West Flemish Pass Exploration Drilling Project

Chapters 1 to 4: Introduction, Project Description, Consultation and Engagement, and Methods

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Final Report

January 2020

Executive Summary

Chevron Canada Limited (Chevron) is proposing to undertake exploration drilling activities within its existing offshore exploration licence (EL) in the Flemish Pass, approximately 375 kilometres (km) northeast of St. John's, Newfoundland (NL). The West Flemish Pass Exploration Drilling Project (herein referred to as "the Project") may involve drilling up to eight exploration and delineation / appraisal wells over the term of the EL (2016 to 2025), with an initial well proposed to be drilled in 2021, pending regulatory approval.

The exploration rights to EL 1138 were awarded to Chevron and its co-venturer Anadarko Canada E&P Ltd by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) in 2016. The term of this EL extends from January 15, 2016 to January 15, 2025. Chevron will serve as the operator for this exploration drilling program.

The Canadian Environmental Assessment Agency (now the Impact Assessment Agency of Canada; Agency) determined that the drilling of a well on EL 1138 constitutes a "designated project" under section 10 of the R*egulations Designating Physical Activities* and therefore requires review and approval according to the requirements of the *Canadian Environmental Assessment Act, 2012* (CEAA 2012). Following submission of the Project Description document, the Agency determined that an environmental assessment was required and Environmental Impact Statement (EIS) guidelines (Appendix A) were issued on December 20, 2018. The environmental assessment will be undertaken pursuant to CEAA 2012. New federal environmental assessment legislation (Bill C-69) received Royal Assent on June 21, 2019; however, this will not apply to the currently proposed Project, which will continue under CEAA 2012.

The EIS focuses on the identification and assessment of potential adverse environmental effects of the Project on valued components (VCs), which are environmental attributes associated with the Project that are of interest or concern to Indigenous peoples, regulatory agencies, Chevron, resource managers, scientists, key stakeholders, and/or the general public. Similar to other exploration drilling projects that have recently gone through the CEAA 2012 process, the following six VCs were selected:

- Marine Fish and Fish Habitat (including Species at Risk)
- Marine and Migratory Birds (including Species at Risk)
- Marine Mammals and Sea Turtles (including Species at Risk)
- Special Areas
- Indigenous Peoples and Community Values
- Commercial Fisheries and Other Ocean Users

The potential environmental effects from both routine activities and accidental events on each VC were assessed, as were cumulative effects arising in combination with effects from other past, present, or likely future projects and activities. Supporting studies conducted to inform the environmental effects assessment include drill mud dispersion modelling (Appendix C); an underwater sound assessment (Appendix D); and oil spill fate and trajectory modelling (Appendix F).

Similar to other offshore exploration drilling projects, routine Project activities with potential environmental interactions include:

- Presence and operation of the mobile offshore drilling unit (MODU) (including light and underwater sound emissions, air emissions, and establishment of a safety zone)
- Vertical seismic profiling (underwater sound emissions)
- Discharges (including discharge of drill muds and cuttings and other discharges)
- Well abandonment (plugging, suspending, and abandoning)
- Supply and servicing operations (including helicopter transportation and Project supply vessel operations)

With the implementation of proposed mitigation measures, adverse residual (i.e., after planned mitigation is applied) environmental effects from planned routine activities associated with the Project are predicted to be not significant. Most potential adverse Project effects will be addressed by engineering design, standard mitigation measures, and best management practices. VC-specific mitigation measures are identified where warranted. Most environmental effects are predicted to be reversible and of limited duration, magnitude, and geographic extent.

The assessment of environmental effects associated with potential accidental events focus on credible worst-case accidental event scenarios. These include include spills that could occur during MODU (synthetic-based mud spill) or supply vessel (marine diesel spill) operations, and a subsea well blowout incident (crude oil spill). Should a large-scale accidental event occur (i.e., subsea well blowout), significant adverse environmental effects have been predicted for marine and migratory birds, Indigenous people and community values, and commercial fisheries; however, the likelihood of an accidental event occurring is considered low. While oil spill modelling is based on an unmitigated spill (i.e., no response, containment or clean-up), Chevron plans every well drilling program with a focus on prevention, and will have an approved Project-specific Oil Spill Response Plan in place prior to spudding the well.

In summary, the Project is not likely to result in significant adverse residual environmental effects, including cumulative environmental effects, provided that the proposed mitigation measures are implemented.

Compliance with the EIS Guidelines (Appendix A) is demonstrated with a concordance table (Appendix B), which indicates where requirements have been addressed in this EIS document.

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Abbreviations

Accord Acts	*Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*
ADW	Approval to Drill a Well
AGC	Atlantic Groundfish Council
Agency	Canadian Environmental Assessment Agency
API	American Petroleum Institute
ASP	Association of Seafood Producers
bbl	barrel
BHA	bottom hole assembly
BMP	best management practices
BOP	blowout preventer
CAC	criteria air contaminants
CEAA 2012	*Canadian Environmental Assessment Act, 2012*
CER	Canadian Energy Regulator (formerly National Energy Board)
CEPA	*Canadian Environmental Protection Act, 1999*
CH_4	methane
Chevron	Chevron Canada Limited
CNWA	*Canadian Navigable Waters Act*
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CNSOPB	Canada Nova Scotia Offshore Petroleum Board
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CWS	Canadian Wildlife Service
dB	decibels
DFO	Fisheries and Oceans Canada
DND	Department of National Defence
DP	dynamic positioning
DST	drill stem test
EA	Environmental Assessment
Eastern NL SEA	Eastern Newfoundland Strategic Environmental Assessment
ECCC	Environment and Climate Change Canada
EEZ	Exclusive Economic Zone
EIS	Environmental Impact Statement
EIS Guidelines	Guidelines for the Preparation of an Environmental Impact Statement pursuant to the *Canadian Environmental Assessment Act, 2012*
EL	Exploration Licence

ESRF	Environmental Studies Research Fund
FAAR	Federal Authority Advice Record
FFAW-Unifor	Fish, Food and Allied Workers-Unifor
FPSO	floating, production, storage and offloading
FSC	food, social and ceremonial
ft^3	cubed feet
g/kg	grams per kilogram
g/L	grams per litre
GHG	greenhouse gas
HADD	harmful alteration, disruption or destruction
ha	hectares
HES	Health, Environment, and Safety
IMO	International Maritime Organization
in^3	inches cubed
km	kilometre
km^2	square kilometre
KMKNO	Kwilmu'kw Maw-klusuaqn Negotiation Office
L	litres
LAA	Local Assessment Area
lb/MMBtu	pounds per one million British Thermal Units
LISA	Labrador Inuit Settlement Area
LNG	liquid natural gas
m	metre
m^3	metre cubed
m^3/d	metre cubed per day
m^3/min	metre cubed per minute
MARPOL	International Convention for the Prevention of Pollution from Ships
MBCA	*Migratory Birds Convention Act, 1994*
MCPEI	Mi'kmaq Confederacy of Prince Edward Island
MFN	Miawpukek First Nation
metocean	meteorological and oceanographic
mm	millimetre
MMBtu	one million British Thermal Units
MMS	Mi'gmawei Mawiomi Secretariat
MODU	Mobile Offshore Drilling Unit
MSDS	Material Safety Data Sheet
MSW	Managing Safe Work
MTI	Mi'gmawe'l Tplu'tagnn Inc.
M-weighting functions	marine mammal auditory weighting functions
N_2O	nitrogen dioxide
NAFO	Northwest Atlantic Fisheries Organization
NB	New Brunswick

NEB	National Energy Board
NGO	non-governmental organization
NL	Newfoundland and Labrador
NL ESA	Newfoundland and Labrador (NL) *Endangered Species Act*
nm	nautical mile
NMFS	National Marine Fisheries Service
NO_X	nitrogen oxides
NRCan	Natural Resources Canada
NS	Nova Scotia
OA	Operations Authorization
OCNS	Offshore Chemical Notification Scheme
OE	Operational Excellence
OEMS	Operational Excellence Management System
OCI	Ocean Choice International
OCSG	Offshore Chemical Selection Guidelines
OSPAR	Oil Spill Prevention, Administration and Response
OWTG	Offshore Waste Treatment Guidelines
PEI	Prince Edward Island
PK	pressure level
PLONOR	Pose Little or No Risk
PM	particulate matter
ppm	parts per million
PTS	permanent threshold shift
QC	Quebec
QMFNB	Qalipu Mi'kmaq First Nation Band
$R_{95\%}$	95% horizontal range
RAA	Regional Assessment Area
R_{max}	maximum horizontal range
rms	root-mean-square
ROV	remotely operated vehicle
SARA	*Species at Risk Act*
SBM	synthetic-based [drilling] mud
SDL	Significant Discovery Licence
SEL	sound exposure level
SEL_{24h}	sound exposure level over 24-hour period
SEL_{cum}	cumulative sound exposure level
SO_2	sulphur dioxide
SOCP	Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment
SO_X	sulphur oxides
SPL	sound pressure level
TWS	Third-party Waste Stewardship

US	United States
US EPA	United States (US) Environmental Protection Agency
UTM	Universal Transverse Mercator
UXO	unexploded ordnance
VC	Valued Component
VME	Vulnerable Marine Ecosystem
VSP	vertical seismic profile
WBM	water-based [drilling] mud
WNNB	Wolastoqey Nation of New Brunswick

1.0 INTRODUCTION

Chevron Canada Limited (Chevron) is proposing to undertake exploration drilling activities within its existing offshore exploration licence 1138 (the EL or EL 1138) in the Flemish Pass, approximately 375 kilometres (km) northeast of St. John's, Newfoundland and Labrador (NL). The West Flemish Pass Exploration Drilling Project (herein referred to as "the Project") may involve drilling up to eight exploration and delineation / appraisal wells over the term of the EL (2016 to 2025), with an initial well proposed to be drilled in 2021 pending regulatory approval.

The exploration rights to EL 1138 were awarded in 2016 (Table 1.1) by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB). The term of this EL extends from January 15, 2016 to January 15, 2025. Chevron will serve as the operator for the Project.

Table 1.1 Licence Size and Interests

EL	Size	Interest
1138	274,732 ha	Chevron Canada Limited (50%) Anadarko Canada E&P Ltd (50%)

The Canadian Environmental Assessment Agency (Agency) determined that the drilling of a well on EL 1138 constitutes a "designated project" under Section 10 of the *Regulations Designating Physical Activities* and thus requires review and approval according to the requirements of the *Canadian Environmental Assessment Act, 2012* (CEAA 2012). The Environmental Impacts Statement (EIS) will follow the published Project-specific guidelines (EIS Guidelines) provided by the Agency (2018). The C-NLOPB also 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). This EIS document is intended to satisfy both the EIS guidelines (Agency 2018) and the Accord Acts EA requirements.

1.1 Project Overview

Chevron proposes to drill up to eight exploration wells on EL 1138 during the term of the EL. The EL is in West Flemish Pass area of the Grand Banks region, just outside and bordering Canada's 200 nautical mile (nm) Exclusive Economic Zone (EEZ). Water depths in the EL range from approximately 400 to 2,200 metres (m). Drilling operations will be conducted within the EL boundaries, but exact well site locations are not yet known).

Wells will be drilled using either a semi-submersible rig or a drillship, referred to as a mobile offshore drilling unit (MODU). The MODU may be changed throughout the drilling program, depending on the results of initial wells. This anticipated, multiple-phase approach for exploration drilling incorporates the analysis of initial well results to inform the execution strategy for subsequent wells.

A fleet of supply vessels and helicopters will provide logistics support and supplies and will be based out of existing onshore facilities in Eastern NL. Since the Project description was submitted, Chevron has decided to not include Marystown as a potential shore base, thereby avoiding the sensitive areas along the southern tip of the Avalon Peninsula (such as the Cape St. Mary's Ecological Reserve) and Placentia Bay. The scope of this EIS does not include onshore activities at these shore-based facilities.

1.2 Scope of the EIS

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

- Vertical seismic profiling (VSP) operations
- MODU mobilization and drilling
  - Mobilization, operation and demobilization of the MODU
  - Establishment of a safety zone
  - Light and sound emissions associated with MODU presence and operation
  - Waste and water management, including discharge of drill muds and cuttings, and other discharges and emissions
- Well evaluation and testing
- Supply and servicing
  - Loading, refueling and operation of supply vessels (for re-supply and transfer of materials, fuel and equipment; on-site safety during drilling activities; and transit between the supply base and the MODU)
  - Helicopter support (for crew transport and delivery of supplies and equipment)
- Well decommissioning, suspension and abandonment

A table of concordance between the EIS Guidelines and this document is provided as Appendix B.

Additional components or activities, beyond the scope of the EIS Guidelines, may be described in more detail in relevant chapters to provide a broader context. Exact well locations will be finalized and confirmed as part of the regulatory approval process for each well in the Project as described in Section 1.5.1.

For the evaluation of the potential adverse environmental effects caused by the Project, the EIS is defined by spatial boundaries. The Project Area refers to the immediate area of the EL within which Project activities and components may occur, including direct physical disturbance to the marine benthic environment, plus a 10 km buffer (Project Area). To assess potential environmental effects that may occur beyond the Project Area, a Local Assessment Area (LAA) and a Regional Assessment Area (RAA) have been defined and are discussed in more detail in Section 4 of this EIS.

The planned temporal scope of the Project covers the term of the EL (from 2016 to 2025), during which planned Project activities (including well drilling, testing, abandonment, and associated activities) may occur. This EIS assumes that, within this nine-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 emissions and their management, Project alternatives, and overall environmental planning and management systems, is provided in Chapter 2.

1.3 Proponent Information

1.3.1 Proponent Contact Information

All communications regarding the environmental assessment for the proposed Project should be directed to the following contacts:

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1.3.2 How Chevron Operates

Chevron Corporation is a leading global integrated energy company, involved in every facet of the energy industry. Chevron Corporation is committed to responsibly developing Canada's energy resources, and as a partner of choice with local communities and Indigenous Peoples. Our company's foundation is built on our values, which distinguish us and guide our actions to deliver results. We conduct our business in a socially and environmentally responsible manner, respecting the law and universal human rights to benefit the communities where we work. We place the highest priority on the health and safety of our workforce and protection of our assets, communities and the environment. We deliver world-class performance with a focus on preventing high-consequence incidents.

Since 1938, Chevron has been exploring for, developing, producing and marketing crude oil, natural gas and natural gas liquids. Headquartered in Calgary, Alberta (AB), Chevron has interests in oil sands projects and liquids-rich shale gas acreage in Alberta; exploration, development and production projects offshore NL; a proposed liquefied natural gas (LNG) project and shale acreage in British Columbia; and exploration and discovered resource interests in the Beaufort Sea region of the Northwest Territories.

Chevron Operational Excellence Management System (OEMS) is a comprehensive, proven means for systematic management of workforce safety and health, process safety, reliability and integrity, environment, efficiency, security, and stakeholders. The implementation of OEMS demonstrates Chevron's commitment to conducting activities in line with applicable legislation, striving to constantly improve

environmental performance, and reducing potential impacts from its exploration and development activities. Operational Excellence (OE) puts into action our Chevron Way value of protecting people and the environment and helps Chevron Corporation achieve its vision to be the global energy company most admired for its people, partnership and performance. These principles comprise the quality assurance and risk management portions of the overall system.

OE objectives include:

- Eliminate fatalities, serious injuries and illnesses
- Eliminate high-consequence process safety incidents and operate with industry-leading reliability
- Assess and manage significant environmental risks
- Use energy and resources efficiently
- Prevent high-consequence security and cybersecurity incidents
- Address risks through stakeholder engagement and issues management

The OE objectives are achieved using Leadership and OE Culture, Focus Areas and OE Expectations, Management System Cycle, and Safeguards.

- Leadership and OE Culture. Chevon's leaders engage employees, contractors and Business Partners to build and sustain our OE culture and deliver OE performance.
- Focus Areas and OE Expectations. Focus areas align with critical OE risks and OE expectations guide Chevron to design, manage and assure the presence and effectiveness of safeguards. Focus areas are:
  - Workforce safety and health
  - Process safety, reliability and integrity
  - Environment
  - Efficiency
  - Security
  - Stakeholders
- Management System Cycle. The Management System Cycle is a systematic approach to set and align objectives, identify, prioritize and close gaps, and strengthen safeguards to improve OE results.
- Safeguards. Chevron establishes, sustains, and assures safeguards are in place and functioning in accordance with legal and OE requirements. Safeguards are the hardware and human actions designed to directly prevent or mitigate an incident or impact.
- Assurance. Assurance programs confirm that safeguards are in place, functioning, and meet internal and external requirements.

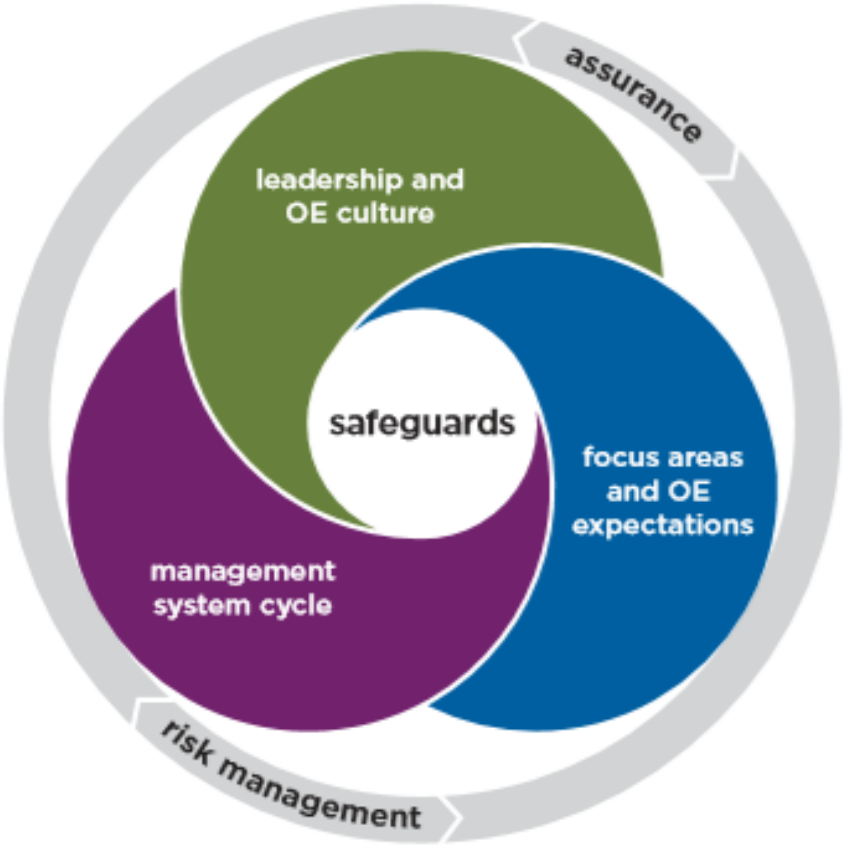

Figure 1-1 Chevron OEMS

1.3.3 Project Team

Personnel undertaking work for the proposed Project are required to meet environmental and health and safety corporate standards as well as government regulations and requirements. Roles and responsibilities related to the Project Team include, but are not limited to, the following.

The Project Owner (i.e., Chevron Canada Limited):

- Require that Project personnel, including contractors, uphold the environmental and regulatory commitments
- Notify regulators, stakeholders, and appropriate First Nations of Project activities and updates
- Set performance standards

The Project Team (e.g., Chevron Canada Limited, consultants, and sub-consults):

- Understand and uphold the environmental commitments, permit conditions, and approvals that are applicable to the work activity being undertaken
- Engage environmental professionals, and the Project Owner, as required, to support Project activities
- Immediately notify the Project Owner of any activity that requires agency notification

Specific members of Chevron's Project Team include:

- Exploration Manager
- Exploration Team Lead
- Geologist
- Geophysicist
- Drilling Engineer
- Regulatory Advisor
- Biologist
- Government and Public Affairs Advisor

1.4 Benefits of the Project

The oil and gas industry is an important component of the provincial NL economy. According to the NL Department of Finance (April 2019), oil production totaled 84.0 million barrels in 2018, up 4.3% (or approximately 3.4 million barrels) relative to 2017. The oil and gas industry in the province of NL accounts for approximately 15.6 % of the total nominal provincial gross domestic product.

The Project is predicted to result in, and contribute to, several economic, social, and technological benefits realized on local, regional and national levels. The 2019 study prepared for Petroleum Research Newfoundland and Labrador, *The Socio-economic Benefits from Petroleum Activity in Newfoundland and Labrador, 2015-2017* (Stantec Consulting Ltd., 2019), provides detailed analysis of the activity levels and expenditures by the petroleum industry in NL; the considerable resultant direct, indirect, and induced economic and community investment benefits to the province; and details other benefits-related developments in such areas as infrastructure, education, training and research and development.

1.4.1 Economic Benefits

The *Memorandum of Agreement between the Government of Canada and the Government of Newfoundland and Labrador on Offshore Oil and Gas Resource Management and Revenue Sharing* (The Atlantic Accord) promotes the development of petroleum resources in the offshore area of NL "for the benefit of Canada as a whole and Newfoundland and Labrador in particular" and recognizes Newfoundland and Labrador as "the principal beneficiary of the oil and gas resources off its shores". The province's offshore oil and gas industry provides a significant opportunity for employment. Additionally, royalties and taxes paid by offshore operators help support provincial government programs, and contribute to services and infrastructure such as transportation, education and health care (Canadian Association of Petroleum Producers 2019).

Although the majority of economic benefits arise from offshore development projects, exploration drilling activities, such as those proposed for the Project, are required to identify potential for such commercial development. Increased exploration drilling is considered a priority of the Province in order to sustain oil and gas industry growth and development (Government of Newfoundland and Labrador 2018).

1.4.2 Social Benefits and Community Investment

At Chevron, we believe that our success is tied to the success of the communities where we operate. Chevron has a National Social Performance Strategy that focuses our support to local partners to strengthen communities. We support programs in geographic areas aligned to our operations as well as in areas where our employees live and work; and in NL, these programs include:

- Education
  - *Chevron Open Minds* learning program at *The Rooms,* NL's largest public cultural space. This innovative school program allows youth to engage in hand-on experiential learning, outside of the classroom, while helping youth build skills in problem solving, writing and critical thinking.
  - Partnerships with Memorial University for scholarships, research chairs as well as mentorship and intern programs in the energy industry.
  - Partnership with The Newfoundland and Labrador Symphony Orchestra "Symphony Goes to the Schools."
- Health and Economic Capacity
  - Support for Stella's Circle, a non-profit partner providing numerous social services and job capacity building to the community.
  - Support to allow students and youth to attend technical and thought-leader conferences and workshops.
  - Support for the Boys and Girls Clubs of St John's in their youth leadership and development programs.
- Community and Culture
  - Support for the Royal St John's Regatta "Learn to Row" program.
- Social Innovation
  - Piloting new programs to address emerging issues of food scarcity and poverty with the Community Food Sharing Cooperative of Newfoundland.

1.4.3 Benefits Plan

In accordance with section 45 of the Accord Act, as operator, Chevron will submit a Benefits Plan to the C-NLOPB for approval. This plan will document Chevron's commitment to providing industrial benefits and employment opportunities on a full and fair basis for the residents of Canada, and in particular, NL, that arise from Project activities. The Benefits Plan will also address how Chevron will develop and implement an education, training, research and development expenditure program in NL; and will describe the consultative, monitoring, and reporting procedures that Chevron intends to establish to help achieve these commitments.

1.5 Regulatory Framework and the Role of Government

The following subsections outline the approvals and authorizations under the pertinent regulatory processes required for the Project. This information is indicative for planning purposes and is not intended to present an exhaustive list of legal and regulatory requirements.

1.5.1 Offshore Regulatory Framework

The C-NLOPB, a joint federal-provincial agency, is responsible for petroleum activities offshore NL, reporting to the federal and provincial Ministers of Natural Resources. The Accord Acts were signed in 1986 by the Government of Canada and the Province of NL promote social and economic benefits associated with petroleum exploitation. The Accord Acts, administered by the C-NLOPB, provide for joint management of all oil and gas activities in the region.

Under the Accord Acts, the C-NLOPB is responsible for the issuance and administration of petroleum and exploration and development rights; administration of statutory requirements regulating offshore exploration, development, and production; and approval of Canada-NL benefits and development plans. This involves the management and conservation of offshore petroleum resources, while protecting the environment, the health and safety of offshore workers, and enhancing employment and industrial benefits for NL and Canadians.

C-NLOPB's decision-making process for offshore oil and gas activities are governed by a variety of legislation, regulations, guidelines, and memoranda of understanding. Exploration drilling programs require an Operations Authorization (OA), issued by C-NLOPB. Prior to the issuance of an OA the following information must be submitted by the Operator for approval by C-NLOPB:

- An EA Report
- A Canada-NL Plan
- A Safety Plan
- An Environmental Protection Plan (including a waste management plan)
- Emergency Response and Spill Contingency Plans
- Regulatory Financial Responsibility Requirements
- Appropriate certificates of fitness for the equipment proposed for use in the activities

For each well in the drilling program, a separate Approval to Drill a Well (ADW) is required. This authorization process involves specific details about the drilling program and well design. There are several regulations under the Accord Acts that govern specific exploration or development activities. There are also various guidelines, some of which have been jointly developed with the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) and the Canadian Energy Regulator (CER; formerly the National Energy Board [NEB]), which are intended to address environmental, health, safety, and economic aspects of offshore petroleum exploration and development activities (Table 1.2).

Table 1.2 Summary of Key Relevant Legislation and Guidelines Associated with Offshore Boards

Legislation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
Canada-Newfoundland Atlantic Accord Implementation Act (S.C. 1987, c. 3) and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act* (R.S.N.L. 1990, c. C-2)	Natural Resources Canada / NL Department of Municipalities and Environment	The C-NLOPB is responsible for interpreting, applying and overseeing provisions of the Accord Acts to all activities of operators in the Canada-NL Offshore Area. The C-NLOPB's role is to manage and conserve the petroleum resources offshore NL a manner that protects health, safety, and the environment while maximizing economic benefits. Various regulations are established under the Accord Acts in order to govern specific petroleum exploration and development activities.	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.
Newfoundland Offshore Petroleum Drilling and Production Regulations (and associated Guidelines)	C-NLOPB	Compliance to these regulations are required when conducting exploratory drilling for and/or production of petroleum.	An OA and an ADW are the primary regulatory approvals necessary to conduct an offshore drilling program, pursuant to the Accord Acts and these regulations.
Newfoundland Offshore Certificate of Fitness Regulations	C-NLOPB	The requirements for the issuance of a Certificate of Fitness to support an authorization for petroleum exploration in the Newfoundland offshore area are outlined in these regulations. The regulations ensure that the equipment and/or installation of exploratory equipment is fit for its purposes and are can be safely operated without threat to persons or the environment in a specified location and timeframe.	The Project will require a Certificate of Fitness.

Table 1.2 Summary of Key Relevant Legislation and Guidelines Associated with Offshore Boards

Legislation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
OWTG	CER / C-NLOPB / CNSOPB	Outlined in these guidelines are recommended practices for the management of waste materials from oil and gas drilling and production facilities operating in the Canada-NL Offshore Area. The preparation of the OWTG considers 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 (EEM) programs in Canada and internationally. The OWTG specify performance expectations for the following types of discharges: • emissions to air • drilling muds and solids • bilge water, ballast water and deck drainage • well treatment fluids • cooling water • desalination brine • sewage and food wastes • water for testing of fire control systems • naturally occurring radioactive material	Adherence to OWTG
OCSG	CER / C-NLOPB / CNSOPB	These guidelines provide a framework for chemical selection that minimizes the potential for environmental effects from the discharge of chemicals used in offshore drilling and production operations. An operator must meet the minimum expectations outlined in the OCSG as part of the authorization for any work or activity related to offshore oil and gas exploration and production.	Adherence to OCSG

Table 1.2 Summary of Key Relevant Legislation and Guidelines Associated with Offshore Boards

Legislation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
		Any chemicals intended for discharge to the marine environment must • be included on the Oslo and Paris Commissions Pose Little or No Risk (PLONOR) to the Environment List • meet certain requirements for hazard classification under the Offshore Chemical Notification Scheme (OCNS) • pass a Microtox test (i.e., toxicity bioassay) • undergo a chemical-specific hazard assessment in accordance with United Kingdom Offshore Chemical Notification Scheme models and/or • have the risk of its use justified through demonstration to the C-NLOPB that discharge of the chemical will meet OCSG objectives.	
Compensation Guidelines Respecting Damage Relating to Offshore Petroleum Activity (Compensation Guidelines) (C-NLOPB and CNSOPB 2017b)	C-NLOPB / CNSOPB	These guidelines describe compensation sources available to potential claimants for loss or damage related to petroleum activity offshore NL and Nova Scotia (NS) and outline the regulatory and administrative roles which the C-NLOPB and CNSOPB exercise respecting compensation payments for actual loss or damage directly attributable to offshore operators.	Adherence to Compensation Guidelines
Environmental Protection Plan Guidelines (NEB et al. 2011a)	C-NLOPB / CNSOPB / CER	These guidelines assist an operator in the development of an Environmental Protection Plan (EPP) that meets the requirements of the Accord Acts and associated regulations and the objective of protection of the environment from its proposed work or activity.	Adherence to Environmental Protection Plan Guidelines

Table 1.2 Summary of Key Relevant Legislation and Guidelines Associated with Offshore Boards

Legislation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
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 / CNSOPB	The SOCP specifies the minimum mitigation requirements that must be met during the planning and conduct of marine seismic surveys, in order to reduce effects on life in the oceans. These mitigation measures are also typically applied to walk-away VSP operations and well site surveys. These mitigation requirements focus on planning and monitoring measures to avoid interactions with marine mammal and sea turtle species at risk where possible and reduce adverse effects on species at risk and marine populations.	Adherence to SOCP
Safety Plan Guidelines (NEB et al. 2011b)	C-NLOPB / CNSOPB / CER	These Guidelines were developed to provide guidance to operators in their development of a Safety Plan to meet the requirements of the *Drilling and Production Regulations*. The Safety Plan Guidelines expect an operator to take all necessary precautions to reduce risk to a level that is as low as reasonably practicable. The Safety Plan Guidelines detail the requirements of an operator's Safety Plan (i.e., procedures, practices, resources, sequence of key safety-related activities, and necessary monitoring measures).	A Safety Plan is required as part of the OA
Incident Reporting and Investigation Guidelines (C-NLOPB and CNSOPB 2018)	C-NLOPB / CNSOPB	These Guidelines assist those with responsibilities under the Accord Acts with the requirements for reporting and investigation of incidents and other events that occur in the offshore area.	Adherence to the Incident Reporting and Investigation Guidelines
Physical Environmental Programs Guidelines (NEB et al. 2008)	CER / C-NLOPB / CNSOPB	These Guidelines identify an operator's regulatory requirements for observing, forecasting and reporting of physical environmental data from drilling or production installations.	Adherence to Physical Environmental Programs Guidelines

Table 1.2 Summary of Key Relevant Legislation and Guidelines Associated with Offshore Boards

Legislation / Guideline	Regulatory Authority	Overview	Potentially Applicable Permitting Requirement(s)
Measures to Protect and Monitor Seabirds in Petroleum-Related Activity in the Canada-Newfoundland and Labrador Offshore Area (C-NLOPB undated)	C-NLOPB	This document summarizes advice from ECCC Canadian Wildlife Service (CWS) to help conserve and protect of seabirds near offshore facilities; these measures are incorporated into C-NLOPB conditions of authorization.	Adherence to Measures to Protect and Monitor Seabirds in Petroleum-Related Activity in the Canada-NL Offshore Area

Of particular relevance to the EA of this Project are:

- The Drilling and Production Guidelines (C-NLOPB and CNSOPB 2017a)
- The Offshore Waste Treatment Guidelines (OWTG) (NEB et al. 2010)
- The Offshore Chemical Selection Guidelines for Drilling and Production Activities on Frontier Lands (OCSG) (NEB et al. 2009)

A summary of environmental assessment and other regulatory requirements are described in Sections 1.5.2 and 1.5.3.

1.5.2 Environmental Assessment Requirements

Offshore exploration drilling, under certain circumstances, is a designated physical activity subject to the requirements of the CEAA 2012. Section 10 of the Regulations Designating Physical Activities under CEAA 2012 includes:

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

The Project constitutes the first drilling, testing, and abandonment of offshore exploratory wells within the EL issued to Chevron by the C-NLOPB. Following submission of the Project Description document, the Agency determined that an EA was required and EIS guidelines were issued on December 20, 2018. The EA will be undertaken pursuant to CEAA 2012. New federal environmental assessment legislation (Bill C-69) received Royal Assent on June 21, 2019; however, this will not apply to the currently proposed Project; which will continue under CEAA 2012.

A provincial EA under the *Environmental Protection Act* is not anticipated to be required based on the proposed Project scope. Chevron will not be constructing onshore facilities as part of the Project. No provincial or municipal permits are currently anticipated to be required for the Project, including for the onshore supply base services that will be sourced from an existing facility. There are two offshore supply bases on the east coast of the Island of Newfoundland, which have been providing support to offshore oil and gas activity in the NL offshore since the early 1990s. These are third-party facilities that have the necessary permits and approvals to undertake activities related to offshore oil and gas projects. No additional modifications or changes to the existing third-party supply base will be required for the purpose of supporting this Project. As a result of the forgoing, the supply base and associated activities are not considered to be within the scope of the Project assessment.

1.5.3 Other Applicable Regulatory Requirements

As defined by the Accord Acts, the NL offshore area regulated by the C-NLOPB includes the greater of lands within Canada's 200 nm EEZ or to the edge of the continental margin. CEAA 2012 defines federal lands as those lands that include the continental shelf of Canada. Therefore, the Project will be carried out on federal lands under the jurisdiction of the C-NLOPB. There is no federal funding involved in this Project.

In addition to the OA and ADW from the C-NLOPB pursuant to the Accord Acts, and EA approval under CEAA 2012, the Project is subject to various federal legislative and regulatory requirements outlined in Table 1.3.

Table 1.3 Summary of Other Potentially Relevant Federal and Provincial Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Canada Shipping Act, 2001	Transport Canada	The *Canada Shipping Act*, 2001 set out the requirements for safety in marine transportation and the protection of the marine environment from damage due to navigation and shipping activities.	Compliance to the Act and its associated regulations is required by all supply vessels (and the MODU, while in transit)
Canadian Environmental Protection Act, 1999 (CEPA)	ECCC	CEPA,1999 pertains to pollution prevention and the protection of the environment and human health 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 Permit (under the *Disposal at Sea Regulations* pursuant to CEPA) is not anticipated to be required in support of the Project as they have not been required in the past for exploration drilling projects.
Fisheries Act	DFO / ECCC (administers section 36, specifically)	The updated *Fisheries Act* contains provisions for the protection of all fish and fish habitats, restores the prohibition against harmful alteration, disruption or destruction (HADD) of fish habitat, prohibits activities that cause the “death of fish” (other than fishing activities), considers the cumulative effects of development activities, and provides improved protection of highly productive, sensitive, rare or unique fish and/or fish habitats	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. A HADD Authorization may now be required
Migratory Birds Convention Act, 1994 (MBCA)	ECCC	Under the MBCA, it is illegal to kill migratory bird species not listed as game birds or destroy their eggs or young. The Act also prohibits the deposit of oil, oil wastes or other substance harmful to migratory birds in waters or area frequented by migratory birds.	A Migratory Bird Handling Permit will likely be required under section 4(1) of the *Migratory Birds Regulations* pursuant to the MBCA to permit the salvage of stranded birds on offshore vessels during the Project.
Canadian Navigable Waters Act (CNWA)	Transport Canada	The CNWA came into force in August 2019 and replaced the former *Navigable Protection Act*. The CNWA applies to anyone planning something that will affect navigation in navigable waters. The CNWA has been expanded to regulate major works and obstructions on all navigable waters, even those not on the schedule and creates a new category for “major” works. “Major works” are those likely to substantially interfere with navigation and will always require approval from Transport Canada. Transport Canada administers the CNWA through the Navigation Protection Program.	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 CNWA.

Table 1.3 Summary of Other Potentially Relevant Federal and Provincial Legislation

Legislation	Regulatory Authority	Relevance	Potentially Applicable Permitting Requirement(s)
Oceans Act	DFO	The *Oceans Act* provides for the integrated planning and management of ocean activities and legislates the marine protected areas program, integrated management program, and marine ecosystem health program. Marine protected areas 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). Section 32 of the Act provides a complete list of prohibitions. 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 minimize effects. All activities must be in compliance with SARA.	Under certain circumstances, the Minister of Fisheries and Oceans may issue a permit under section 73 of SARA authorizing an activity that has potential to affect a listed aquatic species, any part of its critical habitat, or the residences of its individuals. However, such a permit is not anticipated to be required in support of this Project.
Regulations Establishing a List of Spill treating Agents, SOR/2016-108	ECCC	The Minister of the Environment has determined that certain spill-treating agents (as listed in the Regulations) are acceptable for use in Canada's offshore. As a result, the C-NLOPB can authorize the use of one or more of the two spill-treating agent products listed in Schedule 1 of the Regulations to respond to an oil spill.	Specific implications for spill prevention and response, should Chevron request to deploy dispersants in the unlikely event of an oil spill.
Newfoundland and Labrador (NL) *Endangered Species Act* (NL ESA)	NL Department of Fisheries and Land Resources	The NL ESA provides special protection for native plant and animal species considered to be endangered, threatened or vulnerable in the province.	No applicable permitting requirements have been identified for the Project.
Seabird Ecological Reserve Regulation s, NLR 66/97	NL Department of Fisheries and Land Resources	These regulations 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 all-terrain vehicles at all times.	Supply vessels and helicopters will comply with regulatory requirements. No applicable permitting requirements under the *Seabird Ecological Reserve Regulations* have been identified for the Project.

Within offshore NL, different authorities hold jurisdiction over commercial fishing activities that occur either within or outside Canada's EEZ. The Government of Canada holds jurisdiction over management of fisheries for sedentary and non-sedentary species up to the 200 nm limit, and for sedentary species

(e.g., snow crab) to the extent of Canada's defined Continental Shelf. Outside of the EEZ, Northwest Fisheries Organization (NAFO) holds jurisdiction over fisheries management for several species and has the authority to designate legally protected areas such as coral closures.

The Government of Canada announced changes to the *Fisheries Act* and the *Navigation Protection Act* in February 2018. The *Fisheries Act* key changes include: returning to a comprehensive protection against harming all fish and fish habitat (i.e., HADD); prohibiting the 'death of fish' from means other than fishing; strengthening the role of Indigenous peoples in project reviews, monitoring and policy development; considering the cumulative effects of development projects on fish and/or fish habitat; new fisheries management tools to enhance the protection of fish and ecosystems; and clarify and modernize enforcement powers to address emerging fisheries issues and to align with current provisions in other legislation (Fisheries and Oceans Canada [DFO] 2018). The CNWA came into force in August 2019 (Government of Canada 2018) and replaced the former *Navigable Protection Act*. The CNWA applies to anyone planning something that will affect navigation in navigable waters. The CNWA has been expanded to regulate major works and obstructions on all navigable waters, even those not on the schedule and creates a new category for "major" works. "Major works" are those likely to substantially interfere with navigation and will always require approval from Transport Canada. Transport Canada administers the CNWA through the Navigation Protection Program.

1.6 Applicable Guidelines and Resources

Other applicable guidelines and resources, to inform the EA process, may be required for the Project, including government guidelines, Indigenous engagement guidelines, and other relevant studies.

1.6.1 Government Guidelines and Resources

In addition to the EIS Guidelines (Agency 2018) developed for the Project (refer to Appendix A), the EIS preparation also used other guidance developed by the Agency and federal government:

- The Operational Policy Statement, addressing "Purpose of" and "Alternative Means" under the *Canadian Environmental Assessment Act, 2012* (Agency 2015a) was consulted with respect to the assessment of Project alternatives (refer to Section 2.9).
- The Operational Policy Statement, Determining Whether a Designated Project is Likely to Cause Significant Environmental Effects under the *Canadian Environmental Assessment Act, 2012* (Agency 2015b) was considered in defining criteria or established thresholds for determining the significance of residual adverse environmental effects.
- The Operational Policy Statement, Assessing Cumulative Environmental Effects under the *Canadian Environmental Assessment Act, 2012* (Agency 2016a) was taken into consideration during the development of the cumulative effects assessment scope and methods.
- The Agency's Technical Guidance for Assessing Physical and Cultural Heritage or any Structure, Site or Thing that is of Historical, Archaeological, Paleontological or Architectural Significance under the *Canadian Environmental Assessment Act, 2012* (Agency 2015c) was consulted with respect to the consideration of effects on heritage and culture.

- The Agency's Technical Guidance for Assessing the Current Use of Lands and Resources for Traditional Purposes under the *Canadian Environmental Assessment Act, 2012* (Agency 2016b) was consulted with respect to the consideration of effects on Indigenous Peoples.
- Environment and Climate Change Canada-Canadian Wildlife Service's Oiled Birds Protocol and Procedures for Handling and Documenting Stranded Birds Encountered on Infrastructure Offshore Atlantic Canada (ECCC 2016).
- Measures to Protect and Monitor Seabirds in Petroleum-Related Activity in the Canada-NL Offshore Area (C-NLOPB No Date)
- Health Canada's Useful Information for Environmental Assessments (Health Canada 2010) was consulted with respect to the consideration of effects on quality, noise and Aboriginal health.

1.6.2 Aboriginal Policies and Guidelines

Pertinent guidelines which influenced the EA process with respect to Indigenous engagement include:

- Aboriginal Consultation and Accommodation - Updated Guidelines for Federal Officials to Fulfill the Duty to Consult (Aboriginal Affairs and Northern Development Canada 2011)
- Reference Guide: Considering Aboriginal Traditional Knowledge in Environmental Assessments Conducted Under the *Canadian Environmental Assessment Act, 2012* (Agency 2015d)
- The Government of Newfoundland and Labrador's Aboriginal Consultation Policy on Land and Resource Development Decisions (Government of NL 2013)

1.6.3 Other Relevant Studies

There is approximately 35 years of environmental assessment of Newfoundland offshore oil and gas activities to draw information from. Key environmental studies relevant to this EA include:

- The Newfoundland Orphan Basin Exploration Drilling Program Environmental Impact Statement (BP Canada Energy Group ULC 2018)
- Exploration Drilling Environmental Impact Statement (Husky Energy 2018)
- Flemish Pass Exploration Drilling Project (Statoil Canada Ltd 2017)
- Eastern Newfoundland Offshore Exploration Drilling Project (ExxonMobil Canada Properties 2017)
- CNOOC Petroleum North America ULC (formerly Nexen Energy ULC) Flemish Pass Exploration Drilling Project (Nexen Energy ULC 2018)
- Eastern Newfoundland Strategic Environmental Assessment (AMEC 2014)
- Environmental Assessment of Equinor Canada Ltd. (formerly StatoilHydro Canada Ltd.) Exploration and Appraisal / Delineation Drilling Program for Offshore Newfoundland, 2008-2016 (LGL 2008)
- Hebron Project Comprehensive Study Report (ExxonMobil Canada Properties 2011)

In the preparation of this EIS, the above reports, as well as other relevant studies, and peer-reviewed literature have been reviewed and referenced. The Project Area falls within the study area for the Eastern Newfoundland Strategic Environmental Assessment (Eastern NL SEA) (AMEC 2014) and the study area of the Regional Assessment of Offshore Oil and Gas Exploratory Drilling East of NL. The Regional Assessment was initiated in October 2018 under CEAA 2012; however, this assessment is not yet complete.

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2.0 PROJECT DESCRIPTION

This chapter provides an overview of key Project information. It gives the overall context of the Project by explaining the rationale and need for the Project; describing the location and nature of Project components and activities, including the management of emissions and discharges that would likely be generated by the Project; and potential accidental events with associated environmental planning and management considerations. Details on required personnel, the Project schedule, and alternative means for carrying out the Project are also provided. Activities associated with the Project are drilling within EL 1138, possible appraisal (delineation) drilling in the event of a hydrocarbon discovery within the EL, VSP, well testing, eventual well decommissioning and abandonment (or suspension) procedures, and associated supply and service activities.

2.1 Rationale and Need for the Project

Exploration drilling is required to assess the potential for important geological formations and hydrocarbon reserves within the EL. To compliment previous geophysical data collected in the region, this exploration drilling will help determine the presence, nature and quantities of potential hydrocarbon resources within the EL.

Several economic, social, and technological benefits of the Project are outlined in Section 1.4. These benefits are realized on local, regional, and national scales, and include a potential contribution to energy diversity and supply. Global energy demands for the next several decades are expected to include requirements for oil and natural gas. To maintain production to meet this global demand for energy, exploration is a critical activity to enable continued oil and gas discoveries.

2.2 Project Location

EL 1138 is in the Flemish Pass area. It is approximately 375 km northeast of St. John's, Newfoundland, Canada; the nearest community is Flatrock (approximately 370 km), on the Avalon Peninsula. The nearest "residences" to the Project would be the *SeaRose* floating, production, storage and offloading (FPSO) vessel at Husky's White Rose oil development field, approximately 130 km from EL 1138. Water depths in the EL range from approximately 400 to 2,200 m.

A Project Area has been proposed that encompasses the EL with an approximate 10 km buffer. The LAA and the RAA are defined by the study area boundaries that will extend beyond the Project Area and are based on potential environmental interactions with routine and unplanned Project activities (including recognition of potential cumulative environmental effects); these are further described in Chapter 4. EL and Project Area coordinates are provided in Tables 2.1 and 2.2, respectively, and are shown on Figure 2-1.

Table 2.1 EL 1138 Coordinates

Latitude	Longitude
48°30'N	47°00'W
48°30'N	47°15'W
48°30'N	47°30'W
48°20'N	47°00'W
48°20'N	47°15'W
48°20'N	47°30'W
48°10'N	47°00'W
48°10'N	47°15'W
48°10'N	47°30'W
48°00'N	47°15'W
48°00'N	47°30'W

Table 2.2 Project Area Coordinates

Label	X (UTM NAD 83, Zone 22)	Y (UTM NAD 83, Zone 22)	Longitude	Latitude
A	805009.6153	5390072	46° 51' 48.156" W	N48° 35' 21.655"
B	809057.4088	5312548	46° 51' 54.621" W	N47° 53' 30.259"
C	733017.1165	5309106	47° 52' 57.174" W	N47° 53' 34.585"
D	730288.8723	5373550	47° 53' 2.643" W	N48° 28' 22.328"
E	739197.9915	5381353	47° 45' 33.296" W	N48° 32' 22.667"
F	753957.5124	5382022	47° 33' 33.256" W	N48° 32' 23.437"
G	753699.4323	5387538	47° 33' 33.716" W	N48° 35' 22.141"

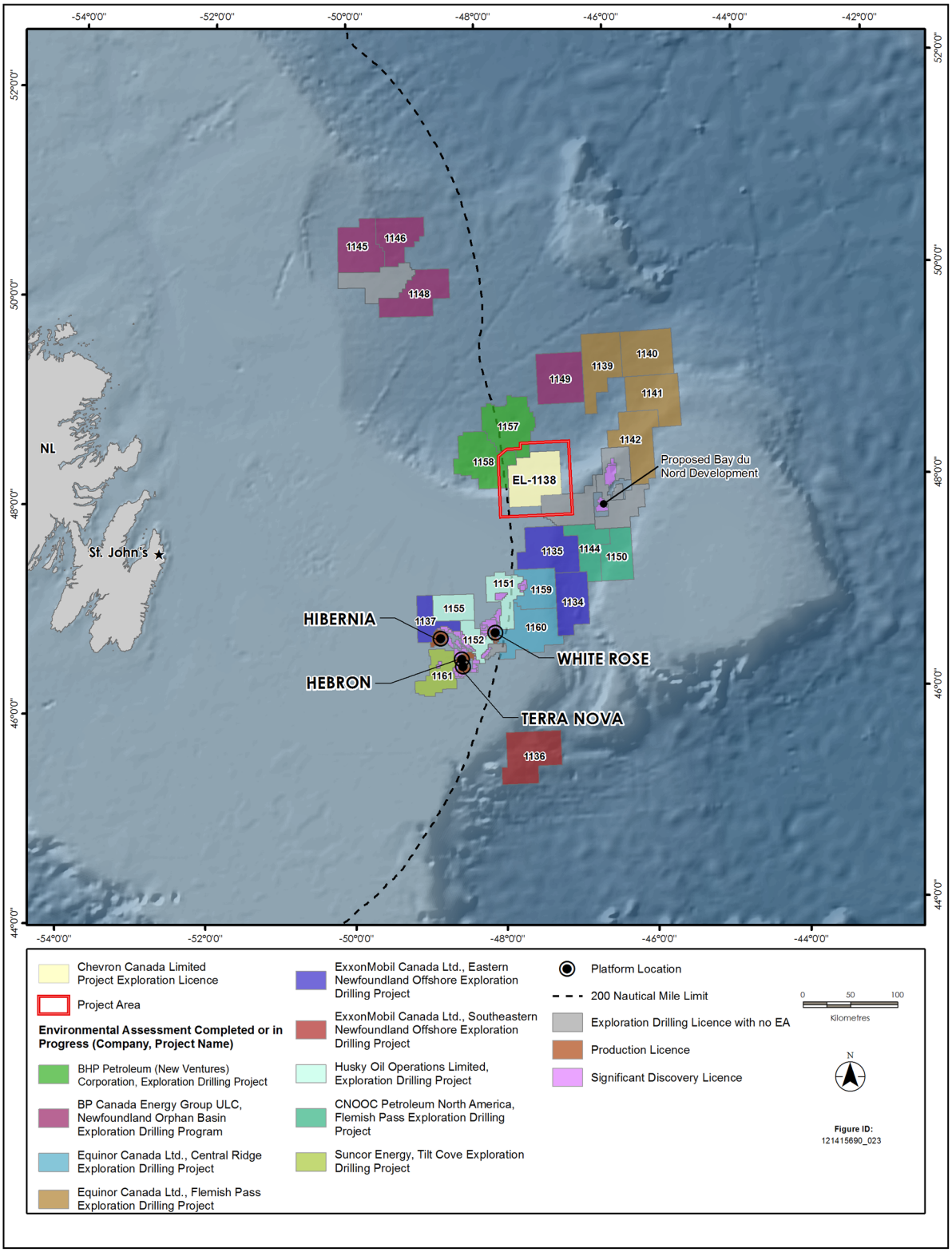


Figure 2-1 Exploration Licence 1138 and Project Area

No wells have been drilled in EL 1138 (or the Project Area). Several wells have been drilled to the east of the Project Area, primarily in the vicinity of Equinor Canada's Bay du Nord license. There are no zoning designations that apply to the Project Area. The Project will not take place on lands that have been subject to a regional study as described in sections 73-77 of CEAA 2012; however, the Project Area does fall within the study area for the Eastern NL SEA completed by the C-NLOPB in August 2014 (AMEC 2014). The Project Area falls within the study area of the Regional Assessment of Offshore Oil and Gas Exploratory Drilling East of NL initiated in October 2018 under CEAA 2012; however, this assessment is not complete.

The EL is located beyond the boundaries of Canada's EEZ (200 nm limit), near a NAFO Vulnerable Marine Ecosystem (VME) closure (Sackville Spur 6), which was established in January 2010, to protect corals and sponges from bottom-contact fishing gear. This closure area does not include any prohibitions applicable to oil and gas exploration activities. The Project Area is in a region where multiple fishers harvest for commercial purposes and commercial fishing activity has historically been high in certain areas of the EL. More information on the physical, biological, and socio-economic characteristics of the Project Area can be found in Chapters 5, 6, and 7, respectively.

Specific well sites are not yet determined but drilling operations will be conducted within the defined boundaries of EL 1138 (Figure 2-1). To optimize the potential discovery of hydrocarbon reservoirs, prospective areas will be selected based on several factors, including:

- Geophysical data
- Geohazard data
- Seabed baseline conditions, including environmental sensitivities and anthropogenic features
- Regional well data

The results of the 3D seismic interpretation will help identify the potential well location on EL1138. The 3D seismic interpretation will be used to assess the components of the petroleum system. If a reasonable chance of a viable hydrocarbon accumulation is deemed to exist, optimal well target locations at the reservoir interval will be selected based on the seismic data. The 3D seismic data will be used to assess the shallow formations which would be encountered while drilling en route to the reservoir, to develop optimal drilling designs and procedures and to avoid safety hazards and/or mechanical failures.

Once a specific well site has been determined and prior to drilling, the well site location is surveyed, generally using a remotely operated vehicle (ROV) to inspect the seabed for sensitive habitat (e.g., habitat-forming corals). This survey is distinct from the geohazard survey noted above and is included in the EA as part of the Project scope. This survey may also be used to inform discussions and planning for potential follow-up and monitoring with respect to drill waste discharges, as it will provide baseline data for coral and sensitive benthic habitat that may be present (refer to Chapter 8, Marine Fish and Fish Habitat). A description of existing anthropogenic features, including unexploded ordnances (UXOs), shipwrecks, and tele-communication cables can be found in Section 7.3.4. The ROV survey will also be used to ground-truth findings from the geohazard baseline review, confirming the absence of sensitive habitat or environmental features, shipwrecks, debris on the seafloor, and UXO. The survey will encompass an area of 500 m from the proposed well site and be carried out prior to drilling. In the case that environmental or anthropogenic sensitivities are discovered during the survey, Chevron will notify the C-NLOPB immediately

to discuss an appropriate course of action. This may lead to further investigation and/or moving the well site, if it is feasible to do so.

2.3 Project Components

The drilling vessel and the offshore exploration wells are the two main physical components of the Project. Components related to servicing and supplying offshore activity (logistics-related components) include supply vessels and helicopters for the transportation of personnel and equipment, and a supply base in the St. John's, NL, region.

The drilling vessel, supply vessels, helicopters, and supply base will be used by the Project on a temporary basis through contractual arrangements.

2.3.1 Drilling Components

2.3.1.1 Drilling Vessel

The Project will use a MODU (either a semi-submersible rig or a drillship) (Figure 2-2). A drillship is typically used in relatively deep waters (either on anchor or using dynamic positioning (DP) systems at greater depths) or in areas where increased mobility is required due to ice or other factors and operational risks. A drillship would either be moored in position over the drilling site or, as is more likely for this drilling program, maintained on station by DP. A semi-submersible rig is typically used at moderate depths, such as on the Grand Banks, and anchored in place. Chevron has not yet selected the MODU that will be used to drill the wells for the Project.

2.3.1.2 MODU Selection and Approval Process

Chevron will use several criteria for MODU selection to ensure safe, compliant, and reliable wells are drilled. The focus in the selection process is on regulatory compliance, meteorological and physical oceanographic conditions, and the technical capability of the MODU. The MODU must be able to operate in the water depths and meteorological and oceanographic (metocean) conditions of the EL and be winterized should year-round drilling be required.

After the selection of the MODU, it will be subject to a Chevron internal rig intake process which requires verification from the operator of the rig that contracted drilling installation conform to company practices and industry standards. Pursuant to the Accord Acts, the *Newfoundland Offshore Certificate of Fitness Regulations*, and the requirements of an OA, a Certificate of Fitness for the drilling vessel will be obtained, which will be issued by a recognized, third-party, Certifying Authority prior to approval for use. This assures that the drilling installation is fit for purpose, functions as intended, and remains in compliance with the regulations without compromising safety and/or polluting the environment.

The following sub-sections provide additional detail on the two types of MODUs, currently under consideration for use by Chevron (i.e., semi-submersible drilling rig and drillship).

Source: Schofield Publishing 2007

Figure 2-2 Illustration of Drill Ship (front) and Semi-submersible (back)

2.3.1.3 Semi-Submersible MODU

A semi-submersible consists of a lower hull of horizontal pontoons with vertical columns extending upward, supporting a large upper deck, containing drilling equipment, storage areas, and personnel quarters. To ensure stability, a ballast system is used to submerge the lower hull to a pre-determined depth. Compared to a ship-shaped hull, the semisubmersible configuration provides a relatively stable platform by reducing environmental loading. In shallow water (<1,200 m), the semi-submersible drilling installation is often moored in position over the drilling site using mooring lines and anchors. In deep waters, a DP system is used to maintain position, which rely on the drilling unit's thrusters, controlled by a computerized DP system using Global Positioning System and acoustic positioning system.

Given that the water depth range of the Project is 400 to 2,200 m depth, either the anchoring or DP system may be used. In shallow water, the standard mooring technique for a semi-submersible is a multi-point mooring system using a combination of wire rope, chains, and anchors and a specialized anchor handling vessel. In deep water DP mode, energy signals are transmitted from the acoustic system to transponders (receivers) positioned on the seafloor, which then send signals back to the transmitter, allowing an accurate calculation of the position of the transponder relative to the vessel (Kongsberg Maritime 2016). The drilling unit's thrusters, controlled by the DP system, keep the vessel in position.

Figure 2-3 is a photo of the West Hercules, a semi-submersible that has operated in the Canada-NL Offshore Area.

Source: Seadrill 2017

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

2.3.1.4 Drillship

A drillship is a self-propelled drilling vessel, capable of ultra-deep-water wells due to its large deck load capacity and increased storage area. Drillships, like semi-submersibles, use DP to maintain position and rotate the ship into prevailing weather, which minimizes pitch and roll motion. Unlike a typical offshore vessel, drillships have a drilling package and a moon pool (an opening located in the bottom of the hull of the vessel). The moon pool allows for direct access to the water, enabling drilling equipment to connect to equipment on the seafloor to drill the well.

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: Stena Drilling 2017

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

2.3.2 Offshore Exploration Wells

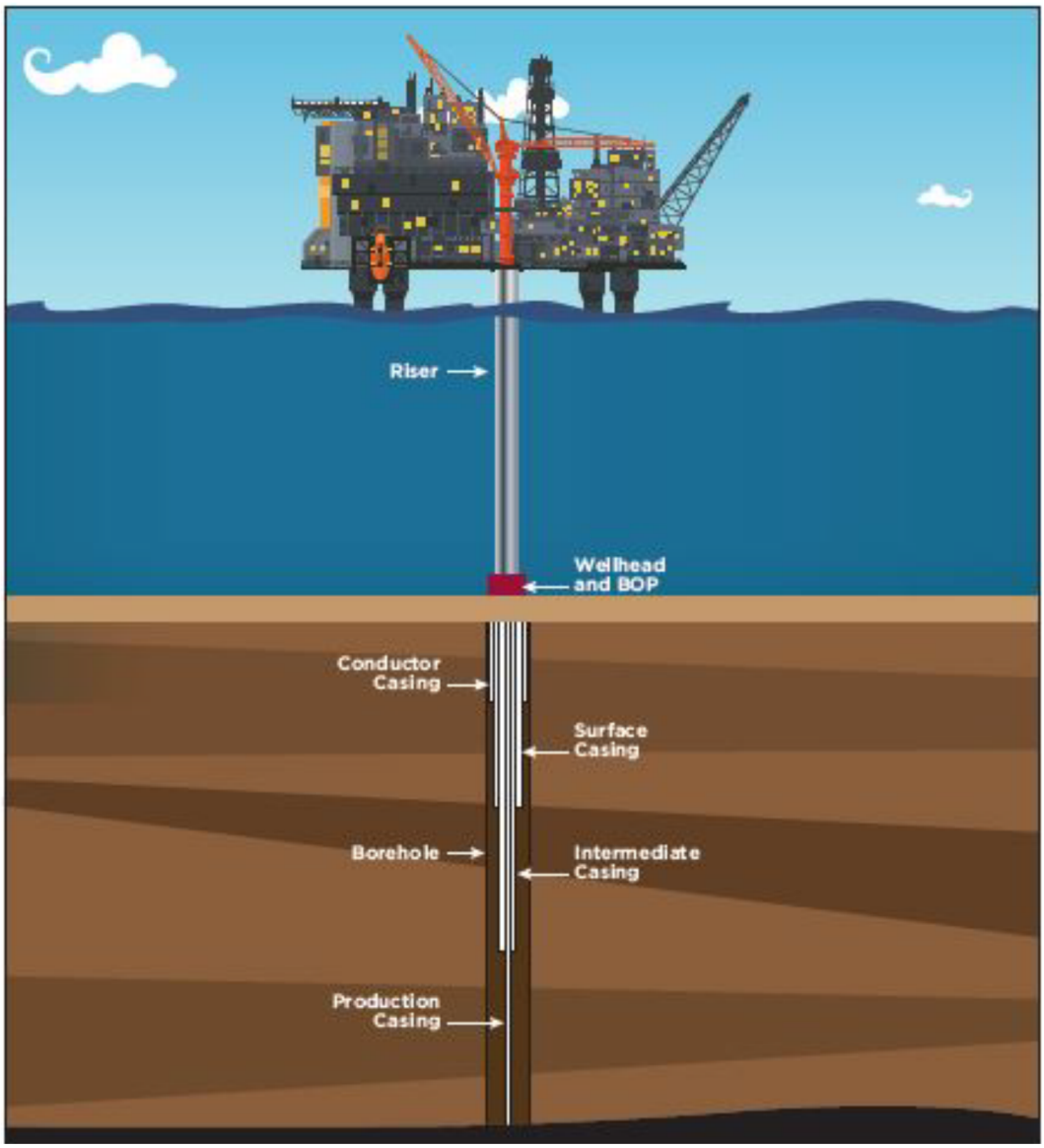
Chevron may drill up to eight wells over a ten-year period from 2016-2025, depending on the results of the initial well, and proposes to commence drilling in Q2 2021, pending regulatory approval. It is anticipated that it will take approximately 180 days to drill each well. The well design and location for the proposed wells have not yet been finalized and will depend on many factors, such as the geology of the formations. Table 2.3 outlines indicative well casing plans. Once well design and locations are finalized, the details will be submitted for review and approval by the C-NLOPB as part of the OA and ADW for each well submitted in association with the Project.

Table 2.3 Indicative Well Casing Plan for Project Wells*

Section	Section Name	Drilling Fluid	Hole Size	Casing Size	Interval Length
1	Conductor Section	Seawater / WBM	42	36	100
2	Surface Casing	Seawater / WBM	26	22	400
3	Intermediate Casing	SBM / WBM	17½	13 3/8	1,500
4	Production Hole	SBM / WBM	12¼	9 5/6	1,500
* Final well casing plan for each well may differ as Project planning advances and will be presented in ADW application					

The drill bit at each section will get progressively smaller and the borehole is secured with a liner installed within the wellbore (casing). The casing forms the major structural component of the wellbore and is made up of a series of steel pipes. It serves many important functions such as preventing caving of the formation into the wellbore, separating the formations to prevent flow or cross flow of formation fluids, and allows for control of the formation fluids and pressure as the well is drilled.

A typical casing configuration is shown in the schematic of a completed offshore well, in Figure 2-5. This figure is for illustrative purposes only and does not necessarily represent the Project casing design. More information on the offshore wells and drilling process is provided in Section 2.4.2.



Source: CAPP 2017
BOP = Blowout preventor

Figure 2-5 Schematic of Completed Offshore Well Showing Casing Configuration

2.3.3 Supply and Servicing Components

Logistical arrangements for supply and servicing activity will be required in support of offshore drilling operations so that equipment and supply stocks are maintained at sufficient levels to support ongoing drilling operations.

Supply and servicing components and activities included in the scope of this EIS encompass supply vessel operations (e.g., loading, transit and unloading of vessels) and helicopter support (e.g., crew transport and delivery of supplies and equipment). Activity within a supply base is not considered within the scope of this EIS; however, it is described below with respect to supply vessel routes.

The onshore supply base supports offshore drilling operations in NL and is used for storing, staging and the loading or unloading of material onto the supply vessel, going offshore or returning onshore. Supply base facilities are third-party owned and operated and are subject to provincial and/or municipal regulatory requirements, including government permits and approvals, and certifications compliant with port facilities under the *Marine Transportation Security Act*. Supply vessels and helicopters, based out of the St. John's region, will be used to transport personnel, equipment and materials to and from the MODU and supply base during the drilling program. The supply vessels and helicopters will be contracted to third-party service providers on a temporary basis.

The supply vessels have not yet been selected; however, the fleet will be selected to fulfill the following functions for the MODU:

- Supply food, fuel, dry bulk, drilling fluids and drilling tools and equipment
- Waste transportation
- Assist in emergency response situations
- Monitor the safety zone around the MODU and intercept vessels if required

The Project will likely require two or three supply vessels. A standby vessel will remain at the MODU at all times during drilling activities. Figure 2-6 is a photo of a typical supply vessel that could be used on the Project.

Source: DOF Group 2013

Figure 2-6 Typical Supply Vessel

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. Supply vessels will meet operator marine-vessel vetting requirements and additional inspections / audits, including the C-NLOPB pre-authorization inspection process in preparation for the Project.

Helicopter support will be used for crew transfers and delivery of light supplies to and from the MODU. They may also be used for emergency support services, such as medical evacuation from the rig and search and rescue operations, if requested by the Canadian authorities. Figure 2-7 shows a typical offshore helicopter that could be used to support the Project.

Source: Cougar Helicopters Inc. 2017

Figure 2-7 Typical Offshore Helicopter

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

2.4 Project Activities

2.4.1 MODU Mobilization and Drilling

Rig intake activities will include a rigorous inspection and certification process, required to deliver a Certificate of Fitness before an OA will be issued by the C-NLOPB. Once approved and permits are received, the MODU will be mobilized to the drilling location.

Depending on the MODU selected, mobilization will involve either towing or self-propulsion. Once in place, positioning and stability operations will occur, including ballasting to increase the stability of the MODU and implementation of the DP or multi-point mooring system to maintain position.

If a DP system is being used, acoustic transponders will be installed on the seafloor prior to MODU mobilization. Typically, the transponders are installed one to two weeks before the MODU arrives on site

and can take up to 18 hours to install once the vessel arrives. An ROV visual inspection of approximately 200 m radius from the well location is completed to confirm that there are no drilling hazards present.

If the MODU is moored, anchors are set on the seabed prior to or at the time of MODU arrival. Typically, mooring anchor spreads consist of 8 to 12 anchors with anchor chain and/or wire to connect the moorings back to the MODU. If anchors are pre-set prior to MODU arrival, the anchor handling vessel deploys the anchors, associated chain / wire, and locator buoys, and a surveyor confirms the anchor deployment position. The vessel winch is used to tension the anchor. If anchors are not pre-set, the MODU will pass the anchors to the anchor handling vessel for deployment and tension upon arrival. An ROV visual inspection of an approximately 200 m radius from the well location is completed to confirm that there are no drilling hazards present prior to anchor deployment.

Once the MODU is in place, directly above the proposed well site, an ROV will survey the seabed prior to drilling. If environmental or anthropogenic sensitivities are discovered during the ROV survey, Chevron will contact the C-NLOPB immediately to discuss an appropriate course of action. This may involve further investigation and/or moving the well site if feasible to do so.

Pursuant to the *Newfoundland Offshore Petroleum Drilling and Production Regulations*, a safety zone (500 m radius from the well location or when moored, 50 m from the outer extent of the anchors) will be established around the MODU. The safety zone is intended to prevent collisions between the MODU and other vessels operating in the area. This safety zone will remain in place from the initial mobilization time until well suspension or abandonment. The standby vessel will monitor the safety zone and Chevron will provide details of the safety zone to the Marine Communication and Traffic Services for broadcasting and publishing in the Notice to Shipping and Notice to Mariners. Safety zone details will also be communicated during ongoing consultations with Indigenous and non-Indigenous fishers.

Navigational safety will be maintained throughout the Project. All radio communication systems, obstruction lights, navigation lights, and foghorns will be kept in working order onboard the MODU and supply vessels. Radio communications between the MODU and supply vessels, and the MODU and shore, will be put in place and maintained.

Oil and gas wells consist of multiple sections, each of which is typically drilled with increasingly smaller drill bit diameters. There are many available drill bit sizes for drilling. The top interval or section, with the largest diameter hole, begins at the sea floor. The drill bit is rotated by the drill string which is a series of joints of pipe, controlled from the MODU. Drilling fluids (also known as “muds”) are required to lubricate the drill bit.

The types of drilling fluids (e.g., water-based mud [WBM], synthetic-based mud [SBM]) used, depend on the well design and the anticipated geological conditions. Wellbore construction will typically begin with the spud of the well into the seabed and running and setting conductor and surface casing followed by cementing. During this process, drilling is typically done with a WBM, where drill cuttings, drilling mud, and cement returns from casing cementing will be circulated to the seabed surrounding the wellhead. For safe and efficient drilling, the fluids must comprise a base fluid, weighting agents, and other chemicals. The Operator’s chemical selection process will reduce the potential for environmental effects from discharge by adhering to regulatory requirements and the OCSG (refer to Section 2.9.3 regarding chemical selection and management).

Drilling fluids from the MODU are pumped through the drill string to the drill bit. Rock layers are broken up by the drill bit which grinds the rock as it rotates downward. This creates fragments of rock known as drill cuttings, which are flushed out of the wellbore through the annulus by the drilling fluid.

It will take approximately 180 days to drill each well. The process is broken down into two phases: riserless drilling; and riser drilling. In the first sections of the well (conductor and/or surface) there is no closed- loop riser; therefore, WBMs and/or seawater will be used to flush cuttings and excess cement to the seafloor and release them directly into the marine environment pursuant to regulatory guidelines and OWTG. The drilling fluid, in this case, is also used to provide overbalance to the formation pressure with the hydrostatic pressure in the wellbore and to keep the drill bit cool. Once the initial sections are drilled, the wellhead can be installed and the blowout preventer (BOP) and a closed-loop system (riser) can be connected to the well. The riser is a conduit which allows the fluids, used in the drilling of the well, to be recirculated back to the MODU, and either be recycled and reused, treated and discharged or stored onboard for disposal at shore. Since the riser returns the drilling fluid to the MODU for treatment, either a WBM or SBM can be used.

The conductor section is the first section of the well and provides the initial structural foundation for the borehole and wellhead. It will be approximately 42” diameter and 100 m deep. After drilling, a steel casing is cemented in place to secure the wellbore and to prevent the seepage of muds and other fluids. An alternative method requires no cement where the conductor string is drilled directly into place (“jetted” into place).

After completion of the conductor section, a second section is drilled to a pre-defined depth with a smaller drill bit. Once drilled, the wellbore is secured by running and cementing a surface casing string. The cement seals the formation, preventing the loss of drilling fluid and permanently seals the annular spaces between the casing and the wall of the borehole. The casing is cemented into place using a slurried cement, which is pumped through the casing and up into the annular space, solidifying prior to drilling out the string. The annular space is adequately sealed using excess cement for extra reinforcement, in case irregularities in the formation result in a larger annular space than expected. In a riserless phase any extra cement may be discharged to the seafloor.

The high-pressure wellhead, connected to the top of the surface string, is a pressure-containing mechanism that is the receptacle for further casing strings used in drilling. It will be lowered down onto the wellhead on the conductor with the surface casing string already attached. Like the conductor section, drill cuttings and fluids will be discharged onto the seafloor, pursuant to the OWTG.

After surface casing installation is complete, the BOP and the riser are connected to the wellhead. The riser creates a conduit back to the MODU. The BOP is a critical piece of safety equipment that houses a system of high-pressure valves, which protect the crew and the environment by preventing water or hydrocarbons from escaping into the environment in the event of an emergency or equipment failure. More information on the BOP and additional well control features is provided in Section 2.5.

After the riser and BOP have been installed, WBMs are no longer required as drilling fluids and cuttings can be circulated back to the MODU for treatment. It is unknown at this time which drilling fluids will be used for the remainder of the well sections, but it will be either WBM or SBM. Details such as drilling fluid

selection, section depth, and other well design components depend on the specific geology and predicted pore pressures encountered at each well. The remaining sections of the well are drilled to predefined depths and as above, casing is cemented in place at set depths to reinforce the wellbore. This sequence of events is repeated until the total depth of the well is reached. For more information on drilling fluids and drilling waste management, refer to Section 2.8.2.

In the case that total depth cannot be reached, contingency casing sections will be available. A contingency string is effectively an additional string inserted into the well to enable the well to be drilled to total depth and typically come in casing or liner sizes of 18", 11¾", and 7". It is expected that four sections will be enough to complete the well; however, three extra sections may be used if contingencies are required.

If a well is successful, a planned sidetrack may be drilled to explore nearby areas of the reservoir. This will involve a secondary wellbore which will be “kicked off” from the original wellbore using similar methods as described above. Before commencement of any sidetrack drilling, the original wellbore will be abandoned using cement. Because the details and design of the sidetrack depend on the results of the original well, they have not yet been finalized, but will be submitted to C-NLOPB for approval once established.

2.4.2 Vertical Seismic Profiling

VSP may be conducted following the drilling of each well to its target depth (where hydrocarbon reservoirs are predicted to be located). It allows the correlation of seismic data (which is recorded in time measurements) to well depth (recorded in metres (m)). VSP is used within the wellbore to identify potential hydrocarbon deposits.

VSP operations involve deploying an acoustic sound source from the drilling or support vessel, while receivers are positioned at different levels within the drilled hole to measure the travel time. This form of VSP operation is referred to as zero-offset VSP. An offset VSP (also referred to as a walkaway VSP), where the acoustic source is used from a marine vessel and deployed up to 8 km from the well, could also be used in the exploration wells.

Typically, between three and six sound sources are used, with a volume of 150 to 250 cubic inches (in^3) each, although there could be up to 12 sound sources in a larger array. These sound sources are generally positioned at 5 to 10 m water depth. VSP operations typically take approximately one to three days to complete for each well. VSP sound sources are typically smaller and shorter in duration than exploration seismic surveys (refer to Section 2.8.5 for more information on underwater sound generated by VSP).

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

2.4.3 Well Evaluation and Testing

Well evaluation and testing may be required if the exploration drilling results indicate the presence of hydrocarbons in the target formations. The evaluation and testing will help characterize the reservoir and provide further information about the stratigraphic column, viability of a prospect and the commercial potential of reservoirs. Thus, well evaluation and testing are very important components of exploration

drilling. Well flow testing involves flowing the well fluids through temporary test equipment located on the drilling vessel and requires flaring of gases or other hydrocarbons that come to surface for safe disposal.

There are typically three levels of well evaluation for hydrocarbons. The first occurs while drilling in real time, where data are collected both from downhole electronic tools in the bottom hole assembly (BHA) and from mud logging data collected from the mud that returns from the well. Formation data are transmitted to the surface from the downhole tools while drilling, and a separate evaluation of drill cuttings samples and gas entrained in the drilling mud is evaluated for hydrocarbon show. Both datasets are presented in real time logs to be monitored and evaluated at the rig site and data transmitted via satellite system to shore.

The second level of evaluation usually occurs upon favorable data observed while drilling and when the targeted formation(s) have been fully drilled. Additional logs and formation pressures may be run on dedicated tools, such as drill pipe or wireline, that collect advanced datasets to evaluate a potential hydrocarbon reservoir. This testing is used to gather information about subsurface characteristics such as potential productivity, connected volumes, fluid properties, composition, flow, pressure, and temperature. These data, together with the data collected during initial well evaluation, can build a comprehensive picture of reservoir potential.

The third level of evaluation to fully evaluate a reservoir and its potential for oil production is the well flow test. A well flow test involves the rigging up of temporary production facilities on the drilling rig to allow the well to flow in a steady state and controlled manner to the surface to obtain a dynamic dataset. Samples of oil are collected to fulfill requirements of a significant discovery. The oil produced throughout this period is usually directed to a flare boom and burned (flared) with a safe and efficient burner system that limits emissions and the risk of spillage to the sea. The amount of time flaring in a well test operation will be kept to a minimum but will need to be sufficient to collect necessary datasets. It is anticipated that two rig-days of flaring will be sufficient for a well test. There are emerging downhole technologies that may have the potential to substitute the requirements of the surface well test. A well test may not occur right after the drilling phase but may be scheduled later depending on rig schedule, anticipated sea states, and weather conditions. In the event of a delayed well test, the well will be secured with required barriers in place and suspended prior to moving the drilling rig off location.

Well testing will be subject to Chevron's well test assurance process, which is designed to promote safe and efficient well test operations. A Job Safety Analysis will be held before the drill stem test (DST) for equipment readiness, handling procedures, equipment, operation and execution, and for safety issues. The Project-specific Waste Management Plan will be reviewed as part of the well planning process. Environmental concerns will be included in the risk assessment and well planning processes.

The flaring of produced gases (and some fluids) will commonly be required during DST operations. Proper installation of burner booms, water curtains, and temporary piping will be required to effectively burn DST produced fluids safely and efficiently. The lighting of the flare pilot will be performed in a safe and controlled environment. Flaring will be performed in daylight hours where the onsite Health, Environment and Safety (HES) representative and other personnel can closely monitor the ocean surface. Vessels will be on standby throughout testing, with boom and dispersant sufficient to capture any oil slick.

If well testing is required, Chevron will inform the C-NLOPB of any plans for well test flaring as part of the ADW process and will report on any flaring activity.

“Formation Testing While Tripping” is an alternative to formation flow testing with flaring and may be used during the Project to assess the discovered hydrocarbon resources or in support of a Significant Discovery Licence (SDL) application. This alternative does not require topside production equipment, flaring of hydrocarbons, and exposure of personnel to pressurized equipment and thus, is safer, more environmentally friendly, and has economic benefits.

2.4.4 Well Abandonment and Decommissioning

Upon acceptable evaluation of the well for hydrocarbons and upon C-NLOPB approval, the well will be permanently abandoned. An abandonment program will be executed using a configuration of cement and permanent mechanical bridge plugs. As a minimum, the C-NLOPB drilling and production guidelines related to abandonment will be adhered to. If Chevron abandonment criteria is more stringent, Chevron standard operating procedures will prevail.

Once the well is abandoned, the last stage in the process is to remove the wellhead from the seabed depending on regulatory requirements. If determined that the wellhead needs to be removed, the preferred method is the mechanical cutter that can cut the wellhead below the seabed and then be retrieved to surface.

If the wellhead is left in place, the only infrastructure that will be left on the seafloor is the wellhead, approximately 5 m in height and take up a permanent footprint of less than 2 m². All other subsea infrastructure (including the BOP) will be removed. If it is required to remove the wellhead, it will be severed below the mudline. Cement plugs will be put in place and the casing pressure tested above the abandonment plugs to confirm plug integrity before the BOP is removed.

Final details about the well abandonment program will be confirmed to the C-NLOPB as planning continues.

2.4.5 Supply and Servicing

Supply vessels and helicopters are used to transport personnel, equipment and materials to and from the MODU during an offshore drilling initiative according to work schedules and rotations, workforce numbers, distances and other factors. Supply vessels typically make regular trips to the drilling unit throughout a drilling program, and a dedicated stand-by vessel will attend to the rig. Supply base activities will be conducted by a third-party contractor and are outside the scope of this EIS.

2.4.5.1 Platform Supply Vessel Operations

The well site will be located offshore in a remote location more than 300 km from the port of St. John’s, Newfoundland. As with all offshore projects in this region, logistics and service requirements for a drilling rig can be challenging especially during seasons of heavy weather, fog, arctic ice and sea states. The primary land base for offshore operations will be St. John’s for supply vessels and helicopter support. In the event of arctic ice impeding entrance to the harbor, a secondary base at Bay Bulls harbor (approximately a 15-minute drive from St. John’s) will be used.

While the MODU is on location, a dedicated stand-by vessel will be stationed near the rig for emergencies and for secondary storage of well tubulars and drilling mud if required. A second vessel will be servicing the MODU by transporting equipment and people (in the event helicopters cannot fly) to and from the MODU. It is anticipated that two to three sailings per week will be required but more are possible if a rig crew change is required.

The typical speed for supply vessels is approximately 12 knots, making travel time to the Project Area approximately 16 to 28 hours (depending on the supply base discussed above). Common shipping routes will be used, as practicable, to reduce incremental marine disturbance. See Figure 2-8 for planned routes.

Supply vessels require certification and approval to work in Newfoundland waters. The supply vessels will follow applicable Port Authority requirements when in a port and will be compliant with the *Eastern Canadian Vessel Traffic Services Zone Regulations* when operating in near-shore or harbour areas. Existing regulatory regimes and best management practices for supply vessel transit is an ongoing, routine activity among all operators in the region.

Personnel and cranes will load and unload the supply vessel with drilling materials, closed piping systems, liquid supplies, and waste (e.g., drilling fluids). Fuel for power and offshore operations at the MODU is transported using the supply vessels and are expected to take place two to three times per week by a third-party contractor.

2.4.5.2 Helicopter Traffic and Operations

Helicopter support will be from the St. John's International Airport and will be the primary method to transport personnel to and from the MODU. One helicopter trip per day is currently planned to support this Project. If helicopters cannot fly because of poor visibility from fog or from high winds, consideration will be given to transport by vessel depending on the long-term weather forecast and the urgency to get people to the MODU. Emergency response, safety procedures and protocol will be in place for transport of personnel offshore. Helicopters will also be used to support medical evacuation from the MODU and search and rescue activities in the area, if required.

Figure 2-8 illustrates the potential transit routes for Project vessels and helicopters.

Exact routes to the well locations from the shore cannot be finalized until well locations are confirmed, which is expected during Q1 2021 period. The distance from the St. John's International Airport to the farthest boundary of the EL is approximately 435 km; and approximately two-hour flight. The helicopter flight paths, determined by the helicopter operators, will avoid military exclusion areas and areas of high environmental sensitivity. The regional CWS office will be contacted for separation distances and altitudes between helicopters transiting to and from the MODU and migratory bird nesting colonies, as per CWS guidelines (Government of Canada 2018) and routes will comply with provincial *Seabird Ecological Reserve Regulations, 2015*.

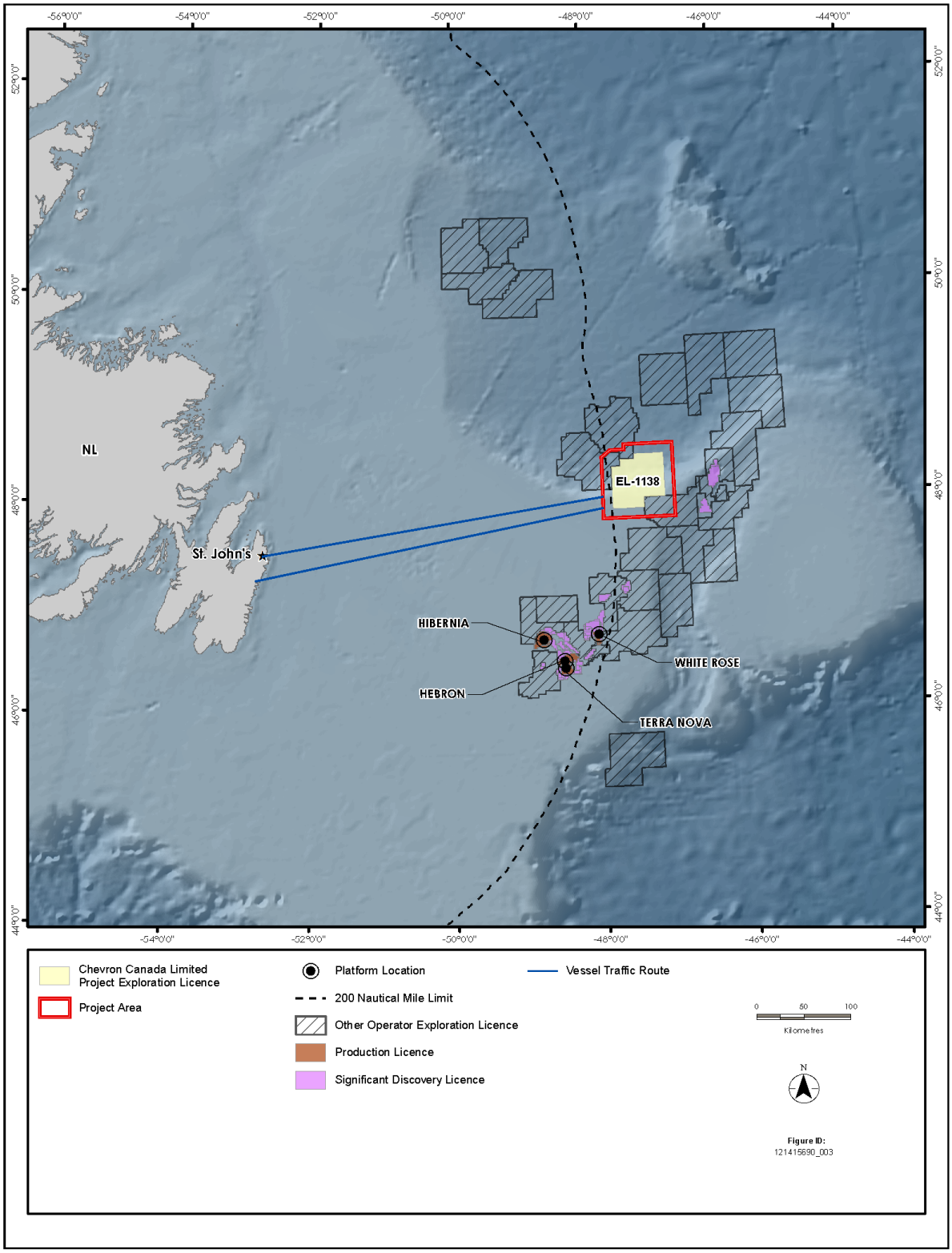


Figure 2-8 Potential Vessel and Helicopter Routes

Specific helicopters have not yet been contracted; but the Project will require that they have a capacity of approximately 12 to 15 passengers and a maximum range of approximately 540 nm (1,000 km) without refueling. The MODU will be equipped with refueling equipment; however, fueling operations are expected to take place at St. John's International Airport.

2.5 Well Control and Blowout Prevention

To prevent a blowout, which is an uncontrolled flow of formation fluids, the formation pressure must be managed. This is done using several barriers, such as the drilling fluid and casing, and dedicated pressure control equipment. If specific well control barriers fail, a blowout can occur.

The primary barrier to well control is the hydrostatic column of drilling mud of a planned density. Primary well control measures and procedures, such as monitoring the formation pressure and adjusting the density of the drilling fluid, are put into place to prevent blowouts. To stabilize the wellbore, drilling fluid density or weight is adjusted to maintain an overbalance of pressure against the formation. In the event of failure of these primary barriers, the BOP system is the next line of defense.

The secondary well control barrier, or BOP, is a mechanical device, made up of a series of different closing mechanisms, designed to seal off the wellbore at the well head, when required. Some of the closing mechanisms include rams that move horizontally across the top of the wellbore, sealing the drill string; blind shear rams used to cut the pipe in the drill string, creating a seal or sealing the wellbore when no pipe is present; and annular preventers which physically close off the wellbore.

The BOPs used as part of this Project will comply with Standard 53 (Blowout Prevention Equipment Systems for Drilling Wells) of the American Petroleum Institute (API). All BOPs will be rated to 15,000 psi working pressure and be installed and pressure tested in each well drilled as part of this Project. The BOPs use hydraulically-operated valves and sealing mechanisms that are open to allow the mud to circulate during drilling but can be quickly closed in the case of a "kick" (when reservoir fluids enter the well).

The BOP sits on the seafloor latched to the wellhead in a subsea drilling operation and all functions are controlled from the drilling unit. The BOP main control panel is situated on the rig floor, with remote stations located at other areas of the rig. The driller is responsible for operating the BOP and shutting in the well if well control is suspected of being compromised. Upon confirmed well control or "kick" indicators suspecting an influx of formation fluids, the well will be shut in quickly and efficiently through an established protocol. A well is shut in by the driller immediately after a kick has been detected. At this point, there is no loss of well control as the BOP is functioning as a barrier. The BOP minimum closing requirements is 45 seconds for rams and 60 seconds for annular preventers.

The BOP control panel can either be used to seal off the well around pipe or with no tubulars in the well. Efforts are made to reduce kick volume and to secure the well. The influx will be circulated out with returns through the choke / kill manifold. The well will not be opened to normal drilling operations until all of the influx has been circulated out and kill mud has been circulated to surface.

Multiple pressure tests will be conducted on the BOP, including on the MODU deck before installation; after installation on the well (testing wellhead connection with the BOP); before drilling out any string of casing;

before commencing a formation flow test; following repairs or any event that requires disconnecting a pressure seal; once every 14 operational days, and periodically throughout the drilling program pursuant to the Drilling and Production Guidelines (C-NLOPB and CNSOPB 2017a). A maximum of seven-day delay of pressure testing is allowed, in certain circumstances, for the 14-day operational testing. All pressure test details and results will be recorded, and testing will follow the Drilling and Production Guidelines.

Testing of the ROV intervention capability will also be required after initial BOP installation, by engaging the ROV control panel to function the controls. The BOP will not be removed until abandonment plugs are installed and tested for integrity.

A discussion of emergency response measures and strategies is presented in Section 15.3.

2.6 Project Personnel

Chevron's multidisciplinary Project team will manage the Project. Specific components of the work will be carried out by contractors, such as the drilling contractor, providing and operating the MODU; well services providers, providing equipment and services for drilling operations; and logistic contractors, providing and operating the supply base, supply vessels, and helicopters.

There will be a range of 100 to 200 personnel working on the drilling rig in various roles including drilling crew, deck crew, marine department along with electricians, welders, motorman, catering, and other disciplines. The drilling operation will be ongoing 24 hours per day starting from moving on to location until after finishing the well and releasing the rig. The core drilling crew will be the rig contractor staff and will be supported by service companies who will travel intermittently to and from the rig to provide specialized services, depending on the phase of well construction. The total persons on board will vary depending on the stage of the drilling operation. Chevron drilling supervisors will be on board to supervise rig activities and will be the primary contact for the land base Chevron office in St. John's.

The St. John's office consists of a project manager, drilling superintendent, logistics support, drilling engineers, and finance and procurement specialists. The superintendent will be on call 24 hours to support the rig where necessary and call out any services and materials required to support the drilling operations.

An emergency response program will be in place to mobilize a specialized team into an incident command centre to support the rig in the unlikely effect of an emergency situation. In an emergency response situation, Chevron personnel throughout North America may be deployed if required to support the St. John's drilling staff.

2.7 Project Schedule

Chevron proposes to commence exploration drilling with an initial well in 2021 pending regulatory approval to proceed. Up to eight exploration wells could be drilled over the term of the EL (2016 to 2025) contingent on the drilling results of the initial well. Drilling activities will not be continuous and will be in part determined by MODU availability and previous wells' results. It is anticipated that each well will take approximately 180 days to drill.

Chevron's preference is to conduct drilling between May and September, although the EIS will assume year-round drilling. VSP operations will take approximately one to three days per well and well testing, where required, would occur over a one to three-month period. Well abandonment will likely be conducted following drilling and/or well flow testing. Wells may be designed for suspension and re-entry, but this will be determined through further prospect evaluation.

Figure 2-9 shows key elements of the proposed Project schedule for the initial well drilling campaign.

Task	2019				2020				2021				2022			
	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4	Q 1	Q 2	Q 3	Q 4
Well Selection, Design and Planning																
Stakeholder and Indigenous Engagement																
Regulatory Permitting																
Logistics Preparation																
Exploration Drilling																
Well Abandonment and Reporting																

Figure 2-9 Planned Project Schedule (for Initial Well Drilling Campaign)

2.8 Emissions, Discharges and Waste Management

Key emissions, discharges and waste streams likely to be generated by the Project are discussed in the following sections and are classified into the following groups:

- Air emissions
- Drilling waste
- Liquid discharges
- Hazardous waste and non-hazardous waste
- Sound emissions
- Light and thermal emissions

Efforts will be made to reduce waste emissions and discharges generated during the Project. Waste generated will be managed and disposed according to regulatory requirements and applicable guidelines. Offshore waste discharges will be managed in compliance with the International Convention for the Prevention of Pollution from Ships (MARPOL) and/or the OWTG, as applicable. Waste not meeting legal conditions for discharge will be brought to shore for disposal and managed in accordance with the NL Waste Management Strategy and other applicable regulatory requirements (including municipal by-laws).

A Waste Management Plan will be prepared as part of the OA application process with the C-NLOPB prior to drilling operations. Information on the releases, wastes, and discharges will be reported as part of a regular environmental reporting program in accordance with regulatory requirements as described in the OWTG.

Additionally, Chevron has their own Third-Party Waste Stewardship (TWS) Standard as part of the Company's Corporate Environmental Stewardship Process. The TWS standard sets forth an approach to select third-party owned and operated waste management facilities (Waste Facilities) that handle waste generated from Chevron operations by evaluating Waste Facilities before use by Chevron Corporation and its subsidiaries and affiliates.

The TWS Standard does not represent Chevron's interpretation of any legal or regulatory requirements that might apply to its operations. Nothing in the standard is intended to conflict with law and, in all cases, Projects are expected to comply with applicable laws and regulations, as they exist now and as such laws and regulations may be adopted, modified or amended in the future. In the event of a conflict between the TWS and any applicable legal requirement, the legal requirement supersedes the standard requirement unless the standard requirement is more stringent. Chevron has elected to adopt uniform standards and operating practices even though some of them may exceed applicable legal requirements. Compliance with government regulations generally achieves our goals of protecting human health, safety, and the environment.

The following subsections provide a general description of typical wastes to be generated over the course of Project activities and how these wastes will be managed.

2.8.1 Atmospheric Emissions

Project activities that will result in air emissions include:

- Fuel combustion from engines associated with the MODU, supply vessels, fixed and mobile deck equipment, and helicopters
- Flaring during well test activity, if well testing is required

These emissions will include criteria air contaminants (CACs), such as carbon monoxide (CO), sulphur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM), and greenhouse gases (GHGs) such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Chevron will comply with the NL *Air Pollution Control Regulations*, Ambient Air Quality Objectives under the *Canadian Environmental Protection Act*, regulations under MARPOL, and the intent of the Global Gas Flaring Reduction Partnership (which seeks to increase the use of associated natural gas and thus reduce flaring and venting).

The International Maritime Organization (IMO) of the United Nations has set limits on NO_X, with Tier III limits that became applicable in 2016 in Emission Control Areas, which include the Canadian EEZ. Marine engines operating within this zone will be subject to these limits. The sulphur limit in fuel in the Emission Control Areas in large marine diesel engines also dropped from 1.0% to 0.1% in accordance with the *Vessel Pollution and Dangerous Chemicals Regulations* under the *Canada Shipping Act*. To reduce GHG emissions in the offshore, the IMO is also responsible for development of efficiency measures that will involve mandatory measures to increase energy efficiency on ships.

Wherever practicable and available, the Project will use ultra-low sulphur diesel fuel to reduce the potential for adverse local air quality effects. Atmospheric emissions from individual project activities will depend on fuel consumption which will vary throughout the Project; however, expected fuel consumption data and

emission estimates from individual project activities are presented below. The emission estimates for MODU operations are based on fuel consumption data from a typical MODU and emission factors from the US Environmental Protection Agency (US EPA) AP-42 (Fifth Edition, Volume 1, Chapter 3.4) and ECCC (2018a). Supply vessel atmospheric emission estimates were based on fuel consumption information from a typical offshore NL supply vessel and emission factors from the US EPA (US EPA 2009) and ECCC (2018a). The helicopter emissions were estimated based on fuel consumption information from Chevron and emissions factors from ECCC and other regulatory sources (ECCC 2018a; Swiss Confederation 2015). Only exhaust emissions have been considered, as it has been assumed that evaporation in diesel engines is negligible.

The emission factors used to calculate the emission estimates are presented in Tables 2.4 and 2.5, and the fuel consumption data and estimated emissions are presented in Tables 2.6 and 2.7.

Table 2.4 Emission Factors for Project Activities - CACs

Air Contaminant	Emission Factors		
	MODU (based on US EPA AP42) (lb/MMBtu)	Supply Vessels[b] (lb/MMBTU)	Helicopters (g/kg fuel)
CO	0.85	0.71	0.95[c]
NO_X	3.2	8.98	18[c]
SO_X	0.0505[a]	2.56	4[d]
PM	0.1	0.3	0.4[c]

Notes:
[a] The emission factor for SO_2 in US EPA AP-42 is calculated based on 1.01S1, where S1 is the sulphur in the fuel oil. The emission factor assumes that all Sulphur in the fuel is converted to SO_2. It has been assumed that the sulphur content of the fuel oil will be 0.05%. The emission factor for SO_2 is therefore 0.0505.
[b] US EPA. 2009. "Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories."
[c] Swiss Confederation. 2015. "Guidance on the Determination of Helicopter Emissions."
[d] Emission factor assuming all Sulphur is converted to SO_2. The Sulphur content of aviation fuel was assumed to be 4,000 ppm, or 4 g/kg.

Table 2.5 Emission Factors for Project Activities - GHGs

Air Contaminant	Emission Factors[a]		
	MODU (g/L)	Supply Vessels (g/L)	Helicopters (g/L)
CO_2	2681	2681	2560
CH_4	0.133	0.25	0.09
N_2O	0.4	0.072	0.071

Note:
[a] Environment and Climate Change Canada. 2018a. National Inventory Report 1990-2013: Greenhouse Gases Sources and Sinks Part 2.

Table 2.6 Estimated Daily Criteria Air Contaminant Emissions for the MODU, Support Vessels and Helicopter

Source	Daily Fuel Consumption (tonnes)	Daily Energy Consumption (MMBtu)	CO (tonnes per day	NO_X (tonnes per day)	SO_X (tonnes per day)	PM (tonnes per day)
MODU	44.2	1,895	0.73	2.76	0.04	0.09
Supply Vessel	24.0	1,029	0.33	4.20	1.20	0.14
Helicopter	2.05	-	0.002	0.04	0.01	0.001
TOTAL	70	2,923	1.07	6.99	1.25	0.23

Table 2.7 Estimated Daily Greenhouse Gas Emissions for the MODU, Support Vessels and Helicopter

Source	Daily Fuel Consumption (L)	CO_2 (tonnes per day	CH_4 (tonnes per day)	N_2O (tonnes per day)	CO_2e (tonnes per day)[a]
MODU	52,342	140	0.007	0.021	147
Supply Vessel	28,423	76.2	0.007	0.002	77.30
Helicopter	2,533	6.49	0.0002	0.0002	6.54
TOTAL	-	223	0.014	0.021	230

Note:
[a] Global Warming Potentials – CO_2 = 1; CH_4 = 25; N_2O = 298

Exact fuel consumption data are not available because the MODU for the drilling program has not yet been selected. For a drill ship MODU (as an example) it is anticipated that the daily fuel consumption would be approximately 43 tonnes (52 m³). For comparison, the Scotian Basin Exploration Project, offshore Nova Scotia, used the West Aquarius in 2018 for drilling, and reported a daily fuel consumption averaging between approximately 35 m³ and 40 m³ in full drilling mode (some days less than 30 m³ daily fuel consumption) and between 55 m³ and 80 m³ when in standby mode (BP 2018).

In support of MODU operations, it is possible that two supply vessels, with two to three trips per week, will be required. One supply vessel will remain on standby at the wellsite. Based on the boundaries of the EL, the furthest distance a supply vessel will travel from the onshore supply base to the MODU, is 439 km. The supply vessel emissions will depend on the speed of the vessels; however, it has been estimated that on average, the supply vessels will consume approximately 24 tonnes (28 m³) of fuel per day.

It is anticipated that one round-trip per day will be required for helicopters to transport crew to and from the MODU. Based on the boundaries of the EL, the furthest distance that the helicopter will travel from St. John's to the MODU, is 435 km. On average a helicopter would consume approximately 2.05 tonnes of fuel (2.53 m³) per day of a 180-day drilling program.

With respect to greenhouse gas (GHG) emissions, it is estimated that there could be approximately 230 tonnes of carbon dioxide equivalent (CO_2e) emissions associated with operational drilling, vessel traffic, and helicopter traffic per day or approximately 41,450 tonnes CO_2e over the drilling program, assuming a 180-day drilling program per well drilled. Assuming there could be between zero to three wells drilled per

year over the term of the EL, annual GHG emissions resulting from the Project could range from 0 to approximately 124,349 tonnes CO_2e per year. These emissions represent approximately 0% to 1.2% of the total reported provincial GHG emissions for 2016 (704,000,000 tonnes CO_2e) and approximately 0% to 0.02% of the 2016 national emissions (704,000,000 tonnes CO_2e) (ECCC 2018b). During well testing events, an additional 26,000 tonnes CO_2e may result from the combustion of produced oil and the flaring of produced gas over the life of the project (based on four wells tested over the life of the project).

If initial wells are successful and require well flow testing, a well test program will be developed and executed on subsequent wells drilled as part of the primary term of the license. Any well flow testing would result in atmospheric emissions from the flaring activity.

Well flow testing occurs over a short period of time at the end of the drilling program and is considered a non-routine activity. The well flow testing will typically last no more than a month but could extend up to three months. The activity within this period will vary and it is likely that flaring will be required intermittently. Flaring may be for operational purposes, such as flushing or bleeding, with low flow rates, or during a series of separate well flow test periods. The time periods for these flaring activities would be one to six hours per flaring event, or two or three days per test period, respectively. The amount of time flaring in a well test operation will be kept to a minimum but will need to be sufficient to collect necessary datasets. It is anticipated that two rig-days of flaring will be sufficient for a well test. If well flow testing is required, it is most likely that there is a single target containing hydrocarbons within each well which could be subject to a well flow test.

For the purposes of estimating GHG emissions from a non-routine flaring event, it has been assumed that each well would likely have one target for potential testing as part of the evaluation program, and the maximum volume of oil and gas flared per target would be no more than 12,580 bbls (2,000 m^3) and 538,020 m^3 (19 million ft^3), respectively. The tonnes of CO_2e emitted from one target during a well flow test are 6,472 tonnes.

With a three wells per year assumption, it is estimated that up to 12,944 tonnes of CO_2e could be released from non-routine flaring during well flow testing, per year. NL's annual GHG emissions is 10,300 kilotonnes CO_2e per year, as reported for 2016 (ECCC 2018b). This estimate represents approximately 0.12% of the province's annual GHG emissions.

GHG reduction targets set by the Government of NL's Climate Change Action Plan (2019) are as follows: a 35% to 45% reduction in regional GHG emissions below the 1990 emission levels by 2030; and a 30% reduction in Provincial GHG emissions below 2005 levels by 2030. It is not expected that the Project's emissions will affect regional, provincial or federal emission targets, as CO_2e predictions represent a very minor increment to existing CO_2e levels for the Province.

The Agency (2003) categorized the magnitude of a projects GHG emissions as "low", "medium", and "high". This EIS attributes these categories quantitatively based on evaluation of GHG emissions from other industrial facilities, provincial, national, and global quantities released, and regulatory thresholds (such as reporting thresholds for GHG emissions to provincial and federal programs). The quantity of the Project GHG emissions (tonnes of CO_2e per year) for this Project is based on the following criteria:

- Less than 10,000 tonnes CO_2e per year is considered "low"

- Between 10,000 and 500,000 tonnes CO_2e per year is considered “medium”
- Greater than 500,000 tonnes CO_2e per year is considered “high”

Routine Project activities (assuming that up to three wells could be drilled in one year) and non-routine Project flaring (assuming that up to two wells are tested per year) are estimated to have a total GHG emissions of approximately 137,293 tonnes CO_2e per year (“medium” magnitude category using Agency criteria), approximately 1.3% of NL’s average annual emissions and 0.02% of the national 2016 inventory.

Chevron will adhere to federal and provincial compliance and reporting requirements for emissions which are currently being reviewed and updated by the federal and provincial governments.

2.8.2 Drilling Waste Discharges

The Project will generate several drilling-related waste streams (drill cuttings, drill fluids, and cement), which will all be disposed of in accordance with the OWTG.

WBM or seawater will be used to drill the shallow sections of the wells with deeper sections drilled with either WBM or SBM (as described in Section 2.4.1).

WBM consists of approximately 75% of water, which can be freshwater, seawater or brine. Several substances are added to the WBM, including barium sulphate (barite) and bentonite clay. The barite helps to balance formation pressures within the well by acting as a control for mud density. Bentonite clay thickens the mud, increasing its viscosity and thus helping to suspend and carry drill cuttings to the surface. To obtain the required drilling properties of the fluid, other substances can be added to the WBM, such as thinners, filtration control agents, and lubrication agents. The majority of WBMs discharged are classified under the Offshore Chemical Notification Scheme (OCNS) as substances that pose little or no risk to the environment (PLONOR).

SBM is manufactured through a chemical process and contains non-aqueous (water insoluble) fluids, as a water-in-oil emulsion. Typically, SBMs are made up of internal olefins, alpha olefins, polyalphaolefins, paraffins, esters, or blends of these materials. As with WBMs, weighting materials, such as barite, are used to control density, as well as additives to manage viscosity, fluid loss, alkalinity, emulsion stability and wettability, where required. SBMs have several beneficial properties, including improved lubricity, thermal stability, wellbore integrity, and protection against gas hydrates in the well, and thus may be selected over WBM.

For drilling during the initial riserless sections of the well, it is proposed that cuttings and WBM or seawater fluids will be disposed directly to the seabed. Whereas, cuttings from subsequent sections, will be returned to the MODU, via the riser, for treatment.

To manage cuttings, the MODU will be equipped with specialized solids control equipment, such as shale shakers. Shale shakers are used in the first phase of solids control and are made up of a system of coarse and fine mesh screens that sift out the cuttings. The purpose of the shale shakers is to simply and quickly recover the drilling fluids from the cuttings. Drilling fluids can then be re-used in the drilling process. Centrifuges are another component of solids control equipment that may be required depending on the design of drilling fluid, and geological characteristics for reconditioning of the drilling fluid for re-use. After

solids control treatment, WBM cuttings and excess or spent WBM can be discharged to sea from the MODU through a caisson pursuant to the OWTG.

When using SBM, cuttings will require additional treatment to enable disposal in accordance with the OWTG. It is expected that SBM treatment will be conducted by sending the cuttings to a cuttings dryer, a high speed centrifuge which separates the drilling fluid from the cuttings. The OWTG requirement for treated SBM cuttings to be discharged to sea is that a 48-hour mass weighted average of retained "synthetic on cuttings" is below a threshold of 6.9 g/100 g. To ensure compliance with the OWTG, the concentration of SBM on cuttings will be monitored on the MODU. In accordance with the OWTG, the remaining or spent SBM will not be discharged to the sea. Any spent or excess SBM that cannot be re-used, will be brought back to shore for disposal.

2.8.2.1 Drill Cuttings Deposition Modelled for the Project

To establish the expected deposition of drill waste from the drilling program, drill waste deposition modelling has been conducted. Since well site locations have not yet been selected, representative wellsites were used for drill waste modelling (Table 2.8).

Table 2.8 Drill Waste Deposition Modelling Locations

Location	EL	Water Depth (m)	Latitude (N)	Longitude (W)
West Flemish 1	EL 1138	1,500	48°13'20" N	47°11'00" W
West Flemish 2	EL 1138	500	48°01'00" N	47°18'23" W

The model input assumed SBM would be used after the initial wells are drilled and once the riser is installed. Potential discharges for the entire well, including WBM discharges at seafloor for initial well sections (pre-riser installation), bulk WBM discharges, and treated SBM associated cuttings from the MODU, post-riser installation, was accounted for in the model.

Representative drilling schedules were provided to RPS by Chevron to characterize discharges from five to six planned drilling sections at West Flemish 1 (deep well [1,500 m]) and West Flemish 2 (shallow well [500 m]), respectively (Tables 2.9 and 2.10). The first two sections will be drilled using seawater and WBM at both sites. The remainder of the drilling sections will require the use of SBM at both sites. The discharge schedule provided by Chevron. consists of a release of 610 m³ of drill cuttings and 5,041 m³ of drilling fluids at West Flemish 1 (1,500 m) and 620 m³ of drill cuttings and 5,045 m³ of drilling fluids at West Flemish 2 (500 m) over the duration of the anticipated drilling campaign. This captures approximately two months of work at each location with 66 days of active discharge.

During the initial phase of drilling (first 2 sections in Tables 2.10 and 2.11), all cuttings and WBM are expected to be released directly to the seabed (5 m above the wellhead on the seafloor). Subsequent sections will be drilled using SBM and cuttings will be returned to the platform and cleaned prior to discharge. The direct release of bulk SBM was not expected to occur as part of operational drilling, although for modelling, it was presumed that a fraction of the drilling fluid (approximately 6.9% by mass of the SBM cuttings) would remain adhered to cuttings drilled with SBM. The release of these combined surface returns (cuttings and adhered SBM) was simulated from a depth of 5 m below the sea surface at a continuous discharge rate.

Table 2.9 Proposed Drilling Program for West Flemish 1 (1,500 m)

Drilling Component	Diameter (inches)	Drilling period		Drilling Duration (days)	Discharge Duration (days)	Cuttings Discharge		Drilling Fluid (Mud) Discharge[1]		Drilling Fluid Type	Release Depth[2]
		Scheduled	Alternative Scheduled			vol (m^3)	rate (m^3/d)	vol (m^3)	rate (m^3/d)		
Conductor*	42”	Summer (July-August)	Spring (April-May)	1	1	89	89	1,049	1,049	WBM	Seafloor
Surface**	26”	Summer (July-August)	Spring (April-May)	1	1	137	137	3,977	3,977	WBM	Seafloor
Intermediate	17.5”	Summer (July-August)	Spring (April-May)	10	5	233	46.5	9.32	1.86	SBM	Surface
Production	12 ¼”	Summer (July-August)	Spring (April-May)	20	10	114	11.4	4.56	0.46	SBM	Surface
Reservoir	8 ½”	Summer (July-August)	Spring (April-May)	30	15	36.6	2.4	1.46	0.1	SBM	Surface
Total				62	32	610		5,041			

Information provided by Chevron.
Each row defines drilling sections beginning with the sediment-water-interface (top) down to the reservoir (bottom).
Notes:
1. Cuttings from sections drilled with SBM were modelled with an additional 6.9% by weight to account for base fluid that was assumed to be adhered to cuttings
2. Releases were simulated at 20 m above seabed and 5 m below the sea surface
* 4 hours drilling @ 4 m^3/min pump rate = 960 m^3 + hole displacement to pad mud 89 m^3
** 16 hours drilling @ 4 m^3/min pump rate = 3840 m^3 + hole displacement to pad mud 137 m^3

Chevron

Table 2.10 Proposed Drilling Program for West Flemish 2 (500 m)

Drilling Component	Diameter (inches)	Drilling period		Drilling Duration (days)	Discharge Duration (days)	Cuttings Discharge		Drilling Fluid (Mud) Discharge[1]		Drilling Fluid Type	Release Depth[2]
		Scheduled	Alternative Scheduled			vol (m^3)	rate (m^3/d)	vol (m^3)	rate (m^3/d)		
Conductor*	42”	Summer (July-August)	Spring (April-May)	1	1	89	89	1,049	1,049	WBM	Seafloor
Surface**	26”	Summer (July-August)	Spring (April-May)	1	1	137	137	3,977	3,977	WBM	Seafloor
Intermediate	26” (under-reamed)	Summer (July-August)	Spring (April-May)	3	2	137	68.5	5.48	2.74	SBM	Surface
Intermediate	16”	Summer (July-August)	Spring (April-May)	10	5	195	39	7.8	1.6	SBM	Surface
Production	12 ¼”	Summer (July-August)	Spring (April-May)	20	10	114	11.4	4.56	0.46	SBM	Surface
Reservoir	8 ½”	Summer (July-August)	Spring (April-May)	30	15	36.6	2.4	1.46	0.1	SBM	Surface
Total				65	34	620		5,045			

Information provided by Chevron.
Each row defines drilling sections beginning with the sediment-water-interface (top) down to the reservoir (bottom).
Notes:
1. Cuttings from sections drilled with SBM were modelled with an additional 6.9% by weight to account for base fluid that was assumed to be adhered to cuttings
2. Releases were simulated at 20 m above seabed and 5 m below the sea surface
* 4 hours drilling @ 4 m^3/min pump rate = 960 m^3 + hole displacement to pad mud 89 m^3
** 16 hours drilling @ 4 m^3/min pump rate = 3840 m^3 + hole displacement to pad mud 137 m^3

Chevron

The schedule provided by Chevron indicated an expected spud date of summer, 2021. Because the drilling schedule may be delayed, a modelling strategy was developed to compare the potential differences in seabed deposits during different offshore conditions for the scheduled and alternative drilling periods. Two deterministic scenarios were performed at the theoretical well location using the MUDMAP dispersion model, each covering a period of approximately two months (spanning all active drilling stages and time necessary to allow for settling of fine particles):

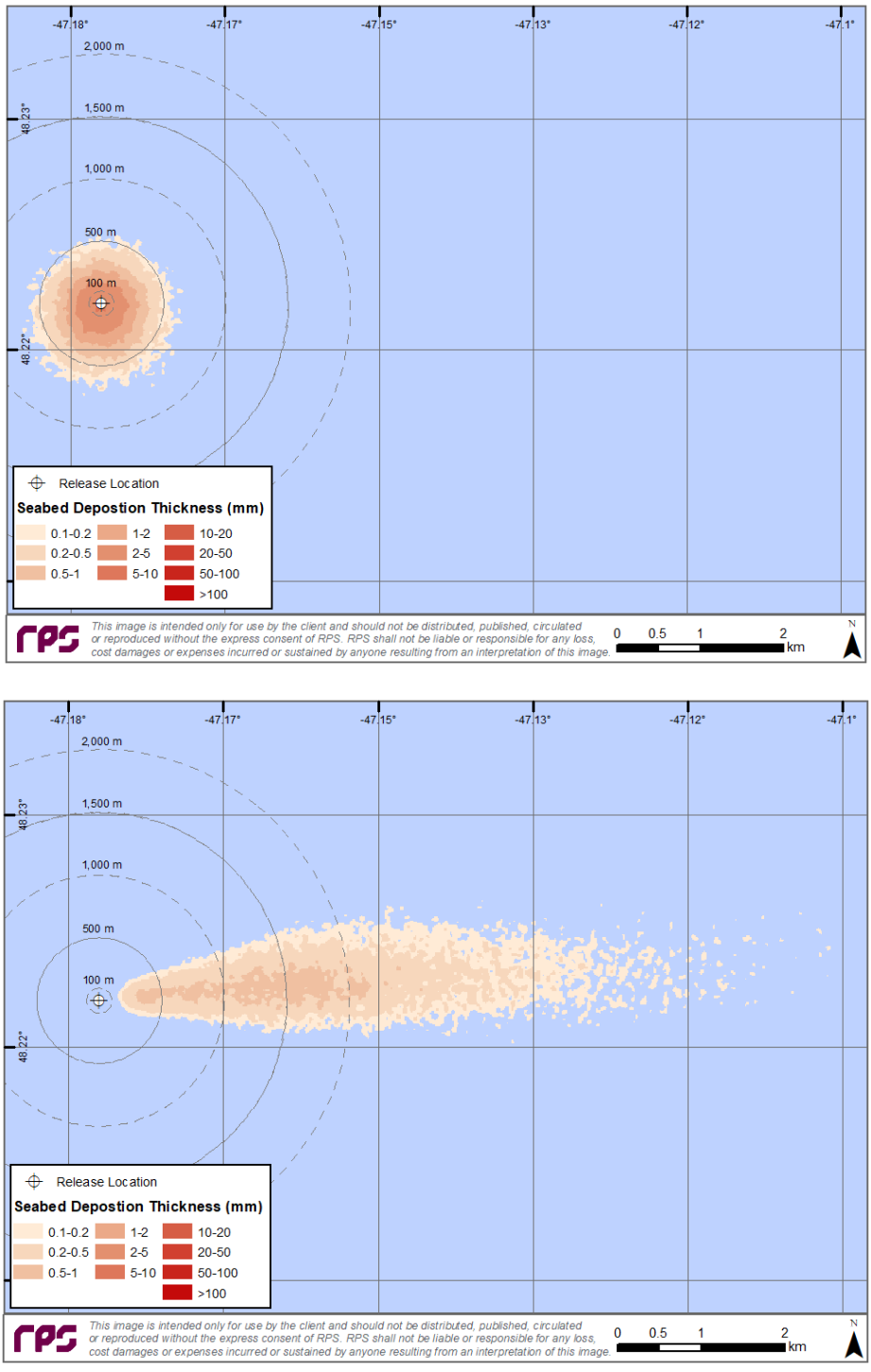
1. Scenario 1 - scheduled drilling period (Summer; July-August)
2. Scenario 2 - alternative drilling period (Spring; April-May)

Metocean conditions, such as ocean currents, at the time of well discharge play a major role in determining the extent and thickness of the drill cuttings deposited on the seabed via dispersion (advection and mixing). strong eastward-directed currents persist near the drilling site throughout the year. RPS performed a qualitative review of the HYCOM time series between 2006 and 2012, comparing current statistics (speeds and directions) from each year at multiple depths for each modelled season. Current trends for the two model periods during 2012 agreed with the overall seven-year trend and were thus deemed suitable as a representative modelling period.

2.8.2.2 Model Results

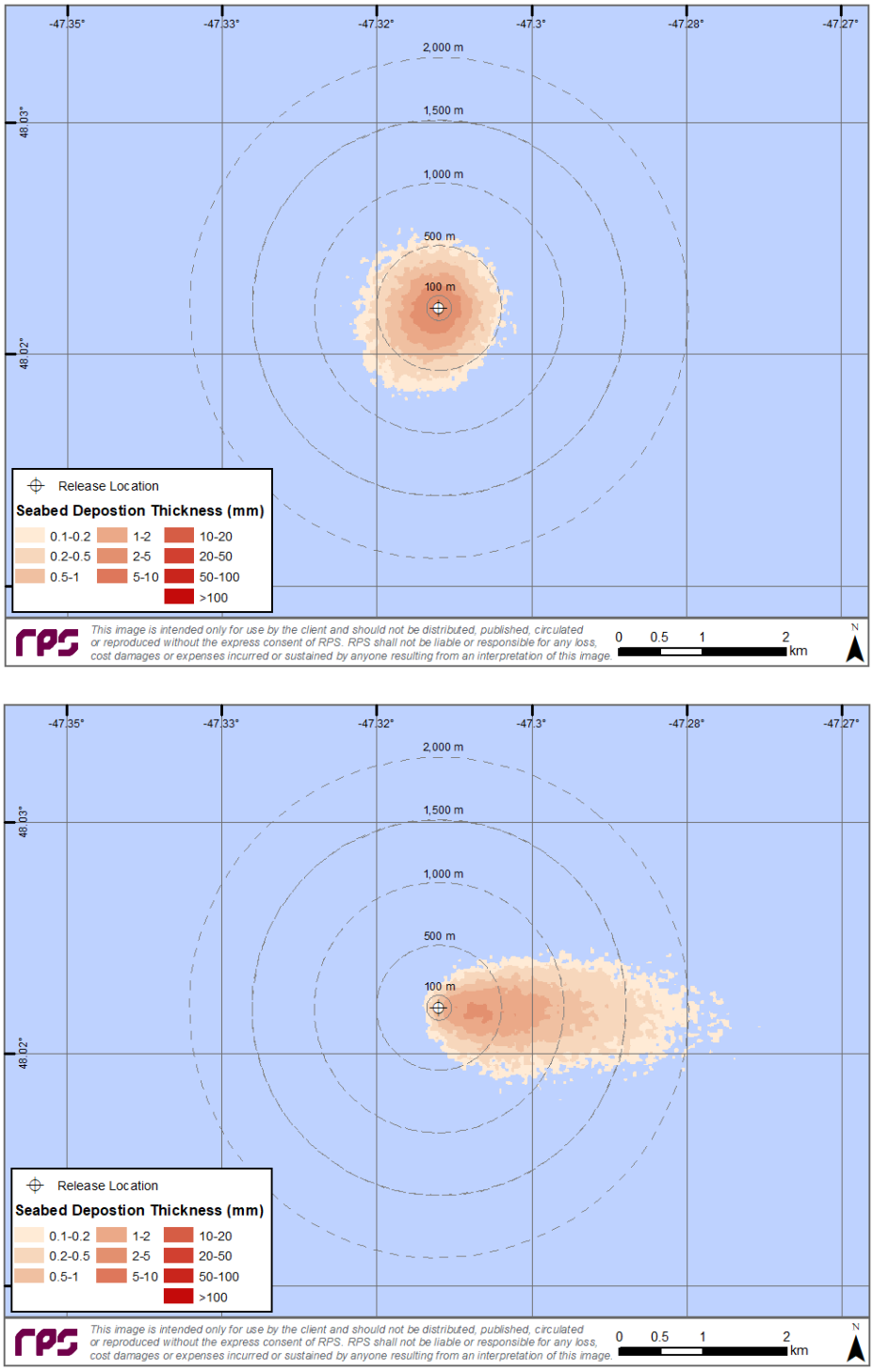
The output of each MUDMAP simulation is a predicted concentration grid that estimates the loading to the seabed, associated with each drill section. These grids were aggregated outside of the MUDMAP model to produce maps of cumulative deposition from all discharged sections. Figures 2-10 and 2-11 depict the model-predicted deposition patterns from an aerial view. Table 2.11 summarizes the cumulative areal extent of seabed deposition for operational discharge simulations >0.01 mm. Deposition thicknesses were calculated based on mass accumulation on the seabed, sediment bulk density, and the assumption of no voids (i.e., zero porosity) (Table 2.12).

The summer modelling scenarios (July to August) had more tightly confined mud/cuttings pile up to 5.3 mm, when compared to the spring simulations (Figures 2-10 and 2-11). Fine blankets of sediment are predicted to extend radially away from the wellhead during the summer conditions and are predicted to extend much further to the east during the spring season. Because the spring scenario (April to May) had more extensive spreading to the east, subsequently thinner depositional thicknesses were predicted near the wellhead and further away. In both cases, deposition of muds and cuttings exceeding 1 mm was predicted to remain confined within 1 km from the drilling site (Figures 2-10 and 2-11) and cover less than 2.545 km² (Table 2.12). Depositional thicknesses at or above the predicted no effect concentration threshold of 6.5 mm (Smit et al. 2008) were not predicted to occur in either deep or shallow scenarios. These low thicknesses can likely be attributed to the extremely long settling times for the finer silts / clays, which make up most of the cuttings. Due to the relatively low settling velocities of cuttings drilled with SBM and the depth over which it needs to settle (500 to 1,500 m), no measurable thicknesses were reported above 0.1 mm for surface releases as they dispersed through the water column.



Deposition results from all drilling sections during the scheduled summer (top) drilling period and during the alternative scheduled spring (bottom) drilling period.

Figure 2-10 Predicted Thickness of Seabed Deposition of Discharged Mud and Cuttings at West Flemish 1 (1,500 m)



Deposition results from all drilling sections during the scheduled summer (top) drilling period and during the alternative scheduled spring (bottom) drilling period.

Figure 2-11 Predicted Thickness of Seabed Deposition of Discharged Mud and Cuttings at West Flemish 2 (500 m)

Table 2.11 Areal Extent of Predicted Seabed Deposition (by thickness interval) for Operational Discharge Simulations in Early Spring and Spring

Deposition Thickness (mm)	Cumulative Area Exceeding (km²)			
	West Flemish 1 (1,500 m)		West Flemish 2 (500 m)	
	Summer	Spring	Summer	Spring
0.1-0.2	1.0506	2.5455	1.1611	1.6399
0.2-0.5	0.7847	1.3702	0.8415	1.1056
0.5-1	0.4648	0.2910	0.4752	0.5489
1-2	0.2765	0.0000	0.2708	0.2572
2-5	0.1356	0.0000	0.1206	0.0246
5-6.5	0.0044	0.0000	0.0001	0.0000
Maximum Thickness (mm)	5.27	0.94	5.00	2.38

Table 2.12 Maximum Distance of Thickness Contours (distance from release site) Predicted for Operational Discharge Simulations

Deposition Thickness (mm)	Maximum extent from release site (km)			
	West Flemish 1 (1,500 m)		West Flemish 2 (500 m)	
	Cumulative Summer	Cumulative Spring	Cumulative Summer	Cumulative Spring
0.1-1	0.76	7.92	0.81	2.57
1-6.5	0.37	0	0.35	0.98

When comparing the different drilling periods, the predicted areal extent of deposition for the spring drilling period (April to May) was larger than the summer drilling period (July to August) for thicknesses less than 0.5 mm (Table 2.12). Stronger currents during the spring period were predicted to transport the cuttings and mud particles further from the discharge site allowing for more dispersion before settling. This resulted in a larger overall footprint; however, the thicknesses over this larger area were predominantly less than 0.5 mm. Due to the increased dispersion during spring, footprints for thicknesses greater than 0.5 mm were also decreased compared to those in the summer.

Summer simulations for both sites had weaker subsurface current regimes, which led to footprints extending radially from the discharge site at higher thicknesses. Depositional thicknesses above 0.1 mm were predicted to extend radially approximately 760 to 810 m during the summer due to low dispersion by weak subsurface currents. Maximum depositional thicknesses of 5.3 and 5.0 mm were predicted for West Flemish 1 (1,500 m) and West Flemish 2 (500 m), respectively, covering an area of approximately 1.1 km².

Spring simulations for both sites were subject to stronger seabed currents associated with the spring season, and predicted depositional footprints were elongated, extending much further to the east from the sites. Depositional thicknesses above 0.1 mm were predicted to extend upwards of 2.6 km for the shallow

West Flemish 2 (500 m) and as much as 7.9 km for the deeper West Flemish 1 (1,500 m). Because of this increased dispersion, the maximum thickness was predicted to be 2.38 km² with a cumulative area of 1.6 km² above 0.1 mm for West Flemish 2 (500 m) and 0.94 mm with a cumulative area of 1.6 km² above 0.1 mm for West Flemish 1 (1,500 m).

Data generated from these predictive models are used to predict potential environmental effects on fish and fish habitat (particularly the benthic environment), as it pertains to burial and smothering (refer to Section 8). More information on drill waste deposition modelling for the Project can be found in RPS Group (2019) (Appendix C).

Cement constitutes a part of the well barrier envelope and is used during casing installation and plug and abandonment; it prevents the escape of hydrocarbons, and thus is a critical safety barrier in the well. Excess cement is used to demonstrate that the cement job has been completed and that the annular space has been filled. If the annual space is larger than expected due to irregularities in the formation wall, the extra cement also provides contingency.

During the initial, riserless, phases of the well, a volume of approximately 200 tonnes (an area of 83 m³) of excess cement slurry and drilled (hard) cement may be discharged to the seabed. After riser installation, cement waste will be circulated back to the MODU, and the cement unit will be cleaned (rinsed) to prevent cement from hardening in the tanks and lines. Cleaning operations, once per cementing operation, is estimated to produce a discharge of approximately 1 to 2 m³ of cement slurry from the MODU below the water surface. Any cement bulks and additives not utilized during drilling operations will be transported to shore for future use or disposed at an approved facility.

Cement management and discharge during the riserless phase of drilling is the only option. However, Chevron will log all cementing operations which will help improve the accuracy of calculations to estimate how much cement is required and help reduce excess cement. ROV surveys will also be conducted before, once during, and at the end of the drilling program, to visually monitor the extent of any discharged excess cement.

2.8.3 Liquid Discharges

The MODU, supply vessel and drilling equipment, generate several types of liquid wastes. Some of which can be discharged directly into the marine environment, following treatment where necessary, and in accordance with the OWTG. Typically, the effluent discharge points on a MODU are just below or above the sea surface and will depend on the MODU design.

Major liquid discharge streams and management is described in Table 2.13.

Table 2.13 Potential Project-Related Liquid Discharges

Discharge	Source and Characterization	Waste Management
Produced water	Produced water, which includes formation water encountered in a hydrocarbon bearing reservoir, would only be produced during well evaluation and testing processes	If volumes of produced water are large, some produced water may be brought onto the MODU for treatment so that it can be discharged according to the OWTG. Small amounts of produced water may be flared
Bilge and deck drainage water	As water from various sources (such as sea spray, precipitation, washdown during systems testing, seawater seepage) may contact equipment and machinery, deck drainage and bilge water may be contaminated with oil and other chemicals	Deck drainage and bilge water will be discharged according to the OWTG (≤15 mg/L residual oil in water)
Ballast water	Ballast water is seawater stored in dedicated tanks used for MODU and supply vessel stability and balance; it typically does not contain hydrocarbons or chemicals	Ballast water will be discharged according to Transport Canada's *Ballast Water Control and Management Regulations* and IMO *Ballast Water Management Regulations*. The ballast tank on the MODU will be flushed prior to arriving in Canadian waters
Grey and black water	Black water (includes sewage water) and grey water (includes ablution, laundry and galley water) will be generated on the MODU and supply vessels	Sewage will be macerated prior to discharge in accordance with OWTG (6 mm) and MARPOL
Well treatment and testing fluids	Well testing can result in formation fluids (i.e., hydrocarbons and associated water) brought to surface. Well testing is typically required to gather information about the subsurface characteristics and to convert an EL to an SDL	If well testing results in gas, oil or formation water brought to surface, these will be flared for safe disposal. All flaring, if required, will be optimized to the amount necessary to characterize the well potential and as necessary for the safety of the operation
BOP fluids	The BOP is regularly pressure and function tested over the duration of the well. BOP fluids are released directly to the ocean during testing in the following scenarios: 1. BOP installation and removal (approximately 665 bbl [105 m³] per well, assuming two BOP pulls) 2. During unlatching and pulling of the Lower Marine Riser Package (approximately 324 bbls or 360 m³, assuming once per well to trouble shoot or for weather) 3. During BOP operations and testing activity including flushing choke and kill lines (approximately 48 bbls [7.5 m³] per well) BOP control fluid would also be discharged to the marine environment if the BOP is activated in response to an emergency event. BOP fluids are typically freshwater-based, seawater-soluble chemicals	BOP fluids and any other discharges from the subsea control equipment will be discharged according to OWTG and OCSG

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

2.8.4 Hazardous and Non-hazardous Waste

Waste management plans and procedures will be designed to prevent unauthorized waste discharges and transfers and will ensure waste generated offshore (MODU and supply vessels) will be managed and disposed in accordance with relevant regulations and municipal bylaws. Putrescible solid waste, specifically food waste generated offshore, will be disposed according to OWTG and MARPOL requirements. Macerated food waste will not be discharged within 3 nm from land.

Packaging material, scrap metal, and other domestic wastes and recyclables are considered non-hazardous wastes and will be stored in designated areas on board the MODU. At scheduled intervals, the non-hazardous wastes be shipped to shore by supply vessels and collected onshore by a third-party contractor for disposal at an approved Chevron facility and in compliance with federal and provincial regulations.

The Project will likely generate some solid and liquid hazardous wastes, including oily wastes (e.g., filters, rags, and waste oil), waste chemicals and containers, batteries, biomedical waste, and spent drilling fluids. The medical personnel onboard the MODU will be responsible for collection of biomedical waste, which will be stored in special containers before being sent onshore for incineration. There will be designated areas on the MODU for storage of hazardous wastes until a scheduled transferred to shore on a supply vessel for disposal by a third-party contractor at an approved facility. Transfer of hazardous wastes will be conducted according to the *Transportation of Dangerous Goods Act* and any applicable approvals for their transportation, handling, and temporary storage will be obtained as required.

2.8.5 Sound Emissions

The MODU, supply vessels, and air gun source array during VSP operations will generate underwater sound. The type of MODU and the method of positioning (i.e., DP or mooring system) will influence the level of underwater sound generated by a MODU. Continuous underwater sound will be generated by the MODU, whereas underwater sound from VSP operations is a temporary sound source. The extent to which sound travels is determined by environmental conditions, including water depths, salinity and temperature.

The existing underwater soundscape in the vicinity of the Project Area was characterized in previous studies by JASCO Applied Sciences (Matthews et al. 2017), as well as predictions of underwater sound transmission loss for representative source levels for the MODU, VSP survey, and supply vessels (Matthews et al. 2017). An Environmental Studies Research Fund (ESRF) recording station near EL 1138 was used to describe the ambient sound levels and various contributors to the soundscape in the area. Contributors included in the ESRF study were anthropogenic contributors (vessel traffic, seismic surveys, and oil and gas extraction activity) and naturally occurring ambient sound contributors (including wind, other environmental phenomena, as well as fin whales) (see Section 5.8).

2.8.5.1 Underwater Sound Modelled for the Project

Underwater sound from drilling or transiting vessels can be characterized as non-impulsive, whereas a seismic survey or VSP sound source is characterized as impulsive, underwater sound. These activities will introduce acoustic sound into the water, which could potentially disturb marine mammals. The goal of the

modelling study was to estimate the root-mean-square (rms) pressure level, referred to as sound pressure level (SPL), sound exposure level over 24 h period (SEL_{24h}), for drilling and DP and peak sound pressure level (PK) for the VSP only. SPLs represent the pressure component of sound, and SELs are a measure of energy (pressure squared) and incorporate the duration of the signal. Cumulative SELs (SEL_{cum}) can also be used, measuring the total sound energy at a receiver location over a period of time, capturing the overall sound levels at the sound receivers as a result of multiple sound events over a period of time (Southall et al. 2007).

The acoustic field was modelled at one site within EL 1138. The modelling was performed for the sound speed profile in the water column for May. Schlumberger Dual Magnum 2,400 in^3 airgun array was used as a proxy seismic source. *Seadrill West Sirius* semi-submersible platform was used as proxy for the MODU.

The SEL_{24h} and PK were assessed against the threshold levels for the onset of Permanent Threshold Shift (PTS) relevant to marine mammal groups using respective marine mammal auditory weighting functions (M-weighting functions) as per Southall et al. (2007) and National Marine Fisheries Service (NMFS 2018).

The seismic source will be deployed from or near the drilling platform and was assumed to be stationary for the duration of the survey. For the purpose of SEL_{24h} calculations, it was assumed that the maximum number of pulses delivered within a 24-hour period is 2,040. A summary of expected source levels and transmission loss for the MODU and VSP survey is presented in Section 2.8.7; refer to Appendix D for more information.

The specific supply vessels to be used to support drilling operations are currently unknown. Sound source levels for a typical supply vessel currently used in the NL offshore area are 188.6 dB re 1 µPa @ 1 m rms SPL (refer to Appendix D). Sound from a supply vessel was not modelled. Previous models of underwater sound generated by supply vessels indicated that sound propagated from the supply vessel DP thrusters (45 km) was similar to the sound generated by a MODU's DP thrusters (50 km) (Matthews et al. 2018).

2.8.5.2 Model Results

Three types of acoustic field metrics were modelled for each source: rms SPL, cumulative sound exposure level (SEL), and peak SPL (Zykov and Alavizadeh 2019; Appendix D). The modelled fields were assessed against the criteria thresholds defined in NMFS (2018).

2.8.5.2.1 VSP

The ranges to the criteria defined permanent threshold shift (PTS)-onset thresholds for the SPL are presented in Table 2.14. Examples of the vertical distribution of the SPL field and the contour map of the maximum-over-depth SPL field around the source is provided in Appendix D.

Table 2.14 VSP 2400 in³ Airgun Array: Maximum (R_{max}, km) and 95% ($R_{95\%}$, km) Horizontal Ranges from the Source to Modelled PTS-onset Thresholds Defined for the SPL Field

Marine Mammal Group	Threshold (dB re 1 µPa)	R_{max}	$R_{95\%}$
NMFS (2018)			
Low-frequency cetaceans	219	0.02	0.02
Mid-frequency cetaceans	230	—	—
High-frequency cetaceans	202	0.20	0.19
Phocid pinnipeds (underwater)	218	0.03	0.03
Otariid pinnipeds (underwater)	232	—	—

The 24-hour SEL field was assessed against impulsive source criteria for each marine mammal group defined in NMFS (2018) after application of specific M-weighting functions. The PTS-onset threshold ranges based on M-weighted 24-h SEL field are provided in Table 2.15. The threshold contour map and PTS-onset threshold contour map are provided in Appendix D.

Table 2.15 VSP 2400 in³ Airgun Array: Maximum (R_{max}, km) and 95% ($R_{95\%}$, km) Horizontal Distances from the Source to PTS-onset thresholds Based on the 24 hour M-weighted SEL Field

Marine Mammal Group	PTS-onset		
	SEL (dB re 1 µPa²·s)	R_{max}	$R_{95\%}$
NMFS (2018)			
Low-frequency cetaceans	183	4.52	4.16
Mid-frequency cetaceans	185	<0.02	<0.02
High-frequency cetaceans	155	0.13	0.12
Phocid pinnipeds (underwater)	185	0.30	0.27
Otariid pinnipeds (underwater)	203	<0.02	<0.02

2.8.5.2.2 MODU

Vessels are non-impulsive or continuous sound sources. The acoustic field around drilling platform was modelled at a single modelling site for the propagation condition typical for May. For the purpose of the SEL_{24h} calculations it was assumed that the vessels are stationary, and the source levels do not change with time. The SEL_{24h} field was assessed against non-impulsive source criteria for each marine mammal group defined in Southall et al. (2007) and NMFS (2018) after application of specific M-weighting functions.

The PTS-onset threshold ranges based on M-weighted SEL_{24h} field are provided in Table 2.16. The PTS-onset threshold contour map is provided in Appendix D.

Table 2.16 Semi-Submersible Platform: Maximum (R_{max}, km) and 95% ($R_{95\%}$, km) Horizontal Distances from the Source to PTS-onset Thresholds Based on the 24-hour M-weighted SEL Field

Marine Mammal Group	PTS-onset		
	SEL (dB re 1 µPa²s)	R_{max}	$R_{95\%}$
NMFS (2018)			
Low-frequency cetaceans	199	0.14	0.14
Mid-frequency cetaceans	198	<0.04	<0.04
High-frequency cetaceans	173	0.25	0.25
Phocid pinnipeds (underwater)	201	0.04	0.04
Otariid pinnipeds (underwater)	219	<0.04	<0.04

2.8.5.3 Atmospheric Sound

Due to the relative low level of atmospheric sound sources (above sea level) and limited transmission of sound through the air-sea interface, atmospheric sound (e.g., sound above the sea surface) is not of particular concern for this Project. The *SeaRose FPSO* at Husky's White Rose oil development field is the nearest "residence" to the Project Area (approximately 125 km). The separation distance between the Project and the *SeaRose FPSO*, as well as the Project and coastal communities on the Island of Newfoundland, would not result in perceived atmospheric sound generated by Project activities.

The effects of human receptors to atmospheric sound, generated by helicopter traffic associated with the Project will be limited by using the existing operational airport (St. John's International Airport). Effects of helicopter traffic (including atmospheric sound) on wildlife will be mitigated through avoidance of bird colonies (refer to Section 9.3). DFO will be contacted for separation distances and altitudes between helicopters transiting to and from the MODU and marine mammals.

2.8.6 Light and Thermal Emissions

The MODU and supply vessel navigation and deck lighting will be operating 24 hours a day and thus generate artificial lighting throughout drilling and supply vessel operations as a requirement for maritime safety and crew safety.

Flaring activity that is carried out during well flow testing will generate light and thermal emissions on the MODU on a temporary basis, at the end of drilling operations. During this time (one to three-month period), it is possible that there could be several, intermittent, short periods of flaring, lasting up to two or three days. It is not expected that well flow testing will take place on the first two wells drilled as part of the Project (refer to Section 2.4.3 for further information).

The Project Area, an otherwise dark-sky site, will experience an increase in night-time light levels, where the MODU will be illuminated at night.

2.9 Alternative Means of Carrying out the Project

2.9.1 Options Analysis Framework

All project environmental assessments must consider and discuss technically and economically feasible, alternative means of carrying out the project and provide potential environmental effects of such alternative means, pursuant to section 19(1)(g) of CEAA 2012. The Agency (2015) provides an Operational Policy Statement for Addressing “Purpose of” and “Alternative Means” under the CEAA 2012, describing the process for consideration of alternative means of carrying out the Project.

There are several components of the Project, such as well site location, that are yet to be finalized. Some of these components will be confirmed to C-NLOPB as part of the OA and ADW process.

2.9.2 Identification and Evaluation of Alternatives

For the analysis of alternative means, the EIS Guidelines suggest consideration of the following:

- Drilling fluid selection (e.g., WBM or SBM)
- Drilling unit selection
- Drilling waste management
- Water management and effluent discharge
- Alternative platform lighting options (including flaring) to reduce attraction and associated mortality of birds

For each these aspects of the Project, the technical feasibility and economic feasibility, as well as the environmental effects (where applicable) of the alternative means is described.

In identifying the technical feasibility of alternative means, criteria that could influence safe, reliable, and efficient operations, are considered. For the potential technology to be considered it must be available and verified for similar operations and in a similar environment (i.e., offshore drilling in deep water), without compromising personnel and process safety. Economic feasibility considers capital and operational project expenditure, which could be impacted directly (e.g., equipment and personnel requirements) and indirectly (e.g., schedule delays).

The options for the alternative means, identified above, is summarized below in Tables 2.17, 2.18, 2.19, 2.20 and 2.21. The Project is assessed based on the preferred alternative means (i.e., assumed to be the base case that is assessed for environmental effects in Chapters 8 to 13 of this EIS).

2.9.2.1 Drilling Fluids Selection

For this Project the drilling fluid used could be either WBM or SBM, and selection and formulation of the drilling fluids depend on the well design and the expected geology. Provided that the components of the

fluids are selected and disposed of according to the OCSG and OWTG, respectively, either WBM or SBM are acceptable options.

Both drilling fluids are available within NL; however, the technical feasibility of each drilling fluid differs. When drilling through challenging geological conditions, SBM can generally be more efficient than WBM, including areas containing hydrate shales.

Table 2.17 summarizes and compares the various attributes of WBM and SBM. The preferred option is to use WBM and SBM in different sections of the well because, while SBM has its technical and economic advantages, it cannot be used to drill riserless sections of the well. The EIS therefore considers the use of both WBM and SBM in the effects assessment.

Table 2.17 Summary of Drilling Fluid Alternatives Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
SBM only	No	Yes	Yes	SBM is not permitted for ocean discharge without treatment, therefore SBM cannot be used for riserless drilling where the cuttings are disposed directly on the seafloor	Not preferred
WBM only	Yes	Yes, although potential challenges with borehole stability	Yes – although potential increased cost from nonproductive time and losses	No substantial difference between options. Both are considered acceptable provided that appropriate controls are in place and chemicals are selected in accordance with OCSG (EIS considers both WBM and SBM in effects assessment)	Exclusive use of WBM feasible but not preferred
WBM / SBM hybrid for different sections	Yes	Yes	Yes		Preferred alternative

2.9.2.2 Drilling Unit Selection

There are three main types of drilling units for offshore drilling: a jack-up rig, a semi-submersible drill rig, and a drillship. The latter two were described in Section 2.3.1.3 and 2.3.1.4, respectively.

The MODU that will be used to drill the wells for the Project has not yet been selected by Chevron; however, since the water depths in EL 1138 are greater than 100 m, a jack-up rig is not technically feasible. The MODU selection and approval process (outlined in Section 2.3.1.1), therefore only considers a semi-submersible MODU and drillship. These MODUs are technically and economically feasible options and would have comparable environmental effects. Thus, both MODUs are assessed in this EIS. Table 2.18 summarizes the comparison of drilling unit options.

Table 2.18 Summary of Drilling Unit Alternatives Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
Jack-up Rig	Yes	No, given water depths of ELs	Not considered as option because not technically feasible.		Not feasible
Semi-submersible	Yes	Yes	Yes	Both options are considered to be environmentally acceptable and would have comparable environmental effects in terms of lighting, emissions and discharges, and underwater sound (EIS considers both options in effects assessment)	Potentially preferred alternative
Drillship	Yes	Yes	Yes		Potentially preferred alternative

2.9.2.3 Drilling Waste Management

The main drilling waste management options for consideration are:

- Disposal at sea
- Offshore reinjection
- Ship- to-shore for onshore treatment/disposal

Depending on the type of drilling fluid used (e.g., WBM or SBM), the preferred option will vary. Since it is proposed that different drilling fluids will be used for different sections of the well, it is likely that a combination of drilling waste management options will be used.

Section 2.8.2 outlines ocean disposal of WBM and SBM drilling waste, including required onboard treatment prior to disposal, where applicable.

Cuttings reinjection is an alternative method of offshore disposal and involves processing cuttings waste into a slurry (i.e., mixing them with a liquid) and then pumping them into a dedicated well, designed for reinjection. Cuttings are reinjected into targeted formations down the well, under pressurized conditions. Although offshore injection of cuttings from fixed wellhead platforms is verified technology, subsea injection from MODUs is not practical due to the specialized equipment required (i.e., flexible injection riser and a specially designed wellhead). The technology has also only been developed for water depths of 305 m, much shallower than the depths of the EL. This technical infeasibility in deep water, the additional storage capacity required for specialized equipment, the installation of this equipment, and the geological uncertainty, adds both complexity and cost to the operation. Re-injection is therefore not considered to be a technically or economically feasible alternative for an exploration drilling program.

Cuttings can also be shipped to shore for onshore disposal using a supply vessel and then transported to an approved waste management facility for treatment and disposal. In this case, waste would have to be shipped out of province because there are no approved treatment facilities for SBM waste in NL. Although

offshore effects associated with drilling waste discharge may be reduced, onshore disposal will cause potential environmental effects via increased transportation (e.g., atmospheric emissions) and onshore treatment and disposal (e.g., habitat alteration). The costs associated with ship-to-shore options are expected to be higher than the offshore options due to additional transportation costs. Some of the operational risks associated with onshore disposal include:

- Onshore waste management facility availability and supply vessel availability
- Poor weather conditions affecting supply vessel transit, impacting their ability to collect cuttings on a regular basis (drilling operations may have to stop)
- Additional health, safety and environmental risk introduced due to additional truck and vessel traffic, and additional exposure and handling of material.

Following the OWTG, discharge to the water column following treatment (where applicable) is the preferred option for cuttings generated as part of the Project and therefore has been assessed as part of the Project (refer to Chapter 8). As noted in Section 2.4.1, during the riserless phase of drilling, WBM cuttings will be discharged at the seafloor (as is permitted by the OWTG), as there is no mechanism to return cuttings to the MODU. Table 2.19 Summarizes this analysis of alternative means for drilling waste management.

Table 2.19 Summary of Drilling Waste Management Alternatives Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
Discharge to water column (following treatment of SBM on cuttings)	Yes	Yes	Yes	Some localized effects are expected on the seafloor from discharge of cuttings (assessed in Section 8)	Preferred alternative
Offshore Reinjection	Yes	No	Not considered as option because not technically feasible		Not feasible
Ship-to-shore (SBM-associated cuttings)	Yes	Yes	Yes – but increased costs from increased transportation and operational delays	Some limited offshore effects are expected from increased transportation, and some onshore effects from transportation and onshore disposal of waste including increased health, safety and environment risks associated with truck and vessel traffic and exposure and handling of waste material	Not preferred alternative

2.9.2.4 Water Management

Effluent discharges that will be generated on the MODU and the associated water management systems are described in Section 2.8.3. Liquid wastes not approved for discharge in the OWTG will be transported onshore for transfer to an approved disposal facility, while those that conform to the OWTG will be discharged from the MODU to the marine environment. Specific discharge points on a MODU are fixed and

cannot be changed or re-configured but are typically just below or above the sea surface. Once a MODU is selected, Certificate of Fitness will be obtained from an independent third-party Certifying Authority (refer to Section 1.5.1) which will include confirmation that effluent discharge and water management systems comply with relevant legislation.

2.9.2.5 Offshore Vessel Lighting (including Flaring)

Lighting is required under Canadian and international law and will be used on the MODU and the supply vessels 24 hours a day throughout drilling and supply vessel operations for maritime and crew safety. Reduction of light can therefore not be considered an alternative means, as it could compromise the safety of drilling installation personnel and / or third-party navigators.

Spectral modified lighting has been tested on offshore platforms and has demonstrated a reduced effect on marine birds; particularly the use of green and blue light (Marquenie et al. 2014). In some regions spectral modified lighting has satisfied regulatory requirements; however, commercial availability, limited capability in extreme weather, safety concerns around helicopter approach and landing, and lower energy efficiency, has restricted implementation in the offshore oil and gas industry (Marquenie et al. 2014).

The MODU used for the Project will be supplied by a third-party drilling contractor and is an existing drilling unit. Chevron will select a MODU based on technical capabilities as well as safety considerations and is not aware of any operating MODUs equipped with spectral modified lighting that have the technical capability to support the Project.

Lighting will be maintained at a level that will not impede the safety of the workforce or drilling operations (Table 2.20). The EIS considers the environmental effects associated with standard MODU lighting (refer to Chapter 9).

Table 2.20 Summary of Lighting Alternatives Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
Standard MODU lighting	Yes	Yes	Yes	Some localized visual effect is expected which could affect migratory birds (assessed in Section 9)	Preferred alternative
Spectral modified lighting	Yes	No – limited capabilities in extreme weather; safety concerns with helicopter approach and landing	No – not considered as commercially viable yet	Not considered as option because not feasible	Not feasible

Flaring will be required for safe disposal of hydrocarbons, and some liquid waste, if well flow testing is carried out (refer to Section 2.4.3 for more information on well testing). Flaring will contribute to platform lighting and potential attraction of birds. A formation test while tripping, which does not require flaring, is an alternative to well flow testing; however, it does not provide the same data, and hence, its suitability will be

assessed on a case-by-case basis. A formation test while tripping will be considered by Chevron in each case to ensure well testing meets C-NLOPB requirements.

An alternative option, if flaring is required, could be to manage the timing of flaring activity to reduce light generated during flaring. For example, planning flaring such that it doesn't begin during periods of poor visibility, including at night and/or during inclement weather. However, upon commencement of flaring, restricting well testing periods in this way may compromise the data gathered. If flaring could not be carried out continuously it could result in prolonged well testing activity (i.e., greater than one month as currently predicted), increasing operational costs and risks.

In the event of a well test, flaring is expected to be short term, intermittent and will be reduced as much as practicable. If and when it occurs, actual flaring is expected to last three to four days. If flaring is required, Chevron will notify the C-NLOPB in accordance with "Measures to Protect and Monitor Seabirds in Petroleum-Related Activity in the Canada-NL Offshore Area". A water curtain will be used, which protects personnel and equipment on the MODU by limiting the transfer of radiated heat from the flare, thereby mitigating risk of fire. Another potential benefit of the water curtain, based on its position, is the deterrence of birds from the area around the flare. Because the water curtain potentially reduces adverse effects of flaring on birds, it could be considered a technically and economically feasible option as a flare shield.

Flaring alternatives are provided in Table 2.21. The analysis of Project effects (refer to Chapter 9) assumes there will be flaring during well testing.

Table 2.21 Summary of Flaring Alternative Analysis

Option	Legally acceptable?	Technically feasible?	Economically feasible?	Environmental Issues	Preferred Option
No flaring	No	Not considered as option due to regulatory and safety requirements. current regulatory practice requires formation flow test with flaring to secure Significant Discovery Licence. Industry continues to advocate for alternative methods.			Not feasible
Formation testing while tripping	Yes	Yes – although may not fulfill C-NLOPB data requirements in all cases	Yes	No flaring therefore reduced light and atmospheric emissions and reduced risk of bird attraction and mortality	Potentially preferred alternative
Reduced flaring (i.e., no flaring during nighttime or inclement weather)	Yes	Yes – although activity could give result to compromised data	Yes – but increased MODU costs and risk of delays	Reduced flaring would still result in some measure of light and atmospheric emissions	Not preferred alternative
Flaring as required with flare shield (water curtain)	Yes	Yes	Yes	Some limited offshore effects are expected from the light and atmospheric emissions generated during flaring. These are expected to be intermittent and brief in duration over a temporary period at the end of drilling (assessed in Section 9)	Preferred alternative

2.9.3 Chemical Management

The Project has not yet confirmed the details of chemicals to be used or identified the potential alternatives, as the EIS is prepared prior to well planning or drilling program design. A contractor for drilling fluid and cementing has not been selected and the development of the drilling fluid basis of design for the wells is currently underway. As planning continues, Chevron will follow chemical management and selection processes to define the ways in which chemicals will be chosen and used in accordance with the OCSG, and other regulatory requirements (Table 2.22).

Table 2.22 Applicable Offshore Chemical Management Legislation and Guidelines

Legislation	Regulatory Authority	Relevance
Canadian Environmental Protection Act, 1999 (CEPA)	ECCC	Provides for the notification and control of certain manufactured and imported substances. The Domestic Substances List is a list of substances approved for use in Canada. Schedule 1 includes a list of substances that are considered toxic and subsequent restrictions or phase out requirements
Fisheries Act	DFO; ECCC	Prohibits the deposition of toxic or harmful substances into waters containing fish
Hazardous Product Act	Health Canada	Standards for chemical classification and hazard communication
Migratory Birds Convention Act, 1994 (MBCA)	ECCC	Prohibits the deposition of harmful substances in waters or areas frequented by migratory birds
Pest Control Products Act	Health Canada	Regulates the importation, sale and use of pest control products, including products used as biocides offshore
OCSG	C-NLOPB	Framework for the selection of drilling and production chemicals for use and possible discharge in offshore areas

The procedure and criteria for offshore chemical selection, established by the OCSG, aims to promote the selection of lower toxicity chemicals to minimize the potential environmental effects of a discharge where technically feasible. At a minimum, selection of drilling chemicals will be in accordance with the OCSG and Chevron will document the process used to evaluate prospective chemicals.

2.9.3.1 Proposal for Use: Initial Screening and Regulatory Controls Identification

Table 2.22 outlines the legislation for which the screening of a proposed chemical will follow. The screening process includes specific aspects of the use of the chemical, including likely volume demand and discharge assumptions. Pursuant to the regulations, certain restrictions, controls and prohibitions, in agreement with applicable regulatory agencies, will 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) or have not been used previously for the purpose which is proposed

- Chemicals that are identified as toxic under Schedule 1 of the *Canadian Environmental Protection Act, 1999* (CEPA). In the event that a proposed chemical is listed under Schedule 1 of CEPA, Chevron will consider alternative means of operation, and / or will evaluate less toxic alternatives

2.9.3.2 Chemicals Intended for Marine Discharge: Toxicity Assessment

Chevron will conduct a further assessment for chemicals that will be discharged to the marine environment, following the initial screening activity identifying any restrictions, controls and prohibitions on proposed chemicals. This assessment will be carried out to evaluate the potential toxicity of proposed chemicals (and any constituents of the chemical as applicable), and to establish if additional restrictions, controls or prohibitions are required. Following the assessment, a chemical screening procedure will be developed for the Project. The procedure will describe the process for screening chemicals that are intended to be used by Chevron for drilling operations. Additionally, the procedure will outline a chemical review process for the proposed drilling chemicals and promote the selection of lower toxicity chemicals to reduce environmental impact where technically feasible.

The OCSG chemical selection framework states that any chemicals intended for discharge to the marine environment shall be reviewed against the following criteria:

- Be included on the Oil Spill Prevention, Administration and Response (OSPAR) list of substances that PLONOR to the environment or
- Meet certain requirements for hazard classification under the OCNS or
- Pass a Microtox test (i.e., toxicity bioassay) or
- Undergo a chemical-specific hazard assessment in accordance with the OCNS model or
- Demonstrate that the risk of its use is justified through demonstration to the C-NLOPB that discharge of the chemical will meet OCSG objectives

Further detail is provided in the following:

- 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 OCNS hazard rating. This scheme ranks chemical products per a hazard quotient based on a range of physical, chemical and ecotoxological properties of products, including toxicity, biodegradation and bioaccumulation information.
- The Chemical Hazard and Risk Management model is used to determine the hazard quotient, 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, Chevron 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, Chevron will consider alternative means of operation, and / or will evaluate 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.

The OCSG apply to the following categories of chemicals that could be used as part of the Project:

- Drilling fluids, including sweeps and displacement fluids
- Well conditioning fluids
- BOP fluids
- Cement slurry
- Fuel, including diesel
- Hydraulic oil and greases
- Fire suppressant systems
- Cleaning fluids
- Biocides

The OCSG do not apply to the following categories of chemicals:

- The selection of domestic chemicals and other chemicals that are used on an installation that are not directly associated with drilling activities, such as those used for accommodations, catering, equipment and facility maintenance (e.g., lubricants, paints, etc.), safety systems and laboratory operations
- The selection of chemicals that are used on supply vessels and helicopters

The details about chemical types and volumes are not yet known. A Material Safety Data Sheet (MSDS) is available for chemicals on board the MODU and supply vessels. The inventory of chemicals on board the MODU will be regularly monitored reported annually to the C-NLOPB, outlining each chemical used including the hazard rating, quantity used, and its ultimate fate.

Furthermore, the Project will adhere to Chevron's TWS standard which defines waste as the following:

> Any material that is surplus, unwanted, scrap, contaminated, unusable, etc. designated for disposal, re-use, reclaiming, recycling, treatment, or discharge either at Chevron or third-party facilities, or material that is stored before those actions. This term is a Chevron-internal term used for convenience in the TWS Standard; it is not intended to supersede regulatory definitions or represent Chevron's interpretation of any regulatory definitions that might apply to these materials. TWS does not define waste for Corporate reporting; refer to the most recent Operational Excellence Data Reporting Standard (OEDRS) for Corporate waste reporting guidance.

The TWS standard also defines non-contaminated waste as the following:

If a waste contains any level of contaminant (hydrocarbons and/or other non-naturally occurring substances), it is considered contaminated, even if the material has undergone decontamination. A non-contaminated material is one that is essentially free of hydrocarbons and other non-naturally occurring substances that were introduced to the material from industrial use or contact, such as use in process/equipment, contact with hydrocarbons or chemicals, etc. Clarification of non-contaminated scrap metal:

1. Process equipment and piping, although “cleaned”, would be considered “contaminated” and therefore be “in-scope” for TWS. This contaminated scrap metal would have to be sent to a TWS Selected-for-Use recycling or disposal facility (e.g., scrap metal from offshore operations).
2. Structural steel that has not been in contact with process streams could be considered non-contaminated and therefore “out-of-scope” for TWS. This steel would not have to be recycled or disposed of at a TWS Selected-for-Use Waste Facility.

2.10 Environmental Management

2.10.1 Chevron’s Operating Management System

Chevron’s OEMS is a comprehensive, proven means for systematic management of process safety, personal safety & health, the environment, reliability, and efficiency. The implementation of OEMS demonstrates Chevron’s commitment to conducting activities in line with applicable legislation, striving to constantly improve environmental performance, and reducing potential impacts from its operations. These principles comprise the quality assurance program that Chevron calls OEMS. The three parts of the OEMS are Leadership Accountability, Management System Process, and OEMS Expectations.

- Leadership Accountability identifies executives and managers accountabilities for OEMS implementation for continual improvement which supports the goal of world class performance. Leaders determine which requirements and behaviours apply to their specific organization roles and take action to integrate them into routine duties.
- The Management System Process compares performance against the OEMS objectives. Gaps between the current performance and objectives are closed through formal plans.
- OEMS is used to manage business and Health Environment and Safety risks and is based on guiding principles called OE Expectations. OE Expectations are organized under 13 elements and identify specific requirements for the management of safety, health, environment, reliability and efficiency. These expectations are met through processes and standards put in place by local management. The environmental elements are certified to the international standard for environmental management systems ISO 14001 by an external verification company (DNV) and are subject to regular audits.

2.10.2 HES Management Planning

A key step in understanding and planning to avoid, mitigate, and/or compensate for potential environmental impacts, is the incorporation of resource information in the planning of a Project’s design, pre-construction, construction, and operation phases. The Environmental Protection Plan (EPP) will consider site specific

conditions, resource information, local, regional, provincial, and federal regulations, and best management practices to ensure mitigation, compensation, and monitoring protocols are implemented effectively during later Project phases.

2.10.2.1 Environmental Protection Plan

An EPP will be developed following receipt of an Environmental Assessment Certificate. The EPP will outline the requirements of the Project Environmental Assessment Certificate, and provincial and federal legislation. Project permits (i.e., C-NLOPB, Minister of Environment, Oil and Gas Commission) may have additional environmental conditions. Therefore, the EPP is to be used in conjunction with all project permits. The EPP will be updated to incorporate new Project information, provincial and/or federal requirements on an as needed basis. Where applicable, the EPP will be developed to address Project phases that include: design, construction, operation and maintenance, and decommissioning.

The objectives of the EPP include, but are not limited to, the following:

- Provide information for Project personnel to conduct work in a manner that avoids or reduces potential adverse environmental effects
- Satisfy Environmental Assessment Certificate approval conditions
- Comply with other applicable legislative and/or regulatory requirements
- Inform regulators, interested stakeholders, First Nations of the Project's environmental commitments
- Outline environmental mitigation measures related to various Project phases and activities
- Serve as a reference and provide information regarding methods, procedures, guidelines, and monitoring protocols, as they apply
- Provide for adaptive management strategies and procedures in the event special circumstances occur

2.10.2.2 Safety Plan

Chevon's Managing Safe Work (MSW) Process is to identify, assess, and mitigate, control or eliminate the risks associated with work. The MSW process provides for the identification and evaluation of job task hazards, specification of control measures, management of those measures, control of the work and behaviors to support safe work.

This MSW OE process covers work performed by Chevron employees and their delegates and contractors. To comply with this process, requirements are as follows:

1. Work shall be performed consistent with the Project's design and intent.
2. Conduct an MSW Engagement Session to identify supervision, by level in the organization, and associated behaviors specific to supporting the MSW Process. Measurement, tracking and review of these identified behaviors shall be established along with setting appropriate accountability.
3. Work planning shall include a hazard analysis.
4. Safe Work Practice standards that meet or exceed Chevron's Safe Work Practice standards will be maintained
5. A job safety analysis shall be performed prior to the beginning of work.
6. A Stop Work Authority policy shall be established, communicated and reinforced.

In accordance with Chevron's MSW process, and provincial and federal regulations and permits, a Project Safety Plan will be developed prior to drilling activities.

2.10.2.3 Incident Management Plan

The purpose of this section is to provide information on the Chevron Business Unit's concept of operations for responding to incidents, regardless of nature, severity, or location. Incidents often occur without warning. As a result, members Chevron's incident management team often begin their work in a reactive phase. The initial priority is to move from a reactive to a proactive phase of operations, as safely and quickly as possible. This is done by engaging in a fully integrated Incident Management System whose primary objective is the establishment and maintenance of command and control over the incident and emergency response operations.

Chevron has developed an Immediate Notification Procedure. The purpose of the procedure is to ensure that the appropriate level of response is brought to bear on incidents and potential or actual crisis situations, by appropriate personnel, in a timely fashion. Notifications can be for information purposes alone, or they can result in the activation of (an) Onsite Response Team(s) [ORT(s)], (a) Emergency Management Team(s) [EMT(s)] (consisting of both Field & Asset EMT Members), and/or the Chevron Crisis Management Team (CMT).

A Project specific Emergency Response Plan (ERP) will be developed to include an incident management plan prior to drilling activities.

2.10.2.4 Spill Response Plan

Spill procedures and equipment will be in place for all work vessels prior to mobilization. Any deficiencies shall be corrected and re-inspected before arrival on the Project. Contractors will provide their own Spill Preparedness and Response Plan for review and approval. Hardcopies of the plan will be posted or available at appropriate locations. Personnel will be trained in spill prevention and response, as well as the operation and maintenance of equipment to prevent and contain any accidental discharge, as appropriate.

A Project Spill Preparedness and Response Plan will be developed to include spill response information and requirements prior to drilling activities.

2.10.3 Standard Mitigative Measures

Offshore NL has a long history of oil and gas exploration and well-established oil production operations; as such, most potential environmental interactions are well understood, and standard mitigation measures are well known. Chevron's policies and procedures and/or regulatory guidelines will be applied to manage any potential adverse environmental effects predicted in this EIS. Chevron will reduce adverse environmental effects of waste discharges on the marine environment by adhering to offshore guidelines such as the OWTG and OCSG, as well as the MARPOL. Chevron will adhere to the SOCP (DFO 2007) during VSP surveys, reducing adverse environmental effects on marine mammals and sea turtles and marine fish. The EIS also proposed site- or Project-specific mitigation measures where necessary.

A summary of general standard mitigation measures to be implemented during this Project is provided in Table 2.23. A complete summary of mitigation and commitments is included in Chapter 17.

Table 2.23 Standard Mitigation Measures

General
Contractors and subcontractors shall be required to demonstrate conformance with the requirements that have been established, including HES standards and performance requirements.
Chevron will obtain a Certificate of Fitness from an independent third-party Certifying Authority for the MODU prior to commencement of drilling operations in accordance with the C-NLOPB's *Offshore Certificate of Fitness Regulations*.
Chevron will collect detailed site-specific information on climatic, meteorological, and oceanographic conditions as part of the planning and design of an offshore program and implement a physical environment monitoring program, including metocean monitoring, onsite weather observation, and ice management, as required by the Offshore Physical Environment Guidelines (NEB et al. 2008).
Chevron and contractors working on the Project will regularly monitor weather forecasts to forewarn supply vessels, helicopters, and the MODU of inclement weather or heavy fog before it poses a risk to their activities and operations. Extreme weather conditions that are outside the operating limits of supply vessels or helicopters will be avoided if possible. Captains / Pilots will have the authority and obligation to suspend or modify operations in case of adverse weather or poor visibility that compromises the safety of supply vessel, helicopter, or MODU operations.
Icing conditions and accumulation rates on supply vessels, helicopters, and the MODU will be monitored during fall and winter operations, particularly when gale-force winds may be combined with air temperatures below -2°C (DFO 2012).
Safe work practices will be implemented to reduce exposure of personnel to lightning risk (e.g., restriction of access to external areas on the MODU or supply vessel during thunder and lightning events).
Prior to drilling activity, Chevron will conduct a comprehensive regional geohazard baseline review, followed by detailed geohazard assessments for each proposed well site.
Chevron will require the Drilling Contractor provide details of the safety zone to the Marine Communication and Traffic Services for broadcasting and publishing in the Navigational Warning and Notices to Shipping and Notices to Mariners. Details of the safety (exclusion) zone will also be communicated by Chevron during ongoing consultations with commercial and Indigenous fishers.
Chevron will develop and implement a compensation program for damages resulting from Project activities. This compensation program will be developed in consideration of C-NLOPB guidelines, including the Compensation Guidelines Respecting to Damages Relating to Offshore Petroleum Activities (C-NLOPB and Canada-Nova Scotia Offshore Petroleum Board [CNSOPB] 2017b).
General
A pre-drill survey will be conducted at each well site to confirm the presence or absence of unexploded ordinance or other seabed hazards. The pre-drill survey will also include a coral and sponge survey (developed in consultation with DFO) to confirm the presence or absence of any aggregations of habitat-forming corals or sponges or any other environmentally sensitive features.
Presence and Operation of the MODU
To maintain navigational safety at all times during the Project, obstruction lights, navigation lights, and foghorns will be kept in working condition on board the MODU and supply vessels. Radio communication systems will be in place and in working order for contacting other marine vessels as necessary.
The MODU will be equipped with local communication equipment to enable radio communication between the supply vessels and the MODU's bridge. Communication channels will also be put in place for internet access, and enable communication between the MODU and shore.

Table 2.23 Standard Mitigation Measures

In accordance with the *Newfoundland Offshore Petroleum Drilling and Production Regulations*, a safety (exclusion) zone (estimated to be a 500-m radius) will be established around the MODU within which non-Project related vessels are prohibited.
An imagery-based seabed survey will be conducted in the vicinity of the proposed well site(s) to confirm the absence of sensitive environmental features, such as habitat-forming corals or species at risk (as well as shipwrecks, debris on the seafloor, unexploded ordnance). The survey will be carried out prior to drilling. If environmental or anthropogenic sensitivities are identified during the survey, Chevron will move the wellsite to avoid affecting them if it is feasible to do so. If it is not feasible, Chevron will consult with the C-NLOPB to determine an appropriate course of action. This survey will also provide baseline data for coral and sensitive benthic habitat that may be present and be used to inform discussions on potential follow-up and monitoring with respect to drill waste discharges.
Lighting will be reduced to the extent that worker safety and safe operations is not compromised. Reduction of light may include avoiding use of unnecessary lighting, shading, and directing lights towards the deck.
Supply vessel and MODU contractors will have a Maintenance Management System designed to direct the maintenance and efficient operation of the vessels and MODU, and all equipment.
Waste Management
Air emissions from the Project will adhere to applicable regulations and standards including the Newfoundland and Labrador (NL) *Air Pollution Control Regulations*, National Ambient Air Quality Objectives, Canadian Ambient Air Quality Standards, regulations under the International Convention for the Prevention of Pollution from Ships MARPOL and the intent of the Global Gas Flaring Reduction Partnership.
Offshore waste discharges and emissions associated with the Project (i.e., operational discharges and emissions from the MODU and supply vessels) will be managed in accordance with relevant regulations and municipal bylaws as applicable, including the OWTG (NEB et al. 2010) and MARPOL, of which Canada has incorporated provisions under various sections of the *Canada Shipping Act*. Waste discharges not meeting legal requirements will not be discharged to the ocean and will be brought to shore for disposal.
Selection of drilling chemicals will be in accordance with the Offshore Chemical Selection Guidelines for Drilling and Production Activities on Frontier Lands (OCSG; NEB et al. 2009), which provides a framework for chemical selection to reduce potential for environmental effects. During planning of drilling activities, where feasible, lower toxicity drilling muds and biodegradable and environmentally friendly additives within muds and cements will be preferentially used. Where feasible the chemical components of the drilling fluids will be those that have been rated as being least hazardous under the Offshore Chemical Notification System scheme and pose little or no risk to the environment.
Discharges of SBM mud and cuttings will be managed in accordance with the OWTG. SBM cuttings will only be discharged once the performance targets in OWTG of 6.9 g/100 g retained “synthetic on cuttings” on wet solids can be satisfied. The concentration of SBM on cuttings will be monitored on the MODU for compliance with the OWTG. In accordance with OWTG, no excess or spent SBM will be discharged to the sea. Spent or excess SBM that cannot be re-used during drilling operations will be brought back to shore for disposal.
Waste Management
Excess cement may be discharged to the seabed during the initial phases of the well, which will be drilled without a riser. Once the riser has been installed, cement waste will be returned to the MODU. Cement waste will then be transported to shore for disposal in an approved facility.
Small amounts of produced water may be flared. If volumes of produced water are large, some produced water may be brought onto the MODU for treatment so that it can be discharged in line with the OWTG.
Deck drainage and bilge water will be discharged according to the OWTG which state that deck drainage and bilge water can only be discharged if the residual oil concentration of the water does not exceed 15 mg/L.
Foreign vessels operating in Canadian jurisdiction must comply with the *Ballast Water Management Regulations* and Transport Canada’s *Ballast Water Control and Management Regulations* of the *Canada Shipping Act, 2001* during ballasting and de-ballasting activities.

Table 2.23 Standard Mitigation Measures

Putrescible solid waste, specifically food waste generated offshore on the MODU and supply vessels, will be disposed of according to OWTG and MARPOL requirements. In particular, food waste will be macerated so that particles are less than 6 mm in diameter and then discharged. There will be no discharge of macerated food waste within 3 nm from land.
Sewage will be macerated to a particle size of <6 mm and discharge as per the OWTG.
Cooling water will be discharged according to the OWTG which states that any biocides used in cooling water are selected in line with a chemical management system developed in line with the OCSG.
BOP fluids and any other discharges from the subsea control equipment will be discharged according to OWTG and OCSG.
Liquid wastes, not approved for discharge in OWTG such as waste chemicals, cooking oils or lubricating oils, will be transported onshore for transfer to an approved disposal facility.
Waste generated offshore on the MODU and supply vessels will be handled and disposed of in accordance with relevant regulations and municipal bylaws. Waste management plans and procedures will be developed and implemented to prevent unauthorized waste discharges and transfers.
Biomedical waste will be collected onboard by the medical professional and stored in special containers before being sent to land for incineration.
Transfer of hazardous wastes will be conducted according to the *Transportation of Dangerous Goods Act.* Applicable approvals for the transportation, handling and temporary storage, of these hazardous wastes will be obtained as required.
Information on the releases, wastes and discharges will be reported as part of a regular environmental reporting program in accordance with regulatory requirements as described in the OWTG.
VSP Surveys
Passive acoustic monitoring will be implemented
VSP activity will be planned and conducted in consideration of the Statement of *Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment* (SOCP; DFO 2007).
Supply and Servicing Operations
Supply vessels will follow established shipping lanes where they exist (i.e., in proximity to shore); where these do not exist, supply vessels will follow a straight-line approach to and from the Project Area. During transit to/from the Project Area, supply vessels will travel at vessel speeds not exceeding 22 km/hour (12 knots) except as needed in the case of an emergency.
In order to reduce the potential for vessel strikes during transiting activities outside the Project Area, supply vessels will reduce speed to a maximum of 13 km/hour (7 knots) when marine mammals or sea turtles are observed or reported within 400 m of a supply vessel, except if not feasible for safety reasons.
Supply and Servicing Operations
In the event that a vessel strike with a marine mammal or sea turtle occurs, Chevron will contact the C-NLOPB, DFO's Canadian Coast Guard Regional Operations Centre, Indigenous groups as soon as reasonably practicable but no later than 24 hours following the collision. Indigenous groups will also be notified.
Lighting on supply vessels will be reduced to the extent that worker safety and safe operations is not compromised. Reduction of light may include avoiding use of unnecessary lighting, shading, and directing lights towards the deck.

Table 2.23 Standard Mitigation Measures

The supply vessels selected for this Project will be equipped for safe all-weather operations, including stability in rough sea conditions and inclement weather. In addition, measures to reduce superstructure icing hazards on supply vessels will be implemented as necessary and may include (DFO 2012): • Reducing vessel speed in heavy seas • Placing gear below deck and covering deck machinery, if possible • Moving objects that may prevent water drainage from the deck • Making the ship as watertight as possible • Manual removal of ice if required under severe icing conditions
A supply vessel will remain on standby at the MODU at all times in the event that operational assistance or emergency response support is required.
Supply vessels will undergo Chevron's internal verification process, as well as additional external inspections / audits inclusive of the C-NLOPB pre-authorization inspection process, in preparation for the Project.
Well Abandonment
A seabed survey will be conducted at the end of the drilling program using a remotely-operated vehicle (ROV) to survey the seabed for debris.
Use of explosives will not be employed for removal of wellheads.
Supply vessel routes transiting to and from the MODU will be planned to avoid passing within 300 m of migratory bird nesting colonies during the nesting period and will comply with provincial *Seabird Ecological Reserve Regulations, 2015* and federal guidelines in order to minimize disturbance to colonies (ECCC 2017).
The regional CWS office will be contacted for separation distances and altitudes between helicopters transiting to and from the MODU and migratory bird nesting colonies, as per CWS guidelines (Government of Canada 2018) and routes will comply with provincial *Seabird Ecological Reserve Regulations, 2015*.
Once wells have been drilled to true vertical depth and well evaluation programs completed (if applicable), the well will be plugged and abandoned according to applicable Chevron practices and C-NLOPB requirements. The final well abandonment program has not yet been finalized; however, these details will be confirmed to the C-NLOPB as planning for the Project continues.

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3.0 CONSULTATION AND ENGAGEMENT

Chevron recognizes the importance of early and ongoing Indigenous and stakeholder engagement that continues over the life of the Project. Chevron is committed to collaborating with Indigenous peoples of Canada and other stakeholders to build long term trusting and mutually beneficial relationships based on the principles of inclusion, transparency, respect and accountability.

3.1 Government Departments and Agencies

Regulatory stakeholders are typically engaged to confirm specific regulatory requirements / processes and/or data requests. Key regulatory stakeholders for the Project are:

- C-NLOPB
- Government of Canada
  - CEA Agency
  - DFO
  - ECCC
  - Canadian Coast Guard
  - Natural Resources Canada (NRCan)
  - Department of National Defence (DND)
  - Transport Canada
- Government of NL
  - Municipal Affairs and Environment
  - Fisheries and Land Resources
  - Natural Resources

To date, Chevron has met with the CEA Agency, the C-NLOPB, DFO, ECCC (including the Canadian Wildlife Service [CWS]), NRCan, Transport Canada, National Defence (DND), Health Canada, and the NL Department of Natural Resources in planning and developing the EIS to obtain relevant baseline information and/or guidance in assessment methods and approach. A log of Project-related consultation with government departments and agencies is provided in Table 3.1. These same government departments and agencies also participated in the review of the Project Description and EIS guidelines. This EIS incorporated comments provided during the review processes and meetings where applicable.

Key items for discussion with government departments and agencies during preparation of the EIS included general Project scope, spill modelling approach and methods, and monitoring programs for migratory species, including species at risk. Chevron will continue to engage government departments and agencies during EIS review and post-EIS regulatory approvals.

Table 3.1 Communications with Government Departments and Agencies

Date	Method	Purpose
CEA Agency		
August 24, 2018	Email	Project introduction. Meeting request. Included map of lease area of interest.
September 21, 2018	Meeting	Project introduction with representatives from Chevron and Stantec. Request for comments, information, concerns, or questions regarding the Project.
December 3, 2019	Meeting	Project introduction with representatives from Chevron and the new Agency satellite office in St. John's. Discussed project timeline, and regional assessment.
C-NLOPB		
August 24, 2018	Email	Project introduction. Meeting request. Included map of lease area of interest.
September 18, 2018	Meeting	Project introduction with representatives from Chevron and Stantec. Request for comments, information, concerns, or questions regarding the Project.
November 26, 2018		Federal Authority Advice Record (FAAR) in response to Project Description submission
DFO		
August 24, 2018	Email	Project introduction. Meeting request. Included map of lease area of interest.
September 20, 2018	Meeting	Project introduction with representatives from Chevron and Stantec. Request for comments, information, concerns, or questions regarding the Project.
November 30, 2018		FAAR in response to Project Description submission
ECCC		
August 24, 2018	Email	Project introduction. Meeting request. Included map of lease area of interest.
September 18, 2018	Meeting	Project introduction with representatives from Chevron and Stantec. Request for comments, information, concerns, or questions regarding the Project.
November 26, 2018		FAAR in response to Project Description submission
NRCan		
August 31, 2018	Email	Project introduction. Request for comments, concerns, or questions regarding the Project. Included map of lease area of interest.
November 13, 2018		FAAR in response to Project Description submission
Transport Canada		
September 25, 2018	Email	Project introduction. Request for comments, concerns, or questions regarding the Project. Included map of lease area of interest.
November 26, 2018		FAAR in response to Project Description submission

Table 3.1 Communications with Government Departments and Agencies

Date	Method	Purpose
DND		
September 25, 2018	Email	Project introduction. Request for comments, concerns, or questions regarding the Project. Included map of lease area of interest.
November 26, 2018		FAAR in response to Project Description submission
Health Canada		
August 31, 2018	Email	Project introduction. Request for comments, concerns, or questions regarding the Project. Included map of lease area of interest.
Parks Canada		
November 6, 2018		FAAR in response to Project Description submission
NL Department of Natural Resources		
September 26, 2018	Email	Project introduction. Request for comments, concerns, or questions regarding the Project. Included map of lease area of interest.

Chevron is planning to meet with regulatory agencies in January 2020 to present an overview of the EIS and the results of spill modelling. Consultation with government departments and agencies will continue throughout the EIS review process and during preparation of follow-up and monitoring programs.

3.2 Indigenous Groups

Chevron is committed to collaborating with Indigenous peoples and their communities in Canada to build long-term trusting and mutually beneficial relationships based on the values of inclusion, transparency, respect and accountability.

Chevron is committed to early and frequent Indigenous engagement based on the principles outlined above. Chevron will provide details about the Project and discuss potential issues and concerns, as well as proposed mitigations, where applicable. Chevron will ensure Indigenous groups are regularly informed about the status of Project planning and implementation.

In Atlantic Canada there are several Indigenous communities that hold commercial communal fishing licences for NAFO Divisions that overlap the Project Area. None of the Indigenous groups engaged to date identified active fishing within the Project Area at this time, and any current fishing by commercial fishers is occurring at some distance from proposed drill sites.

There are no documented food, social and ceremonial (FSC) fisheries within or near the Project Area. Interactions between Project activities (routine or unplanned) and species harvested for commercial or FSC purposes outside the Project Area may potentially occur during species migration to traditional fishing grounds. There is also the potential for the presence of species at risk and/or species of cultural importance in the Project Area (e.g., Atlantic salmon). Indigenous organizations and communities in Newfoundland and Labrador (NL), Nova Scotia (NS), Prince Edward Island (PE), New Brunswick (NB), and Quebec (QC) may have a potential interest in the Project.

The EIS Guidelines (Section 5.1) specify that Chevron engage the following Indigenous groups:

Newfoundland and Labrador

- Labrador Inuit (Nunatsiavut Government)
- Labrador Innu (Innu Nation)
- NunatuKavut Community Council (NCC)
- Qalipu Mi'kmaq First Nation Band (QMFNB)
- Miawpukek Mi'kamawey Mawi'omi (Miawpukek First Nation) (MFN)

Nova Scotia

- Assembly of Nova Scotia Mi'kmaq Chiefs (ANSMC) through the Kwilmu'kw Maw-klusuaqn Negotiation Office (KMKNO):
  - Acadia First Nation
  - Annapolis Valley First Nation
  - Bear River First Nation
  - Eskasoni First Nation
  - Glooscap First Nation
  - Membertou First Nation
  - Paqtnkek Mi'kmaw Nation
  - Pictou Landing First Nation
  - Potlotek First Nation
  - Wagmatcook First Nation
  - We'koqmaq First Nation
- Sipekne'katik First Nation
- Millbrook First Nation

Prince Edward Island

- L'Nuey Epekwitk Mi'kmaq Rights Initiative (formerly the Mi'kmaq Confederacy of PEI [MCPEI]):
  - Abegweit First Nation
  - Lennox Island First Nation

New Brunswick

- Mi'gmawe'l Tplu'taqnn Inc. (MTI):
  - Fort Folly First Nation
  - Eel Ground First Nation
  - Pabineau First Nation
  - Esgenoôpetitj First Nation
  - Buctouche First Nation
  - Indian Island First Nation
  - Eel River Bar First Nation
  - Metepnagiag Mi'kmaq First Nation
- Elsipogtog First Nation

- Wolastoqey Nation in New Brunswick (WNNB):
  - Kingsclear First Nation
  - Madawaska Maliseet First Nation
  - Oromocto First Nation
  - St. Mary's First Nation
  - Tobique First Nation
  - Woodstock First Nation
- Peskotomuhkati Nation at Skutik (Passamaquoddy)

Quebec

- Mi'gmawei Mawiomi Secretariat (MMS):
  - Micmas of Gesgapegiag
  - La Nation Micmac de Gespeg
  - Listuguj Mi'gmaq Government
- Les Innus de Ekuanitshit
- Nutashkuan Innu First Nation

Chevron may use a variety of engagement methods to inform and involve identified Indigenous groups, such as:

- Written and visual communications (letters, emails)
- Phone calls
- Information updates and bulletins
- Face-to-face meetings and workshops

Engagement with Indigenous groups was initiated by Chevron on October 4, 2018. A letter of introduction with a general Project description and map was sent to all Chiefs and Councils and consultation representatives (subsequent engagement has occurred through the consultation representatives, as requested). In April 2019, Chevron followed up on their initial request to Indigenous groups with a Project update.

Chevron is aware that there are a number of similar offshore exploration drilling EAs at various stages of environmental assessment under the CEAA 2012 legislation. Chevron understands the importance of recognizing and learning from ongoing engagement with Indigenous groups and has joined with other operators to collaborate on current and future engagement to reduce burdens that may be caused by multiple engagement requests from multiple operators to Indigenous groups. Where possible, Chevron will coordinate opportunities for engagement with the exploratory drilling programs in the Flemish Pass and Orphan and Jeanne d'Arc Basins, including Husky Oil Operations Ltd, CNOOC International, Suncor Energy, BP Canada Energy Group ULC, Equinor Canada, BHP (Petroleum) Canada, and ExxonMobil Canada.

As part of a joint workshop effort (Chevron, BHP, and Suncor), a series of workshops were held with Indigenous groups in three regional centres (St. John's, Moncton, and Quebec City) in September 2019 to discuss interests and concerns.

As the Project planning moves forward, Chevron will incorporate actions and mitigations to address the concerns and interests of Indigenous groups, as applicable. Concerns and priorities raised during engagement and how these have influenced Project planning are addressed and documented in this EIS and shared with Indigenous groups.

Each of the identified Indigenous groups has and will continue to be notified by the Impact Assessment Agency of Canada about the steps in the EIS development process and of opportunities to review and provide comments on key documents. Chevron remains available to meet with interested Indigenous groups to discuss details of their proposed exploration drilling program, and any concerns and interests they raise.

A description of engagement activities with each Indigenous group is presented in the following sections, along with a summary of key issues and concerns raised by Indigenous groups to date.

3.2.1 Newfoundland and Labrador Indigenous Groups

A summary of engagement with NL Indigenous groups is provided in Table 3.2.

Table 3.2 Engagement with Indigenous Groups in Newfoundland and Labrador

Date	Engagement Activity	Details
Nunatsiavut Government		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
May 7, 2019	Incoming Email	Response to April 8th letter outlining potential impacts on commercial communal and traditional fishing; importance of contributing monitoring data to Regional Environmental Assessment / SEA processes; request to be involved in Indigenous fisheries communications plan.
July 23, 2019 and August 21, 2019[1]	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
September 10, 2019	Email	Provided details of workshops and final agenda.
September 10, 2019	Incoming email	NG unable to attend workshop.
November 11, 2019	Outgoing email	Follow-up to St. John's workshop – provided meeting summary and presentations.

[1] Note – all engagement activities related to workshops with Atlantic region Indigenous groups were conducted jointly between Chevron, BHP, and Suncor. BHP (July 23, 2019) and Suncor (August 21, 2019) sent workshop information and background materials to all 41 Indigenous groups on behalf of all three companies.

Table 3.2 Engagement with Indigenous Groups in Newfoundland and Labrador

Date	Engagement Activity	Details
Innu Nation		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 26, 2019	Incoming email	Confirmed attendance at St. John's workshop.
September 10, 2019	Email	Provided details of workshops and final agenda.
September 23, 2019	Workshop: St. John's	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.
November 11, 2019	Outgoing email	Follow-up to St. John's workshop – provided meeting summary and presentations.
NCC		
October 4, 2018	Email	Project introduction, including map of EL 1138
November 13, 2018	Letter	Response to Project Description
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 30, 2019	Incoming email	Confirmed attendance at St. John's workshop.
September 10, 2019	Email	Provided details of workshops and final agenda.
September 23, 2019	Workshop: St. John's	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.
November 11, 2019	Outgoing email	Follow-up to St. John's workshop – provided meeting summary and presentations.

Table 3.2 Engagement with Indigenous Groups in Newfoundland and Labrador

Date	Engagement Activity	Details
QMFNB		
October 4, 2018	Email	Project introduction, including map of EL 1138
November 8, 2018	Letter	Response to Project Description
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 26, 2019	Incoming email	Confirmed attendance at St. John's workshop.
September 10, 2019	Email	Provided details of workshops and final agenda.
September 23 and August 21, 2019	Workshop: St. John's	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.
November 11, 2019	Outgoing email	Follow-up to St. John's workshop – provided meeting summary and presentations.
MFN		
October 18, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 12, 2019	Incoming email	Confirmed interest in attending St. John's workshop.
August 20, 2019	Incoming email	Confirmed MFN unable to attend workshops.
September 10, 2019	Email	Provided details of workshops and final agenda.
August 20 - November 30, 2019	Email exchange	Series of emails seeking a date to meet with MFN.
November 11, 2019	Outgoing email	Follow-up to St. John's workshop – provided meeting summary and presentations.

3.2.2 Nova Scotia Indigenous Groups

A summary of engagement with NS Indigenous groups is provided in Table 3.3.

Table 3.3 Engagement with Indigenous Groups in Nova Scotia

Date	Engagement Activity	Details
KMKNO: representing the Assembly of Nova Scotia Mi'kmaq Chiefs (11 of the 13 Nova Scotia Mi'kmaq communities) in consultation and engagement. Those communities are Acadia, Annapolis Valley, Bear River, Eskasoni, Glooscap, Membertou, Paqtn'kek, Potlotek, Pictou Landing, We'koqma'q and Wagmatcook First Nations.		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 8, 2019	Incoming email	Confirmed attendance at Moncton workshop.
September 10, 2019	Email	Provided details of workshops and final agenda.
September 25, 2019	Workshop: Moncton	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.
Millbrook First Nation: Millbrook First Nation Chief and Council represent their community in consultation and engagement.		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
September 10, 2019	Email	Provided details of workshops and final agenda.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.
Sipekne'katik First Nation: Sipekne'katik First Nation Chief and Council represent their community in consultation and engagement.		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.

Table 3.3 Engagement with Indigenous Groups in Nova Scotia

Date	Engagement Activity	Details
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.

3.2.3 New Brunswick Indigenous Groups

A summary of engagement with NB Indigenous groups is provided in Table 3.4.

Table 3.4 Engagement with Indigenous Groups in New Brunswick

Date	Engagement Activity	Details
MTI - represent the following eight Mi'kmaq communities in New Brunswick in consultation/engagement: Amlamgog (Fort Folly), Natoaganeg (Eel Ground), Oinpegitjoig (Pabineau), Esgenoôpetitj (Burnt Church), Tjipõgtõtjg (Bouctouche), L'nui Menikuk (Indian Island), Ugpi'ganjig (Eel River Bar) and Metepenagiag (Red Bank).		
October 4, 2018	Email	Project introduction, including map of EL 1138
November 15, 2018	Letter	Response to Project Description
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 8, 2019	Incoming email	Confirmed attendance at Moncton workshop.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
September 25, 2019	Workshop: Moncton	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.

Table 3.4 Engagement with Indigenous Groups in New Brunswick

Date	Engagement Activity	Details
WNNB supports the following Wolastoqey nations in New Brunswick in consultation and engagement: Matawaskiye (Madawaska), Pilick (Kingsclear), Welamukotuk (Oromocto), Sitansisk (St. Mary's), Neqotkuk (Tobique) and Wotstak (Woodstock).		
October 4, 2018	Email	Project introduction, including map of EL 1138
November 26, 2018	Letter	Response to Project Description (Wotstak provided separate letter dated same)
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 7, 2019	Incoming email	Confirmed attendance at Moncton workshop.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
September 25, 2019	Workshop: Moncton	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.
Elsipogtog First Nation is represented by Kopit Lodge in consultation and engagement.		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.
Peskotomuhkati Nation at Skutik		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.

Table 3.4 Engagement with Indigenous Groups in New Brunswick

Date	Engagement Activity	Details
August 19, 2019	Incoming email	Confirmed attendance at Moncton workshop.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
September 25, 2019	Workshop: Moncton	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.

3.2.4 Prince Edward Island Indigenous Groups

A summary of engagement with the PE Indigenous groups is provided in Table 3.5.

Table 3.5 Engagement with indigenous Groups in Prince Edward Island

Date	Engagement Activity	Details
L'Nuey Epekwitk Mi'kmaq Rights Initiative (formerly MCPEI) – coordinates consultation and engagement on behalf of the two Mi'kmaq First Nations in PEI - Abegweit and Lennox Island.		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
September 13, 2019	Incoming email	MCPEI unable to attend workshop.
September 23, 2019	Incoming email	Request for engagement support funding.
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.

3.2.5 Québec Indigenous Groups

A summary of engagement with the QC indigenous groups is provided in Table 3.6.

Table 3.6 Engagement with Indigenous Groups in Quebec

Date	Engagement Activity	Details
MMS – Ango'temq Nm'Tginen Directorate coordinates consultation on behalf of the three Mi'kmaq communities in Quebec - Listiguj, Gespeg and Gesgapegiag.		
October 4, 2018	Email	Project introduction, including map of EL 1138
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 15, 2019	Incoming email	Confirmed attendance at Quebec City workshop (attended Moncton workshop).
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
September 25, 2019	Workshop: Moncton	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups. (Note – MMS representatives attended Moncton workshop).
November 11, 2019	Outgoing email	Follow-up to Moncton workshop – provided meeting summary and presentations.
Nutashkuan Innu First Nation		
October 4, 2018	Email	Project introduction, including map of EL 1138
November 13, 2018	Letter	Response to Project Description
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
April 15, 2019	Incoming Email	Responded to April 8th letter requesting information on impacts. Emphasized the lack of consideration of underwater ecosystems, as well as the cartographic scales used in EIS. Attached Nutashkuan's feedback//comments on ExxonMobil, Equinor, Nexen and Husky's EIS.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
August 8, 2019	Incoming email	Confirmed attendance at Quebec City workshop.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
September 27, 2019	Workshop: Quebec City	Information exchange and dialogue regarding the following topics: introduction to company, indigenous knowledge and social value, approach to the EIS, emergency preparedness and response, well control strategies, environmental monitoring, cumulative effects and ongoing communication with Indigenous groups.

Table 3.6 Engagement with Indigenous Groups in Quebec

Date	Engagement Activity	Details
November 11, 2019	Outgoing email	Follow-up to Quebec City workshop – provided meeting summary and presentations.
Les Innus de Ekuanitshit		
October 4, 2018	Email	Project introduction, including map of EL 1138
November 26, 2018	Letter	Response to Project Description
April 8, 2019	Email	Provided update on progress of EA; requested information on potential impacts on rights, and any Indigenous knowledge the group would like to share.
July 23, 2019 and August 21, 2019	Email	Invitation to attend a series of proposed workshops in St. John's, Moncton and Quebec City in September and provided proposed agenda for feedback; outlined known issues of concern to Indigenous groups brought forward through previous exploration drilling EAs.
September 10, 2019	Outgoing email	Provided details of workshops and final agenda.
November 11, 2019	Outgoing email	Follow-up to Quebec City workshop – provided meeting summary and presentations.

3.2.6 Concerns Raised during Indigenous Consultation

Leading up to the development of the EIS, Chevron provided opportunities for Indigenous groups to meet and discuss the environmental assessment and proposed exploration drilling program through a series of jointly-organized (Chevron, BHP, Suncor), full-day workshops in St. John's, Moncton and Quebec City in September 2019; and, to provide written feedback. Chevron also gathered information regarding concerns and interests previously expressed by Indigenous groups during environmental assessments on similar proposed exploration drilling programs by five other oil and gas operators.

The main concerns discussed with Indigenous groups at September 2019 workshops in St. John's, Moncton, and Quebec City are outlined in Table 3.7. These reflect the concerns and interests expressed to date by Indigenous groups that have participated in direct engagement, and reviews of previous EIS and requests for information during various environmental assessment processes on similar exploration projects.

Chevron will continue to engage with interested Indigenous groups throughout the environmental assessment and exploration drilling program.

Table 3.7 Concerns Expressed by indigenous Groups during September 2019 Workshops

Atlantic Salmon (and other culturally important species): • Potential impacts of exploration drilling (both operations and potential accidents) on Atlantic Salmon populations that may migrate and over-winter in the Project Area. These populations return to their natal rivers and streams where they could be harvested for traditional purposes (FSC). Some of these populations are listed under the Species at Risk Act (SARA), and in many cases, Indigenous communities do not harvest for FSC purposes, due to ecological concerns. • There is a lack of data, and not enough is known about the presence and behavior of Atlantic salmon in offshore areas where exploration drilling may occur. • Concerns regarding loss or harm to species of importance has two elements: one relates to the ability to access the species for traditional and current practices, which would include human health, cultural and spiritual practice – including teaching traditions to younger generations, and the practice of kinship; and the other element of concern relates to the general loss or absence of species of importance that are a part of the natural ecosystem. • Other culturally important species of concern to Indigenous groups include American eel, swordfish, tuna, ground fish, lobster, crab, sea turtles, sharks and marine mammals. *Action / Mitigation*: • Chevron recognizes the importance of salmon to Indigenous groups in the Atlantic region, as well as the uncertainty associated with the known presence and activities of Atlantic salmon in the Project Area. Chevron, along with other oil and gas companies provides funding to the Environmental Studies Research Fund (ESRF) for studies related to environmental and social issues to support sound decision-making for oil and gas projects. The ESRF is funding research in this area that involves Indigenous peoples. • Chevron has robust Oil Spill Response and Emergency Response Plans that put safeguards in place to prevent spills and other emergencies. These plans will be shared with Indigenous groups. • Chevron will develop an Indigenous Fisheries Communications Plan to establish protocols for ongoing communication and information-sharing with interested Indigenous groups, and
Potential Impacts to Indigenous Fisheries: • There are concerns about potential impacts from operations, or in the case of an emergency that may result in adverse environmental effects on traditional, commercial and commercial communal fisheries. For example – many concerns and questions were raised regarding the unknown behavioral impacts on Atlantic salmon and other species of operations -- such as underwater noise, light, vibration and changes to water quality. • Although there are currently no active fisheries being conducted by Indigenous groups in the immediate vicinity of the Project, concerns were expressed for the potential future ability to fish in areas currently designated as safety zones. *Action / Mitigation*: • Chevron will continue to engage with Indigenous groups throughout the exploration drilling program and provide information related to operational activity, as well as the results of environmental monitoring. • Chevron will develop a communication protocol with Indigenous groups to provide regular Project updates during operations, and to inform Indigenous groups in the event of an emergency. • While there are no current active fisheries in the immediate Project Area, Chevron will continue to work with Indigenous fishers to minimize any potential impact on their ability to exercise their rights to fish.
Cumulative Effects: • There is a perceived lack of a comprehensive approach to analyzing, understanding and addressing the potential for cumulative impacts of so many proposed projects in the region on the environment, and on Indigenous rights. It is anticipated that the current Regional Assessment underway in Atlantic Canada will attempt to address cumulative effects on a broader level. *Action/Mitigation*: • Chevron is participating in the Regional Assessment where a more regional and multi-faceted approach is being taken to examining cumulative effects of multiple projects and interactions with other ocean users. Chevron will apply any applicable new learnings from the regional assessment to their exploration drilling Project.

Table 3.7 Concerns Expressed by indigenous Groups during September 2019 Workshops

Indigenous Knowledge: • The EIS and Project implementation should consider and integrate Indigenous traditional and ecological knowledge regarding aquatic, nearshore and offshore environments. • Indigenous groups recognize the complexity and sensitivity of gathering and applying or integrating Indigenous Knowledge in EIS and further, to operations – particularly in an area as geographically and culturally diverse as the Atlantic region. Many issues must be considered, for example, who undertakes a study, what is the area of interest, who has access to the results of the study, confidentiality and protection of information, where that information is managed and maintained, and by whom. *Action / Mitigation:* • Chevron has endeavoured to gather Indigenous knowledge, where available or provided, and recognizes the importance of considering Indigenous knowledge in its operations. • Chevron has engaged with Indigenous groups to discuss Indigenous knowledge as applicable to their proposed exploration drilling program. The proponent has also reviewed the more than fifty submissions provided by Indigenous groups on prior and similar proposed exploration drilling programs in the same geographic region.
Environmental Impacts: • In addition to concerns regarding potential impacts to fishing and fishing rights, Indigenous Groups have general concerns regarding the potential impacts of exploration drilling operations on the marine environment, including changes to water quality, fish and fish habitat, marine plants, migratory birds and marine mammals and increased contributions to atmospheric emissions and climate change. *Actions / Mitigations*: • Potential impacts to the environment are addressed through the EIS's analysis of VCs (see Chapters 8 to 12).
Lack of Original and Recent Baseline Studies: • Indigenous groups have observed that the EIS's submitted to date have relied on existing data and studies, and some of them are considered to be outdated. Indigenous groups would like to see original/new baseline studies done for all of the exploration projects. *Actions / Mitigation*: • Chevron will make full use of existing studies, published literature, information available from federal and provincial agencies, and the regional assessment in the preparation of its EIS.
Compensation: • Indigenous groups are aware of the C-NLOPB guidelines in place for loss or damage to fishing gear and vessels due to unforeseen interaction with the Project, or in the case of an emergency. However, specific compensation concerns of Indigenous groups relate to the following: - Potential impacts on commercial communal fisheries. The impacts on commercial communal fisheries would be different than a "regular" commercial licence because the licences are "owned" by the Band (community) itself, they are not transferrable, cannot be sold, and the profits are often used to sustain employment, programs and services, and community infrastructure - Because of the importance of the connection between Indigenous populations and the natural environment, potential impacts on FSC fisheries may include impacts on cultural and spiritual practices, community cohesion, intergenerational teaching and a sense of well-being. *Actions / Mitigations*: • Chevron would consider any damages to Indigenous fishing activity resulting from Chevron's proposed offshore activities on a case-by-case basis and in consultation with Indigenous groups. Chevron will also adopt the C-NLOPB Compensation Guidelines Respecting Damages Relating to Offshore Petroleum Activity.

Table 3.7 Concerns Expressed by indigenous Groups during September 2019 Workshops

Oil Spill Response: • A number of concerns have been expressed by Indigenous groups regarding oil spill response, including: - Concerns about oil reaching shoreline, impacting fisheries and traditional territories. - Companies need to demonstrate the accuracy of probability calculation and trajectories of oil spills. - Capping stacks – a capping stack should be located and maintained in Atlantic Canada. - Lack of communication between oil and gas companies and Indigenous groups during recent oil spills. - How can Indigenous groups/communities be involved in emergency response? - Concerns expressed regarding contamination or fish taint from an oil spill and how this impacts not only consumption, but also perception and cultural norms. *Actions / Mitigations*: • Chevron is building upon the previous efforts of other oil and gas companies to create capacity and awareness of industry and company standards to prevent and respond to an emergency. Chevron participated in three workshops with Indigenous groups where emergency preparedness and oil spill response has been discussed in detail, including – management practices, oil spill modelling, capping stacks and other technology, and the oil spill response Incident Command System (ICS). • Chevron will develop a robust oil spill response plan in advance of any project activity. • To ensure Indigenous groups are informed of operational activity during exploratory drilling, Chevron will develop an Indigenous Fisheries Communications Plan in consultation with Indigenous groups that includes a protocol for communicating with Indigenous groups during operations, and in the event of an emergency.
Environmental Monitoring: • Indigenous groups want to see comprehensive monitoring and follow-up programs, including research and data collection related to impacts on Indigenous groups – e.g., fish and fish habitat, birds and marine mammals. • Indigenous groups would like to be involved with environmental monitoring; and, to be kept informed of results of environmental monitoring programs throughout the exploration drilling program, and in the event of an incident or spill that may result in adverse environmental effects. *Action / Mitigation*: • During and post-operations, Chevron will share the results of environmental monitoring with Indigenous groups through developed communications plan. At the conclusion of exploration drilling, and once results are available, Chevron will share final environmental monitoring results with Indigenous groups.
Communication and Ongoing Involvement of Indigenous Groups: • Indigenous groups want to be actively informed of activities and outcomes during operations, and in the event of an incident or spill that may result in adverse environmental effects. *Action / Mitigation*: • Chevron will develop an Indigenous Fisheries Communication Plan in consultation with Indigenous groups to outline a process and content for regular operational updates during the drilling campaign, as well as outreach to Indigenous groups in the unlikely event of an emergency.

3.2.7 Planned Future Engagement with Indigenous Groups

Chevron will continue to engage with the identified Indigenous groups during the EA process. Engagement will include opportunities to provide information regarding their community and key documents. Chevron co-hosted a workshop with Indigenous communities in September 2019, focusing on spill modelling, spill prevention and response, methods, and environmental monitoring and follow-up monitoring plans. Chevron will also continue to meet with interested Indigenous groups throughout the Project planning process. Chevron will implement an Indigenous Communities Fisheries Communication Plan during the drilling program. This Plan will provide a framework communicating regular operational updates to Indigenous groups, as well as the process for emergency notifications, if needed.

3.3 Fisheries Stakeholders

A key form of mitigation of potential effects of the Project on fisheries is early and ongoing consultation with the fishing industry. The location and timing of fishing activities are important to consider when identifying potential fisheries stakeholders and scheduling meetings. The following is a list of initial fisheries stakeholders engaged, or to be engaged, for the Project:

- One Ocean
- Fish, Food and Allied Workers-Unifor (FFAW-Unifor)
- Association of Seafood Producers (ASP)
- Ocean Choice International (OCI)
- Atlantic Groundfish Council (AGC)
- Canadian Association of Prawn Producers

One Ocean, which acts as a liaison between the oil and gas and fishing industries, has developed a protocol that provides guidance on consultation approach.

Table 3.8 provides a summary of engagement with fisheries stakeholders.

Table 3.8 Summary of Engagement with Fisheries Stakeholders

Date	Type of Engagement	Purpose
One Ocean		
August 24 2018	Email	Project introduction. Meeting request. Included map of lease area of interest.
September 17, 2018	Meeting	Project introduction with representatives from Chevron and Stantec. Request for comments, information, concerns, or questions regarding the Project.
FFAW-Unifor		
August 24, 2018	Email	Project introduction. Meeting request. Included map of lease area of interest.
September 19, 2018	Meeting	Project introduction with representatives from Chevron and Stantec. Request for comments, information, concerns, or questions regarding the Project.
December 2, 2019	Meeting	Project update on information used to conduct EIS; discussion of outstanding concerns
OCI		
August 24, 2018	Email	Project introduction. Meeting request. Included map of lease area of interest.
September 17, 2018	Meeting	Project introduction with representatives from Chevron and Stantec. Request for comments, information, concerns, or questions regarding the Project.

Table 3.8 Summary of Engagement with Fisheries Stakeholders

Date	Type of Engagement	Purpose
ASP		
August 23, 2018	Email	Project introduction. Meeting request.
December 13, 2019		Project update on information used to conduct EIS; discussion of outstanding concerns
Canadian Association of Prawn Producers		
August 31, 2018	Email	Project introduction. Request for comments, concerns, or questions regarding the Project. Included map of lease area of interest.
AGC		
August 31, 2018	Email	Project introduction. Request for comments, concerns, or questions regarding the Project. Included map of lease area of interest.

The key concern noted was regarding increased vessel traffic between the Project Area and shorebase could interfere with inshore / nearshore fisheries. Standard communication on vessel movement will be required to reduce adverse effects to commercial fisheries and other ocean users. Chevron will continue to engage commercial fishers to share Project details, as applicable and determine the need for a fisheries liaison officer during mobilization and demobilization of the MODU. This engagement will be coordinated through One Ocean, Fish, Food and Allied Workers-Unifor, Ocean Choice International, Association of Seafood Producers, and Groundfish Enterprise Allocation Council. This will be accomplished through the development and implementation of a Fisheries Communication Plan.

3.4 Other Public Stakeholder Groups

Other public stakeholders include industry associations and non-governmental organizations. Chevron will monitor activities and communications generated by these groups and participate in local industry events as appropriate including supplier information sessions, seminars, and conferences.

The Agency received responses to the Chevron Project Description submission from the Newfoundland and Labrador Oil and Gas Industries Association (November 26, 2018, letter), the Balaena Institute for Cetacean Conservation Studies (November 26, 2018, letter), and a private citizen (November 6, 2018, email).

4.0 ENVIRONMENTAL ASSESSMENT METHODS

This chapter outlines the methods used to assess the effects of routine Project activities and accidental events, as well as the potential cumulative effects of the Project. The EA methods used to prepare this EIS have been developed by Stantec in consideration of the requirements of CEAA 2012 and guidance issued by the Agency. They have been used in previous assessments for offshore exploration projects within the Newfoundland and Nova Scotian offshore areas that have been reviewed and approved by the Agency or are currently under review. The approach taken in this assessment has taken into consideration feedback provided by regulators and stakeholders through the Information Requirement stage of these previous offshore exploration environmental assessments.

In general, the methods outlined follow the guiding principles as set out in the Project-specific Guidelines, *Guidelines for the Preparation of an Environmental Impact Statement pursuant to the Canadian Environmental Assessment Act, 2012* West Flemish Pass Exploration Drilling Project (EIS Guidelines), issued by the Agency on December 20, 2018 (see Appendix A). These guiding principles stress the importance of environmental assessment as a planning and decision-making tool, with emphasis on the early identification of mitigation and follow-up programs. In addition to what is known about the potential environmental effects of offshore exploration activities, this EIS identifies Project-specific sensitivities and mitigation strategies, including environmental design features.

Guiding principles also include meaningful public participation and engagement with Indigenous groups. As described in Chapter 3, Chevron recognizes the importance of early and ongoing Indigenous and stakeholder engagement that continues over the life of the Project. Chevron believes that it is important to operate in Newfoundland and Labrador by building relationships with Indigenous groups and key stakeholders. Chevron is committed to collaborating with Indigenous peoples of Canada and communities to build long term trusting and mutually beneficial relationships based on the principles of inclusion, transparency, respect and accountability.

4.1 Scope of the Environmental Assessment

This EIS has been prepared in accordance with the requirements of CEAA 2012, the EIS Guidelines and EA guidance documents issued by the Agency. The concordance table (Appendix B) outlines the specific requirements of the Project-specific guidelines and where these requirements have been addressed within the EIS. More detail on the scope of the Project, scope of the factors to be considered, the selection of valued components (VC) to be considered, and the spatial and temporal boundaries are provided below.

4.1.1 Scope of the Project

The scope of the Project was first defined in the Project Description submitted by Chevron to the Agency on October 23, 2018 and is further discussed in Chapter 2 of this EIS. Chevron proposes to drill up to eight exploration wells on EL 1138 during the term of the EL. Activities associated with the Project and are: drilling within EL 1138; possible appraisal (delineation) drilling in the event of a hydrocarbon discovery within the

EL; vertical seismic profiling (VSP); well testing; eventual well decommissioning and abandonment (or suspension) procedures; and associated supply and service activities.

As indicated in the EIS Guidelines, the scope of the Project to be assessed therefore includes:

- Mobilization, operation and demobilization of a mobile offshore drilling unit(s) (MODU(s)) designed for year-round operations for the drilling, testing and abandonment of up to eight wells, including consideration of proposed safety exclusion zones. Drilling may occur in various water depths under consideration, using MODU(s), and with multiple drilling units operating simultaneously, if applicable
- Vertical seismic profiling or any other in-water works (e.g., well site surveys) to support the specific exploration wells under consideration, but excluding surveys potentially required to support the conduct of the EA (e.g., environmental baseline surveys) and surveys related to the broader delineation of resources
- Well evaluation and testing
- Loading, refuelling and operation of marine supply vessels (i.e., for re-supply and transfer of materials, fuel, and equipment; on-site safety during drilling operations; and transport between the supply base and the MODU(s) and helicopter support (i.e., for crew transport and delivery of light supplies and equipment) including transportation to the MODU(s).

Based on this, the following routine Project activities with the potential to affect the environment have been specifically identified and considered in this assessment:

- Presence and operation of a drilling vessel (including lights and flare, underwater sound, and safety zone)
- VSP surveys (underwater sound)
- Discharges and emissions (e.g., drill muds and cuttings, liquid discharges, atmospheric emissions)
- Well abandonment
- Supply vessel (underwater sound) and helicopter operations

Non-routine events (i.e., accidental events or malfunctions) have also been identified and considered within the scope of the Project, including blowouts (uncontrolled release of hydrocarbons during drilling), and platform and vessel batch spills and releases (e.g., hydraulic fluid, drilling mud, diesel). Accidental releases, or “spills”, have the potential to occur in the offshore (e.g., during drilling) or nearshore (e.g., during supply vessel transit) environment.

4.1.2 Scope of the Factors to be Considered

Pursuant to section 19 (1) of CEAA 2012 and as reiterated in the EIS Guidelines, the EA of a designated project must consider:

- Environmental effects of the project, including the environmental effects of malfunctions or accidents that may occur in connection with the project and any 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
- The significance of the effects referred to above

- Comments from the public
- Mitigation measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the project
- The requirements of the follow-up program in respect of the project
- The purpose of the project
- Alternative means of carrying out the project that are technically and economically feasible and the environmental effects of any such alternative means
- Any change to the project that may be caused by the environment
- The results of any relevant regional study pursuant to CEAA 2012

As required by the EIS Guidelines, the assessment focuses on the VCs identified in Section 4.1.3 in relation to section 5 of CEAA, 2012. The scope of the factors to be considered focuses the EA on relevant issues and concerns. Under section 5(1) of CEAA 2012, the environmental effects that are to be addressed 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 as defined in section 2 of the *Fisheries Act* and fish habitat as defined in subsection 34(1) of that 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*
   iv. any other component of the environment that is set out in Schedule 2 [of CEAA 2012]
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
   iii. outside Canada
c) With respect to Indigenous 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
   iv. any structure, site or thing that is of historical, archaeological, paleontological, or architectural significance

Certain additional environmental effects must be considered under section 5(2) of CEAA 2012 when carrying out a designated project requires a federal authority to exercise a power or perform a duty or function conferred on it under any Act of Parliament other than CEAA 2012. This applies to the Project.

Chevron will require authorizations from the C-NLOPB under the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* for the Project to proceed. No other authorizations are known to be required. Therefore, the following environmental effects have also been considered under section 5(2):

a) A change, other than those referred to in paragraphs 5(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
b) An effect, other than those referred to in paragraph 5(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.

These categories of direct and indirect environmental effects have been considered in defining the scope of the EA, including the scope of factors to be considered.

4.1.3 Identification and Selection of Valued Components

The approach to identifying and selecting Valued Components for this Project was consistent with the requirements of CEAA 2012. The selection of VCs considered the following:

- Technical Knowledge of the Project (i.e., the nature and extent of Project components and activities) (refer to Chapter 2)
- Requirements of CEAA 2012 and regulatory guidance including the Project-specific EIS Guidelines provided by the Agency (2018; now the Impact Assessment Agency of Canada) and included in Appendix A
- Discussions with regulatory agencies, technical experts, key stakeholders, public and Indigenous Groups during the pre-application process (refer to Chapter 3)
- Baseline conditions for the physical (Chapter 5), biological (Chapter 6) and socio-economic (Chapter 7) existing environments
- Ongoing consultation with Indigenous Groups
- Ongoing consultation with key stakeholders
- Lessons learned from previous similar environmental assessments, such as Environmental Assessment of StatoilHydro Canada Ltd. Exploration and Appraisal / Delineation Drilling Program for Offshore Newfoundland, 2008-2016 (LGL Limited 2008), Equinor's (formerly Statoil Canada Ltd.) Flemish Pass Exploration Drilling Program (Statoil 2017), ExxonMobil's Eastern Newfoundland Offshore Exploration Drilling Project (ExxonMobil 2017), (formerly Nexen Energy ULC) Flemish Pass Exploration Drilling Project (Nexen Energy ULC 2018) Husky's Exploration Drilling Project (Husky 2018), and BP's Newfoundland Orphan Basin Exploration Drilling Project (BP 2018), as well as the Eastern NL SEA (AMEC 2014)
- Professional judgement based on the experience of the assessment team

The VCs selected for the EIS include:

- Marine Fish and Fish Habitat (including Species at Risk)
- Marine and Migratory Birds (including Species at Risk)
- Marine Mammals and Sea Turtles (including Species at Risk)
- Special Areas
- Indigenous Communities and Activities
- Commercial Fisheries and Other Ocean Users

The atmospheric environment (i.e., air quality, light and sound and greenhouse gas) is discussed extensively in this EIS primarily in terms of physical pathways. In particular, air quality is discussed both in terms of Project-related emissions (Section 2.8.1) and ambient conditions (Section 5.5). GHGs are discussed in Section 2.8.1. Light is discussed in Section 2.8.6. Underwater sound is discussed in Sections 2.8.5.1 and 2.8.5.2 and Appendix D, with atmospheric sound discussed in Section 2.8.5.3. The effects related to these pathways are evaluated in the context of applicable receptor VCs. For example, the effects of underwater sound on marine fish and marine mammals are discussed in Sections 8.3 and 10.3, respectively. The effects of light on marine fish and marine birds are discussed in Sections 8.3 and 9.3, respectively. For this reason, atmospheric environment is not considered to be a stand-alone VC.

4.1.4 Spatial and Temporal Boundaries

The spatial and temporal boundaries for the assessment were selected based on geographic extent of the measurable potential environmental, social, heritage and human effects of the Project (including Project activities and components). The spatial boundaries include:

- **Project Area** (Figure 4-1): The Project Area is the boundary that encompasses the immediate area within which Project activities and components occur (EL 1138) and incorporates an approximate 10 km buffer. The Project Area is consistent across each VCs. Well locations within the Project Area have not yet been identified within the Project Area. See Table 2.2, Section 2.2, for Project Area coordinates.
- **Local Assessment Area (LAA)**: The LAA is the maximum area within which environmental effects from routine Project activities and components can be predicted or measured with a reasonable degree of accuracy and confidence. It consists of the Project Area and adjacent areas where Project-related environmental effects are reasonably expected to occur (i.e., the transit route to St. John's or Bay Bulls) based on available information including effects thresholds, predictive modelling and professional judgement. The LAA is defined for each VC.
- **Regional Assessment Area (RAA)** (Figure 4-2): The RAA is the area that establishes the context for determination of significance of Project residual environmental effects from Project activities and components. It is also the area within which potential cumulative effects – the residual effects from the Project in combination with those of past, present and reasonably foreseeable projects – are assessed. Although the RAA is intended to be much broader than the LAA, which focuses on the extent of potential effects associated with routine Project activities for each VC, it is possible that effects from larger scale unplanned events (e.g., blowout) could extend beyond the RAA. The RAA is consistent for each VCs, except for the Indigenous People and Community Values VC which has a larger RAA to encompass the various Indigenous communities which have the potential to be affected by Project-related activities.

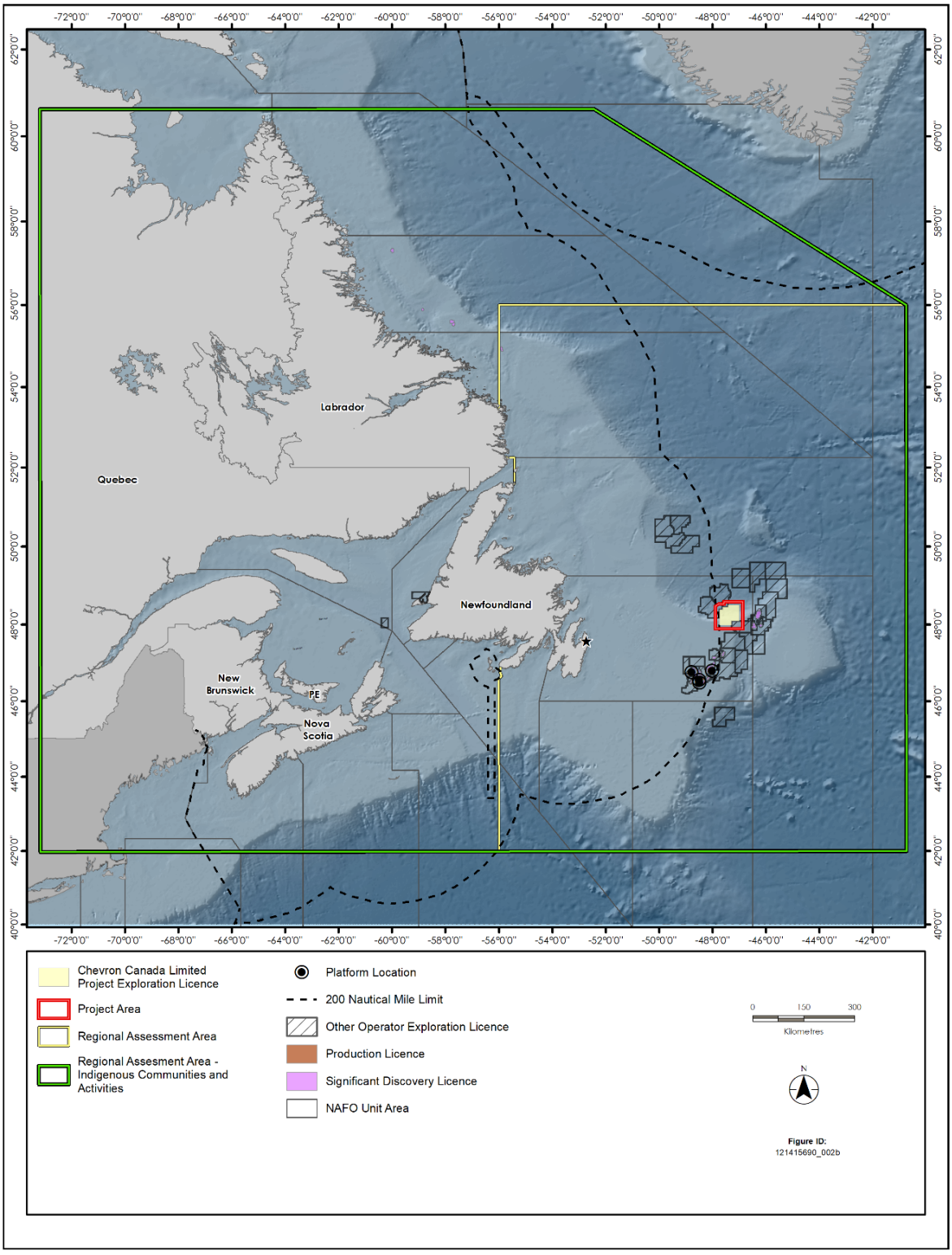

Figure 4-1 Project Area

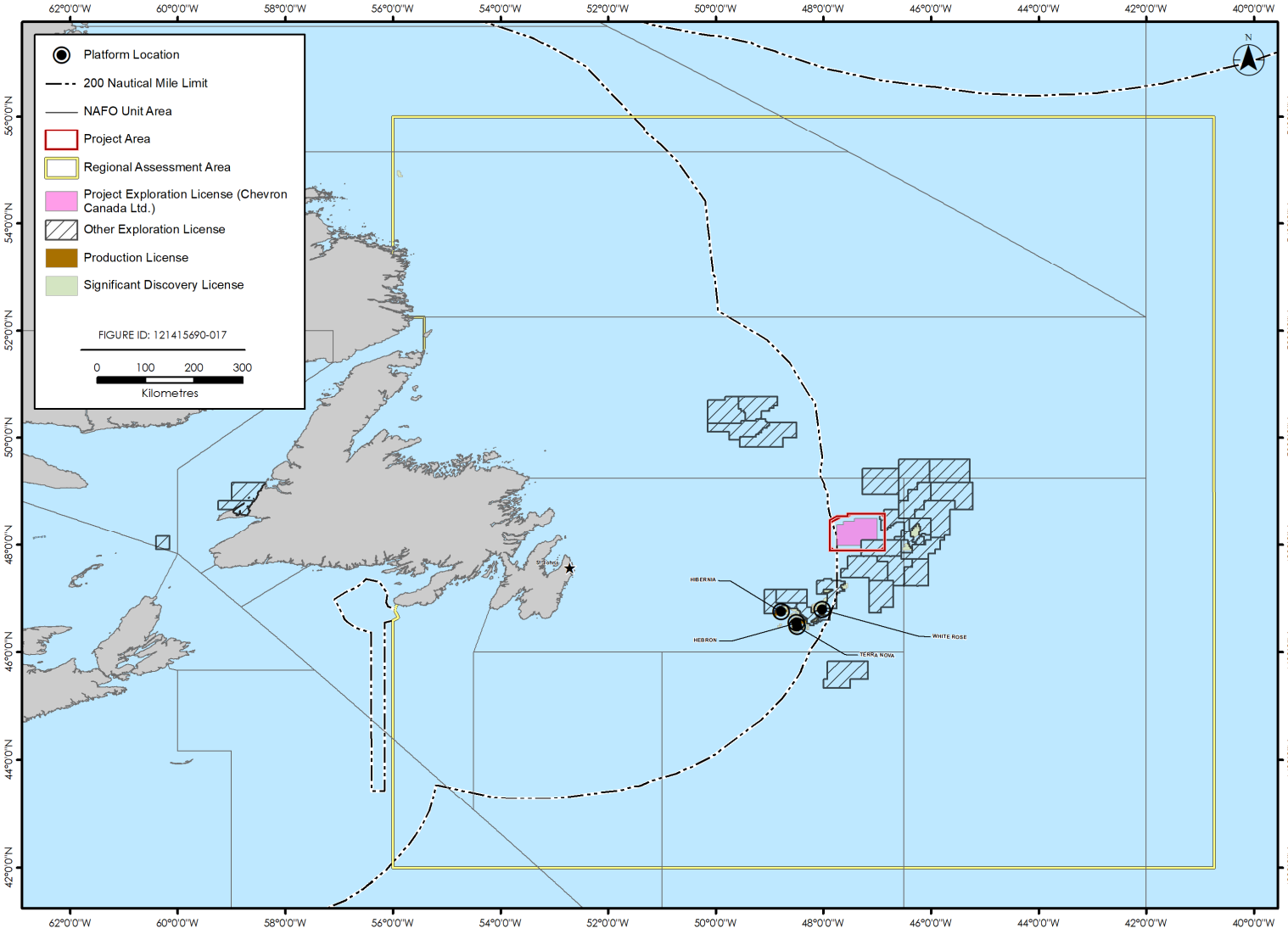

Figure 4-2 Regional Study Area

Temporal boundaries identify when an environmental effect is evaluated in relation to specific project phases or activities. The temporal boundaries for this Project include each Project phase such as well drilling, testing and abandonment.

Based on the current schedule, the temporal boundaries for the assessment are:

- Chevron proposes to commence exploration drilling with an initial well in 2021. Between 2021 to 2025, up to eight exploration wells could be drilled over the term of the EL contingent on the drilling result of the initial well.
- Drilling is expected to occur between May – September, although this EIS assumes year-round drilling.
- Well testing (if required, dependent on drilling results) could also occur at any time during the temporal scope of this EIS.
- Wells abandonment will be conducted following drilling and / or well flow testing.

Key temporal characteristics associated with VCs are also considered temporal boundaries for assessment (e.g., spawning, migration, fishing seasons). These are described and included in the assessment of VCs, as applicable.

4.2 Environmental Effects Assessment (Planned Project Components and Activities)

The following subsections describe the approach and organization for the assessment of routine Project activities on each VC.

4.2.1 Study Boundaries

Spatial and temporal boundaries have been assigned to the environmental effects assessment for each VC. These boundaries are described in Section 4.1.4.

4.2.2 Effects Evaluation Criteria (Characterization of Residual Effects)

Criteria, including direction, magnitude, geographic extent, frequency, duration, reversibility, and ecological or socio-economic context, are used for characterizing the residual adverse effects on each VC. Table 4.1 defines these criteria which are further customized in each VC-specific assessment.

Table 4.1 Criteria Used to Support Environmental Effects Assessment

Criteria	Description	Quantitative Measure or Definition of Qualitative Categories
Direction	The long-term trend of the residual environmental effect relative to baseline	Positive – a residual environmental effect that moves measurable parameters in a direction beneficial to [VC] relative to baseline Adverse – a residual environmental effect that moves measurable parameters in a direction detrimental to [VC] relative to baseline
Magnitude	The amount of change in measurable parameters or the VC relative to existing conditions	Negligible – no measurable change Biophysical VCs: Low – a detectable change but within the range of natural variability Moderate – a detectable change beyond the range of natural variability, but with no associated adverse effect on the viability of the affected population High – measurable change that exceeds the limits of natural variability, with an adverse effect on the viability of the affected population Socio-economic 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 Moderate - 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
Geographic Extent	The geographic area in which a residual environmental effect occurs	Project Area – residual environmental effects are restricted to the Project Area Local Assessment Area – residual environmental effects extend into the LAA Regional Assessment Area – residual environmental effects extend into the RAA
Frequency	Identifies how often the residual effect occurs and how often during the Project	Unlikely event – effect is unlikely to occur Single event – effect occurs once Multiple irregular event – effect occurs at no set schedule Multiple regular event – effect occurs at regular intervals Continuous – effect occurs continuously
Duration	The period of time required until the measurable parameter or the VC returns to its existing condition, or the residual effect can no longer be measured or otherwise perceived	Short term - for duration of the activity, or for duration of accidental event Medium term - beyond duration of activity up to end of Project, or for duration of threshold exceedance of accidental event – weeks or months Long term - beyond Project duration of activity, or beyond the duration of threshold exceedance for accidental events - years Permanent - recovery to baseline conditions unlikely

Table 4.1 Criteria Used to Support Environmental Effects Assessment

Criteria	Description	Quantitative Measure or Definition of Qualitative Categories
Reversibility	Pertains to whether a measurable parameter or the VC can return to its existing condition after the Project activity ceases	Reversible – will recover to baseline conditions before or after Project completion Irreversible – permanent
Ecological or Socio-economic Context	Existing condition and trends in the area where residual environmental effects occur.	Undisturbed – The VC is relatively undisturbed in the RAA, not adversely affected by human activity, or is likely able to assimilate the additional change Disturbed – The VC has been previously disturbed by human development or human development is still present in the RAA, or the VC is likely not able to assimilate the additional change

4.2.3 Significance Definition

Significance criteria or thresholds were developed for each VC for the purposes of assessing residual environmental effects and identifying the threshold beyond which a residual effect would be considered significant. In accordance with CEAA 2012, the determination of significance includes considering whether the predicted residual environmental effects of the Project are adverse, significant, and likely. The definition and determination of significance criteria and thresholds for this Project aligned with the guidance provided in the Operational Policy Statement, *Determining Whether a Designated Project is Likely to Cause Significant Environmental Effects Under the Canadian Environmental Assessment Act, 2012* (Agency 2015). Where pre-established standards or thresholds do not exist, significance criteria have been defined qualitatively and justifications for the criteria provided.

4.2.4 Existing Conditions

Existing conditions of the marine physical environment (Chapter 5), marine biological environment (Chapter 6) and socio-economic environment (Chapter 7) is described to provide the setting for the Project. These sections provide an understanding of the receiving environment and are based on a review of available information.

4.2.5 Potential Environmental Changes, Effects, and Associated Parameters

The environmental effects assessment identifies and focuses on likely environmental interactions between the Project and the VC 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. An overview of the identified potential interactions between the VC and each of the main Project components and activities are presented in Table 4.2.

Table 4.2 Potential Interactions between Planned Project Activities and Valued Components

Planned Activity	Valued Component					
	Marine Fish and Fish Habitat (including Species at Risk)	Marine and Migratory Birds (including Species at Risk)	Marine Mammals and Sea Turtles (including Species at Risk)	Special Areas	Indigenous Communities and Activities	Commercial Fisheries and Other Ocean users
Presences and Operation of a MODU (including drilling, associated safety zone, lights, and sound)	✓	✓	✓	✓	✓	✓
Vertical Seismic Profiling	✓	✓	✓	✓	✓	✓
Discharges (e.g., drill muds / cuttings, liquid discharges)	✓	✓	✓	✓	✓	✓
Well Testing with Flaring	-	✓	-	-	✓	-
Well Abandonment	✓	-	✓	✓	✓	✓
Supply and Servicing	✓	✓	✓	✓	✓	✓

4.2.6 Environmental Effects Assessment and Mitigation

The environmental effects assessment for each VC examines the degree and nature of change to, and resulting effects on, the existing environment that may occur as a result of planned Project activities. Baseline conditions for each VC are considered in the effects assessment to determine the sensitivity or resiliency of the VC to further disturbance and/or change.

The implementation of mitigation measures to reduce or eliminate potential adverse effects are fully integrated into the effects assessment. Mitigation may include documented practices, measures proven effective in the past, best management practices (BMPs), as well as measures developed specifically for the Project. In some cases (e.g., fishing gear loss) compensation measures may be warranted. Each VC assessment indicates how the mitigation measures will reduce or eliminate potential adverse effects on the VC.

The effects assessment also considers relevant scientific literature, baseline and monitoring results and other available information (e.g., community, stakeholder, and Indigenous Knowledge) in the analysis of potential Project-related environmental changes to the VC that may result through one or more mechanisms or pathways. The focus of the effects assessment is on residual effects (i.e., those effects that remain after application of planned mitigation). The effects assessment for each VC concludes with a summary section on the residual environmental effects of the Project's activities and components and evaluates the significance of these effects based on the VC-specific significance definitions stated within each VC section. If a significant adverse residual effect is predicted, then the likelihood of this occurrence is also discussed.

4.3 Project-specific Modelling

Chevron undertook several Project-specific modelling studies to understand the fate and behavior of discharges and emissions from the Project. The models are applicable to various VC's effects assessment for the Project and summarized below.

4.3.1 Drill Cuttings Dispersion Modelling

RPS conducted the drill cutting dispersion modelling on the seabed (see Sections 2.8.2.1 and 2.8.2.2). This model characterizes the release of drill cuttings associated with drilling activities during the Project. This assessment is based upon operational discharges. Dispersion of discharged cuttings and muds from the drilling platform were simulated using RPS's MUDMAP modelling system. MUDMAP is a highly advanced, three-dimensional plume model used routinely to evaluate potential environmental effects from marine discharges including drill cuttings, drilling muds and produced water. Further details on this modelling are found in Appendix C.

4.3.2 Underwater Sound Modelling

JASCO completed the underwater sound modelling for drilling activity (including supply vessels) to determine the potential zone of influence on protected marine mammals, sea turtles, and fish species from exposure levels of sound received into the marine environmental (see Sections 2.8.5.1 and 2.8.5.2). Sound associated with the operation of the drilling installation and from a VSP survey were modelled. A full summary of the results from the underwater sound modelling are provided in Appendix D.

4.3.3 Spill Trajectory Modeling and Probability Analysis

RPS conducted the spill trajectory modelling, which considers the releases of crude oil from hypothetical subsurface blowouts, as well as a surface release (e.g., marine diesel from bunkering accidents) (see Section 15.2). RPS also developed two models to complete this analysis: the OILMAPDeep model and SIMAP model. The OILMAPDeep model will be used to characterize the near-field blowout dynamics for a subsurface release of oil, and the output data will be used as an input to the SIMAP which simulates far-field oil trajectory and fate. For the probability analysis, RPS partnered with ERC to complete this work. Further information on the Spill Trajectory Modelling and probability analysis are presented in Appendix F.

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 near the Project, as well as the significance of these potential effects. The cumulative effects assessments for the VCs are provided together in Chapter 14, which also includes a detailed description of the methods used, in accordance with the Agency's (2016) Operational Policy Statement, *Assessing Cumulative Environmental Effects Under CEAA 2012*.

4.5 Accidental Events

The environmental effects associated with the potential accidental events which may occur as a result of the Project are assessed in Chapter 15. This section assesses effects based on the worst credible accidental scenarios. Appropriate mitigation measures and contingency plans are provided, and a conclusion regarding the significance of residual environmental effects and their likelihood of occurrence is given.

4.6 Effects of the Environment on the Project

Effects of the environment on the Project are assessed in Chapter 16. This section considers how local environmental conditions and natural hazards (e.g., extreme weather) could adversely affect the Project and thus result in potential effects on the environment (e.g., accidental events). Potential adverse effects of the environment on a project are typically a function of project design and environmental conditions (e.g., geology, ice conditions) that could affect the project. These effects are generally mitigated through engineering and environmental design criteria, industry standards, and environmental monitoring which are discussed.

4.7 References

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