Area. Appendices C and D should be consulted for further details.

5.6.1 Measured Soundscape near Drilling Operations

An acoustic recorder was deployed in the Flemish Pass from June-October 2014 and from May-September 2015. From May-September 2015 the recorder was 13.4 km from the West Hercules drilling installation at well site BdN4 L-76, and 230 km from JASCO recording Station 19, sponsored by the Environmental Studies Research Fund (ESRF) (Figure 5-42). The recordings were analyzed to characterize the baseline soundscape, the presence of marine mammals, and characterize the soundscape during Statoil's 2014-2016 drilling program.

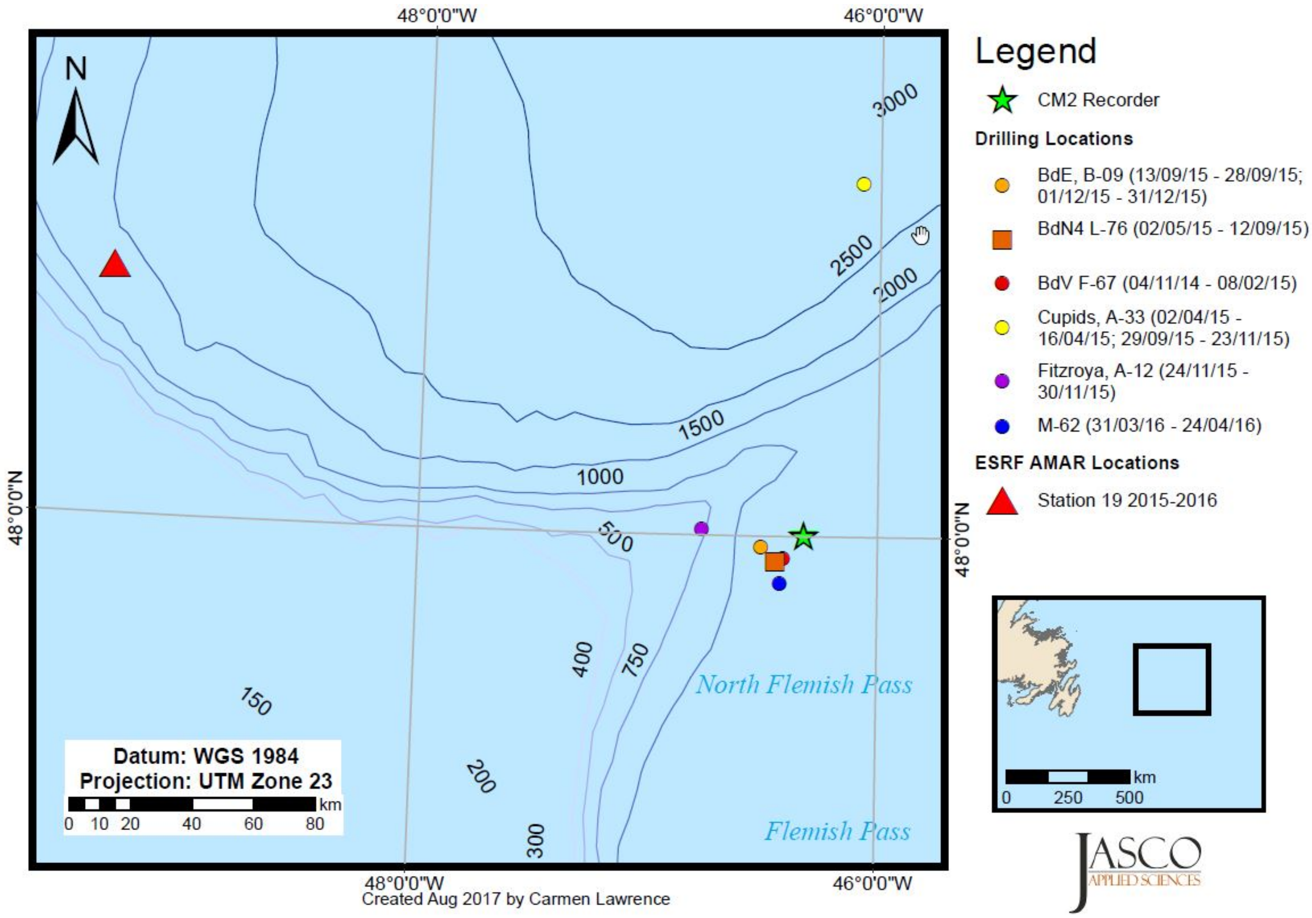


Figure 5-42 Statoil CM2 Recorder, ESRF Station 19 Recorder, and Statoil 2015-2016 Drilling Locations off the East Coast of Newfoundland

Geophysical surveys increased baseline sound levels by 10-35 dB throughout the summer months (Figure 5-43). Drilling operations by the semi-submersible West Hercules generated sound levels similar to those previously reported for the Stena IceMAX off Nova Scotia (MacDonnell 2016).

Five confirmed species of marine mammals, plus an unknown number of dolphin species (up to six), were detected acoustically. Baleen whale detections were sparse and occurred predominantly in the late summer and early fall, showing pronounced seasonal variations as a result of changes in vocal behaviour, migratory movements, or both. Blue whales were detected once in early August and once in early October in 2014, and three times in early September 2015. Only one fin whale call was detected at the beginning of the study period in 2014, but detections increased in early fall 2015. The occurrence of northern bottlenose whales was sporadic throughout the study period in each year and were acoustically active during geophysical surveys. In both years, sperm whale calls occurred continuously throughout the recording. Delphinids, which include pilot whales as well as several species of dolphins, were the most broadly detected class. Noise associated with anthropogenic activities, namely geophysical surveys, vessel traffic and oil and gas activities, at times restricted or prevented the ability to detect some species.

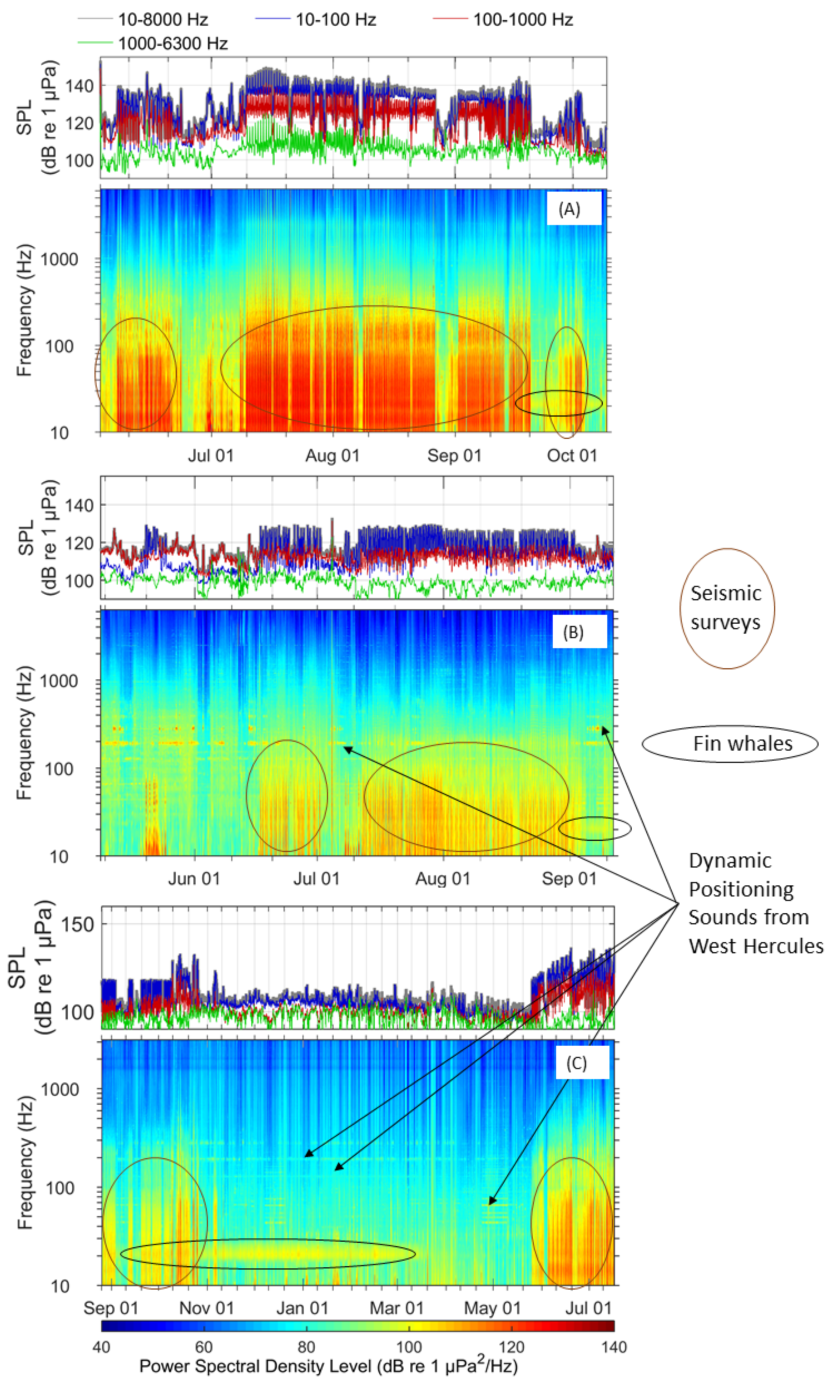


Figure 5-43 Baseline Sound Levels

5.6.2 Soundscape by Band

To simplify the discussion of the existing soundscape, Appendix C divides the frequency spectrum into five bands. Table 5.30 provides a classification of known biologic, anthropogenic, natural geologic, and measurement system noise and the frequency bands associated with their contributions to the soundscape.

Table 5.30 Frequency Bands and Noise-generating Mechanisms Discussed in the Analysis

Band Name and Frequency Range	Sound Source Type		
	Biologic	Anthropogenic	Geologic
Very low frequency: 10-45 Hz	Fin, blue, Bryde's, Omura's whales	Geophysical pulses	Earthquakes
Low frequency: 45-225 Hz	Fish, baleen whales, pinnipeds	Geophysical pulses, large vessels	-
Mid frequency: 225-2,250 Hz	Baleen whales, fish, pinnipeds	Smaller vessels, large vessels at close range, DP	Wind and wave action
High frequency: 2,250-18,000 Hz	Whistles, sperm whale clicks, baleen song, shrimp	Naval sonar, cavitation bubbles, chains	Sediment movement, rain
Very high frequency: >18,000 Hz	Echolocation clicks	Communicating and positioning devices, naval sonar	-
Note: "-" symbol means that the corresponding sound source does not have significant energy within that specific band.			

To summarize the soundscapes around the Project Area, Appendix C presents the distribution of one-minute sound pressure levels from a data collection program conducted by JASCO in 2015-2016. In August 2015, JASCO deployed 20 acoustic recorders along Canada's east coast for the first year of a two-year baseline monitoring program sponsored by the ESRF program. The recorders were retrieved and redeployed in July 2016.

Data from seven of the recorders are discussed here, as they provide the best available information on the existing sound levels in the Project Area (Figure 5-44). Station 18 was in 80 m of water, 35 km from the Hibernia platform in the existing Jeanne d'Arc Basin development area. Data from Station 7 is presented as an example of a receiver at a location of similar water depth, but away from oil and gas activity. Stations 17 and 19 are in deep water near the Flemish Pass. Their data represents the current deep-water soundscape. Note that Station 19 was moved for the 2016-2017 recording program because in 2015 the Whitehead Laboratory team at Dalhousie University spotted northern bottlenose whales in the area. Stations 4 and 5 are to the southwest of Sable Island. Their data provide examples of the changes in the soundscape associated with deep-water drilling. Station 5 was located 13 km from Shell Canada's 2015-2016 Cheshire drilling campaign. Finally, Station 8 was located near the shipping lanes coming out of the Gulf of St. Lawrence and is presented as an example of ambient noise associated with vessel traffic. The results for Station 8 are summarized in Section 5.6.3.

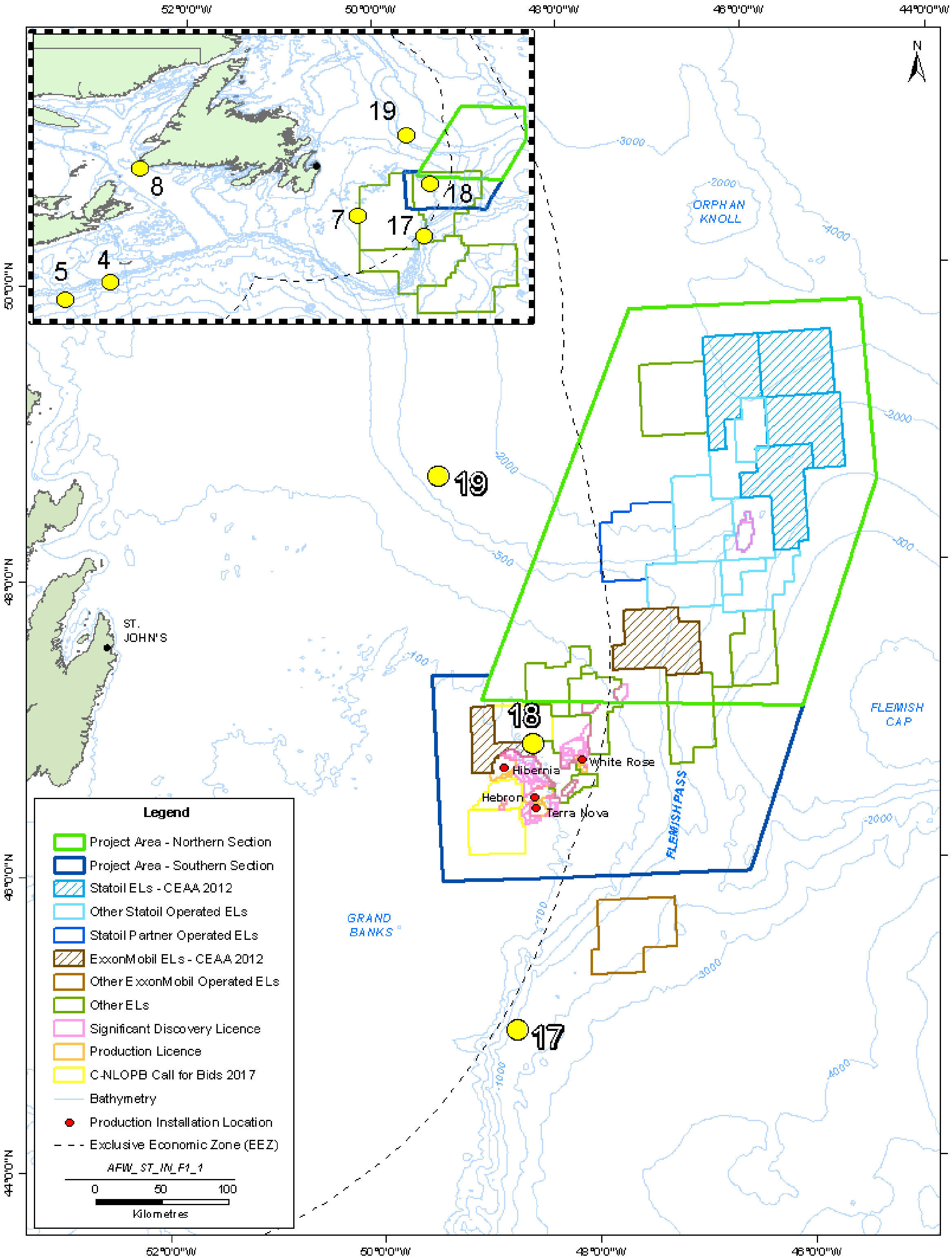


Figure 5-44 Project Areas Showing Locations of the Existing Oil Production Platforms and the JASCO Year-Long Acoustic Recorders (Yellow Dots) Deployed as Part of an ESRF Program

To describe the soundscape in this region, Appendix C presents box-and-whisker plots (or boxplots) for each month in each frequency band. Monthly distributions provide an overview of the range of sound levels and how they change by season. The dominant sound source for each month is indicated by the colour of the boxes. JASCO's experienced analysts identified the dominant sources by inspection of the long-term spectral average figures generated for the ESRF project to identify the sources that would have increased the mean monthly in-band sound pressure level by 3 dB or more from the expected levels in the absence of the source (e.g., Figure 5-45). Boxplots were created from approximately 2,000 one-minute samples collected per month per station. The top and bottom of the boxes show the sound levels exceeded by 25 percent and 75 percent of the one minute samples, respectively. The heavy line across the boxes shows the average monthly sound pressure levels. The lines extending above and below the boxes extend two standard deviations from the mean value. The box plots are ordered from north to south.

The total sound levels across all bands are referred to as the broadband sound pressure levels (SPL). If a source is identifiable as the dominant source in the monthly broadband sound distributions, then the magnitude of its sounds exceeds all other regularly occurring sounds by at least 3-6 dB.

In Figure 5-45, Stations 4 and 17 are examples of the normal magnitude and distribution of sound pressure levels in the open ocean. Ambient sound levels are in the range of 100-105 dB re 1 μPa, with levels slightly higher in the winter due to increased wind and wave activity. At Station 18, the levels are 110-120 dB re 1 μPa continuously, which is likely due to the platform and support vessel sounds from the Hibernia production platform. The soundscape changes from the Shell exploration drilling activity at Station 5 is evident by comparison to the nearby Station 4. Geophysical surveys occurred off the Grand Banks in fall 2015, which increased the SPLs at Station 17 in Sept 2015, and Station 19 in September and October 2015. Surveys north of the Flemish Pass began again in June of 2016 and resulted in maximum sound levels presented here of 140 dB re 1 μPa.

In the very-low frequency band (10-45 Hz), background sound levels in the open ocean are in the range of 90-95 dB re 1 μPa (Figure 5-46). Fin and blue whales have evolved to take advantage of this relatively quiet frequency band. Fin whales were a dominant noise source for at least four months and up to seven months throughout fall, winter, and spring, which was typical for the ESRF stations that were not ice-covered, especially those over the Scotian Shelf and Grand Banks. North Atlantic fin whales emit a short pulse once every 9-18 seconds from October to March. Geophysical survey sounds are an anthropogenic sound source with high energy levels in this band. They were a contributing source at Stations 19 and 17 in the summer months. The fluctuations in the geophysical sound levels were caused by variations of the distance between the geophysical survey vessel and the corresponding recorder, as well as by the total number of survey days within each month. Platform and vessel noise were weakly detectable in this band.

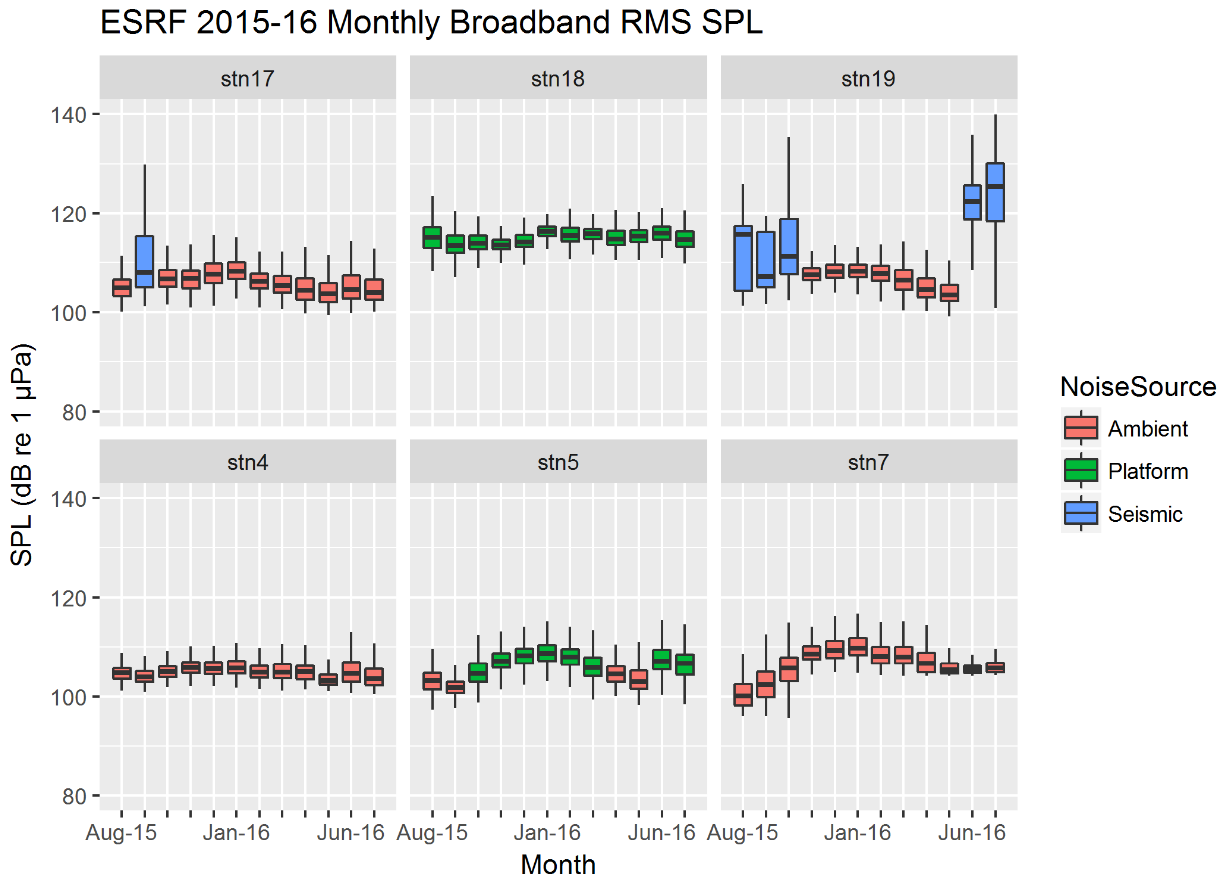


Figure 5-45 10-125,000 Hz Band: Distribution of One-minute SPL for Selected Locations from JASCO's 2015-2016 ESRF Data Set

Notes: Stations 7 and 18 are at <100 m water depth and Stations 4, 5, 17, and 19 are at >1,000 m. All measurements were within 10 m of the seabed. Stations 4 and 5 are located off the southwestern Scotian Shelf and represent examples of deep-water recordings with and without significant man-made noise sources. Station 5 is 13 km from Shell's Monteray Jack drilling campaign using the Stena IceMax. Station 18 is 35 km from the Hibernia platform.

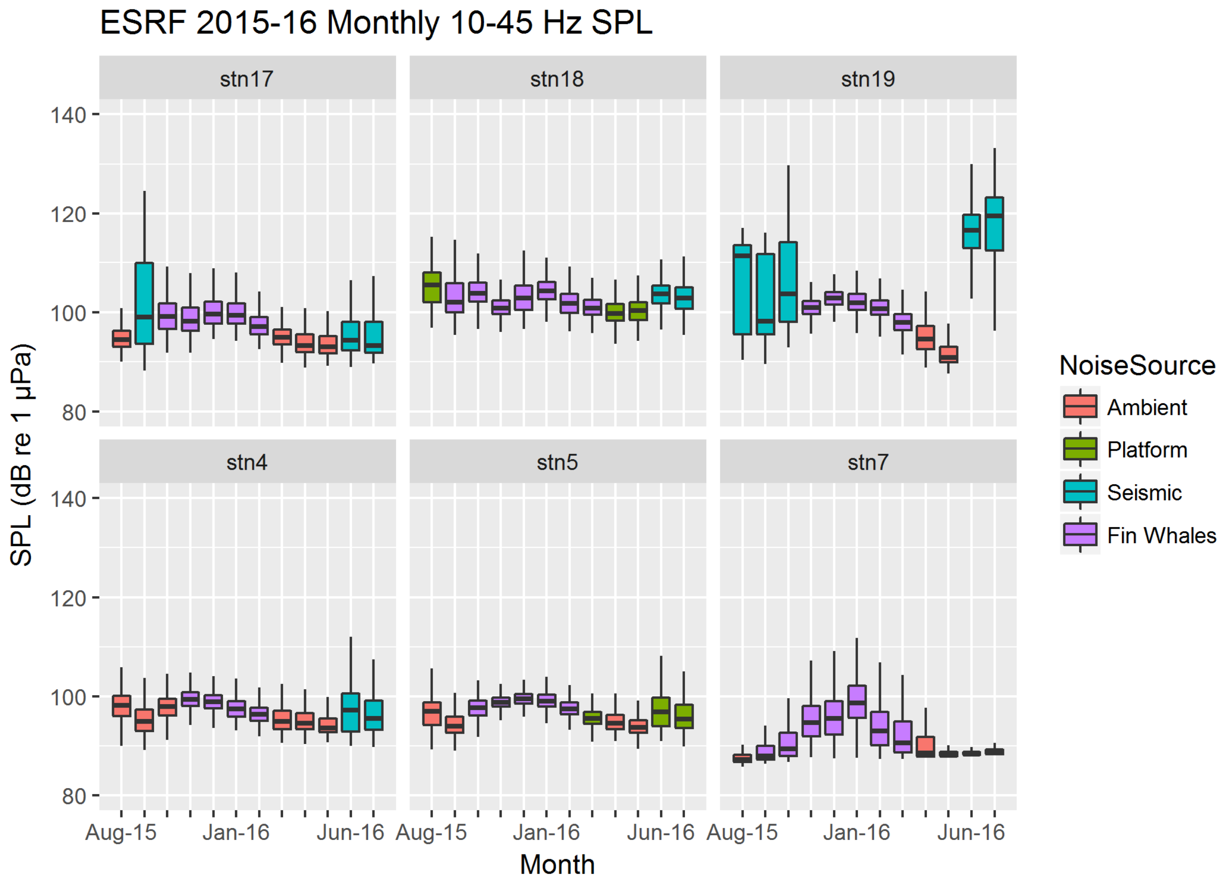


Figure 5-46 10-45 Hz Band: Distribution of One-minute SPL for Selected Locations from JASCO's 2015-2016 ESRF Data Set

Notes: Stations 7 and 18 are at <100 m water depth and Stations 4, 5, 17, and 19 are at >1,000 m. All measurements were within 10 m of the seabed. Stations 4 and 5 are located off the southwestern Scotian Shelf and represent examples of deep-water recordings with and without significant man-made noise sources. Station 5 is 13 km from Shell's Monteray Jack drilling campaign using the Stena IceMax. Station 18 is 35 km from the Hibernia platform.

The low frequency band (45-225 Hz, Figure 5-47) contained the highest levels of platform noise. At Station 18, the levels were approximately 105-115 dB re 1 µPa, nearly the range of the broadband SPL measured at Station 18. The levels varied by small amounts from month-to-month. Station 5 could be considered an example of typical drilling installation sound levels for deep-water operations, with the highest sound pressure levels of 103 dB re 1 µPa during November to February and June to July. The program occurred from October 2015-July 2016 and was suspended from mid-March to early-June 2016. With respect to offshore petroleum production platform sound levels representative of operations in shallow water, the sound levels at Station 18 were approximately15 dB and 20 dB higher than those at Station 7 during winter and summer, respectively. The sound levels at Station 18, 35 km from Hibernia, were also considerably higher than those at Station 5 (13 km from Shell's Cheshire drilling site). This difference is likely due to the presence of three production facilities near Station 18 (Figure 5-47); note Hebron platform was not in operation during this survey period) and the vessel traffic supporting these activities. Also, the deep waters near Station 5 result in higher geometric spreading attenuation of the sound compared to the shallow water near Station 18.

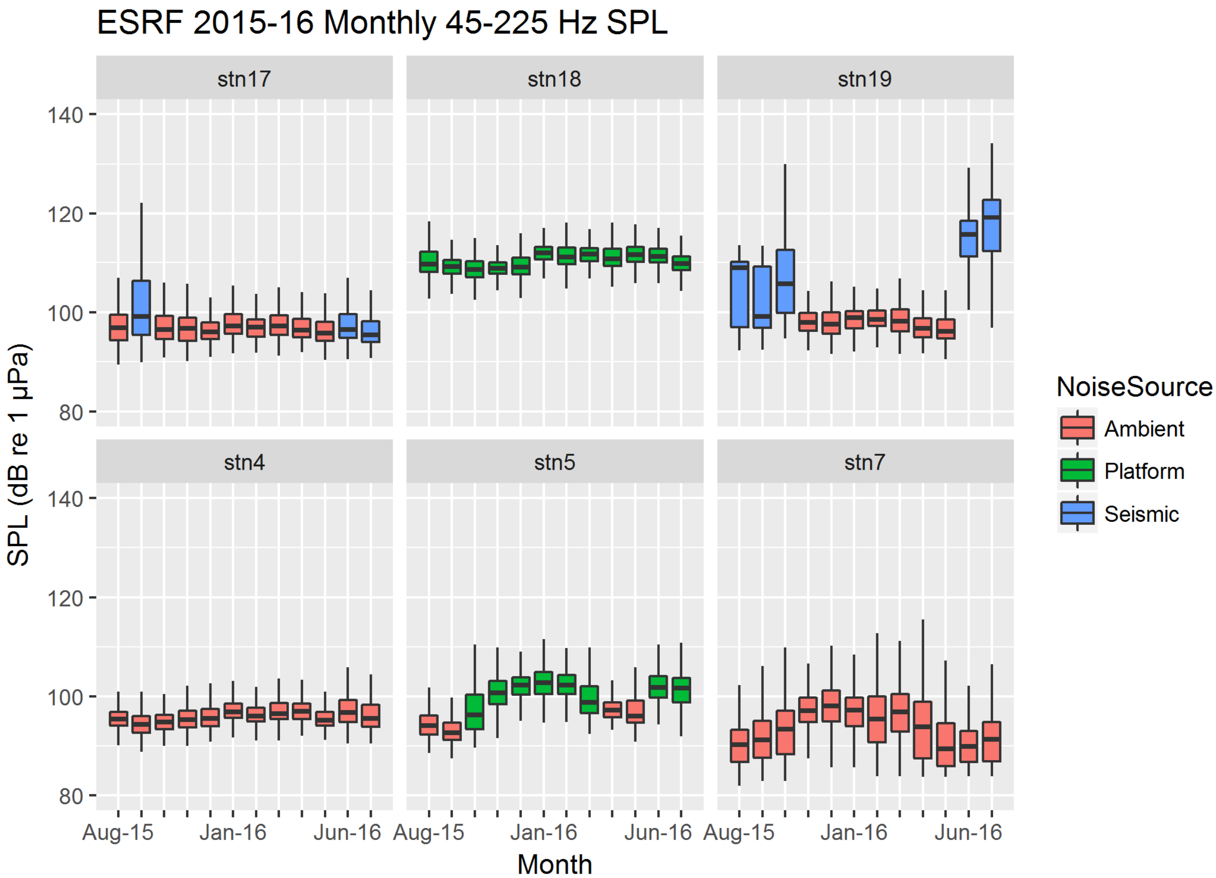


Figure 5-47 45-225 Hz Band: Distribution of One-Minute SPL for Selected Locations from JASCO's 2015-2016 ESRF Data Set

Notes: Stations 7 and 18 are at <100 m water depth and Stations 4, 5, 17, and 19 are at >1,000 m. All measurements were within 10 m of the seabed. Stations 4 and 5 are located off the southwestern Scotian Shelf and represent examples of deep-water recordings with and without significant man-made noise sources. Station 5 is 13 km from Shell's Monteray Jack drilling campaign using the Stena IceMax. Station 18 is 35 km from the Hibernia platform.

The geophysical surveys were source of noise at Stations 17 and 19, although the levels were lower than in the very-low frequency band.

Station 7 shows a wider range of sound levels in the low frequency band in each month compared to the levels from of the deep stations (17, 19, 04, 05). This is because in the absence of nearby anthropogenic sound sources, the levels at Station 7 are mostly driven by underwater noise from wind-driven wave activity, which is significantly higher during winter (November through March).

The mid-frequency band (225-2250 Hz, Figure 5-48) is the highest band affected by human-related sound sources at the resolution of this analysis. A geophysical survey near Station 19 affected sound levels in June and July. All stations showed a decrease in average sound levels in the summer months due to lower average wind speeds. In the case of Station 18, the reduced sound levels in this band from the platforms is likely associated with a change in propagation conditions that kept more of the high frequency sounds close to the surface and away from the bottom recorders (see Section 5.6.3).

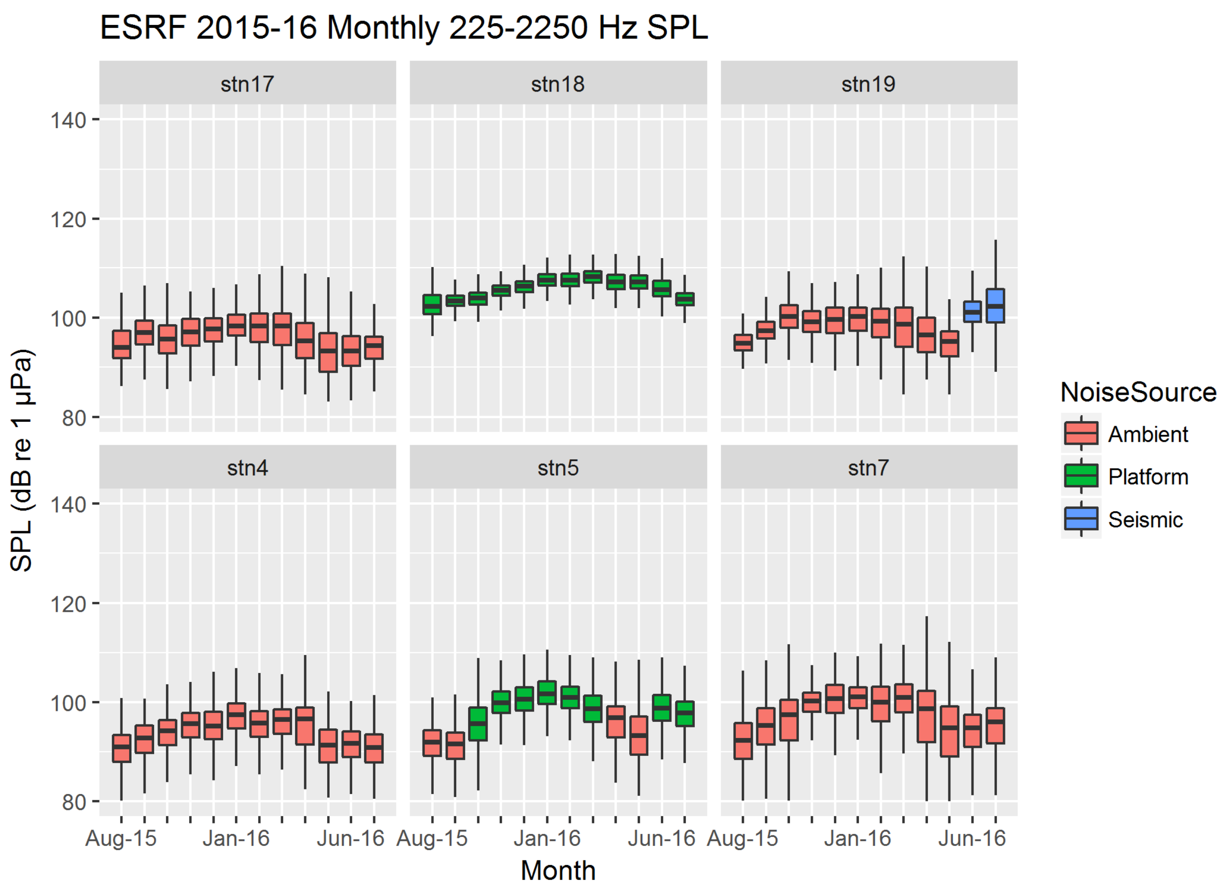


Figure 5-48 225-2,250 Hz Band: Distribution of one-minute SPL for Selected Locations from JASCO's 2015-2016 ESRF Data Set

Notes: Stations 7 and 18 are at <100 m water depth and Stations 4, 5, 17, and 19 are at >1,000 m. All measurements were within 10 m of the seabed. Stations 4 and 5 are located off the southwestern Scotian Shelf and represent examples of deep-water recordings with and without significant man-made noise sources. Station 5 is 13 km from Shell's Monteray Jack drilling campaign using the Stena IceMax. Station 18 is 35 km from the Hibernia platform.

In the high frequency band (2,250-18,000 Hz, Figure 5-49), all six measurement locations show a cycle of lower sound levels in summer and higher sound levels in winter. The absolute levels and spread of sound levels are similar at all stations.

In the very-high frequency band (18,000-90,000 Hz Figure 5-50), the levels shown are known to contain artifacts, caused by hydrophone-self noise frequently exceeding the environmental noise. Higher quality hydrophones were deployed in 2016-2017 to remediate this problem (data not available).

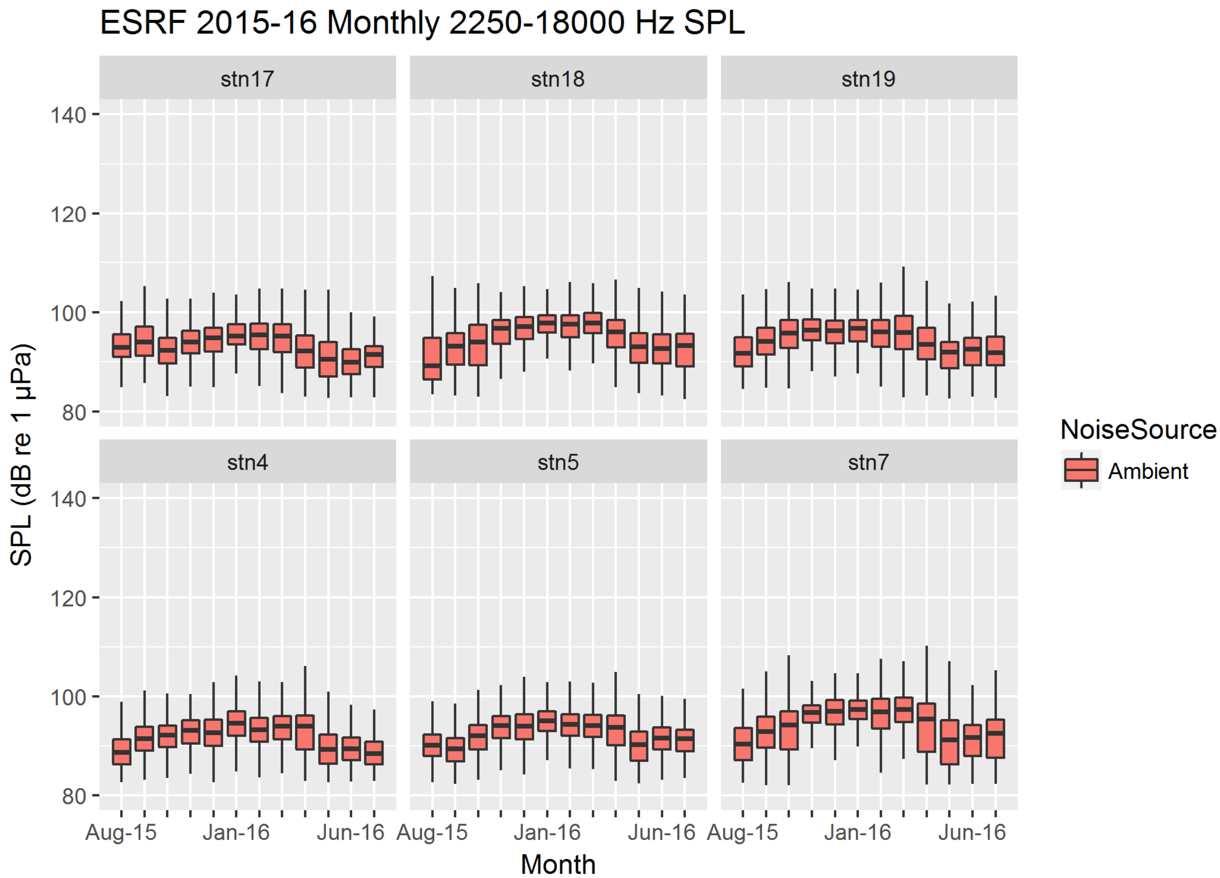


Figure 5-49 2,250-18,000 Hz band: Distribution of one-minute SPL for selected locations from JASCO's 2015-2016 ESRF data set.

Notes: Stations 7 and 18 are at <100 m water depth and Stations 4, 5, 17, and 19 are at >1000 m. All measurements were within 10 m of the seabed. Stations 4 and 5 are located off the southwestern Scotian Shelf and represent examples of deep-water recordings with and without significant man-made noise sources. Station 5 is 13 km from Shell's Monteray Jack drilling campaign using the Stena IceMax. Station 18 is 35 km from the Hibernia platform.

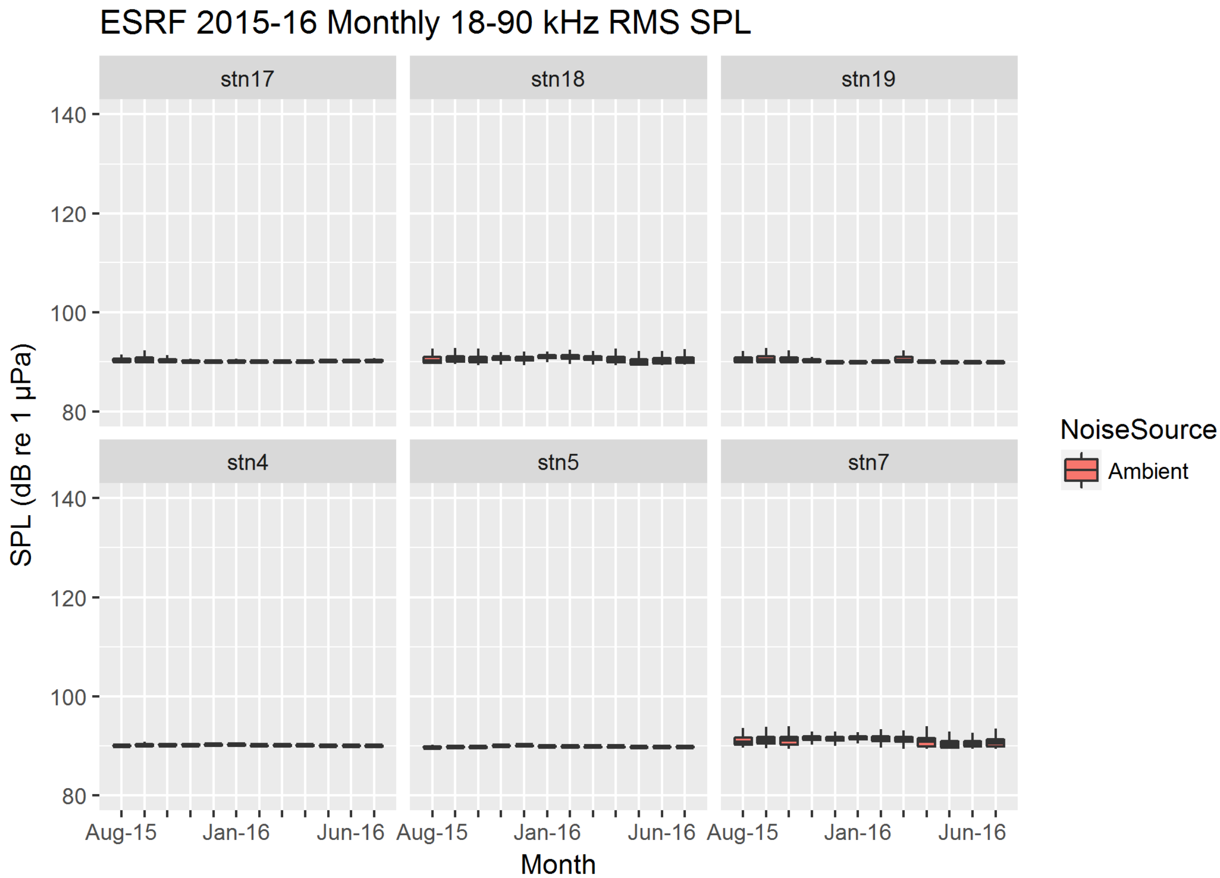


Figure 5-50 18,000-90,000 Hz Band: Distribution of One-Minute SPL for Selected Locations from JASCO's 2015-2016 ESRF Data Set

Notes: stations 7 and 18 are at <100 m water depth and Stations 4, 5, 17, and 19 are at >1000 m. All measurements were within 10 m of the seabed. Stations 4 and 5 are located off the southwestern Scotian Shelf and represent examples of deep-water recordings with and without significant man-made noise sources. Station 5 is 13 km from Shell's Monteray Jack drilling campaign using the Stena IceMax. Station 18 is 35 km from the Hibernia platform.

5.6.3 Effects of Vessels on the Soundscape

At Station 8, vessel occurrence is continuous and expected due to the close proximity of the Cabot Strait shipping lanes (Figure 5-51). Vessel traffic detected at Station 19 likely reflects the supply vessels for the West Hercules travelling between the drilling operation and Newfoundland. Traffic was detected at Station 4, with a reduction in the winter similar to Station 19. The reduction is due both to reduced traffic, shorter propagation ranges, and increased environmental noise masking sound from distant vessels making them difficult to detect. At Station 18, individual vessels were detected on most days; however, they rarely passed close enough to the recorder to be notable peaks in the daily SEL plot.

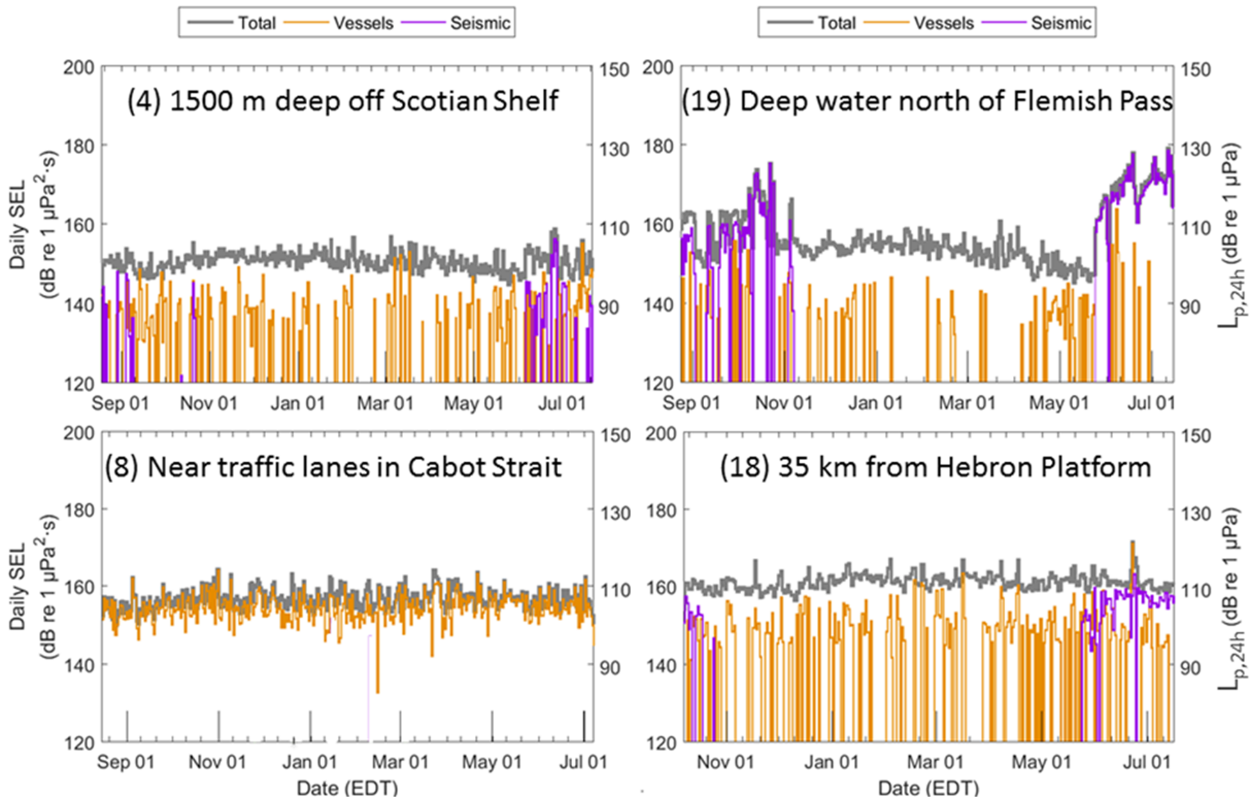


Figure 5-51 Daily Unweighted Sound Exposure levels for Stations 4, 19, 8, and 18

Station 8 is included in Figure 5-51 as an example of the effects of vessel traffic compared to the dynamic positioning sound associated with the oil and gas production platforms. Vessels passed by this location at ranges of 2-10 km on most days, increasing the SEL from the baseline of 150-155 dB re 1 μPa²·s (e.g., Station 4) to 155-165 dB re 1 μPa²·s, or approximately a 10-fold increase in energy, which is similar to the location 35 km from the Hibernia platform. Vessels near Station 8 generally traveled alone and were thus easier for the detector to identify and hence the vessel SEL curve closely matches the total SEL curve. Because vessels dominate the daily SEL, the winter increase in ambient sound is not observed at Station 8 compared to Stations 4 and 19.

5.6.4 Summary of Effects of Sources on the Soundscape

There are four identifiable sources in the Project Area that may have long term effects on the soundscape:

1) *Fin whales*: Fin whales sing from October to March on the Grand Banks. They seem to favour the shallow waters on the Grand Banks compared to the deeper waters off the continental shelf. Their constant notes raise the total sound level in the 10-45 Hz band by 5-10 dB in winter across the Grand Banks and Scotian Shelf. Whales close to a recorder can temporarily increase the one-minute sound levels to 130 or 140 dB re 1 μPa.

2) *Platforms*: Oil and gas exploration and production activities and the associated support vessels increased the SPL in the band of approximately 40-225 Hz by 15-20 dB at ranges of 35 km from a collection of three platforms in shallow water, and 8-10 dB for a single dynamically positioned drilling installation 13 km away in deep water. The sound levels in the band of 225-2,250 Hz were elevated 5-10 dB in both locations. The production platforms are continuous noise sources that cause permanent elevations in the background sound levels. The West Hercules produced tonal sounds that increased the broadband received levels at 13 km by 8-10 dB. The tonal sounds were detectable 230 km away; however, they did not increase the broadband sound levels.
3) *Geophysical Surveys*: Geophysical surveys are known to be one of the most intense sound sources in the ocean (McCauley et al. 2000, Gordon et al. 2003, Nieukirk et al. 2012). The geophysical surveys detected at Station 17 and Station 19 were over 100 km from the recorders and still a dominant sound source. Geophysical array sound's peak frequency is near 50 Hz (Dragoset 1984); however, the frequency range increases as the source vessel gets closer to a measurement location. The measurements reported here included energy up to 1 kHz.
4) *Ambient*: Median sound levels increase 3-5 dB in the winter due to higher wind speeds and storms. The peak frequency band for wind noise is 200-2,000 Hz.

5.7 Ice Conditions

Portions of the Project Area are subject to seasonal incursions of sea ice and icebergs, as well as marine icing during certain wind, wave, and air temperature conditions. Sea ice and iceberg conditions vary each year and by location, and are influenced by colder or milder winter conditions over Newfoundland and the surrounding waters, and seasonal wind patterns. Cold and dry winds from the west through north have the effect of moving ice farther offshore, while northeasterly winds tend to bring ice towards shore. Any of these factors may influence the distribution of ice over the Project Area.

5.7.1 Sea Ice

This section provides an overview of the sea (drift or pack) ice conditions most likely to be encountered in the Project Area. Information is drawn from the CIS Sea Ice Climatic Atlas for the East Coast 1981-2010 (CIS 2011). The atlas includes three key separate statistical analyses of conditions: i) frequency of presence of sea ice; ii) median of ice concentration when ice is present, and iii) median of predominant ice type when ice is present. Thickness can be inferred from ice type. The 1980-2010 atlas provides most recent and comprehensive description of sea ice conditions in the region.

Given that the CIS Regional Ice Charts are not always prepared on the same dates each year, a seven-day period centered on historical dates is used in the atlas. The atlas climate data represent information from charts within three days on either side of the historical date. For example, the chart for historical date 15 January is representative for the period 12 to 18 January.

As noted in the Ice Atlas, variations in the extent of ice over East Coast waters, and hence the Project Area, are great due to both winds and temperatures being effective in changing the location of the ice edge. A large variability in sea ice conditions can therefore be experienced from year to year, and also in a given year, on time scales of days to weeks and over comparatively small geographic scales of tens of kilometres.

To characterize overall conditions, the sea ice is described for four representative "quadrants" over the Project Area – Northern Section and a west and east portion of the Project Area – Southern Section. An approximate midpoint of each quadrant or half was selected (as illustrated in Figure 5-52), which was overlaid on each of the weekly atlas charts. The corresponding frequency of ice presence, ice concentration and ice type was noted for all weeks across the six sub-regions. The resulting tabulations are presented in Tables 5.31 to 5.33. Values are colour-coded to show at a glance the weekly change in ice conditions for all four locations of the Project Area – Northern Section and for the two locations of the Project Area – Southern Section. It is emphasized that for simplicity these tables report just one value for each of the six sub-regions whereas conditions may vary considerably across a specific sub-region. While some of the variation in conditions near these midpoints and in a given sub-region is discussed below, for a higher resolution study the atlas (CIS 2011) should be consulted. It is further noted that conditions reported here are from climatology and each year will be different.

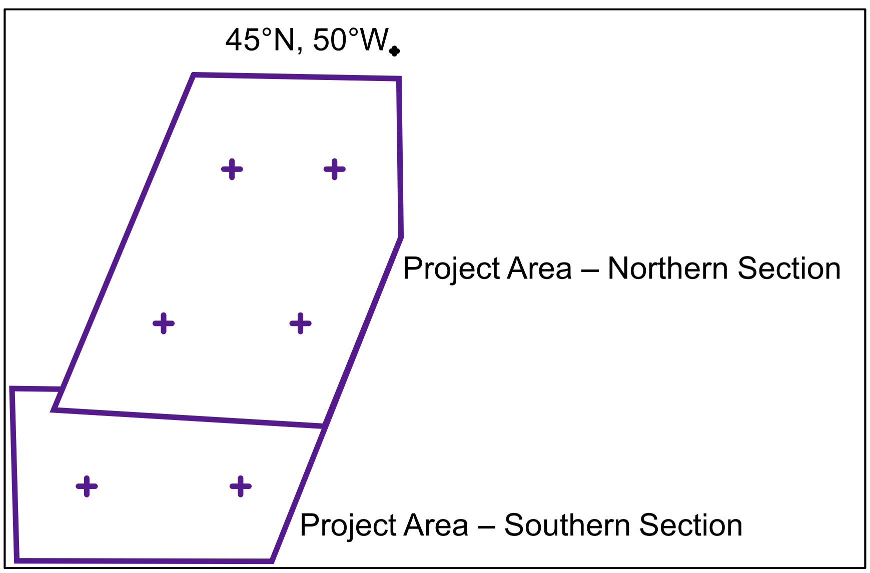


Figure 5-52 Project Area Locations Used for Sea Ice Characterization

Table 5.31 Frequency of Presence of Sea Ice (%)

Frequency of Presence of Sea Ice (%)

Week	Project Area - Northern Section - Northwest	Project Area - Northern Section - Northeast	Project Area - Northern Section - Southwest	Project Area - Northern Section - Southeast	Project Area - Southern Section - West	Project Area - Southern Section - East
Jan 08	0%	0%	0%	0%	0%	0%
Jan 15	0%	0%	1-15%	0%	0%	1-15%
Jan 22	0%	0%	1-15%	0%	0%	1-15%
Jan 29	0%	0%	1-15%	0%	0%	1-15%
Feb 05	0%	0%	1-15%	1-15%	1-15%	1-15%
Feb 12	0%	0%	16-33%	1-15%	1-15%	1-15%
Feb 19	0%	0%	16-33%	1-15%	1-15%	1-15%
Feb 26	1-15%	0%	16-33%	1-15%	1-15%	1-15%
Mar 05	0%	0%	16-33%	1-15%	1-15%	16-33%
Mar 12	1-15%	0%	34-50%	1-15%	1-15%	1-15%
Mar 19	1-15%	0%	16-33%	1-15%	1-15%	1-15%
Mar 26	1-15%	0%	16-33%	1-15%	1-15%	16-33%
Apr 02	0%	0%	16-33%	1-15%	1-15%	1-15%
Apr 09	0%	0%	16-33%	1-15%	1-15%	1-15%
Apr 16	0%	0%	1-15%	1-15%	1-15%	1-15%
Apr 23	0%	0%	1-15%	0%	0%	1-15%
Apr 30	0%	0%	1-15%	0%	0%	1-15%
May 07	0%	0%	0%	0%	0%	0%
May 14	0%	0%	0%	0%	0%	0%
May 21	0%	0%	1-15%	0%	0%	0%
May 28	0%	0%	1-15%	0%	0%	0%
Jun 04	0%	0%	0%	0%	0%	1-15%

Legend

0%	51-66%
1-15%	67-84%
16-33%	85-99%
34-50%	100%

Source: based on CIS 2011

Table 5.32 Median of Ice Concentration, When Ice is Present

Median of Ice Concentration When Ice is Present

Week	Project Area - Northern Section - Northwest	Project Area - Northern Section - Northeast	Project Area - Northern Section - Southwest	Project Area - Northern Section - Southeast	Project Area - Southern Section - West	Project Area - Southern Section - East
Jan 08	less than 1/10	less than 1/10	less than 1/10	less than 1/10	less than 1/10	less than 1/10
Jan 15	less than 1/10	less than 1/10	1-3/10	less than 1/10	less than 1/10	1-3/10
Jan 22	less than 1/10	less than 1/10	4-6/10	less than 1/10	less than 1/10	4-6/10
Jan 29	less than 1/10	less than 1/10	7-8/10	less than 1/10	less than 1/10	7-8/10
Feb 05	less than 1/10	less than 1/10	9-9+1/0	1-3/10	7-8/10	4-6/10
Feb 12	less than 1/10	less than 1/10	4-6/10	4-6/10	1-3/10	7-8/10
Feb 19	less than 1/10	less than 1/10	7-8/10	4-6/10	9-9+1/0	4-6/10
Feb 26	4-6/10	less than 1/10	7-8/10	1-3/10	9-9+1/0	4-6/10
Mar 05	less than 1/10	less than 1/10	7-8/10	4-6/10	7-8/10	7-8/10
Mar 12	1-3/10	less than 1/10	4-6/10	4-6/10	7-8/10	4-6/10
Mar 19	1-3/10	less than 1/10	7-8/10	7-8/10	7-8/10	9-9+1/0
Mar 26	1-3/10	less than 1/10	7-8/10	4-6/10	4-6/10	7-8/10
Apr 02	less than 1/10	less than 1/10	7-8/10	9-9+1/0	7-8/10	4-6/10
Apr 09	less than 1/10	less than 1/10	1-3/10	9-9+1/0	4-6/10	1-3/10
Apr 16	less than 1/10	less than 1/10	4-6/10	4-6/10	4-6/10	4-6/10
Apr 23	less than 1/10	less than 1/10	1-3/10	less than 1/10	less than 1/10	4-6/10
Apr 30	less than 1/10	less than 1/10	7-8/10	less than 1/10	less than 1/10	1-3/10
May 07	less than 1/10	less than 1/10	less than 1/10	less than 1/10	less than 1/10	less than 1/10
May 14	less than 1/10	less than 1/10	less than 1/10	less than 1/10	less than 1/10	less than 1/10
May 21	less than 1/10	less than 1/10	1-3/10	less than 1/10	less than 1/10	less than 1/10
May 28	less than 1/10	less than 1/10	1-3/10	less than 1/10	less than 1/10	less than 1/10
Jun 04	less than 1/10	less than 1/10	less than 1/10	less than 1/10	less than 1/10	1-3/10

Legend
- less than 1/10
- 1-3/10
- 4-6/10
- 7-8/10
- 9-9+1/0
- 10/10

Source: based on CIS 2011

Table 5.33 Median of Predominant Ice Type, When Ice is Present

Median of Predominant Ice Type When Ice is Present

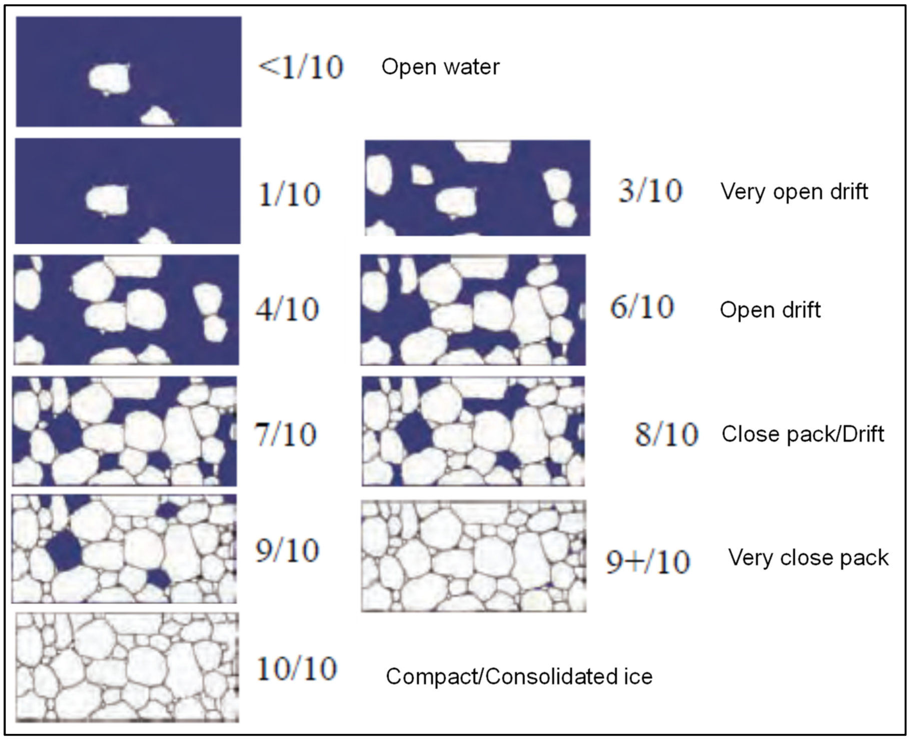
Week	Project Area - Northern Section - Northwest	Project Area - Northern Section - Northeast	Project Area - Northern Section - Southwest	Project Area - Northern Section - Southeast	Project Area - Southern Section - West	Project Area - Southern Section - East
Jan 08	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water
Jan 15	Open or Bergy Water	Open or Bergy Water	Grey-White Ice	Open or Bergy Water	Open or Bergy Water	Grey-White Ice
Jan 22	Open or Bergy Water	Open or Bergy Water	Grey-White Ice	Open or Bergy Water	Open or Bergy Water	Grey-White Ice
Jan 29	Open or Bergy Water	Open or Bergy Water	Grey-White Ice	Open or Bergy Water	Open or Bergy Water	Grey-White Ice
Feb 05	Open or Bergy Water	Open or Bergy Water	Grey Ice	New Ice	Grey Ice	Grey-White Ice
Feb 12	Open or Bergy Water	Open or Bergy Water	Grey-White Ice	Grey-White Ice	Grey-White Ice	Grey-White Ice
Feb 19	Open or Bergy Water	Open or Bergy Water	Thin FY Ice	Grey-White Ice	Grey-White Ice	Thin FY Ice
Feb 26	Thin FY Ice	Open or Bergy Water	Thin FY Ice	Thin FY Ice	Thin FY Ice	Grey-White Ice
Mar 05	Open or Bergy Water	Open or Bergy Water	Thin FY Ice	Thin FY Ice	Thin FY Ice	Thin FY Ice
Mar 12	Thin FY Ice	Open or Bergy Water	Thin FY Ice	Thin FY Ice	Thin FY Ice	Thin FY Ice
Mar 19	Medium FY Ice	Open or Bergy Water	Thin FY Ice	Medium FY Ice	Thin FY Ice	Thin FY Ice
Mar 26	Thin FY Ice	Open or Bergy Water	Medium FY Ice	Medium FY Ice	Thin FY Ice	Thin FY Ice
Apr 02	Open or Bergy Water	Open or Bergy Water	Medium FY Ice	Thick FY Ice	Thin FY Ice	Medium FY Ice
Apr 09	Open or Bergy Water	Open or Bergy Water	Medium FY Ice	Thick FY Ice	Thick FY Ice	Medium FY Ice
Apr 16	Open or Bergy Water	Open or Bergy Water	Medium FY Ice	Thin FY Ice	Medium FY Ice	Medium FY Ice
Apr 23	Open or Bergy Water	Open or Bergy Water	Thick FY Ice	Open or Bergy Water	Open or Bergy Water	Medium FY Ice
Apr 30	Open or Bergy Water	Open or Bergy Water	Old Ice	Open or Bergy Water	Open or Bergy Water	Thick FY Ice
May 07	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water
May 14	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water
May 21	Open or Bergy Water	Open or Bergy Water	Thin FY Ice	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water
May 28	Open or Bergy Water	Open or Bergy Water	Thick FY Ice	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water
Jun 04	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Open or Bergy Water	Old Ice

Legend

- Open or Bergy Water
- New Ice
- Grey Ice
- Grey-White Ice
- Thin FY Ice
- Medium FY Ice
- Thick FY Ice
- Old Ice

Source: based on CIS 2011

To accompany Table 5.31, Figure 5-53 (derived from the MANICE publication (CIS 2005)) illustrates the scale in which ice concentration is reported, from open water (ice concentration of less than 1/10) to compact/consolidated ice (10/10 concentration). To accompany Table 5.33, Table 5.34 from MANICE (CIS 2005) lists the stages of sea ice development that occur together with their associated thickness.



Source: CIS (2005)

Figure 5-53 Ice Concentrations from an Aerial Perspective

Table 5.34 Stage of Development, Sea Ice

Description	Thickness
New	<10 cm
Nilas; Ice rind	<10 cm
Young	10-30 cm
Grey	10-15 cm
Grey-white	15-30 cm
First-year	≥30 cm
Thin first-year	30-70 cm
Medium first-year	70-120 cm
Thick first-year	>120 cm
Source: CIS (2005)	

In general, for this part of the Northwest Atlantic Ocean, for a given week during the ice season, the sea ice is more likely of greater concentration and thickness in the western portions and less severe farther offshore to the east. With passing weeks, as the ice advances, there is potential that thicker sea ice to the west and north will continue to drift farther offshore (south and east).

There is also potential for landfast ice nearshore, which is ice that forms and remains fast along the coast and can extend from a few metres to several hundred kilometres offshore. Landfast ice has the potential to influence conditions within the potential vessel and aircraft traffic routes near to St. John's; however, it is unlikely to be a factor in the Project Area itself.

5.7.1.1 Project Area – Northern Section

5.7.1.1.1 Southwestern Quadrant

Within the Project Area – Northern Section, sea ice is most prevalent over the southwestern quadrant as this region sees the greatest influx of ice that drifts south from Labrador and the northeast coast of Newfoundland and out onto the Grand Banks and east over the Orphan Basin and Flemish Pass. The following discussions are with reference to Tables 5.31 to 5.33.

Ice is present here as early as the week of 15 January and as late as the last week of May, although in May it is only in the form of small intrusions into the western portion of the Project Area. From mid-January through to the beginning of February the frequency of presence of sea ice is 1 to 15 percent, or about as frequent as every six or seven years. This likelihood of ice doubles from the week of 12 February to the week of 9 April. From late February through the week of 19 March ice can be expected up to one-third to one-half of the time in the most southwestern portion of the Project Area – Northern Section.

In mid-January ice concentration is generally 1 to 3/10 with the predominant ice type being grey-white. By the end of January, the ice is predominantly grey-white in 7 to 8/10 concentration, with some patches of 9 to 9+/10, and with some newer grey ice (10-15 cm) to the west. New ice can be expected extending to the east and southeast by the first week of February. By mid-February it is mostly grey-white ice but also patches of thin first-year (FY) ice (ice of not more than one winter's growth, 30-70 cm) that are predominant. Mostly thin FY ice may be present through mid-March with the potential for small patches of 9 to 9+/10.

Beginning approximately the week of 19 March medium FY ice might be expected, and by April some thick FY ice may be present. During the week of 16 April, as the ice begins to retreat, there is potential for a mix of thin, medium, and thick FY ice in concentrations generally of 4 to 6/10 but also small patches of 9 to 9+/10 concentration towards the west. The week of 16 April also shows the potential presence of old ice (ice that has survived at least one summer's melt; second year ice will be generally thicker than FY ice) to the north between 48 and 49°N and 46.5 and 48°W. By the end of April ice present is mostly thick FY with some thick and medium FY in concentrations from less than 1/10 to 7 to 8/10. Old ice is again present the week of 30 April. Through May it is much smaller sized areas of medium and thick FY ice that reach into the western portion of this quadrant at concentrations generally of 1 to 3/10.

5.7.1.1.2 Northwestern Quadrant

Over the northwestern quadrant of the Project Area – Northern Section, there is a 1 to 15 percent likelihood of sea ice in a week, from the first week of February through the first three weeks of April, although this ice presence is generally confined to the south or west (i.e., there is open water to the north and east). Grey ice and new ice are present in concentrations of 1 to 3/10 the first week of February. Through February the ice is generally 4 to 6/10 and 7 to 8/10 concentration. By the end of February and beginning of March the ice is thin FY in concentrations of 4 to 6/10. The highest concentrations are evident approximately the week of 12 March with 7 to 8/10 and some 9 to 9+/10 thin FY ice. For the last half of March, when present, the ice is predominantly in concentrations of 1 to 3/10 and 4 to 6/10. In the southernmost part of this quadrant thick FY (9 April) and old ice (16 April) are present historically (1 to 15 percent of the time) at concentrations of 1 to 3/10.

5.7.1.1.3 Southeastern Quadrant

The southeastern quadrant of the Project Area – Northern Section has a likelihood of sea ice similar to that of the northwestern portion, with ice present 1 to 15 percent of the time from the first week of February through the first three weeks of April, with the exception that in March the likelihood is generally 16 to 33 percent in the western portion. During the first week of February, when present, the ice is in concentrations of 1 to 6/10. Through February the ice is generally 4 to 6/10 and 7 to 8/10 concentration and comprised of mostly grey-white but also thin FY ice. By the beginning of March the ice is thin FY in concentrations of 4 to 6/10.

The greatest ice concentrations are seen approximately the week of 19 March with 7 to 8/10 of medium FY together with some patches of 9 to 9+/10 grey-white ice at the eastern boundary of the Project Area. For the last week of March ice may be present as thin and medium FY with the possibility of some thick FY ice to the southeast corner of this quadrant. Concentrations are generally 1 to 3/10 and 4 to 6/10 in the eastern portion and 7 to 8/10 to the west. For the week of 2 April ice is mostly thick FY at concentrations of 9 to 9+1/0 and 7 to 8/10. Into the next week thick FY ice can persist to the north with medium FY ice to the south. Concentrations over the quadrant at this time are mostly 1 to 3/10 with some 9 to 9+/10 towards the north as well as some patches of less than 1/10. In the southernmost part of this quadrant thick FY (9 April) and old ice (16 April) are present historically (1 to 15 percent of the time) at concentrations of 1 to 3/10. During the week of 16 April there may be thin FY ice towards the west at concentrations of up to 6/10 with open water (<1/10) to the east.

5.7.1.1.4 Northeastern Quadrant

Based on the atlas, sea ice in the northeastern quadrant of the Project Area – Northern Section is infrequent and generally confined to the south reaches at approximately 48 to 49°N. No ice is reported for this sub-region's midpoint location.

The week of 26 March (illustrated in Figure 5-54) shows the median of predominant ice type when the ice season is at its peak in terms of ice extent and presence of FY ice over the Project Area – Northern Section.

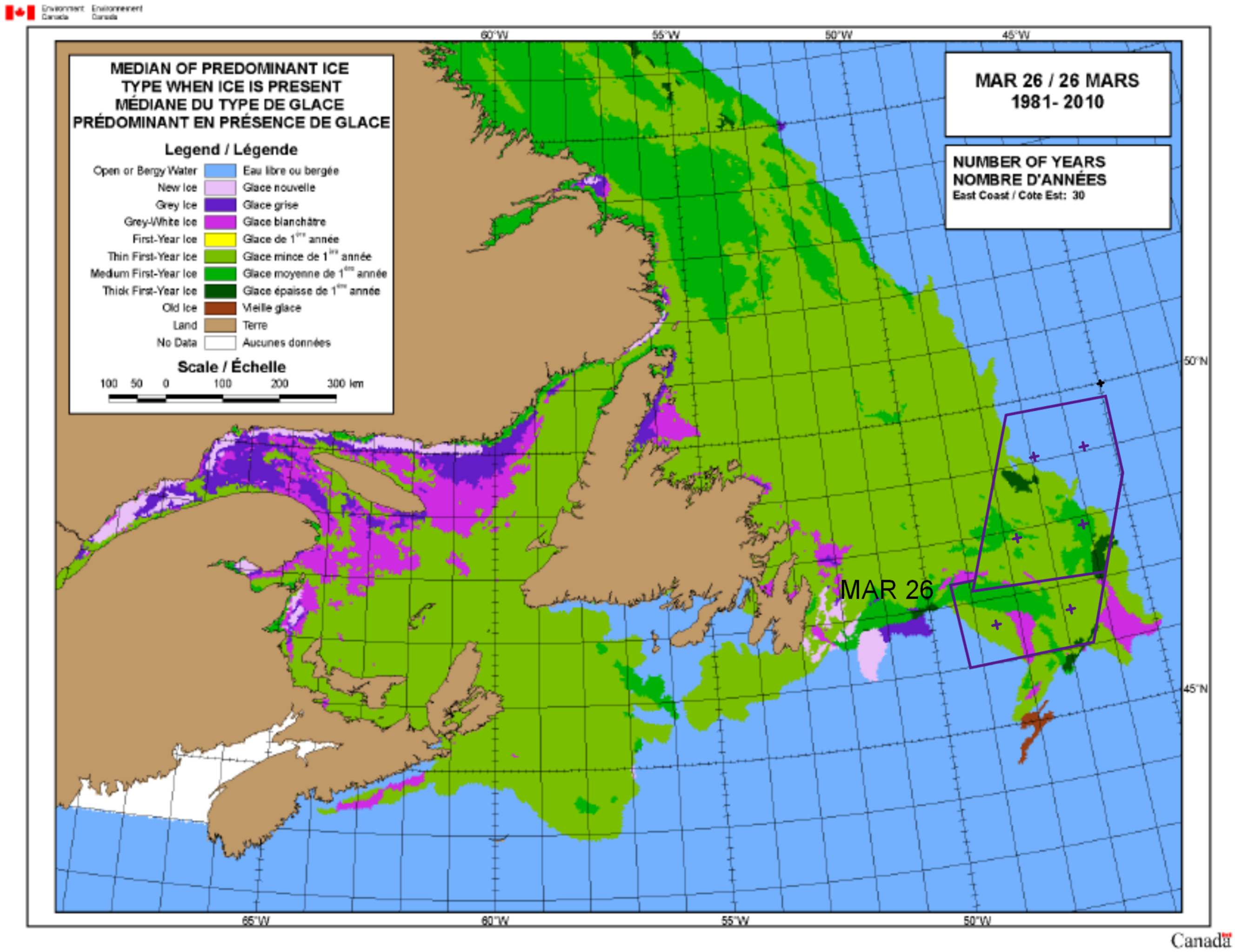


Figure 5-54 Median of Predominant Ice Type When Ice Is Present, Week of Mar 26

5.7.1.2 Project Area – Southern Section

Sea ice is most likely to occur over the northern portion of the Project Area – Southern Section and with a frequency of occurrence of 16 to 33 percent (or every three to six years). The sea ice presence here may typically last from mid-to-late February to the beginning of April. Sea ice is also expected over virtually all portions of the Project Area – Southern Section though somewhat less frequently (approximately every six to seven years) during mid-January to the end of April, though by mid-April the western portions are mostly ice free. May is generally free of ice throughout the Project Area – Southern Section, although the sea ice atlas reports a small patch of old ice (ice that has survived at least one summer's melt: second year ice will be generally thicker than first-year ice), towards the southeast corner in concentrations of 1 to 3/10 as late as the week of 4 June. The southwestern portion of the Project Area – Southern Section may typically experience sea ice for a shorter season, from mid-March to early April.

Sea ice will typically first drift from the northwest into the central portion of the Project Area – Southern Section during the week of 15 January. This will be grey-white ice in light concentrations of 1 to 3/10. By the following week grey and grey-white ice of concentrations as great as 9 to 9+/10 will be present together with ice of concentration 1 to 3/10 and 4 to 6/10. During the week of 29 January ice presence is mostly confined to a narrow strip running north-south in the eastern region consisting of 7 to 8/10 concentration of grey-white ice.

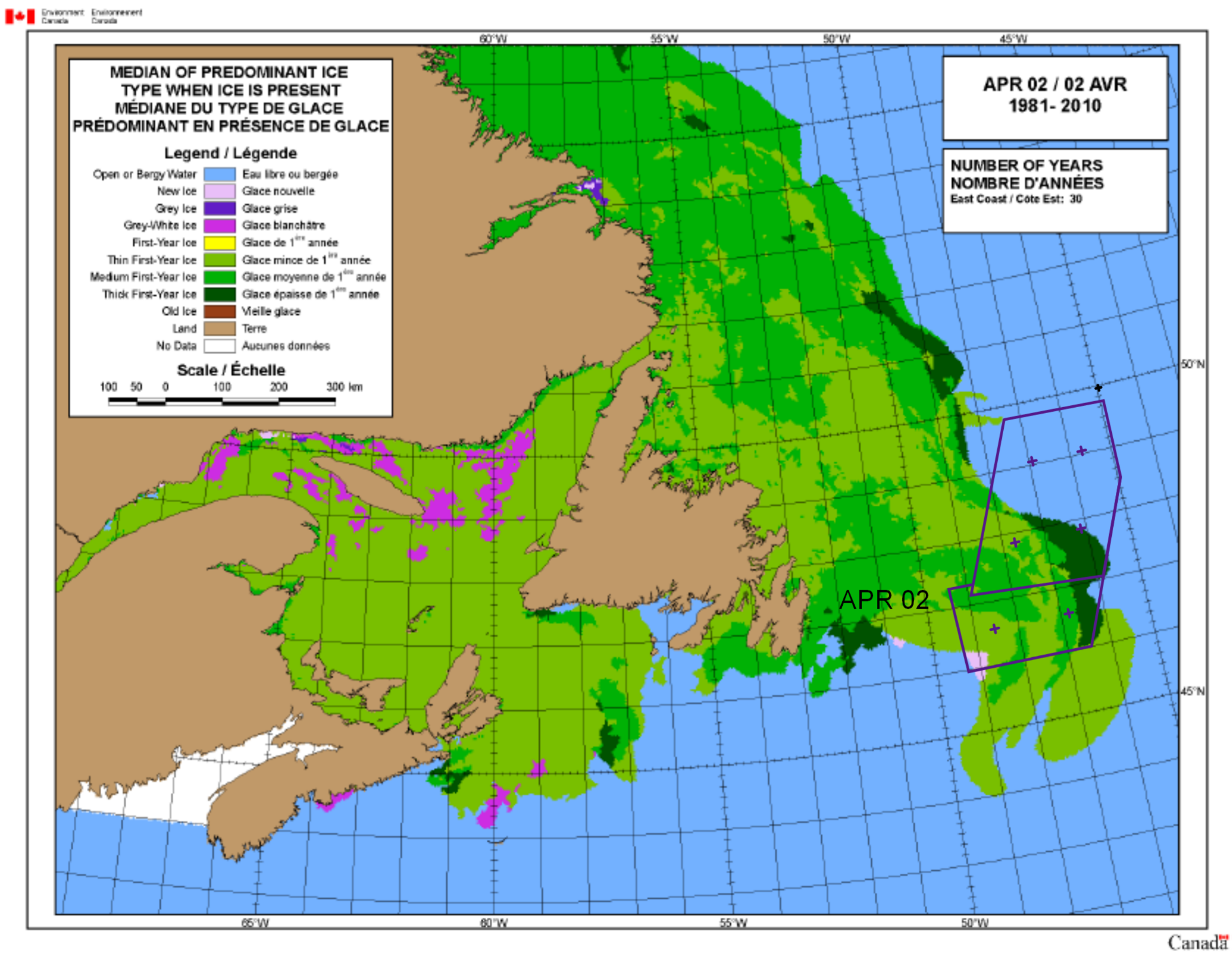
When ice is present at the beginning of February over the northwestern half of the Project Area – Southern Section it will be grey and grey-white ice in concentrations of 7 to 8/10 (to the west) and 4 to 6/10 (to the east). By the week of 12 February some thin FY ice (ice of not more than one winter's growth, 30-70 cm) may be present in the eastern portion of the Project Area – Southern Section; the remainder being grey-white ice. Ice concentrations range from 1 to 3/10 in the southwest and eastern limits to 4 to 6/10 in the northwest and 7 to 8/10, with some 9 to 9+/10 in the central region. Grey-white and thin FY ice can persist from the middle to the end of February, in concentrations of mostly 7 to 8/10 and 9 to 9+10, with lesser concentrations to the east.

In March, median ice concentrations when ice is present are mostly 4 to 6/10 and 7 to 8/10 with greater concentrations generally found over the central portion of the Project Area – Southern Section. In the first week of March, ice will be a mix of new, grey, and grey-white ice in the western portion and mostly thin FY ice to in the east. Thin FY ice is predominant through the rest of March with patches of medium FY (70-120 cm) appearing by the week of 19 March. During the week of 26 March the ice is a mix of medium and thin FY with some grey-white ice present in the south-central portion of the Project Area – Southern Section.

The greatest ice thicknesses can be expected in April. For the week of 2 April, thick FY ice (>120 cm) is the predominant ice type in 9 to 9+/10 concentrations over the eastern portion of the Project Area – Southern Section, while the remainder of the region is a mix of thin and medium FY ice of mostly 4 to 6/10 and 7 to 8/10 concentration. While the southwestern portion of the Project Area – Southern Section on average begins to be ice-free in the week of 9 April, predominantly medium FY ice and some thin FY ice in concentrations of 4 to 6/10 and 1 to 3/10 can be expected over the remaining portion. Greater concentrations of 7 to 8/10 over the central portion and 9 to 9+/10 to the northeast are also seen.

The retreat of sea ice from the eastern portions of the Project Area – Southern Section begins approximately the week of 16 April. Here, ice may still be expected over the central half of the Project Area – Southern Section, consisting of thick FY ice that lies from north to south surrounded by medium FY ice to the west and east, all in concentrations of mostly 4-6/10 with some 1 to 3/10. For the week of 23 April, except for possible ice intrusion to the northwest consisting of thick FY ice concentrations of 1 to 3/10, the western half of the Project Area – Southern Section is generally ice-free. Some medium FY ice of concentration 4 to 6/10 to as high as 9 to 9+/10 may be expected over much of the eastern half. By the last week of April, some thick FY ice in concentrations of 1 to 3/10 may persist in portions of the western half. No ice is expected from the week of 7 May onwards, except for the atlas's report of a trace of old ice

The week of 2 April (illustrated in Figure 5-55) shows the median of predominant ice type when the ice season is at its peak in terms of ice extent and presence of FY ice over the Project Area – Southern Section.



Source: CIS (2011)

Figure 5-55 Median of Predominant Ice Type When Ice Is Present, Week of Apr 02

5.7.1.3 Potential Vessel Traffic Routes

The potential for encountering sea ice while transiting existing and potential vessel traffic routes between St. John's and the Project Area exists from January to May. The greatest frequency of occurrence of sea ice is likely between February and early April at approximately 16 to 33 percent (or every three to six years) with some areas during the week of 12 March indicating a 34 to 50 percent likelihood (Figure 5-56). The greatest risks are likely encountering areas of potentially high ice concentration of 9 to 9+/10 in late February and March (e.g., Figure 5-57) and medium and thick first year ice (≥70 cm) from the end of March through the beginning of May (e.g., Figure 5-58).

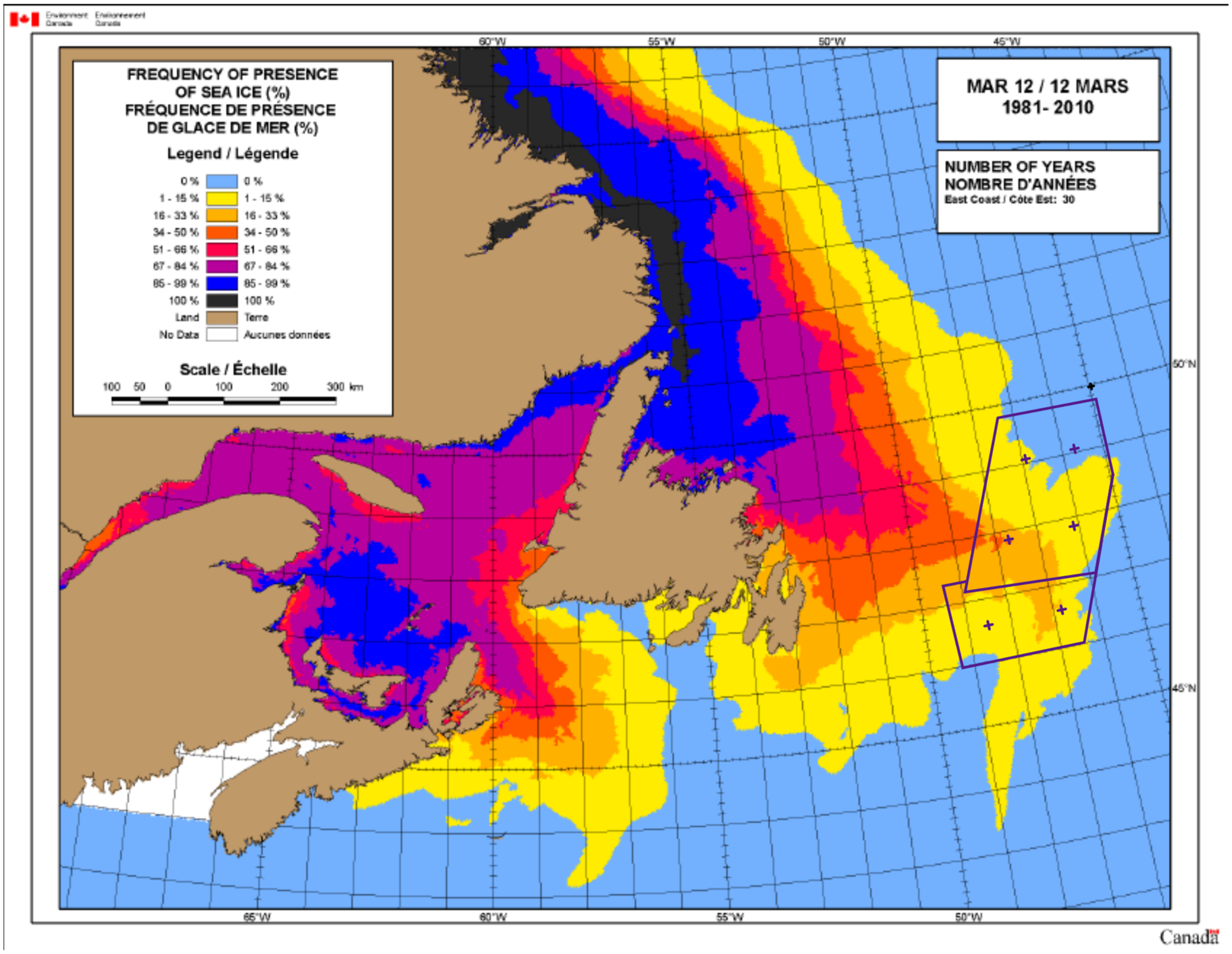


Figure 5-56 Frequency of Presence of Sea Ice, Week of Mar 12

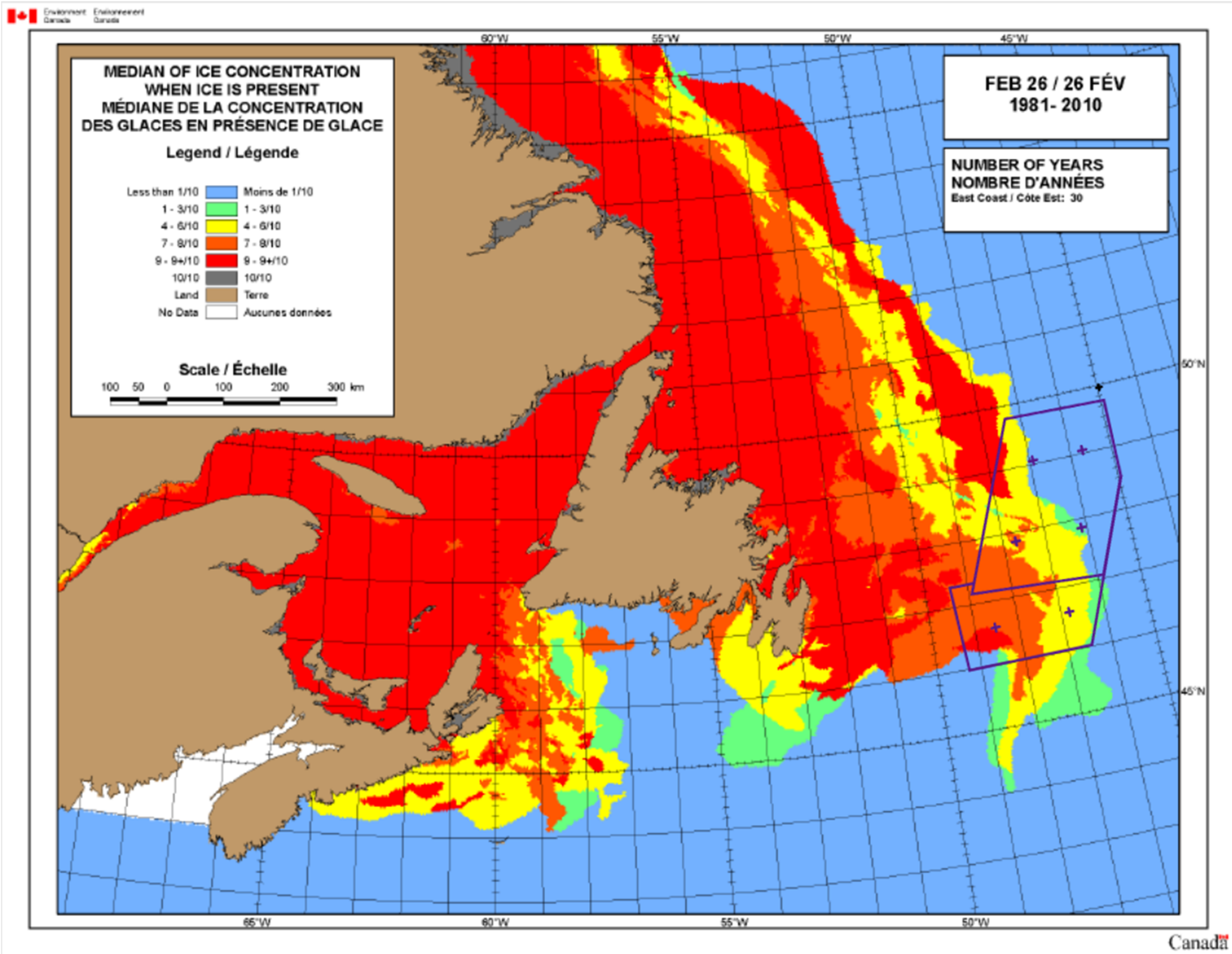


Figure 5-57 Median of Ice Concentration When Ice Is Present, Week of Feb 26

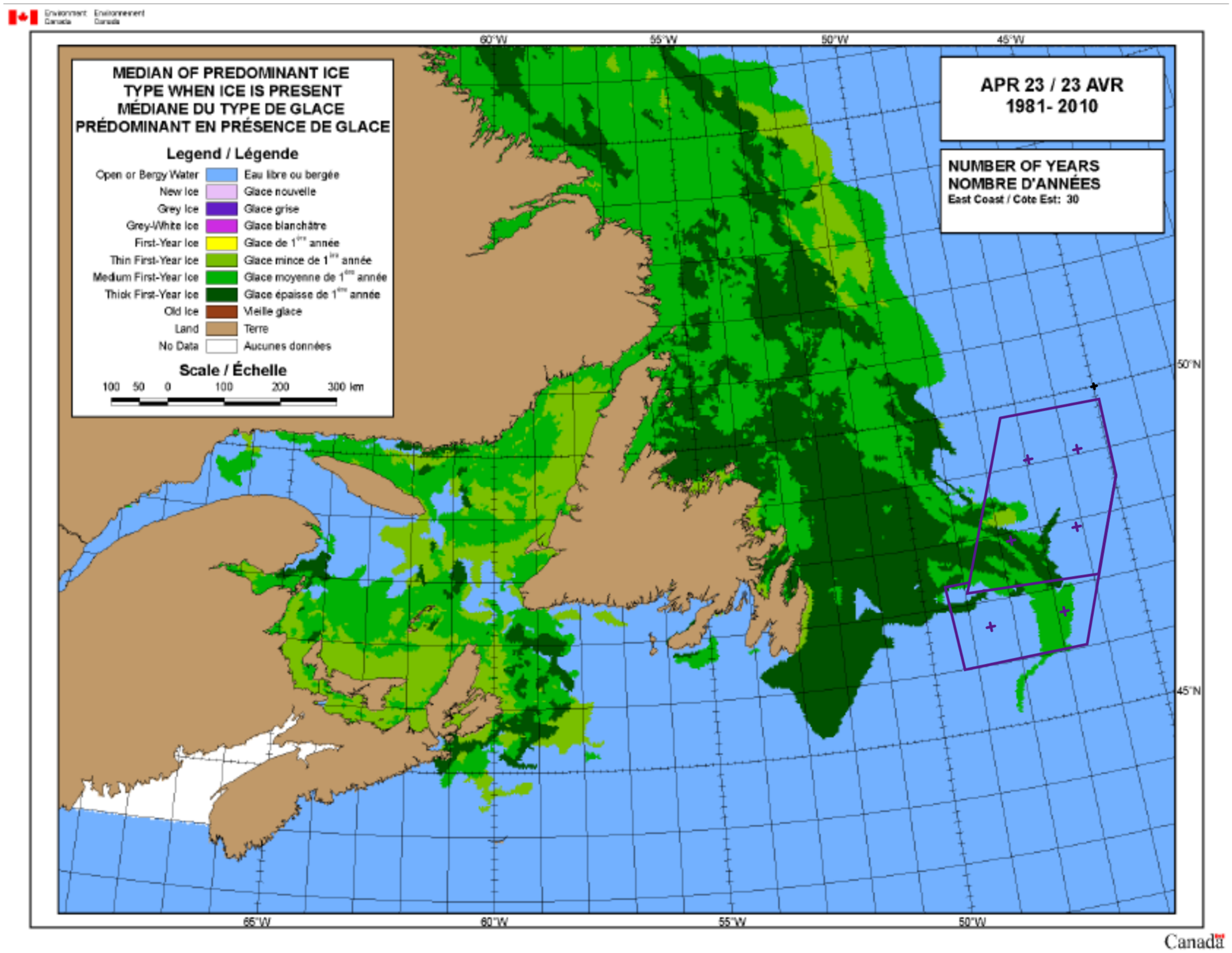


Figure 5-58 Median of Predominant Ice Type When Ice Is Present, Week of Apr 23

Further information on regional ice conditions in this area is provided in the Eastern Newfoundland SEA (Amec 2014), Section 4.1.5.

5.7.2 Icebergs

The East Coast of Newfoundland extending out to and including the Project Area can be high traffic areas for icebergs in their journeys south from the fjords of Greenland. Icebergs are masses of fresh water ice which calve each year from the glaciers along West Greenland. Icebergs are moved by both the wind and ocean currents, and typically spend one to three years travelling a distance up to approximately 2,900 km (1,800 miles) to the waters of Newfoundland. The West Greenland and Labrador Currents are major ocean currents, which move the icebergs around the Davis Strait, along the coast of Labrador, to the northern bays of Newfoundland, and to the Flemish Pass and the Grand Banks.

Icebergs exhibit little or no melting in sea temperatures of approximately 5°C or less while waves and warm air temperatures will tend to erode them in their travels. A medium iceberg (15-50 m high, 50-100 m long) will deteriorate in sea water of 4.4°C in approximately 10 days. Icebergs in sea ice may be less subject to wave erosion. Smaller icebergs are more difficult to detect in sea ice.

While each year is different, icebergs will typically appear offshore by February or March. Easterly and northeasterly winds will have the effect of moving icebergs towards the Newfoundland coast. Their usual path is southward with the ocean currents.

The summary of iceberg sightings for the Project Area presented here is based primarily on the comprehensive NRC-PERD Iceberg Sighting Database (Sudom et al. 2014; NRC 2015). The iceberg sightings are from various sources including industry, aircraft and ship, and include radar, visual and measured observations. Statistics are reported here for first iceberg sightings (excluding re-sightings of the same iceberg), and include size classes ranging from growlers (less than one meter in height, less than five meter in length and mass approximately 500 tonne) to very large icebergs (greater than 100 m in height, greater than 200 m in length, and mass over five Mtonnes). Icebergs of unknown size are also reported.

To provide a characterization of iceberg conditions, rectangular areas that contain the Project Area – Northern Section (four sub-regions: northwest, northeast, southwest, southeast) and Project Area – Southern Section (two sub-regions: west and east), as defined in Table 5.35 and shown in Figure 5-59, were queried for the past 30 years (1985-2014) and summary statistics are reported. Three sets of statistics for the number of icebergs by month and year are presented for each of the six sub-regions in the Project Area in Figures 5-60 to 5-62. Iceberg size statistics including indication of the usual iceberg height and length associated with each size are shown in Figure 5-63.

Table 5.35 Sub-Regions for Iceberg Characterization for the Project Area

Sub-Region	Southern Latitude (°N)	Northern Latitude (°N)	Eastern Longitude (°W)	Western Longitude (°W)
Project Area – Northern Section				
Flemish Pass: NW	48.5850	49.9200	46.8260	48.9027
Flemish Pass: NE	48.5850	49.9200	44.7500	46.8260
Flemish Pass: SW	47.2136	48.5850	46.8260	48.9027
Flemish Pass: SE	47.2136	48.5850	44.7500	46.8260
Project Area – Southern Section				
Jeanne d’Arc Basin: W	47.2136	47.4800	48.9027	49.6200
Jeanne d'Arc Basin: E	45.8900	47.2136	47.6450	49.6200

Data from 2013 and 2015 are absent from the 2015 PERD database release; however, observations for these years were accessed from the International Ice Patrol (IIP) Iceberg Sightings Database (IIP 1995, updated 2016) and are discussed below.

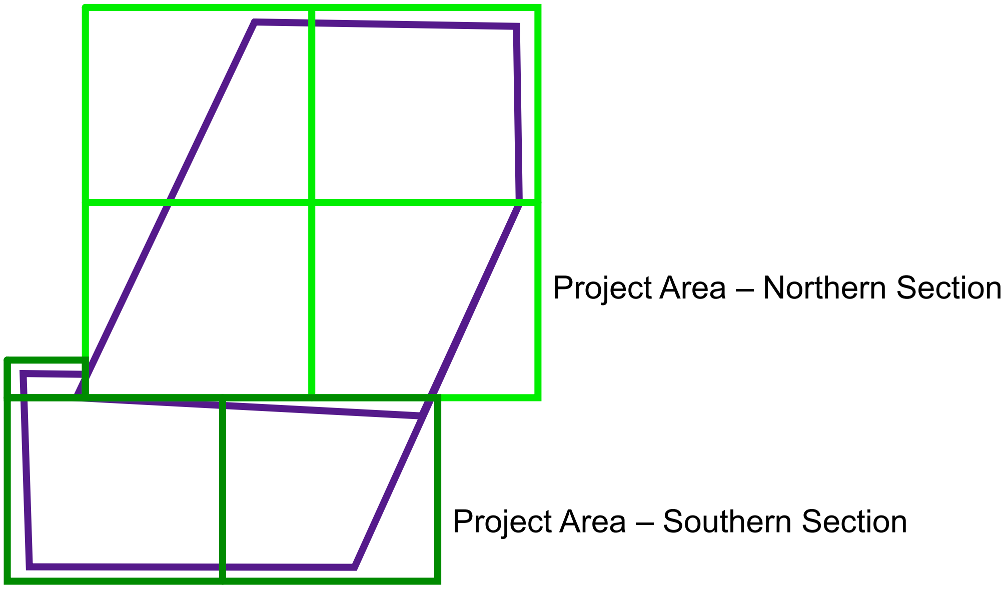
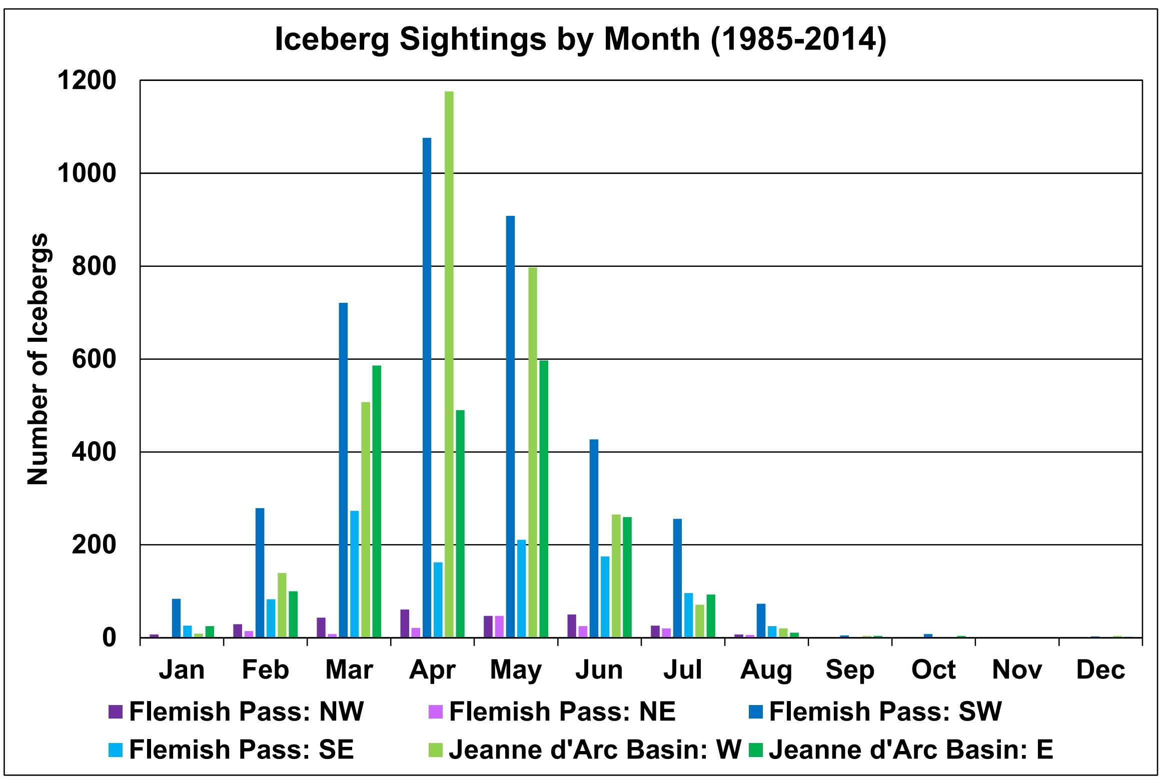
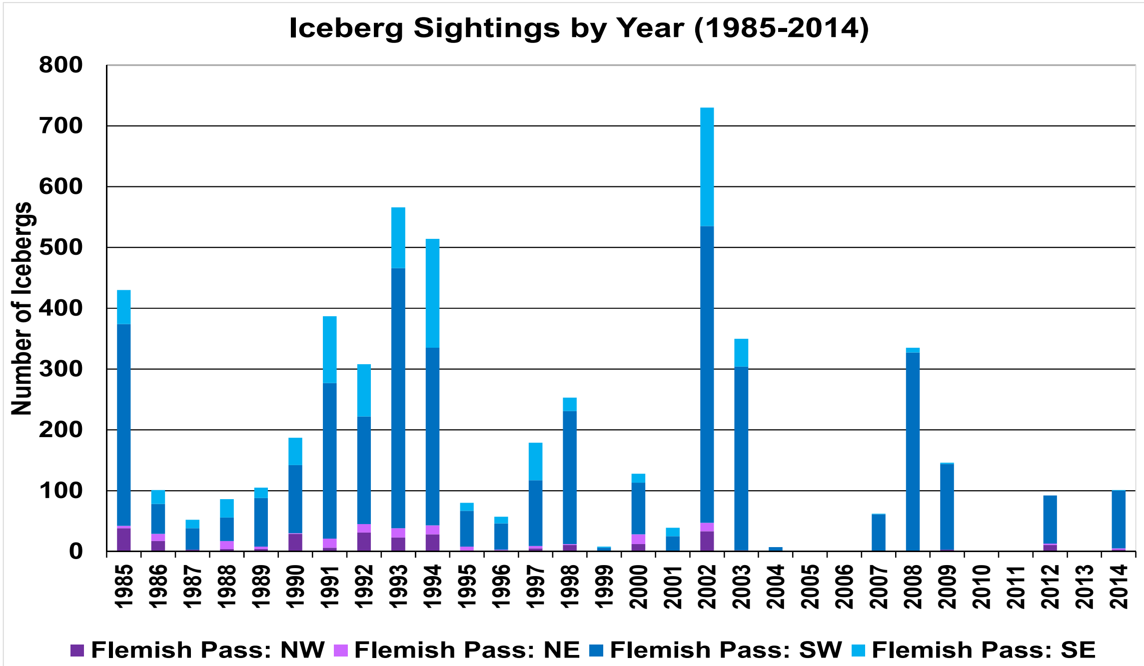


Figure 5-59 Sub-Regions for Iceberg Characterization for the Project Area



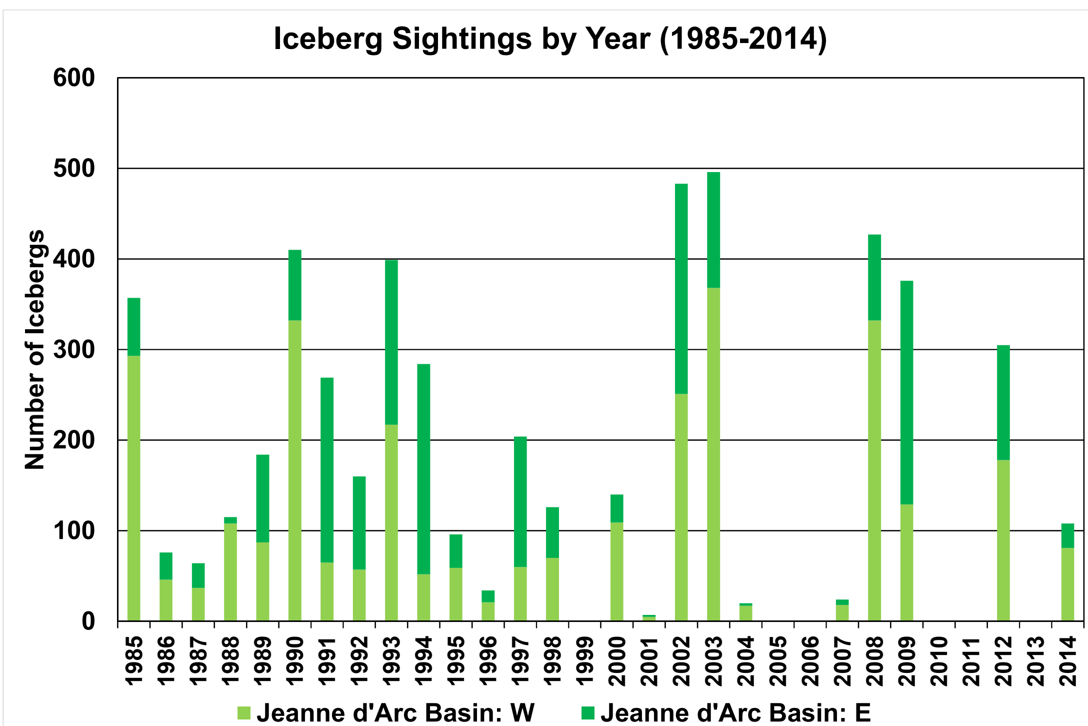
Source: NRC (2015)

Figure 5-60 Iceberg Sightings by Month (1985-2014), Project Area (Northern and Southern Sections)



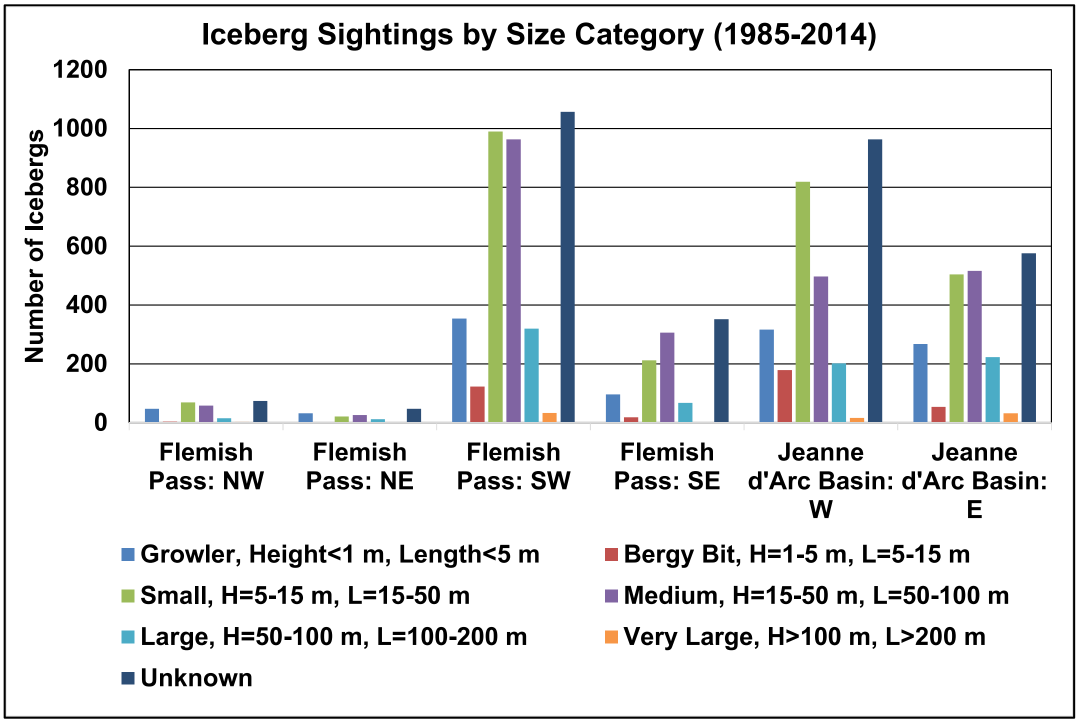
Source: NRC (2015)

Figure 5-61 Iceberg Sightings by Year (1985-2014), Project Area – Northern Section



Source: NRC (2015)

Figure 5-62 Iceberg Sightings by Year (1985-2014), Project Area – Southern Section



Source: NRC (2015)

Figure 5-63 Iceberg Sightings by Size Category (1985-2014), Project Area (Northern and Southern Sections)

5.7.2.1 Project Area – Northern Section

The query of the NRC-PERD database for the Project Area – Northern Section yielded 5,303 icebergs (first sightings) with 72 percent being in the southwest, 20 percent in the southeast, 5 percent in the northwest and 3 percent in the northeast sub-regions.

The iceberg size distribution, by sub-region, is shown in Figure 5-63. Of the 3,773 icebergs in the Project Area – Northern Section, for which size is known, 18 percent are growlers or bergy bits, 70 percent are small or medium, 11 percent are large, and 1 percent are very large.

Icebergs are typically present in the Project Area – Northern Section from January through August, with 67 percent of first sightings during March through May (Figure 5-60) and 95 percent from February through July. Over the 30-year record, 1985-2014, there were 17 sightings after August: 5 in September, 9 in October and 3 in December, with 16 of these sightings located in the southwestern quadrant. The December observations are from December 12 to 20, 1992, at the beginning of the 1993 ice season.

As illustrated in Figure 5-61, each year's ice season is quite different. The number of icebergs reported (first sightings) annually in the Project Area – Northern Section range from zero in 2005, 2006, 2010, 2011 and 2013 to 730 in 2002 and averages 177 sightings.

From the IIP dataset, in 2013 there were numerous icebergs (3,610 sighted in total) off the coast of Labrador, through the Strait of Belle Isle and into the Gulf of St. Lawrence and off the northeast coast of Newfoundland. There were few east of Newfoundland on the Grand Banks and none closer than approximately 100 km from the western boundary of the Project Area.

In 2015, there were 355 first sightings (compared to the 1985-2014 average of 177) in the Project Area – Northern Section, with seven in the northeast sub-region, 56 in the northwest, 40 in the southeast and the largest number, 252, in the southwest. The 355 sightings are shown in Figure 5-64 together with 2015 east coast first sightings. Of the 355 sightings, 11 percent are growlers or bergy bits, 47 percent are small or medium icebergs, 22 percent are large and approximately 1 percent (four icebergs) are very large; approximately 8 percent of the iceberg targets had unspecified size.

5.7.2.2 Project Area – Southern Section

The query of the NRC-PERD database for the Project Area- Southern Section yielded 5,164 icebergs (first sightings) with 58 percent being in the western sub-region and 42 percent being in the eastern sub-region.

The iceberg size distribution, by sub-region, is shown in Figure 5-63. Of the 3,625 icebergs for which size is known, 22 percent are growlers or bergy bits, 64 percent are small or medium, 12 percent are large, and just over one percent (1.3) are very large.

Icebergs are typically present in the Project Area – Southern Section from February through July with 98 percent of first sightings during this period. Over the 30 year record, 1985-2014, the period March through May (Figure 5-60) accounts for 80 percent of sightings, with approximately 10 percent in June, three percent in July and almost five percent in January. One percent of first sightings are in August through December. Of these 49 icebergs, 28 are of unknown size, three are large and 18 are medium sized or smaller.

As illustrated in Figure 5-62, each year’s ice season is quite different. The number of icebergs reported (first sightings) annually for the Project Area – Southern Section ranges from zero in 1999, 2005, 2006, 2010, 2011 and 2013 to 496 in 2003 and averages 172 sightings.

In 2015, there were 281 first sightings (compared to the 1985-2014 average of 172) in the Project Area – Southern Section, with 183 in the western half and 98 in the eastern. The 281 sightings are shown in Figure 5-64 together with all 2015 east coast first sightings. Of the 281, 21 percent are growlers or bergy bits, 32 percent are small or medium icebergs, 14 percent are large and less than one percent (two icebergs) are very large; approximately 32 percent of the iceberg targets had unspecified size.

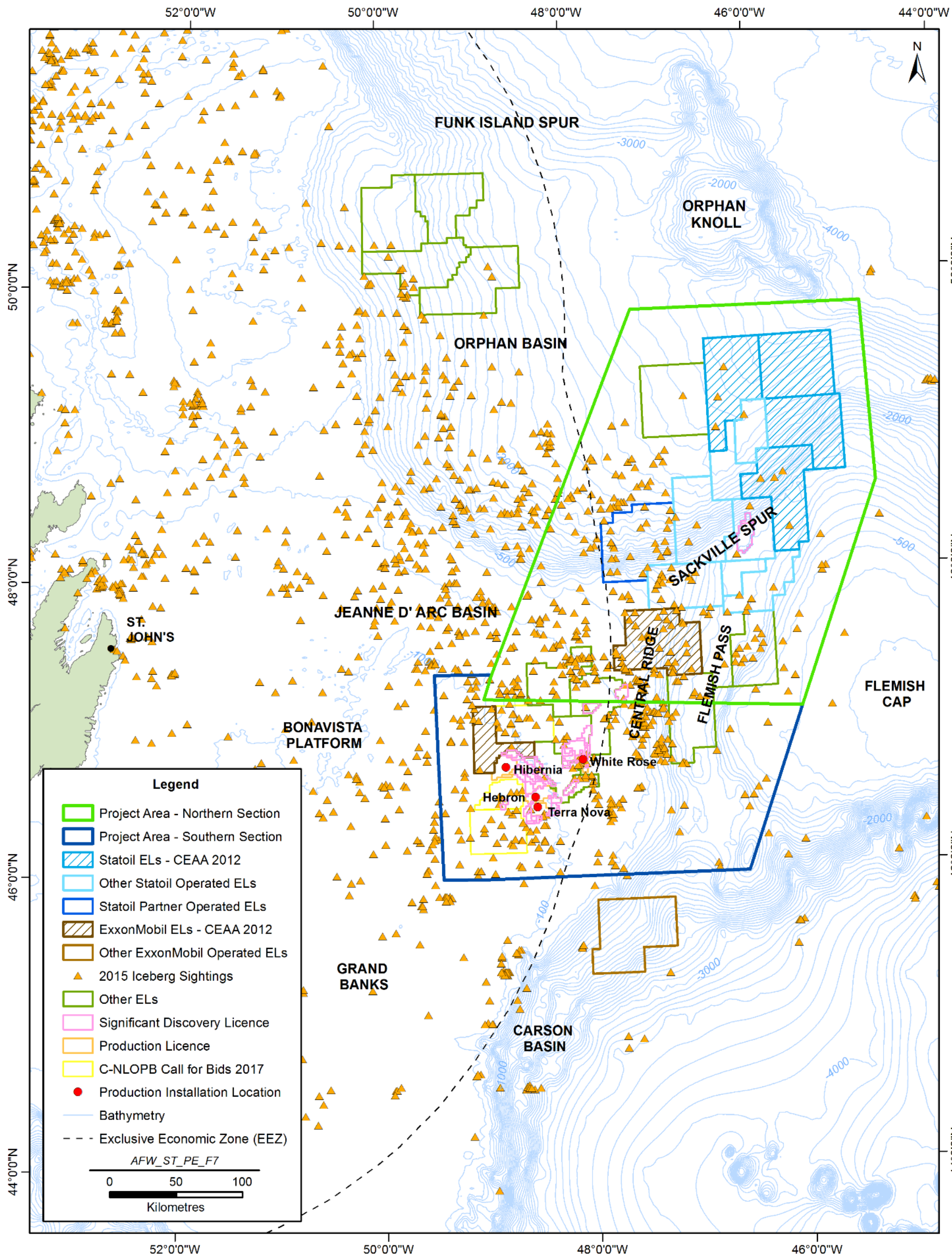


Figure 5-64 Recorded Icebergs Sightings in 2015, Newfoundland Offshore

5.7.2.3 Potential Vessel Traffic Routes

As evidenced by the 2015 distribution of icebergs on the east coast shown in Figure 5-64, there is potential for encountering icebergs while transiting between St. John's and the Project Area. Depending on the iceberg season and location offshore, icebergs may pose a risk for marine traffic anytime during iceberg season from January through August. The potential risk is greatest though the months of March through May.

Daily ice charts from the CIS and supply vessel and helicopter reports of local and regional conditions will provide the most timely and directly useful information for navigation under iceberg conditions. This may result in schedule or vessel route adjustments in response to present and forecasted conditions.

Further information on regional ice conditions in this area is provided in the Eastern Newfoundland SEA (Amec 2014), Section 4.1.5.

5.7.3 Marine Icing

Marine icing, most frequently from freezing spray, is a marine condition that can hinder and limit shipboard or drilling installation activities, increase a vessel's weight and alter its centre of gravity. Freezing spray is most likely to occur from November through April. Air temperatures must be lower than -2°C to produce freezing spray in salt water. Icing conditions are worsened with colder temperatures, high winds, and large waves (Bowyer 1995).

A standardized way to determine the potential ice build-up rate has been developed by Overland (1990), who based his algorithm on empirical observations and the heat balance equation of an icing surface. This algorithm has been used to derive estimates of icing potential in the Project Area – both Northern and Southern Sections - by using concurrent air and sea temperature and wind speed data from ICOADS. The results have been sorted into four different categories based on the severity (light, moderate, heavy, and extreme), and are summarized below.

5.7.3.1 Project Area – Northern Section

The icing potential for vessels in the Project Area – Northern Section (Figure 5-65) is greatest from January through March with total icing potential between 16.2 and 24.6 percent. The potential for moderate, heavy, or extreme icing is greatest in January at eight percent. No icing potential is reported for July through October and the potential is less than one percent in May, June, and November. Annually there is a 6.8 percent of icing potential with 1.8 percent potential of being for moderate, heavy, or extreme icing.

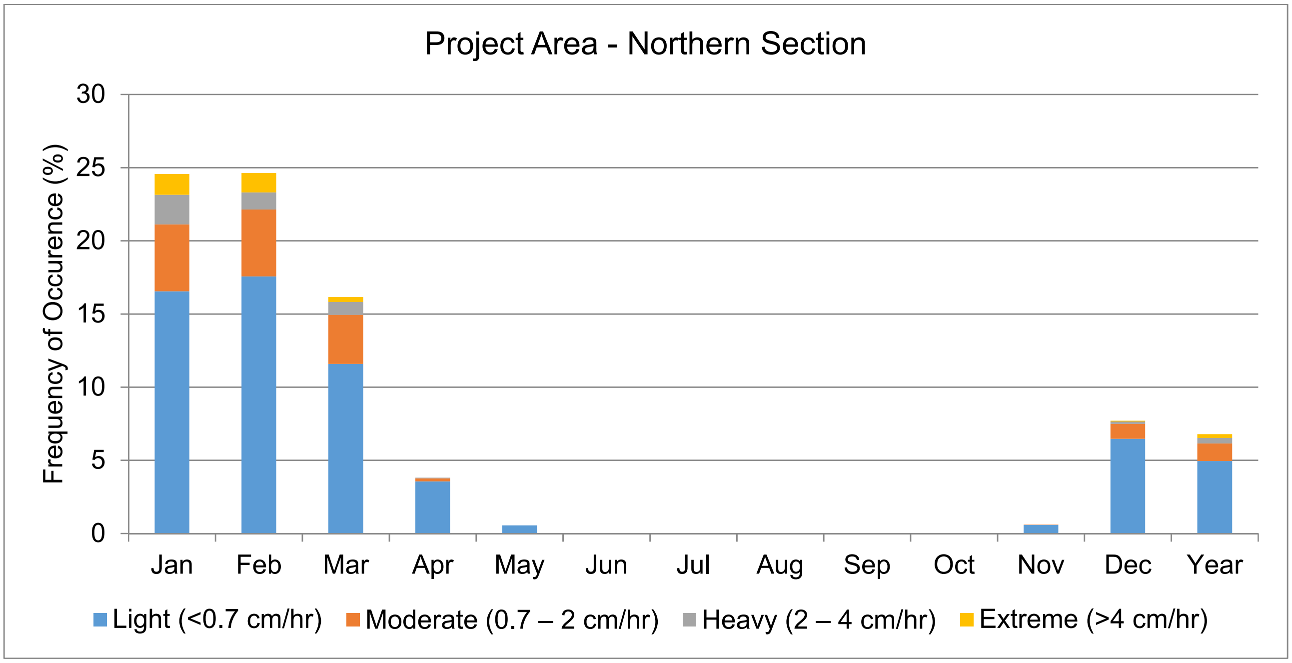


Figure 5-65 Icing Potential, Project Area – Northern Section

5.7.3.2 Project Area – Southern Section

The icing potential for vessels in the Project Area – Southern Section (Figure 5-66) is greatest from January through March with a maximum frequency of occurrence of 27.8 percent in February. There is potential for moderate, heavy, or extreme icing between December and April with the largest values being in February (9.1 percent), January (6.9 percent) and March (5.8 percent). Icing potential is nil between June and October and less than 0.3 percent in May and November. Annually there is a 6.8 percent likelihood of icing potential with 1.9 percent potential of moderate, heavy, or extreme icing – conditions virtually identical to that for the Project Area – Northern Section.

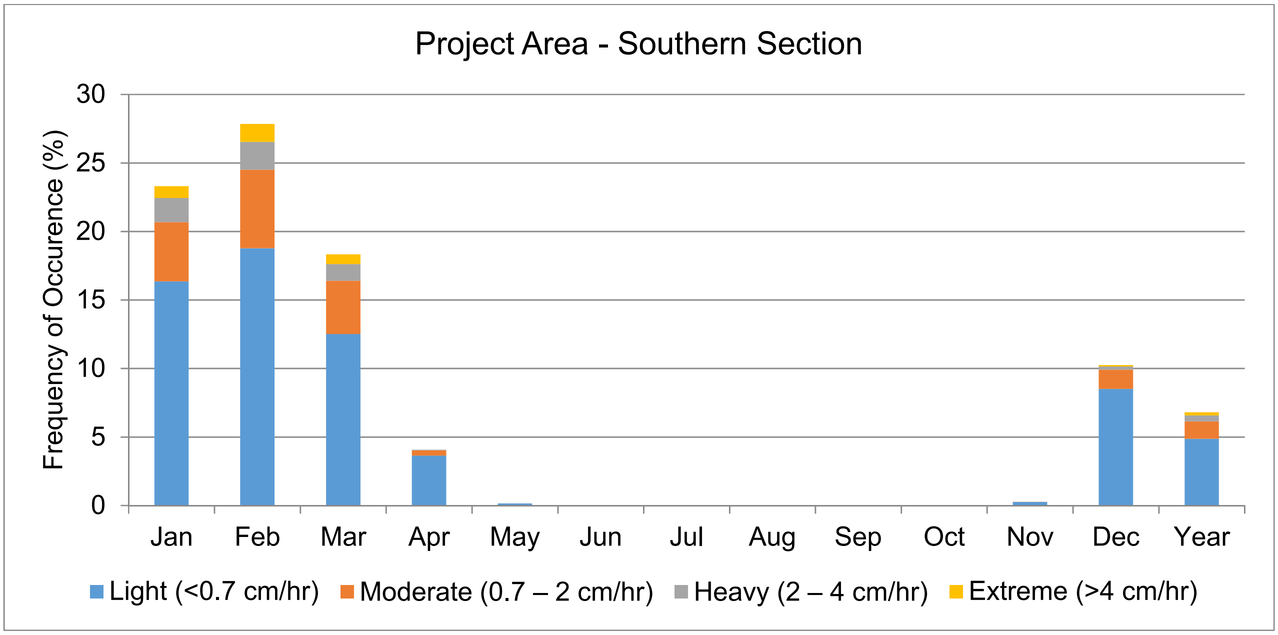


Figure 5-66 Icing Potential, Project Area – Southern Section

5.7.3.3 Potential Vessel Traffic Routes

Marine icing conditions along potential vessel routes from St. John's to the Project Area will be similar to those experienced farther offshore as characterized above for the Project Area – Northern Section and Project Area – Southern Section. This is due to the frequency of conditions of strong winds, low temperatures, and high seas - contributing factors for marine icing – to be encountered along the potential vessel routes being similar to those in the Project Area. Along the vessel routes there will be moderate to severe icing potential between December and April with the greatest risk occurring in January and February. Inspection of vessel icing statistics for January, on the east coast of Newfoundland, indicates a uniform potential of about 10 percent of the time in the areas encompassing the vessel traffic routes, for moderate icing or worse in January (Bowyer 1995). Further information on the regional icing potential environment in this area is provided in Section 4.1.5 of the Eastern Newfoundland SEA (Amec 2014).

5.8 Climate Change

Climate change will likely have some influence on all aspects of the climate system (atmosphere, ocean, cryosphere) over time, although the magnitude and timing of these impacts will vary regionally and across variables. On a global scale, there are three impacts of climate change for which long-term trends are already being observed and future projections are in general agreement, though there remains substantial regional variability, including locations that exhibit trends counter to the global mean (Stocker et al. 2013). The first is that average global temperatures (air and ocean) are increasing, with more extreme warming occurring in the Arctic. The second is that the hydrologic cycle is intensifying as warmer air can hold more moisture, implying that precipitation events on average will tend to be more intense (though not necessarily more frequent) in the future. The third impact is that the mean global sea level is rising.

This section provides an overview of climate change focussed on the Flemish Pass, the Grand Banks and offshore Newfoundland and is organized according to atmospheric variables (wind, temperature, precipitation, and extreme events), oceanographic variables (ocean-water temperatures, waves, currents, and sea level), and cryospheric variables (sea ice and icebergs). As the timeline of the Project spans approximately the next decade, recent trends and variability along with medium-term climate projections are presented.

5.8.1 Atmospheric Climate Changes

5.8.1.1 Wind

Cheng et al. (2014) found that the frequency of high-speed hourly wind gusts in Atlantic Canada is expected to increase under both medium and high GHG emissions scenarios by the mid-21st century. Their study showed the frequency of gusts over 25.0 m/s could double, gusts over 19.4 m/s could increase by around 20 percent, and gusts over 11.1 m/s could increase by 15 percent.

However, in a more recent study (Amec Foster Wheeler 2017a), the median and maximum annual sustained (hourly average) wind speeds, were projected to decrease slightly or remain unchanged over the coming decades, along main transport routes, adjacent to the region of interest. This is illustrated by Figures 5-67 and 5-68, which originate from Amec Foster Wheeler (2017a). This report also found that mean monthly wind directions are not expected to deviate significantly from present day.

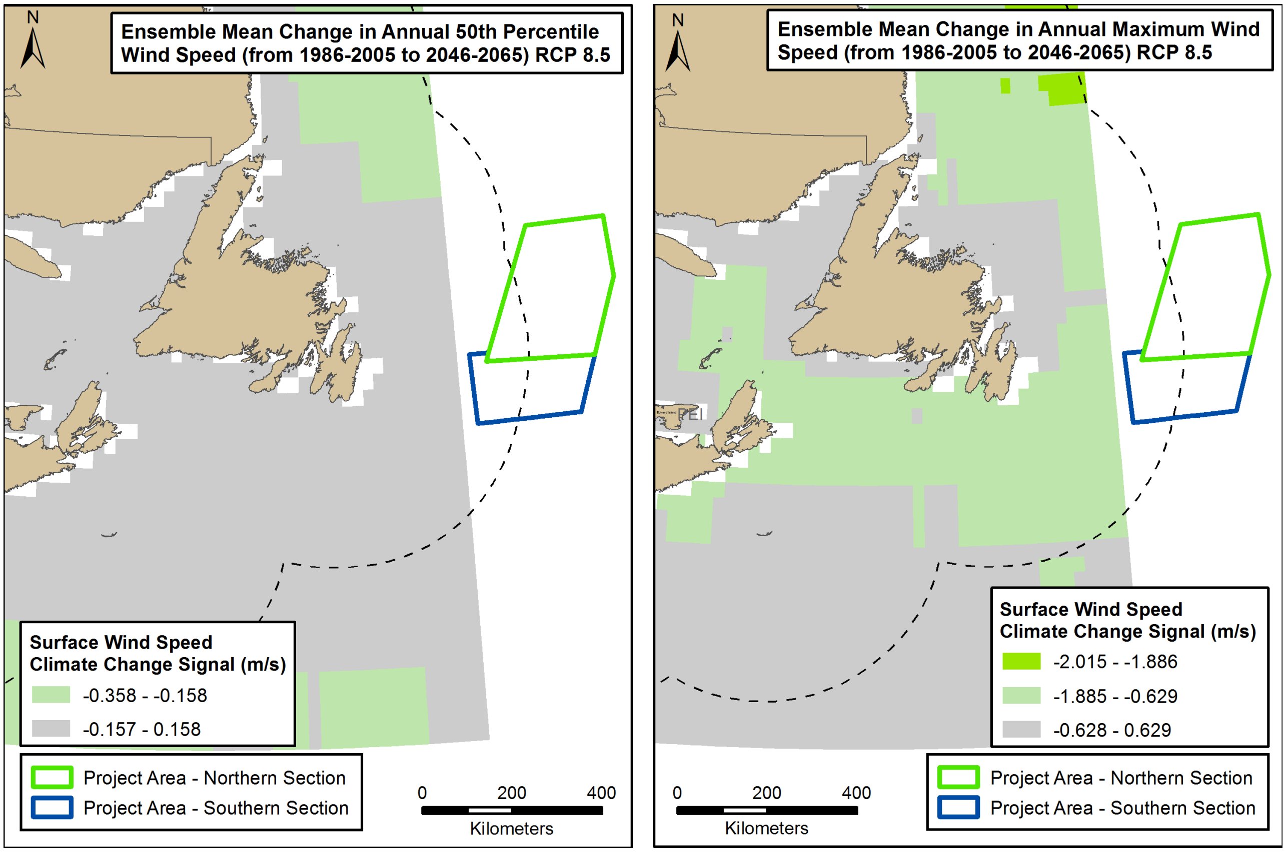
5.8.1.2 Temperature

Air temperatures have increased in coastal meteorological stations in Eastern Canada over the 110-year record by 0.75 ±0.34°C (Savard et al. 2016). Warming in the region has been found to be greater than or equal to global trends (IPCC 2013). This underlying trend is expected to continue and intensify over the coming decades.

IPCC (2014) projects that for 50-70 percent of the years in the mid-21st century the Grand Banks will experience a higher temperature greater than the maximum observed temperature between 1986 and 2005.

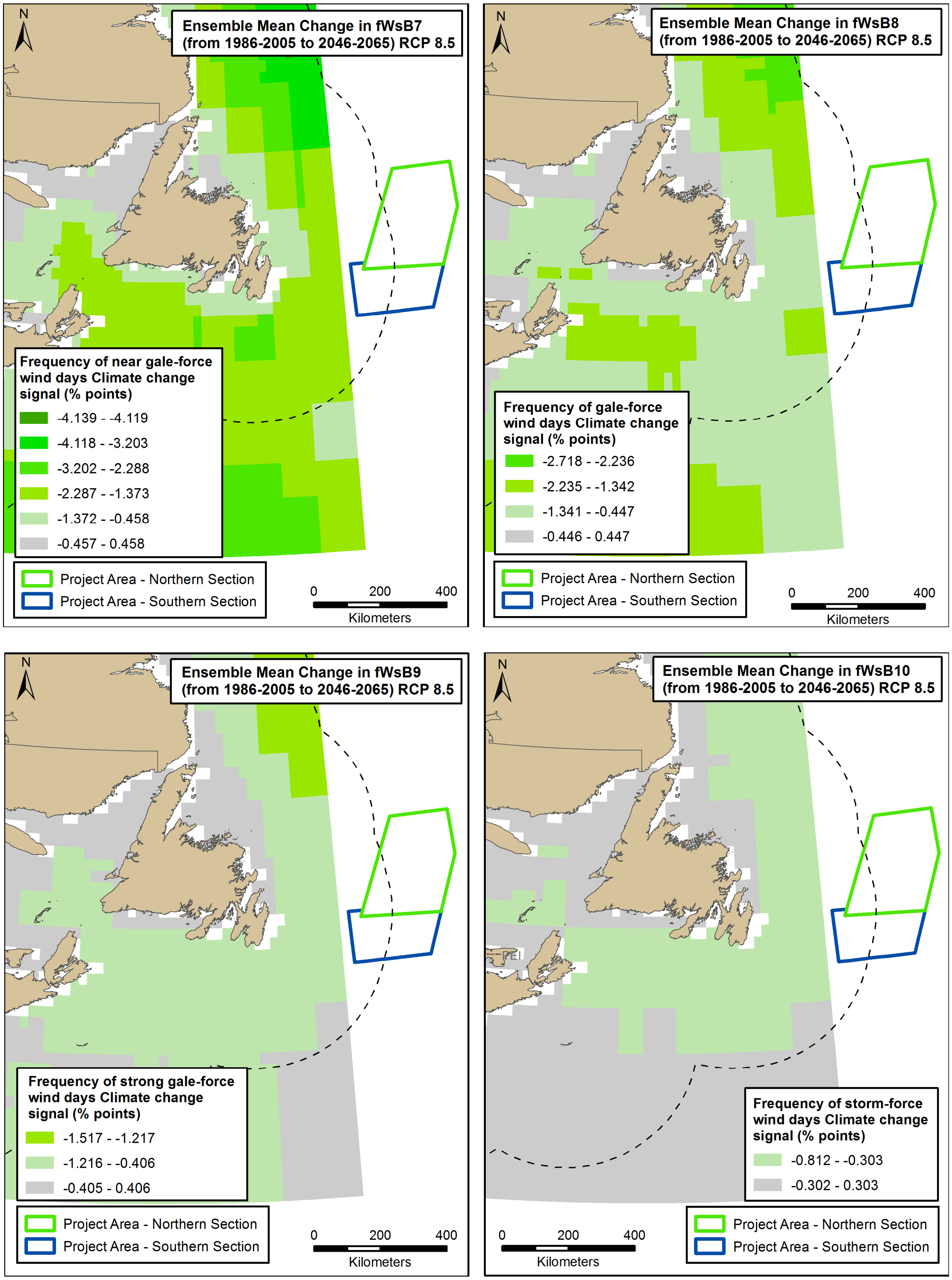
5.8.1.3 Precipitation

IPCC (2014) also shows there is strong agreement among climate models that mean annual precipitation for the region will increase by up to 10 percent. The same report projected that the 20-year return value of annual precipitation extremes would increase by 5-10 percent by mid-century. This does not imply that there will be more precipitation events, but that the events that do occur will tend to produce more precipitation.



Source: Amec Foster Wheeler (2017a)

Figure 5-67 Projected Changes in Median (Left) and Maximum (Right) Annual Sustained Wind Speeds for the Mid-21st Century, Using Six-Member Climate Model Ensemble Forced by the RCP 8.5 Greenhouse Gas Emissions Scenario



Source: Amec Foster Wheeler (2017a)

Figure 5-68 Projected Changes in the Annual Percentage of Days When Daily Max Wind Speed Is >14.4 m/s (fWsB7, Top Left), >17.2 m/s (fWsB8, Top Right), >20.8 m/s (fWsB9, Bottom Left), and >24.7 m/s (fWsB10, Bottom Right)

5.8.1.4 Storms

While there is not expected to be an overall increase in the frequency of tropical storms, the hurricanes that do occur will generally be stronger under climate change, with a higher percentage of Category 3, 4 and 5 storms than has been observed in the past, as shown in Bender et al. (2010). According to Bender et al. (2010), this trend has become more apparent since the 1940s, though some of this may be caused by less comprehensive observations in earlier parts of the record.

With regard to winter storms, Loder et al. (2013) project that there will be a northward shift in storm tracks that will affect the Project Area, predominately caused by a warming arctic and a weakened polar-equatorial temperature gradient. Stemming from this is an expected change in the location and strength of the predominantly west-to-east jet stream. A well-defined west-to-east jet stream is correlated with more and stronger winter storms tracking through the region, while a relatively meandering jet stream associated with a weaker polar-equatorial temperature gradient will create blocking patterns and fewer winter storms.

5.8.2 Oceanographic Changes

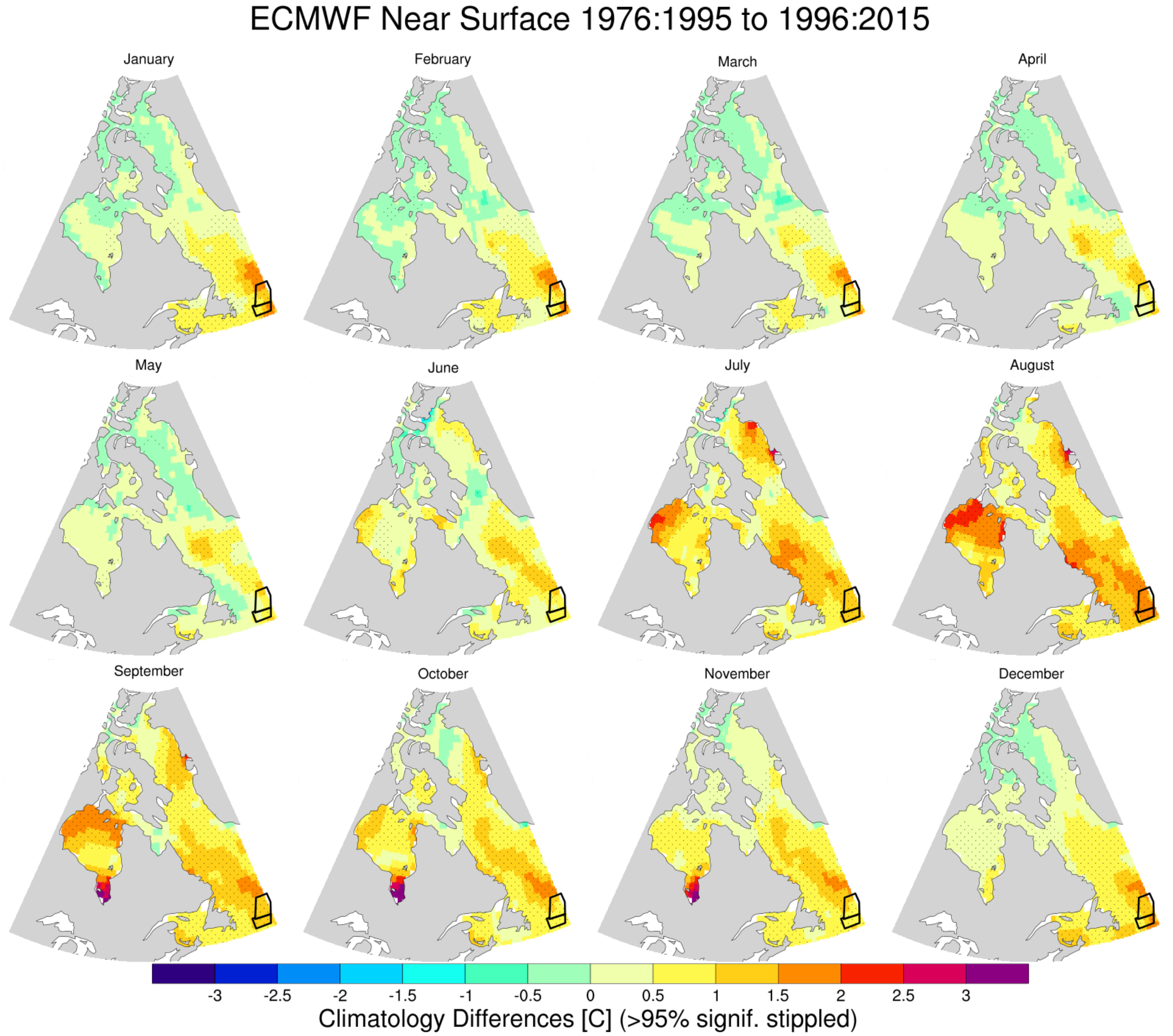
5.8.2.1 Ocean-Water Temperatures

Rising air temperatures in the region have also contributed to warming surface waters, which have increased 0.32°C from 1945-2010 (Han et al. 2013b). These warming trends are expected to continue and increase over the coming decades, although with significant seasonal, interannual, and spatial variability. Warming is expected to be of a smaller magnitude in waters just south of Greenland (including the northeast edge of the Project Area) due to an expected decrease in strength of the Atlantic Meridional Overturning Circulation and associated reduction in northward heat transport (Drijfhout et al. 2012).

Figure 5-69 shows changes in mean monthly water temperature from 1976-1995 to 1996-2015 at depths of approximately five metres, based on ECMWF reanalysis data. The Project Area has experienced warming in each month, although statistically significant warming is most prevalent from late summer to early winter. Warming was also found to be widespread at depths of approximately 45 m (not shown) (Amec Foster Wheeler 2017b).

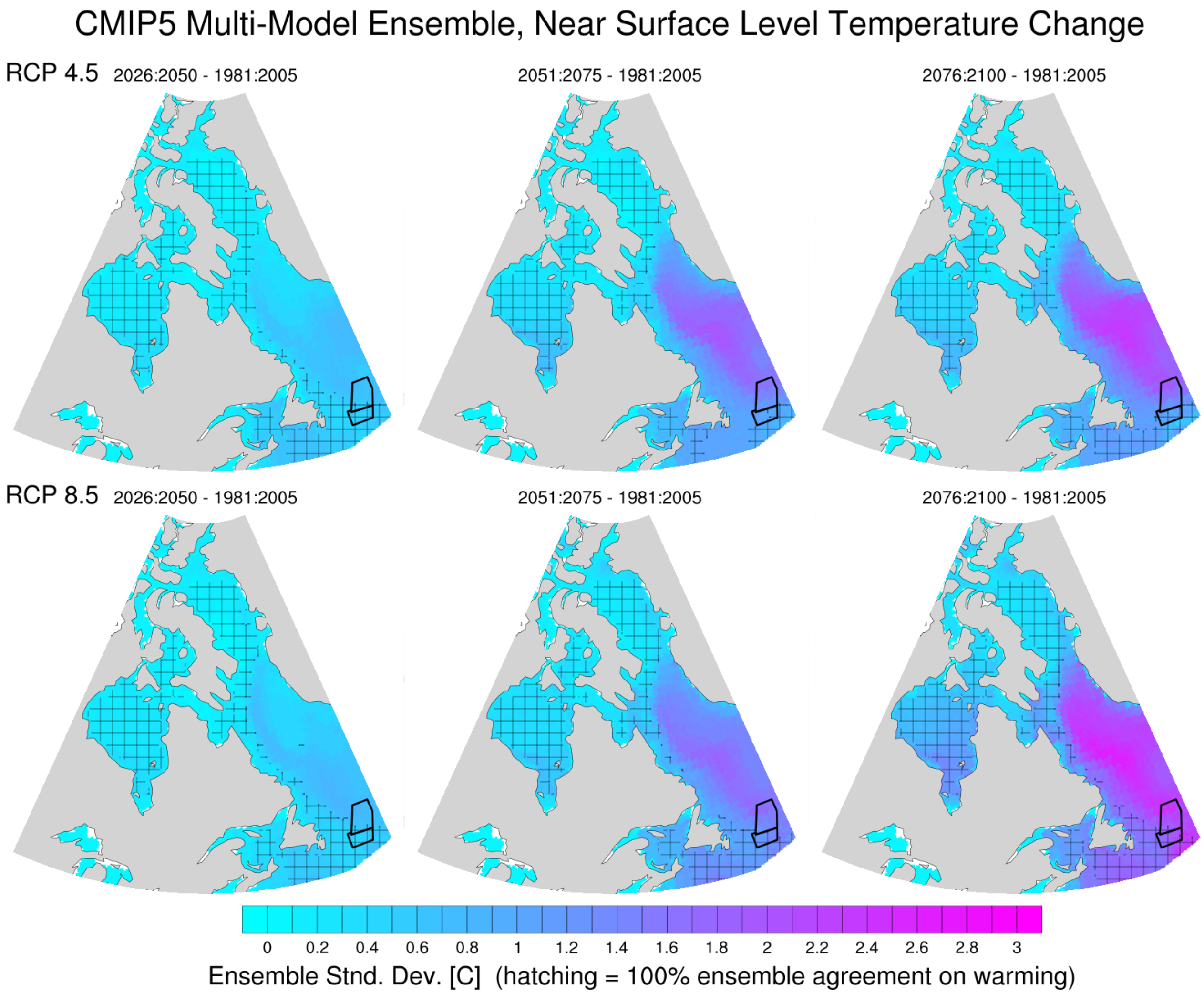
Figure 5-70 shows model agreement and the standard deviation of projected temperature changes of near-surface water (five to seven metre depths). Areas with cross hatching have 100 percent model agreement (based on an ensemble of seven CMIP5 global climate models) that there will be warming. The background colours represent the standard deviation of the magnitude of warming projected, which is a representation of uncertainty.

Figure 5-71 shows a representative GCM projection from the ensemble used to create Figure 5-70. This indicates that the next several decades will experience near surface water temperatures 1-1.5°C warmer than that recorded in 1981-2005.



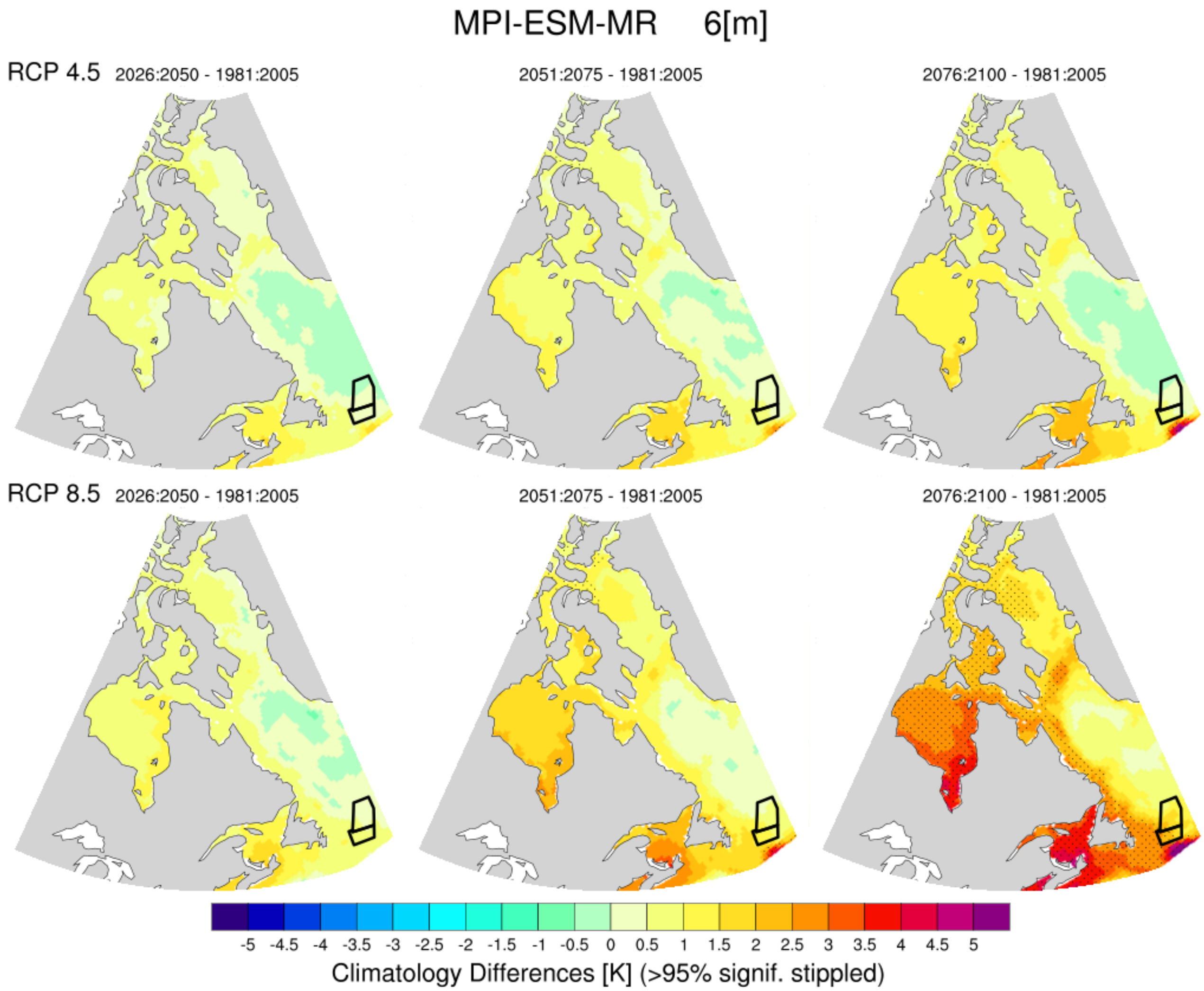
Source: Amec Foster Wheeler (2017b)

Figure 5-69 Changes in Mean Monthly Water Temperature From 1976-1995 to 1996-2015 at Approximately 5 m, Based on ECMWF Reanalysis Data



Source: Amec Foster Wheeler (2017b)

Figure 5-70 Ensemble Agreement of Projected Near-Surface Ocean-Water Temperature Projections

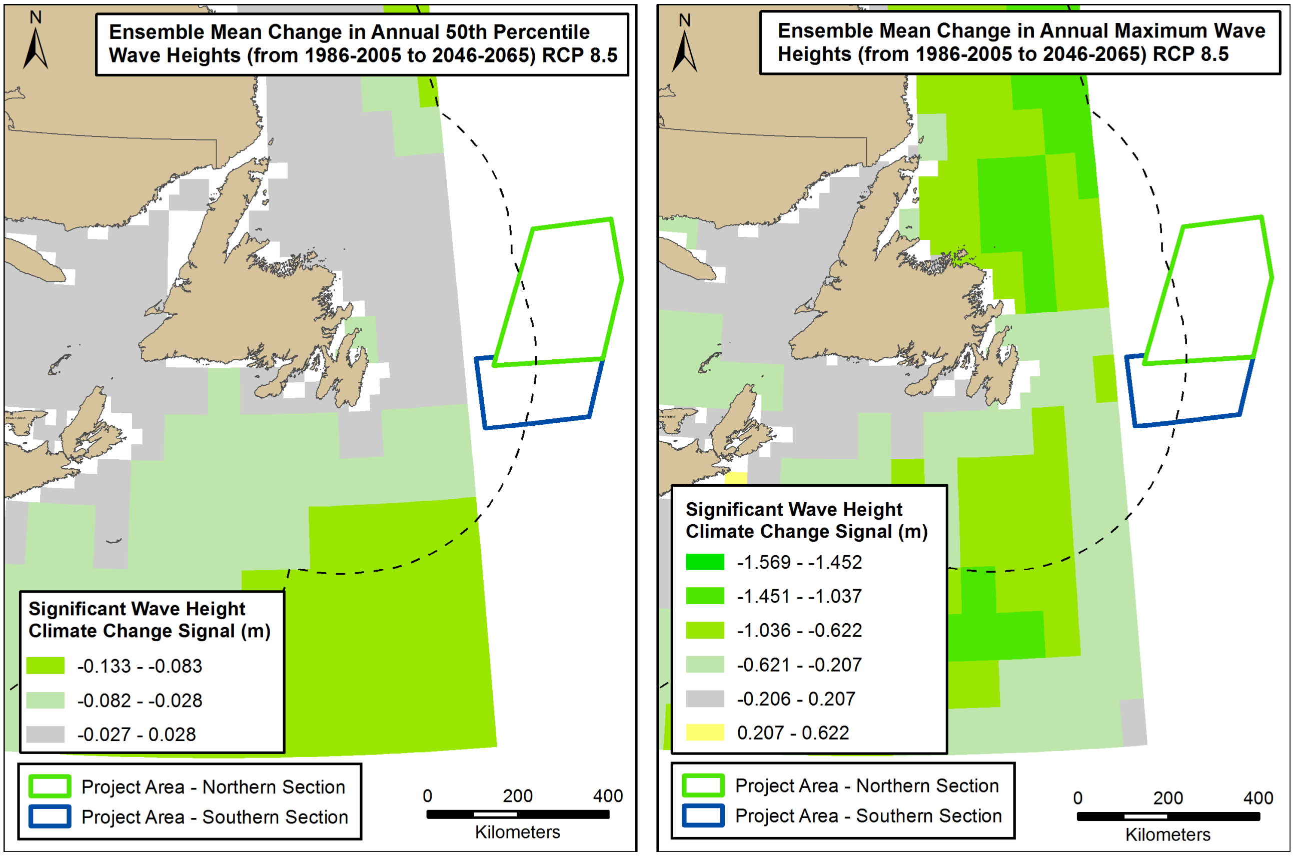


Source: Amec Foster Wheeler (2017b)

Figure 5-71 Representative GCM Projection of 6 m Depth Ocean Water Temperature Change

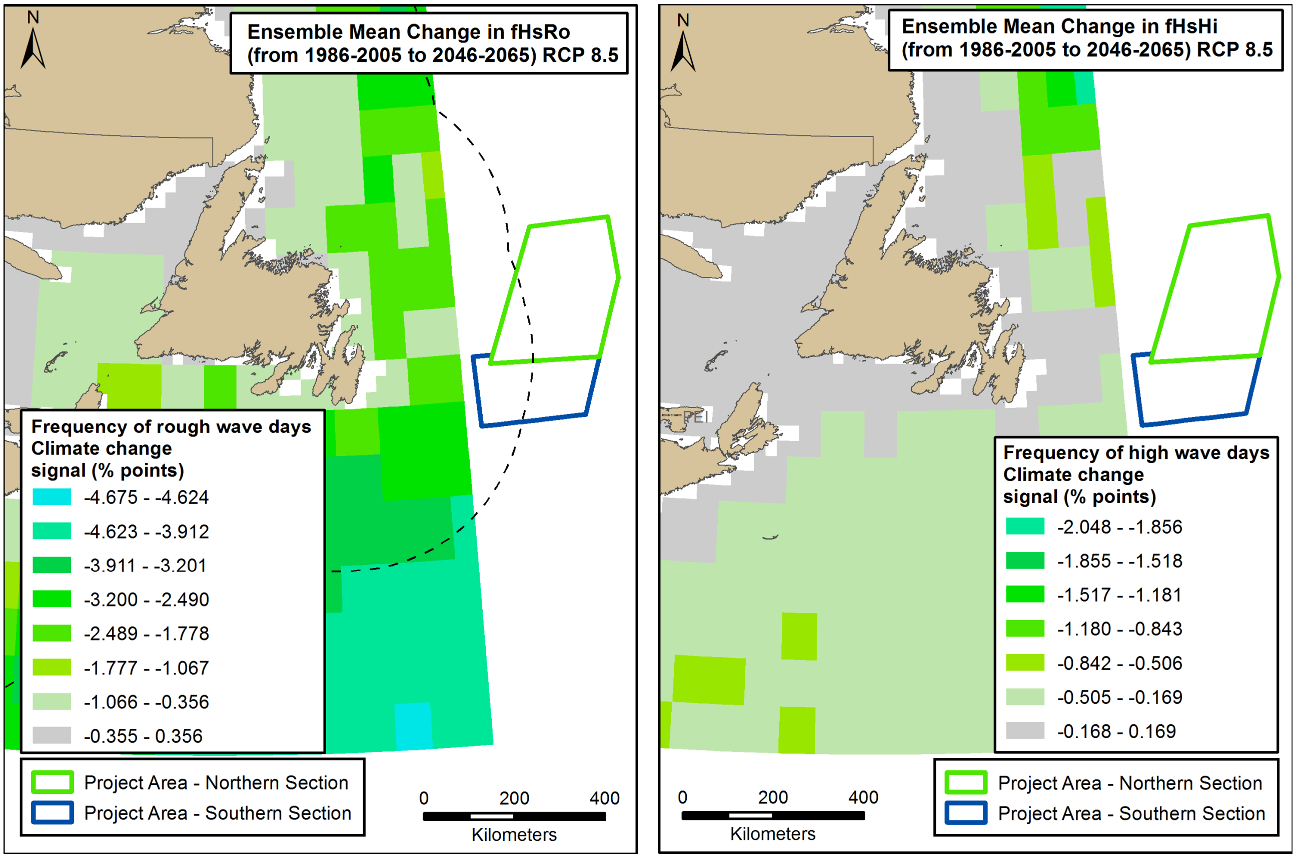
5.8.2.2 Waves

Waves are largely driven by winds, so it follows that as average sustained wind speeds are projected to decrease so are average significant wave heights. Figure 5-72, from Amec Foster Wheeler (2017a) shows that median and maximum annual wave heights are projected to decrease by mid-century, corresponding with the projected decreases in median and maximum sustained wind speeds discussed earlier. Figure 5-73 shows that the annual percentage of rough wave days and high wave days are also projected to decrease by mid-century; this is corroborated by Wang et al. (2014) who projected decreasing significant wave heights throughout the North Atlantic Ocean.



Source: Amec Foster Wheeler (2017a)

Figure 5-72 Projected Changes in Median (Left) and Maximum (Right) Annual Wave Heights for the Mid-21st Century, Using a Six-Member Climate Model Ensemble Forced by the RCP 8.5 Greenhouse Gas Emissions Scenario



Source: Amec Foster Wheeler (2017a)

Figure 5-73 Projected Changes in the Annual Percentage of Days When Daily Max Significant Wave Height is >2.5 m (fHsRo, Left) And >6.0 m (fHsHi, Right)

5.8.2.3 Currents

Han et al. (2013a) found that the subpolar surface gyre transport, of which the Labrador Current is a component and in which the Project Area resides, has been declining in the past two decades, although this is believed to be part of multi-decadal variability as opposed to a long-term downward trend. Han et al. (2013a) also found that the Labrador Current transport is positively correlated with the winter North Atlantic Oscillation in regions north of Grand Banks slope, and negatively correlated in regions further south. What this implies is that over 1992-2011 when the North Atlantic Oscillation was generally weak, the Labrador Current extended southward beyond the Grand Banks but was weaker in strength. A potential mechanism for this is the southward shift of the Gulf Stream which correspondingly allowed this southward extension of the Labrador Current.

5.8.2.4 Sea Level

Primary contributing factors to sea level rise include the thermal expansion of the ocean, increased water amounts from melting ice sheets and glaciers, glacial isostatic adjustments (rising or falling land), and the strength of the Gulf Stream (Yin 2012). Based on satellite altimetry and due to the interaction of the above factors, global sea level has risen at a rate of 3.2 ± 0.4 mm/year from 1993-

2009 (Church and White 2011). As sea levels around eastern Newfoundland are projected to rise on the order of 0.5 to 1 m (or more) by the end of the 21st century (James et al. 2014), the rate of annual sea level rise will likely increase beyond present day trends.

5.8.3 Ice Conditions

As described in the Eastern Newfoundland SEA (Amec 2014), the Arctic has undergone substantial warming since the mid-20th century. Greenland ice sheets have been losing mass and glaciers have continued to shrink almost worldwide over the past two decades. The average rate of ice loss from the Greenland ice sheet has likely increased from 34 Gt/yr over the period 1992 to 2001 to 215 Gt/yr over the period 2002 to 2011. Sea surface temperatures were anomalously high in at least the last 1,450 years (IPCC 2013).

5.8.3.1 Sea Ice

Based on reconstructions over the past three decades, the annual mean Arctic sea ice extent decreased over the period from 1979 to 2012 with a rate likely in the range of 3.5 to 4.1 percent per decade, and the summer sea ice minimum has similarly decreased in the range 9.4 to 13.6 percent per decade. Since 1979, the sea ice spatial extent has decreased for each respective season (IPCC 2013).

There is medium confidence that a nearly ice-free Arctic Ocean in September before mid-century is likely for RCP8.5 (IPCC 2013). The reductions in ice range from 43 percent for RCP2.6 to 94 percent for RCP8.5 in September and from eight percent for RCP2.6 to 34 percent for RCP8.5 in February (IPCC 2013). Based on these historical trends and projections for shrinking Arctic sea ice cover, it is likely that sea ice extent and ice thicknesses will be reduced in the future for offshore Newfoundland and Labrador in general, including the Project Area, especially the timing of freeze-up and melting and the variability and severity of ice seasons. This would be in keeping with increased northern warming as projected by Finnis (2013) for the province, with air temperatures increasing 4 to 6°C in Northern Labrador.

5.8.3.2 Icebergs

The regional iceberg climate is determined by the rate at which icebergs calve (from glacial regions to the north in Greenland, and to lesser extent ice caps on Ellesmere, Devon and Baffin Islands) and their size distribution (mass and draft, and geographic distribution and circulation). These are, in turn, affected by several factors, including local oceanic and atmospheric circulation patterns, water temperature, the frequency and duration of open water conditions (influenced by sea ice extent - iceberg drift is impeded through regions of sea ice) and by a variety of factors affecting the principal iceberg source regions.

The warmer air temperatures could lead to an increase in iceberg calving rates and could provide less obstructed routes from calving sites to the Project Area. While this would increase the number of icebergs in the waters off Newfoundland and Labrador, the increased SST and wave action (from reduced sea ice cover) would increase their melt and deterioration rates. The number of icebergs observed offshore Newfoundland varies widely from year to year, and so long-term trends may take multiple decades to become apparent.

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