Strategic Environmental Assessment in Baffin Bay and Davis Strait

Oil and Gas Life Cycle Activities and Hypothetical Scenarios—May 30, 2018

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Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

A crude oil and natural gas (collectively referred to as hydrocarbons) life cycle activities description and potential hypothetical scenarios has been developed as part of the Strategic Environmental Assessment (SEA) for Baffin Bay and Davis Strait. The objective of the SEA is to develop an improved understanding of potential types of oil and gas related development activities[1] that could one day be proposed within the Canadian waters of Baffin Bay and Davis Strait outside of the Nunavut Settlement Area (NSA), along with their associated adverse effects, benefits, and management strategies. The Nunavut Impact Review Board (NIRB) is responsible for coordinating the SEA and producing a final report that will inform the five-year review of the Government of Canada decision to designate Canadian Arctic waters as off limits to future oil and gas licences.

This report describes a generic, credible and common set of steps or activities covering a typical offshore oil and gas life cycle. Once a region is identified as having potential hydrocarbon reserves, interested companies acquire marine seismic data, the results of which can lead to an interested operator securing an exploration licence for the right to conduct exploration drilling on the licence area. From the perspective of the oil and gas industry, the best-case scenario is the discovery of a commercial oil or natural gas field. If a commercial decision is made to proceed by an operator, a project is developed to bring the oil or gas into production and transported to global markets. Finally, once the project has depleted its reserves, or is no longer economic to continue, facilities would be decommissioned and removed.

The description of typical life cycle activities of offshore oil and gas exploration and production provides the basis for the development of the hypothetical scenarios. The scenarios as described are not a forecast or a prediction of activity. Nor does it suggest any specific schedule of possible oil and gas exploration and development for Baffin Bay or Davis Strait, or if in fact any such activity might occur at all in the foreseeable future. This report is based on discussions with petroleum industry experts with Canadian and world-wide experiences in offshore exploration and development and its application to the Baffin Bay and Davis Strait region. It is also informed by an extensive database of published literature, best practices and operational learnings from past and present offshore projects, and future technology advancements being made by the industry.

Present day Nunavut has had a long history of oil and gas exploration and some limited production has occurred in the high Arctic Islands of the Sverdrup Basin. Over the course of approximately 25 years,172 wells have been drilled in the region and 80,000 km of onshore and marine seismic has been acquired. The exploration to date has resulted in 20 discoveries of oil and natural gas and approximately three million barrels of crude oil were shipped from Bent Horn (on Cameron Island) to refineries in Montreal.

By comparison, the eastern Arctic region of Nunavut has had a much smaller level of interest and activity. While some early marine seismic surveys were conducted in the 1970s, no wells have been drilled in Baffin Bay; three have been drilled in Davis Strait in the Saglek Basin. Two of the wells were dry and one discovered natural gas in volumes

[1] For the purpose of the SEA, ‘oil and gas development’ will refer to the discovery and exploitation of oil and gas deposits and encompasses exploration, production, and decommissioning activities.

that were not considered commercial at the time. The earlier marine seismic data are not considered of sufficient quality or quantity to map potential hydrocarbon prospects or identify promising drilling locations.

Most recently, exploration drilling has occurred on the West Greenland shelf of Baffin Bay. While eight wells were drilled, it appears the oil and gas shows that were discovered are too small to be commercially attractive to develop under current conditions.

Past exploration has identified the following:

- Sedimentary basins with hydrocarbon potential underlying Baffin Bay and Davis Strait are largely unexplored
- To date the potential recoverable volumes appear fairly small
- The region appears to be more gas-prone than oil-prone
- Future exploration activities in the Saglek Basin on the southwest Greenland and on the Labrador shelf could change the picture

Potential Future Oil and Gas Activities

The regulatory regime under which oil and gas activities are carried out are well established and generally robust and workable, while there are opportunities to modernize and improve. The two main authorities are:

- Indigenous and Northern Affairs Canada—responsible under the *Canada Petroleum Resources Act* for rights issuances, issuing exploration, significant discovery and production licences if required, Canada Benefit Plans[2], and royalty management
- National Energy Board—responsible for administering *Canada Oil and Gas Operations Act* and its many technical regulations and guidelines

There are many activities that The National Energy Board is responsible for: the safety of the workforce and public during oil and gas-related activities, protection of the environment, and maximum revenues from producing hydrocarbon reservoirs.

The types of activities generally associated with possible offshore oil and gas exploration and development applicable to the Baffin Bay and Davis Strait regions include:

- Two dimensional (2D) marine seismic surveys to acquire a general understanding of a region's geological structure
- Three dimensional (3D) marine seismic surveys that are more intensive and designed to cover a specific area to support the selection of drilling location(s)
- Geotechnical and geohazard surveys conducted in the vicinity of the well site to detect hazards on the seabed or in the shallow subsurface
- Designing a well-specific drilling program, including:
  - Drill strings, casing and cement
  - Well control and blowout prevention system
  - Drilling fluids structure to create an overbalanced well to prevent the flow of hydrocarbons up the wellbore
- Selecting a drilling unit to fit the conditions under which it will operate, likely a:
  - floating drillship or
  - semi-submersible drilling platform

[2] In addition to a Canada Benefits Plan, an operator is also responsible under the Nunavut Land Claims Agreement to enter into an Inuit Impact Benefits Agreement (IIBA)

- Vertical seismic profiling conducted inside the wellbore and to provide a higher resolution of the structural geology at the drilling location
- Periodic testing of the formation properties during drilling
- Selecting various support vessels, including (as required):
  - Ice-breakers
  - Supply vessels
  - Fuel tankers
  - Wareships for storage of materials
- Aviation support, including:
  - Aircraft (commercial or charter for workforce)
  - Helicopters to move workers and consumables offshore to drilling unit
- Shore based support, including:
  - Staging sites, warehouses and storage yards
  - Communications
  - Office and accommodations
  - Emergency response equipment stockpiles
- Ice management system for tracking and surveillance of icebergs
- Waste management system for handling, storage, treatment and disposal
- Emergency response systems
- Well suspension and abandonment

Activities unique to development and production include:

- Multiple development drilling of the reservoir to reach optimum production
- Design and construction of a production unit, including:
  - A gravity-based structure on the seafloor, which is dependent on water depth
  - Subsea installations that collect oil or gas from the wells and bring to a surface production facility, or to a shore-based facility via a pipeline
  - Floating production, storage and offloading vessel or oil
- Floating liquid natural gas vessel for natural gas
- Transportation of the oil or gas from the offshore or onshore production facility by tankers to global markets
- Final decommissioning of all facilities on the seabed, onshore and offshore and the wells are put into a permanent safe state

Among the many factors that an operator would have to consider when deciding to invest in a project that could cost in the billions of dollars are:

- Operating challenges in the Baffin Bay or Davis Strait environment, in particular, the management of icebergs
- Potential for new discoveries in the region that could improve the economics of scale
- New technologies that could improve operating practices
- Maximizing local and national benefits and reducing environmental impacts
- Cost and business outlook, in particular global supply and demand, and long-term oil and gas pricing
- Political and regulatory stability and predictability

From initial interest in Baffin Bay or Davis Strait, usually based on geological studies and 2D seismic surveys, through to more detailed 3D seismic surveys, seabed surveys, exploration drilling, development, production, transportation, and finally decommissioning, typically requires a long timeline:

- +/- 15–20 years from exploration to discovery
- +/- 30–60 years from discovery to production and decommissioning

Within this timeframe there are several years devoted to consultation, regulatory approvals, implementing benefits agreements, conducting research studies, commercial and economic analysis, engineering design and facilities construction. Actual years of production can be one half or less of the total life cycle timeline, as is typical of many worldwide offshore and Arctic projects.

Abbreviations

bbl	billion barrels
BOEM	Bureau of Ocean Energy Management
BOP	blowout prevention
CDD	commercial discovery declaration
CEAA	*Canadian Environmental Assessment Act*
CNG	compressed natural gas
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
COGOA	*Canada Oil and Gas Operations Act*
CPRA	*Canada Petroleum Resources Act*
DFO	Fisheries and Oceans Canada
DP	dynamic positioning
DPA	development plan approval
EAMES	Eastern Arctic Marine Environmental Studies Program
ECCC	Environment and Climate Change Canada
ECRC	Eastern Canada Response Corporation
EIS	Environmental Impact Statement

EL	exploration licence
EMOBM	enhanced mineral oil-based mud
EPP	Environmental Protection Plan
EPPR	Emergency Prevention, Preparedness and Response
ESSA	*Energy Safety and Security Act*
FEED	front end engineering and development
FLNG	Floating Liquid Natural Gas
FORRI	Frontier and Offshore Regulatory Review Initiative
FPSO	Floating Production, Storage and Offloading
FTWT	Formation Testing While Tripping
GPR	Ground penetrating radar
GBS	Gravity-based Structure
IIBA	Inuit Impact Benefits Agreement
INAC	Indigenous and Northern Affairs Canada
IOL	Imperial Oil Limited
ISB	in situ-burning
LNG	liquefied natural gas
MKI	MultiClient Invest AS

MARPOL	International Convention for the Prevention of Pollution from Ships
MART	Marine Aerial Reconnaissance Team
MWCC	Marine Well Containment Company
MWO	Marine Wildlife Observers
NADF	non-aqueous drilling fluids
NEB	National Energy Board
NIRB	Nunavut Impact Review Board
NRCan	Natural Resources Canada
NSA	Nunavut Settlement Area
NuPPAA	*Nunavut Planning and Project Assessment Act*
OA	Operations Authorization
OBM	oil-based mud
OSPAR	Convention for the Protection of the Marine Environment of the North-East Atlantic
OSRL	Oil Spill Response Limited
PAH	polycyclic aromatic hydrocarbons
PL	production licence
RA	responsible authority

ROV	Remote operated vehicle
SAR	synthetic aperture radar
SBM	synthetic-based mud
SCAT	shoreline cleanup and assessment technique
SDL	significant discovery licence
SEA	Strategic Environmental Assessment
SIMA	Spill Impact Mitigation Assessment
SLAR	side-looking airborne radar
SSRW	Same Season Relief Well
TC	Transport Canada
TD	total depth
MCF	thousand cubic feet
TCF	trillion cubic feet
TD	total depth
USD	US dollar
VOC	volatile organic compounds
VSP	vertical seismic profiling
WA	Well Approval

WBDF	water-based drilling fluids
WBM	water-based mud
WCDS	worst case discharge scenario
WCS	worst case scenario
WMP	Waste Management Plan

1 INTRODUCTION

The following description of oil and gas life cycle activities and hypothetical scenarios is intended to provide a range of options that cover the full complement of oil and gas exploration and development activities that could occur in the Baffin Bay and Davis Strait region outside of the Nunavut Settlement Area (NSA).

It is not based on any specific company project, but rather describes a generic, credible and common set of steps covering a typical life cycle, from the time of initial interest in the region through the acquisition of 2D marine seismic data, to securing an exploration licence (EL), conducting additional 3D marine seismic surveys (if required within the licence area), conducting drilling at one or more well locations, and if a discovery is made, securing a significant discovery licence (SDL).

At that point the rights holder could make a decision to proceed with a development of the oil or gas discovery. Production and transportation to markets would follow until the reservoir was depleted or the project was no longer economic. Finally, all facilities would be decommissioned and removed as required by the regulator.

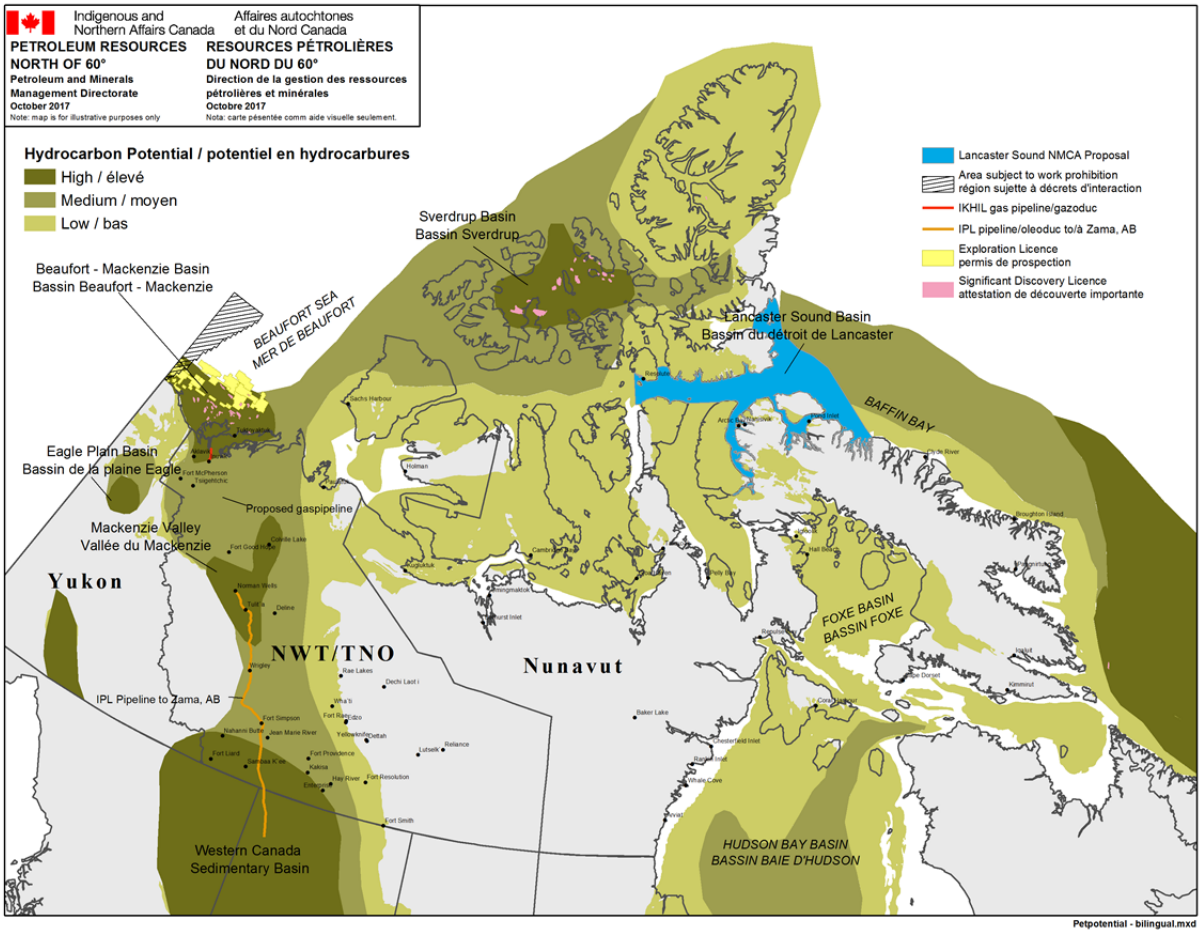
Not all of these steps would necessarily occur for a specific project. It is not uncommon for a company to terminate any further activity after seismic or exploration drilling of one or more wells in the licence area if there is no show of hydrocarbons, or a project may be suspended after making a discovery if it is not yet economic to develop.

The hypothetical scenarios described herein attempt to provide credible and conservative scenarios based on present day and future circumstances, which can include:

- Current interest in the region from oil and gas companies
- Geological potential of the region
- Technical and operating challenges (e.g. Arctic environment, limited infrastructure, climate change)
- Cost and path to commerciality
- Stable and predictable regulatory and political regime
- Local, regional and national benefits
- Global oil and gas supply and demand and competition from other prospects

The scenarios are not a forecast or prediction of activity, nor do they suggest the timing of possible oil and gas exploration and development for the Baffin Bay or Davis Strait. They also do not suggest that any such activity might occur in the foreseeable future.

Figure 1.1 shows that high hydrocarbon potential has been identified within Baffin Bay and Davis Strait (INAC 2008). The high potential areas are a result of sediment buildup consisting of dead plants and animals that accumulated during the mid-Cretaceous period (100 to 145 million years ago). This sediment build-up is a result of ancient rivers flowing to the east and north around the Precambrian Baffin structure from the large inland sea that once covered today's prairie provinces.

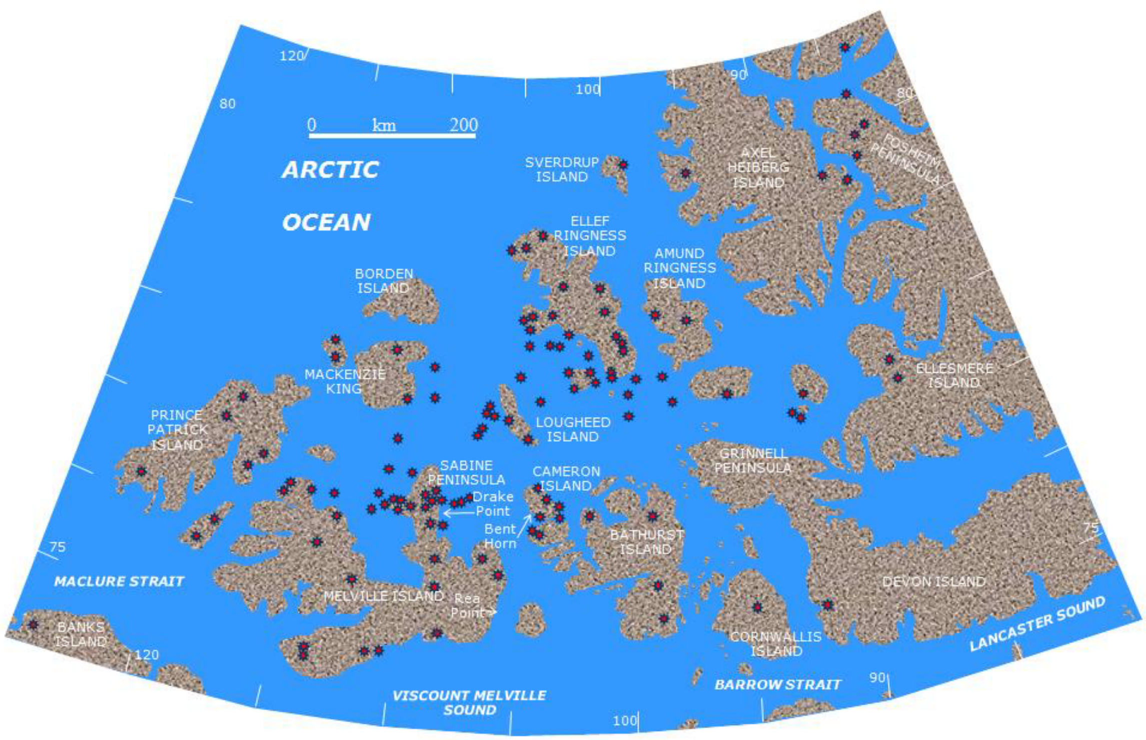


SOURCE: Petroleum and Minerals Management Directorate, Indigenous and Northern Affairs Canada

Figure 1.1 Hydrocarbon Potential Priority Areas in the Canadian Arctic

2 BACKGROUND AND HISTORY OF OIL AND GAS IN BAFFIN BAY AND DAVIS STRAIT

The region that is now the Nunavut Territory has had a long history of oil and gas exploration, with a comprehensive field study by the Geological Survey of Canada first taking place in 1954 in the high Arctic islands (Sverdrup Basin). A series of aerial mapping resulted in Dome Petroleum and partners drilling the first well in the Arctic islands (Dome et al. Winter HarbourNo.1) on southern Melville Island in 1961. Oil companies like the Panarctic Oil consortium (Government of Canada was the major shareholder) and leading geophysical scientists like J.C. Sproule rapidly advanced the knowledge base for the Sverdrup Basin through the 1960s and 1970s. This led to a series of discoveries including the Drake and Helca gas fields on Melville Island, and the Bent Horn oil field on Cameron Island. By 1996, drilling ceased due to plummeting petroleum prices and Panarctic Oil operations were shut down. During the course of 25 years, 176 wells were drilled in the Arctic islands (Figure 2.1), along with approximately 80,000 km of onshore and offshore 2D seismic surveys; with 18 significant discoveries totaling 2 billion barrels (bbl.) of oil and 26 trillion cubic feet (TCF) of natural gas were identified.



SOURCE: Morrell et al. 1995

Figure 2.1 Drill Wells in High Arctic Islands (Sverdrup Basin)

In 1985, the ice-breaking tanker MV Arctic began transporting oil from the Bent Horn oil field on Cameron Island (Figure 2.2) to Montreal. Three million barrels were shipped over the period of 12 years, with the last shipment occurring in 1996.

Photo Credit: D.M. Masterson

Figure 2.2 Bent Horn Oil Field on Cameron Island [Panarctic]

By comparison, the offshore Eastern Arctic region of Nunavut has had a much smaller level of interest and activity. The earliest geophysical data were collected in Davis Strait and northern Labrador Shelf in 1969, with a number of seismic surveys conducted, mostly in Davis Strait, through the 1970s.

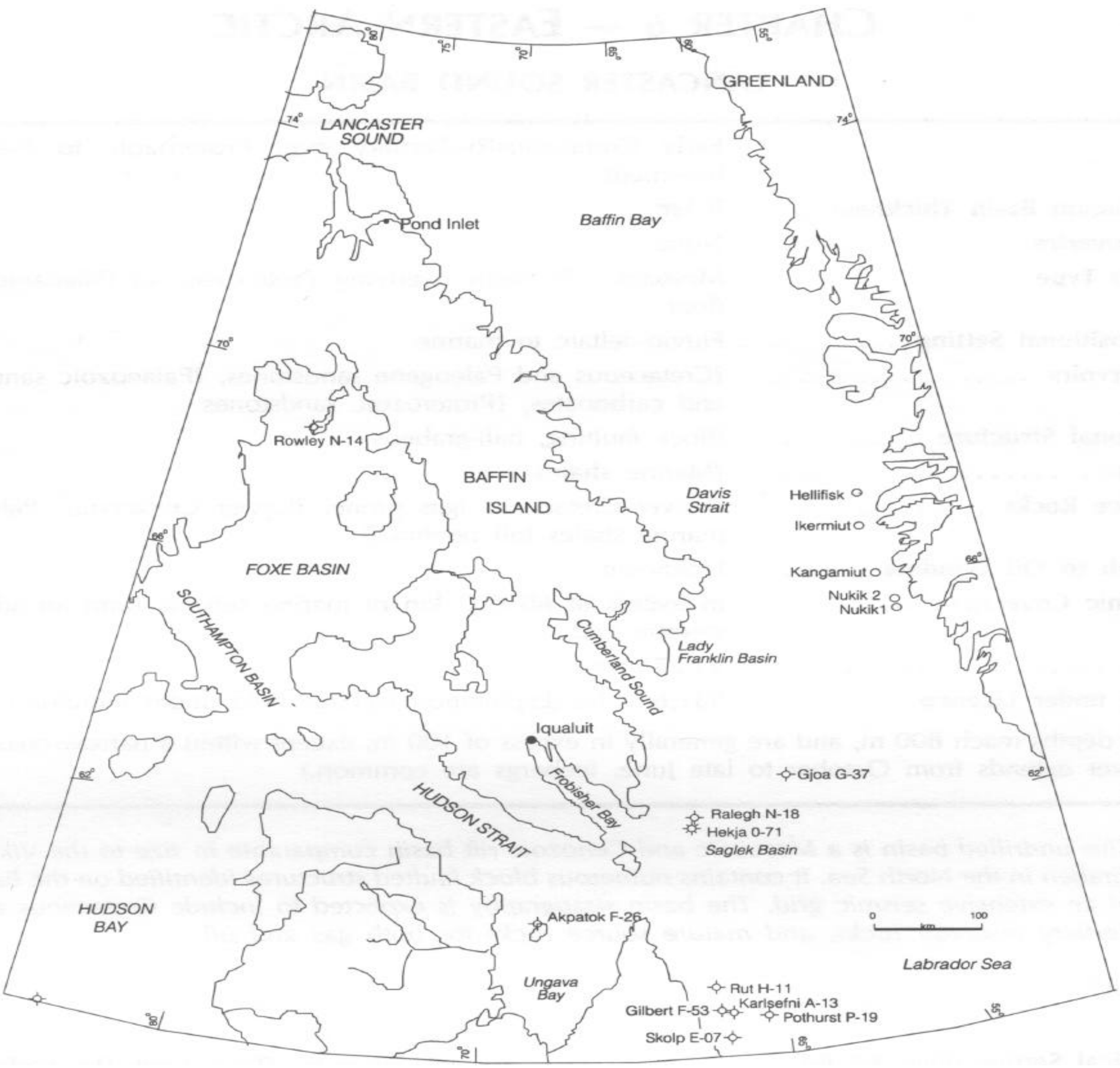
Exploration started in the Lancaster Sound Basin with some 2D marine seismic surveys, and geological field studies on Bylot Island in the early 1970s. Although drilling was approved in principle[3] in 1974, no wells were drilled and a moratorium was put in place in 1978. Lancaster Sound is considered to have high oil and gas potential but with significant geologic risk. It is speculated the basin may be gas-prone rather than oil-prone.

Cretaceous and Paleocene shales (mapped by the Geological Survey of Canada) are possible source rocks for potential oil and gas, and occur along the narrow east Baffin Island shelf and to the east along the much broader West Greenland shelf (Morrell et al. 1995). No wells have been drilled in the Canadian sector of Baffin Bay and there are no areas under existing licences.

[3] Regulatory approval was granted

Three wells have been drilled in Canadian waters in the Saglek Basin of Davis Strait (Figure 2.3):

- Esso HB Gjoa G-37 in 1979
- Aquitaine et al. Hekja 0-71 in 1980
- Canterra et al. Ralegh N-18 in 1980



SOURCE: Morrell et al. 1995

Figure 2.3 Drillwell Locations in Davis Strait[4]

[4] Place names included in Figure 2.3 are not up to date and do not include all Qikiqtaaluk communities. In addition, incorrect spelling of Iqaluit is used.

The Hekja well discovered gas and condensate potential of 4 TCF and present recoverable volume of some 2.3 TCF with today's technology. The other wells were dry. Based on the absence of a thick sedimentary basin that is required for hydrocarbons to accumulate along Baffin Island (with the exception of Lancaster Sound), and poor results from exploration drilling in the Greenland portion of Baffin Bay, future interest could be focused more on the southern portion of Davis Strait (Saglek Basin) vs. further north into Baffin Bay.

Natural subsea oil seeps along the coast of Baffin Island show surface oiling at several locations, such as Scott Inlet. The oil appears to come from shallow fissures between the Cretaceous strata and the Precambrian basement, and is not necessarily indicative of large oil potential.

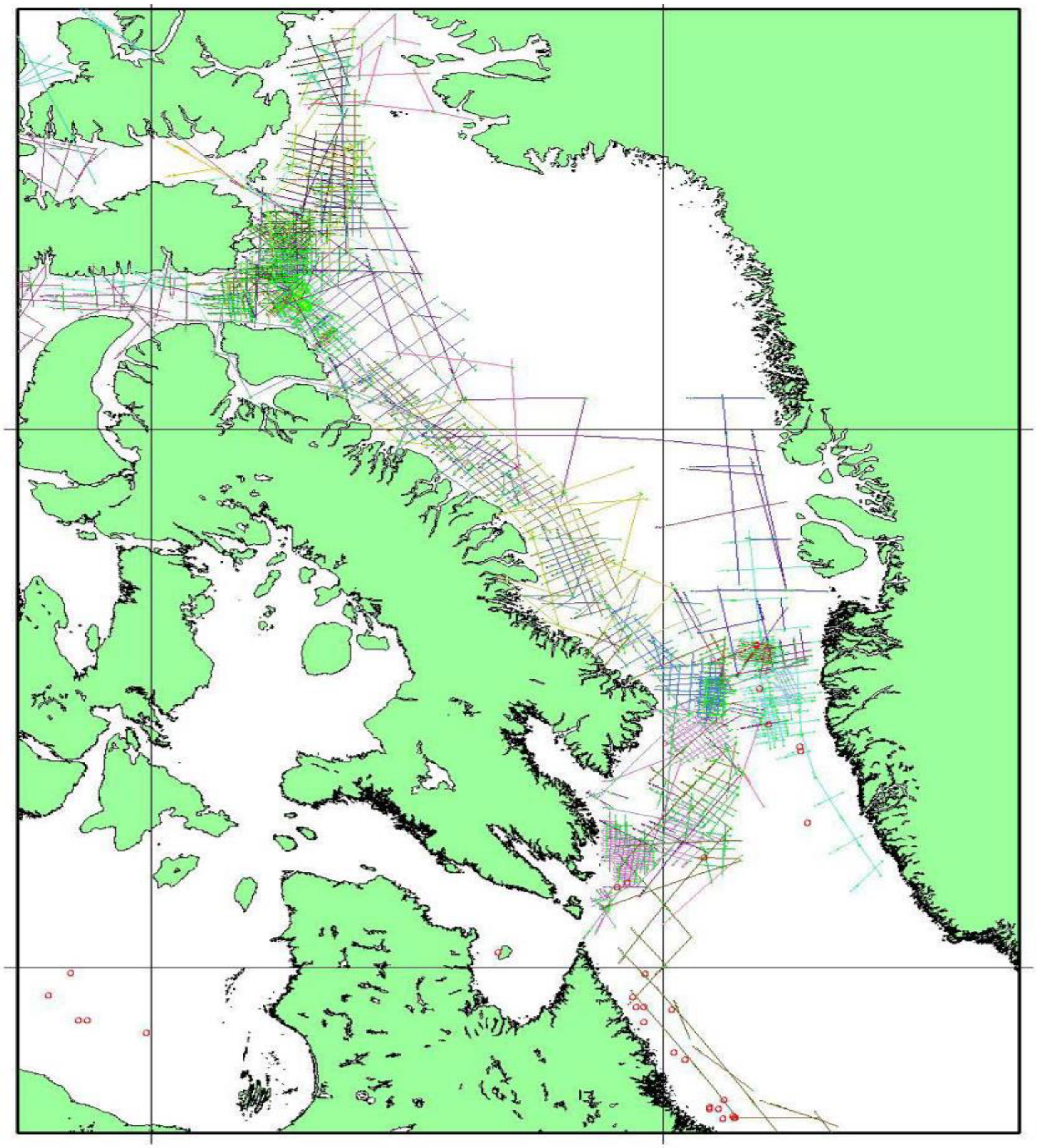
Seismic coverage in the Canadian portion of Baffin Bay and Davis Strait is generally poor. Some 30,000 km of 2D marine seismic were shot in the early 1970s (Figure 2.4). Given the large area and the quality of the early seismic data, it is not considered sufficient quality or quantity today to map prospects and identify potential drilling opportunities.

In the 1970s, five wells were drilled in Davis Strait waters on the West Greenland Shelf, along with 40,000 km of 2D seismic coverage. At the time, results were not promising; these wells were dry and abandoned. Recently, with more modern seismic data collection by Nunaoil in the 1990s, the Greenland authorities initiated a series of licencing rounds, with approximately 20 exploration licences awarded. Many international companies picked up acreage, often through joint ventures and consortiums to reduce the cost and high risks. Following more recent 3D seismic data collection (85,000 km) and eight wells drilled in the waters of West Greenland, results have been disappointing. Most of the licences have since been relinquished. While there were oil and gas shows, it appears that the reservoirs were too small to be commercially attractive under current conditions.

With the limited seismic, drilling and field data collected to date, estimating potential hydrocarbon for the region is difficult to predict. There have been a number of publications with varying estimates. As a general point of reference, the ultimate volumes for oil-in-place and recoverable in the Baffin Bay/Davis Strait is approximately 2B bbl in place and 500+M bbl recoverable. Estimates for gas are approximately 15 TCF in place and 10 TCF recoverable (note that these numbers include the Lancaster Basin, which makes up a significant component of this potential but has been withdrawn from future exploration).

In summary, there are significant geologic factors that may influence future interest in the region:

- Sedimentary basin underlying the region is predominantly unexplored to date
- To date, potential recoverable hydrocarbon volumes appear small; however, future seismic data and drilling on West Greenland Shelf and along the Canadian Labrador Shelf, if conducted, might change this outlook
- Region appears to be more natural gas-prone than oil-prone

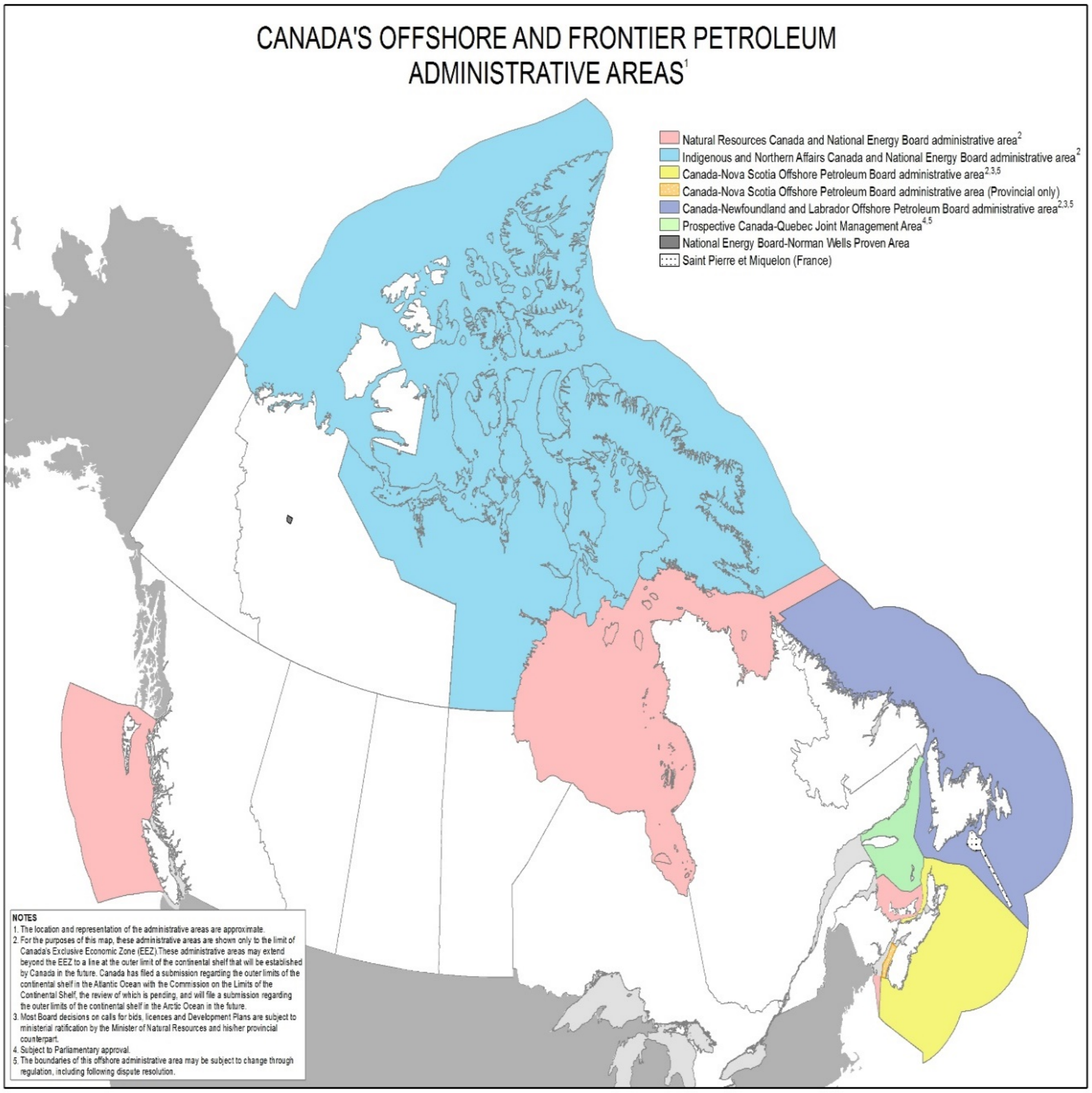


SOURCE: unknown

Figure 2.4 2D Marine Seismic Lines shot in the Early 1970s

3 REGULATORY OPERATING FRAMEWORK

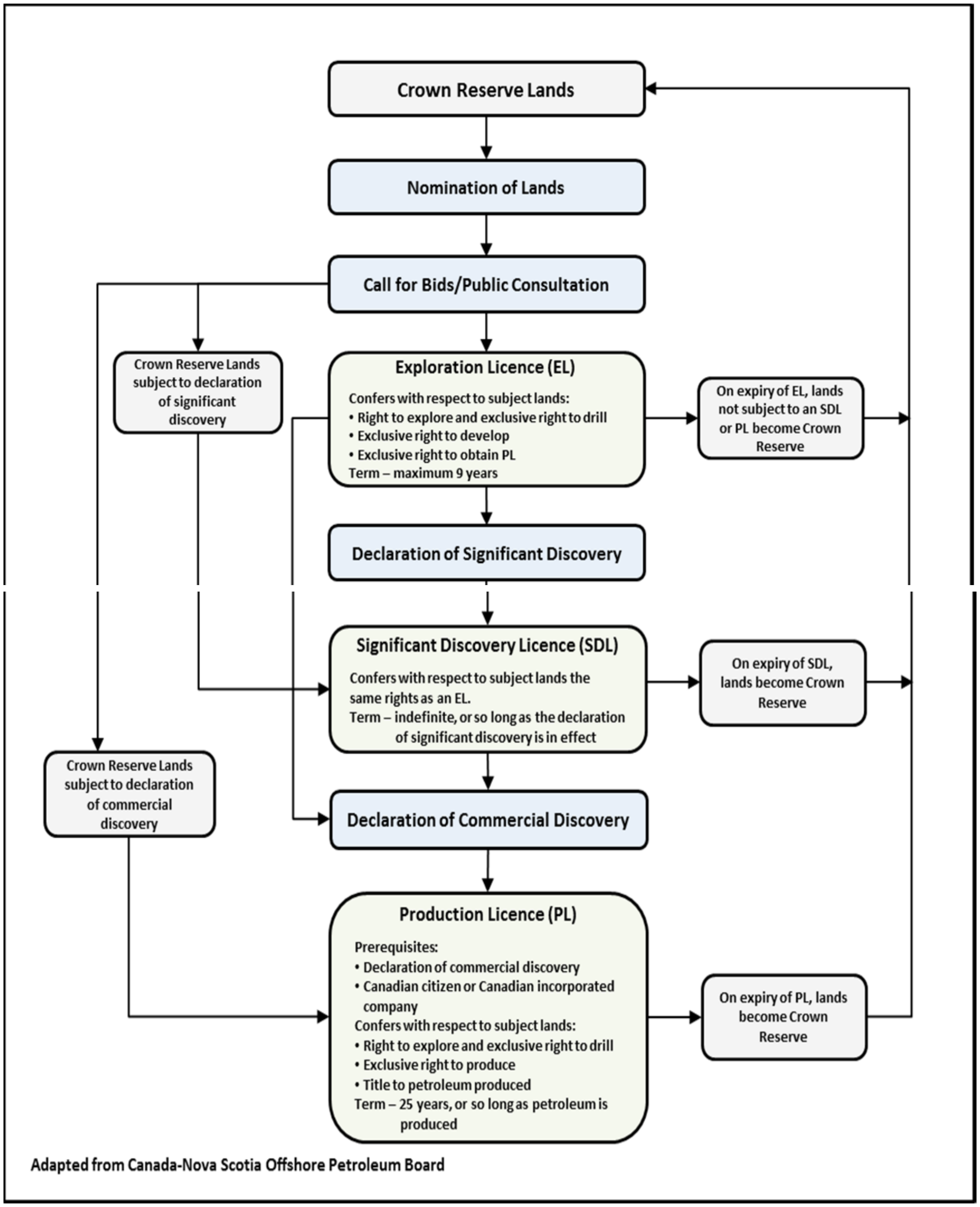
In the Nunavut and Arctic offshore regions, oil and gas activities are regulated by Indigenous and Northern Affairs Canada (INAC), the National Energy Board (NEB), and Natural Resources Canada (NRCan) (Figure 3.1). From proposed development occurring outside the Nunavut Settlement Area, the *Agreement between the Inuit of the Nunavut Settlement Area and Her Majesty the Queen in right of Canada* (Nunavut Agreement) also contains numerous provisions that could be relevant to address effects of development on wildlife harvesting or Inuit. Pursuant to Section 15.4.1 of the Nunavut Agreement, the Nunavut Impact Review Board, the Nunavut Water Board, the Nunavut Planning Commission, and the Nunavut Wildlife Management Board may jointly, as a Nunavut Marine Council, or severally, advise and make recommendations to other government agencies regarding the marine areas, and Government shall consider such advice and recommendations in making decisions which affect marine areas. The Nunavut Agreement articulates no limits on the policy scope of the Nunavut Marine Council's advisory mandate in relation to marine issues.



SOURCE: Natural Resources Canada 2017

Figure 3.1 Nunavut and Arctic Offshore Areas Shaded in blue

INAC is responsible for rights issuance, benefits plans and royalty management under the *Canada Petroleum Resources Act* (CPRA) (Figure 3.2).



SOURCE: Canada—Nova Scotia offshore Petroleum Board 2012

Figure 3.2 INAC Rights Issuance and Licencing Process

The typical INAC process for allocation of Crown land and water for oil and gas exploration involves:

- Call for nominations for an area to identify industry interest (optional)
- Early initial consultation on a potential call for bids for an area
- Formal call for competitive bids with conditions and terms
- An EL may be awarded to a company based on highest work expenditure commitment
- EL confers the right to explore and drill under the terms of the agreement within a nine-year period, and subject to obtaining all the necessary approvals and permits
- If, as a result of drilling, there is a presence of hydrocarbons, the company can declare a discovery and apply for an SDL
- NEB assists INAC in the technical determination of the significant discovery
- INAC may issue an SDL to the company for an indefinite period
- The company at some point may declare a commercial discovery
- INAC may then issue a production licence (PL) to the company with certain conditions, for a period of time or so long as hydrocarbons are produced

While INAC issues licences (EL, SDL, and PL) to the rights holder under the CPRA, it does not authorize the undertaking of work. Any such activities can only take place when the NEB is satisfied that the company has demonstrated it can operate safely, protect the environment, respond in event of emergencies, and manage the oil and gas resources most effectively and efficiently.

Prior to any activity, a company is also required to prepare a Benefits Plan for approval by the INAC Minister, well in advance of the anticipated start date of a proposed work or activity. The Benefits Plan identifies the means for employment of Canadians and for providing Canadian companies with a full and fair opportunity to participate in the supply of goods and services for oil and gas work. The plan is specifically intended to provide northern residents, northern businesses and Indigenous peoples the opportunity to participate in and directly benefit from oil and gas work in their region (to the extent possible). While the Nunavut Agreement provides measures for ensuring that an Inuit Impact and Benefits Agreement is in place prior to major development projects occurring within the Nunavut Settlement Area (NSA), these same provisions may not be applicable for projects occurring outside of the NSA.

A Benefits Plan represents a documented commitment by the operator. To aid the process, INAC has published “Benefits Plan Guidelines for the North” to assist the operator, and ensure the Benefits Plan meets the requirements of the CPRA and the *Canada Oil and Gas Operations Act* (COGOA). Once the plan is approved by the Minister in the form of a Decision Report, an operator is obligated to endeavour to fulfill the commitments therein. The coverage period of a Benefits Plan should accurately reflect the entirety of the activity. In the event that the activity may significantly differ from the activity as originally planned, the operator may be required to provide a Benefits Plan amendment and indicate the potential impact the amendment may have on the previous agreed upon commitments.

INAC reserves the right to undertake reasonable monitoring and/or auditing of an operator and its contractors and subcontractors to verify the commitments are being fulfilled.

Specific objectives of the Benefits Plan for the operator include:

- Conducting early and frequent meetings and communication with northern stakeholders and Indigenous organizations, using a variety of techniques, to share information on potential training, employment and business opportunities
- Implementing business and procurement processes that maximize northern benefits
- Supporting opportunities for education and training with sufficient lead time

- Promoting transferrable skills and succession planning
- Using a transparent and fair procurement and contract award process
- Conducting bid requests in a timely manner to support local supplier participation
- Using best efforts to remove impediments to local supplier participation
- Consideration should be extended to qualified northern indigenous residents and other northern residents for employment and business opportunities
- Providing a forecast of total planned hiring, types of jobs, wages, and work hours
- Providing a forecast of its total planned procurement expenditures

The operator is required to submit a report to INAC on the implementation, execution and results of the approved Benefits Plan. For a single-season activity, such as an exploration drilling program, a single final report is typically required. For a multi-year activity, such as long-term production, an annual or semi-annual report is required, as well as a final report.

A further example of the contents in a Benefits Plan can be found in the Canada-Newfoundland and Labrador Benefits Plan Guidelines (Canada-Newfoundland and Labrador Offshore Petroleum Board 2006, 2016) issued by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB).

In addition to a Benefit Plan under the CPRA, as per Article 26 in the Nunavut Agreement, an operator is required to enter into an Inuit Impact and Benefits Agreement (IIBA) with an Inuit representative organization on its proposed project if it involves development or exploitation of resources located partially or wholly on Inuit Owned Land (IOL). As the possible development scenarios in the SEA Area of Focus are located in Canadian offshore waters and not on IOL, an Inuit Impact and Benefits Agreement would not be required for those activities. The formal contract is legally binding as per the rules of contracts, and describes how Inuit communities that could be affected by the project on their lands can benefit, along with the recognition of negative implications and how any such impacts can be avoided or reduced. Subject areas in an IIBA can include, but not limited to:

- Economic and business development
- Employment opportunities, preferential hiring and training
- Social development and culture
- Environmental protection, wildlife disruption and compensation
- Communications and enforceability

NEB regulates activities in the arctic offshore under the mandate of the COGOA. Its regulations and guidelines, include, but are not limited to:

- Canada Oil and Gas Geophysical Operations Regulations
- Canada Oil and Gas Drilling and Production Regulations
- Canada Oil and Gas Installation Regulations
- Canada Oil and Gas Certificate of Fitness Regulations
- Canada Oil and Gas Operations Regulations
- Oil and Gas Spills and Debris Liability Regulations
- Financial Requirements Regulations and Guidelines Respecting Financial Requirements (Amended) (Canada-Nova Scotia Offshore Petroleum Board et al. 2017)
- Offshore Waste Treatment Guidelines (National Energy Board et al. 2010)
- Offshore Chemical Selection Guidelines for Drilling and Production Activities on Frontier Lands (National Energy Board et al. 2009)

- Safety Plan (Canada-Newfoundland and Labrador Offshore Petroleum Board et al. 2011a) and Environmental Protection Plan (EPP) Guidelines (Canada-Newfoundland and Labrador Offshore Petroleum Board et al. 2011b)
- Information Transparency Guidelines

The NEB's mandate is to promote and oversee the safety of workers and public, and the protection of the environment. The NEB is a quasi-tribunal that operates at arm's length from the federal government. It sets the terms and conditions of any authorized approval, and conducts regular field inspections and monitoring of the operator, with the authority to shut activities down, if there is a non-compliance issue.

Of particular relevance and importance is the NEB's Filing Requirements for Offshore Drilling in the Canadian Arctic (National Energy Board 2014). While these requirements have been in place for many years, they were updated during the NEB's Arctic Offshore Drilling Review in 2011, following the Deep Water Horizon blowout in the Gulf of Mexico in 2010. It provides additional detail to companies applying for an Operations Authorization (OA) for any work or activity, including marine seismic programs or drilling programs. The contents of the OA must include a detailed description of:

- Company's management system
- Risk assessment to identify hazards on the seabed and sub-sea
- Safety plan
- Ice management plan
- Vessel and aviation transportation plan
- Environmental protection plan
- Waste, noise and emissions management plans
- Worst case scenario (WCS) from an uncontrolled release of fluids
- Measures to bring the situation under control
- Spill contingency plan

In addition to obtaining an OA for a single or multi-well drilling program from the NEB, the company is required to obtain a Well Approval (WA) for each individual well drilled. The WA application describes in detail:

- Drilling schedule
- Geophysical aspects of the oil / gas targets
- Results of the site surveys for seabed and subsea geohazards
- Formation pressure predictions
- Drilling system and its suitability for the conditions in which it will operate
- Down hole well description
- Casing design and cementing program
- Drilling fluids system
- Well integrity and barriers
- Blowout preventers and well control system
- Well completion program
- Formation flow testing program
- Well suspension and abandonment program

Under the current *Canadian Environmental Assessment Act, 2012* (CEAA 2012), the NEB is the responsible authority (RA) for assessing the environmental impacts of oil and gas related activities that are located outside of the NSA, including Baffin Bay and Davis Strait. This process is expected to change once the federal *Impact Assessment Act* and *Canada Energy Regulator Act* come into force; details on these changes are subject to final legislation approval.

The company is required to provide the NEB with detailed information in its Environmental Impacts Statement (EIS) on:

- Project description
- Baseline description of the environment and unique factors
- Potential impacts to the natural environment
- Socio-economic impacts arising from environmental effects
- Potential impacts from accidents and malfunctions
- Consultations with Indigenous groups and the public
- Cumulative environmental effects of multiple programs in the area or other activities
- Mitigation measures to avoid or reduce adverse effects, including compensation

Taking into account the implementation of mitigation measures, the NEB as the RA under CEAA 2012, must make a determination as to whether the project activity is likely to cause any significant adverse environmental effects. The NEB cannot grant an authorization under COGOA until it has made the CEAA 2012 determination.

In addition to meeting the requirements under CPRA and COGOA, the company also is required to comply with all other applicable Acts and Regulations for operating in the Arctic offshore, including but not limited to:

- *Arctic Waters Pollution Prevention Act*
- *Canada Shipping Act*
- *Fisheries Act*
- *Nunavut Land Claims Agreement Act*
- *Oceans Act*
- *Species at Risk Act*

In 2016, the federal government's *Energy Safety and Security Act* (ESSA) came into force, which created a stricter liability regime for environmental damage in the Arctic offshore, including:

- Enhancing the polluter pays principle
- Creating higher limits on no-fault, absolute liability for spills from $40M to $1B USD for Arctic waters under COGOA
- Expanding the range and types of damages that can be liable
- Creating more stringent financial resources and responsibility requirements for operators
- Increasing public consultation approaches and broader information disclosure
- Providing stronger enforcement powers and penalty consequences

It is expected there will be regulatory, guidelines and procedural changes in the future arising out of:

- *Federal Impact Assessment Act*
- *Canada Energy Regulator Act*
- Revisions to the *Navigable Waters Act and Fisheries Act*
- Revisions to the CPRA by INAC and NRCan
- Frontier and Offshore Regulatory Review Initiative (FORRI) by INAC and NRCan and in co-operation with provincial and territorial governments, which is intended to modernize and amalgamate many of the regulations under COGOA, using a combination of prescriptive and performance-based approaches.

The Nunavut Agreement provides provisions for the NIRB to review a project proposal that would be located wholly outside the NSA upon request by the Government of Canada or the Government of Nunavut, or with the consent of both governments, upon request by a Designated Inuit Organization if the project proposal may have significant adverse ecosystemic or socio-economic effects within the NSA. Any review would also be subject to the *Nunavut Planning and Project Assessment Act* (NuPPAA).

4 ROUTINE EXPLORATION AND APPRAISAL ACTIVITIES

4.1 Offshore Seismic Survey

Offshore seismic programs are used to collect information on the geological characteristics of the seabed. The oil and gas industry uses seismic surveys to identify areas where potential oil and gas reservoirs may exist. Seismic surveying for oil and gas in the offshore involves mechanically generating low-energy waves at the surface and directing them downward into the Earth's surface below the seabed. Some of that energy is reflected back from different layers of rock below the surface. The returning waves are detected with hydrophones, sensitive measuring devices that record the strength of the wave and the time it takes to travel through the various layers in the Earth's crust and back to the surface. These recordings are then analyzed and transformed into visual images that give a picture of the structure and nature of the rock layers.

There are two main types of seismic surveys, two dimensional (2D) and three dimensional (3D). A seismic survey requires optimal weather, typically from June to September, as rough seas affect the quality of the data.

The 2D method uses a single seismic cable or streamer towed behind the seismic vessel together with a single source. The reflections from the subsurface are assumed to lie directly below the sail line that the vessel traverses. 2D lines are typically acquired several km apart on a broad grid of lines over a large area, and requires oblique lines in addition to the prominent acquisition direction. The method is generally used in frontier exploration areas to produce a general understanding of the regional geological structure. The seismic program proposed by MultiClient Invest AS (MKI) in 2011 was a 2D survey intended to expand the understanding of the regional extent of geological formations in Baffin Bay and Davis Strait; it was not the basis for an exploration drilling program, as the survey line spacing was too coarse for that purpose.

A 3D survey (Figure 4.1) covers a specific area with known geological targets. Sail lines are acquired, at a constant towing speed of approximately 9 km/h (5 knots), with the same orientation (racetrack pattern) and a typical separation of 200–400 m. By using many parallel streamers spaced 25–50 m apart, a 3D survey generates many times more data than 2D within a concentrated spatial area. This results in more detailed subsurface information and allows for more thorough analysis of geological features than 2D seismic data. 3D surveys have now become the preferred method for acquiring more than 95% of marine seismic data acquired worldwide. Increasingly, 3D surveys are being used regularly over time at established production fields to monitor the reservoir characteristics and depletion rates. These are called time lapse surveys or 4D. It is used to determine the change in a reservoir that results from hydrocarbon production.

Photo credit: Empyrean Energy

Figure 4.1 3D Seismic Survey, Offshore China

The seismic streamers detect the low-level of reflection energy using sensitive devices called hydrophones. The hydrophones convert the reflected pressure signals into electrical energy that is digitized and recorded on board the vessel. The streamers are made of a steel or kevlar stress member that provides the physical strength to be towed in rough weather. The streamer is filled with an organic or synthetic fluid that has a specific gravity of less than 1 to make it overall neutrally buoyant. New generation streamers are moving away from traditional liquid-filled cable to a solid cable constructed of extruded foam, which cannot leak if damaged. 3D streamer lengths have increased over time with improved technology and typically range from 5,000–6,000 m or longer. The range of streamer depths varies from 4–5 m for shallow to 8–15 m for deeper water.

There are three types of seismic sources: air source array; waterguns[5]; and vibrators[6]. To date, air source arrays have been the standard for offshore seismic surveys because both waterguns and marine vibrators produce low frequency bandwidth signals which are unable to penetrate as deeply into the subsurface as an air source array (International Association of Geophysical Contractors 2002). Explosives are a historic seismic source and are not used in present day operations.

An air source array is suspended behind the survey vessel on floatation devices to maintain a specified operating depth. Typical air source arrays currently in use will output sound ranging from 220–260 dB at 1 m. This is a

[5] Compressed air is used to force water out of a cylinder, creating an acoustic wave and a signal which is then received by a towed hydrophone array.
[6] Uses continuous input of vibrations to produce a signal that reflects off the sea bed.

theoretical level that can drop to 180 dB at the 500 m safety zone and 170 dB at 1 km from the source. This is similar to the noise made on the surface from cracking and breakup of sea ice. The source array is designed to focus energy downward into the subsurface. The source emits a sound that lasts approximately 0.1 seconds and is repeated every 10–15 seconds.

There are many factors that influence how sound propagates in the water column, including:

- Bathymetry
- Seabed sediment properties
- Ice cover
- Vertical and horizontal sound speed profile
- Water salinity and temperature
- Airgun size, pulse rate, and peak-to-peak pressure

Modeling sound propagation, particularly outward in the water column, is a challenge. It is best done using a project-specific survey plan, location and equipment. It is generally agreed that for impulse signals, a measure of the signal's energy level is the best unit, although for close biological receptors, noise impacts using peak pressure may be more appropriate.

In Canada, the marine seismic companies commonly follow the *Statement of Canadian Practice with Respect to the Mitigation of Seismic Sound in the Marine Environment* (DFO 2007), produced and periodically reviewed and updated by Fisheries and Oceans Canada (DFO 2015). These guidelines represent the minimum standards in Canada for the protection of marine mammals from seismic noise.

Vertical seismic profiling (VSP) refers to a class of borehole seismic measurements used for correlation with surface seismic data, for obtaining images of higher resolution than surface seismic images and for looking ahead of the drill bit. VSP refers to measurements made in a vertical wellbore using geophones inside the wellbore and an energy source at the surface near the well. Most marine VSPs use an air gun as a surface seismic source. Their primary purpose is to tie well data to seismic data to provide higher-resolution information on the structural geology surrounding the wellbore. VSP surveys can also be used to trace the geometry of deviated deep-water wells. 3D marine VSP surveys are conducted using air gun arrays mounted on a vessel that traces multiple parallel survey lines adjacent to the well.

4.2 Offshore Drilling Design and Operation

If seismic data identify a potential hydrocarbon location, the next step would be to drill into the reservoir to a certain distance below the seabed (referred to as the total depth or TD). It is the only way to confirm the presence and type of hydrocarbon (oil or natural gas) and the vertical extent of the reservoir. Additional exploratory drilling (referred to as delineation drilling) is usually required to determine the horizontal extent of the field. The time to drill a well varies, depending on the water depth, well design, depth of the reservoir, weather, ice conditions, and various technical, safety and operating conditions. For example, wells drilled offshore Newfoundland and Labrador have taken from 35 to 65 days, not counting mobilization and demobilization.

Well site geotechnical and geohazards surveys are carried out before a well is drilled, as there is a regulatory and operational need to have detailed information on the area immediately surrounding the well location and the geological layers immediately below the sea bed. Well site survey methods include high-resolution multi-channel seismic data, side-scan sonar, and high-resolution sub-bottom profiles. Some well site surveys also require seabed photography, magnetometer data, or sediment grab samples. The information on the nature of the seabed is needed to determine the presence/absence of physical hazards on the seabed surface. Information on the shallow subsurface is required to determine if there are any unforeseen hazards, such as shallow gas pockets or buried brine channels in the near subsurface that could cause problems if penetrated by drilling.

The first step in a drilling program is to design the well and select the critical equipment and materials, such as drill strings, casing strings, cement, and the blowout prevention (BOP) system (see Section 4.3). The pore pressure and fracture gradient establish the basis for the design of a well, including the mud weight casing program setting depths and the cementing slurry design. The primary barrier to control a well is overbalanced mud weight, which exerts a greater pressure on the well than the exposed pore pressure to prevent hydrocarbons from flowing up the well. The blowout preventers are the secondary barrier. Finally, the well is designed for suspension and eventual abandonment.

Drilling fluids[7] are a key component of the well design. They are a mixture of clay (bentonite) and weighting agents (barite, carbonates and soluble salts). These components have a low aquatic and sediment toxicity, and most are highly biodegradable. The first few hole sections (e.g.,101.6 [42 in.], 76.2 [30 in.], 66 [26 in.] cm in diameter strings) for a well are typically drilled with water-based drilling fluids (WBDF). The majority of WBDF are classified under Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR) Convention 1999 Annex 6 as non-toxic and are typically discharged overboard without treatment. A well might use and discharge approximately 30,000–40,000 bbl.

Once the casing is run and cemented, the subsea BOP and marine drilling riser are installed, which allows drilling fluids to be pumped down the drill string and out through the bit. The cuttings are then circulated up the annulus (void between the drill string and the casing), where they are removed with solids control equipment and the drilling fluid is typically re-conditioned and re-used.

Deeper well sections are drilled using non-aqueous drilling fluids (NADF), which are made up from a synthetic base oil with emulsifiers, weighting agents and other materials designed for higher temperatures and gas hydrate-inhibiting properties. Unlike WBDF, NADF are not directly discharged into the surrounding water, as they are cleaned and reused, although some may be retained on treated cuttings that are discharged. The most common NADF is referred to a Group III NADF formulation with a low polycyclic aromatic hydrocarbons (PAH) and total aromatic content.

Solids control equipment, located on the drilling rig, is used to remove and reduce any synthetic oil content from the solids brought up to the surface to below 6.9 g/100g over a 48-hour mass weighted average as required by the *Offshore Waste Treatment Guidelines* (NEB et al. 2010). Depending on the rock and sediment formation being drilled through, the efficiency can be much greater (i.e., lower oil content). Treated cuttings (i.e., rock chips) are typically discharged below the water line. Depending on the water depth and currents, cuttings can fall onto the seabed in a pile, or be carried away and dispersed over a larger area.

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[7] Also referred to as drilling muds when they are water based, oil based or synthetic based fluids

Drilling fluids are used to:

- Remove drilled solids (cuttings) from the bottom of the wellbore and transport them to the rig for separation and treatment
- Deposit an impermeable cake on the wellbore to seal the formations being drilled into
- Maintain the structural stability of the wellbore
- Cool and lubricate the drill bit

The casing forms the main structural component of the wellbore and serves to:

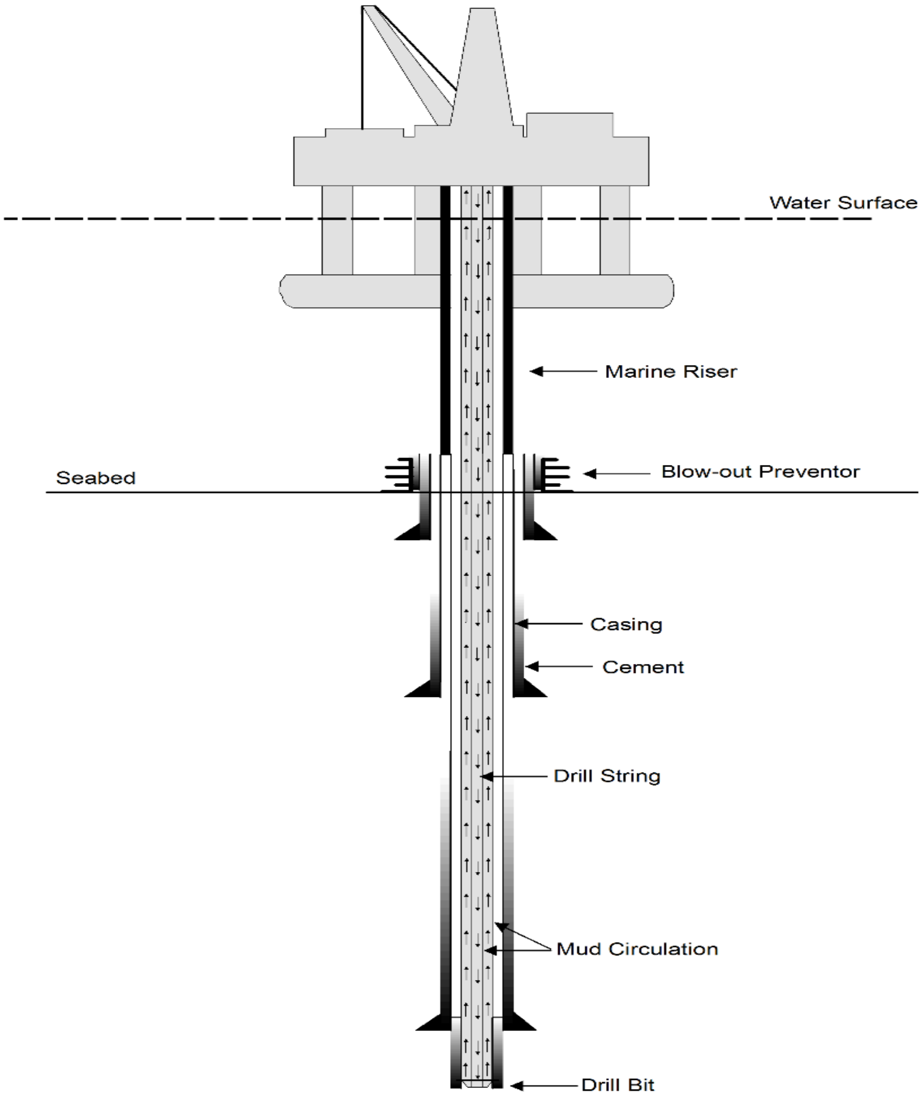
- Prevent the formation from caving into the wellbore
- Isolate the different formations to prevent cross-flow
- Provide the means to maintain control of the formation fluids and pressure as the well is drilled

The wellhead equipment is designed to contain the maximum expected pressure and temperatures in each formation.

A cementing program is developed for each individual casing string. It ensures hydraulic isolation between the formations such that hydrocarbon zones behind the casing will be isolated. The cement weight and strength is designed to be sufficient to:

- Maintain hydrostatic overbalance
- Keep formation fluids under control
- Avoid any unexpected intrusion of oil, gas or water into the wellbore

A schematic of a typical offshore well is illustrated in Figure 4.2.



SOURCE: ExxonMobil

Figure 4.2 Schematic of a Typical Offshore Well (Not to Scale)

4.3 Well Control

The industry's primary approach to well control is prevention. In an effort to prevent well control problems from occurring, the following steps are taken:

- Wells are conservatively designed to handle all identifiable risks (e.g., harsh offshore environment, equipment failure)
- Detailed procedures based on industry experience are established and followed
- Multiple barriers and redundancy are built into well and drilling system designs
- All equipment is inspected and maintained according to specified schedules
- Equipment operators are appropriately trained, and participate in on-going testing and emergency response drills prior to and throughout the drilling program

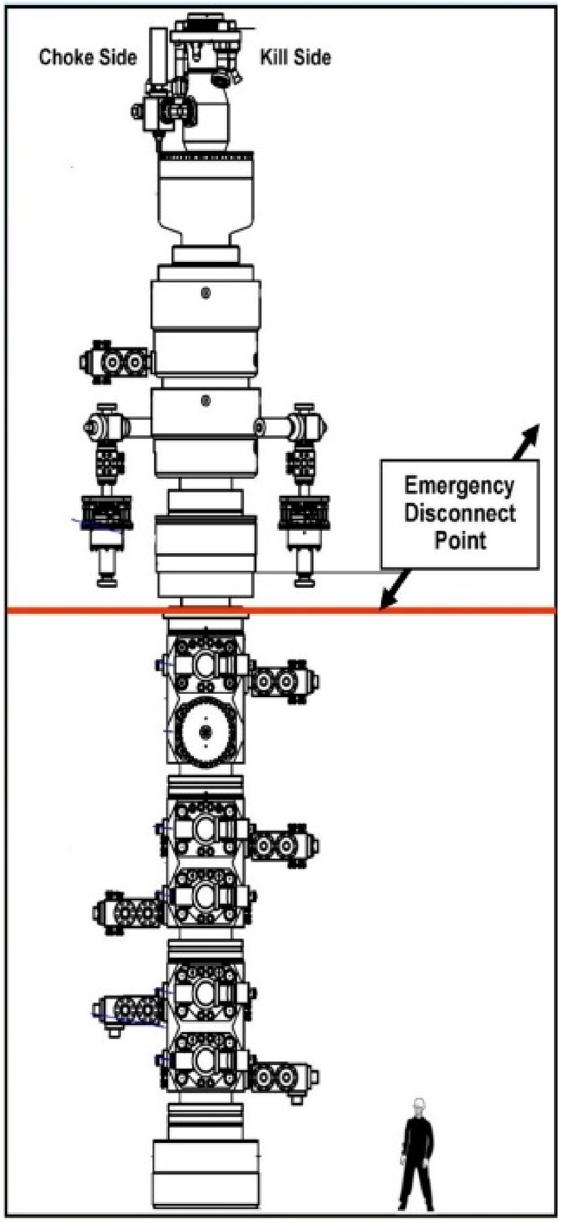
Exploration wells normally use overbalanced drilling mud systems to prevent well flow so that the hydrostatic pressure in the well exceeds the formation pressure. Overbalanced (very dense) fluids provide the primary barrier to well flow.

Logging while drilling techniques would be used in any future drilling in Baffin Bay/Davis Strait. Logging well drilling tools can be used to continuously monitor real time formation properties and hydrostatic pressures in the wellbore. Drilling operators make adjustments to mud weight to maintain hydrostatic overbalance, keep formation fluids under control, and avoid intrusion of oil, gas or formation water into the wellbore. They also select casing setting depths to maintain well bore integrity. Continuous monitoring is carried out to provide early detection of any well flow.

BOPs are designed to shut in a well if well control is lost or compromised. A BOP uses rams to physically close off the well aperture and prevent further loss of pressure and drilling formation fluids. A BOP has a series of redundant systems to transmit control signals from the drilling rig to the subsea equipment.

Drilling operators are certified and trained to quickly activate the secondary barrier or BOP to stop the well flow and properly manage a well control event, so that the primary barrier of overbalanced fluids can be restored. All drilling programs in Baffin Bay/Davis Strait would have multiple contingency plans, including a Well Control Plan and an Emergency Response Plan.

BOPs (Figure 4.3) and other well control and emergency response equipment are expected to be fit for purpose and meet regulatory, industry and operator specific standards.



SOURCE: ExxonMobil

Figure 4.3 Typical Subsea BOP for Offshore Drilling

4.4 Formation Evaluation

During drilling, it is necessary to frequently measure the formation properties, including the porosity and permeability of the rock and the reservoir fluid properties if oil or gas is encountered. This helps to determine whether there is a commercial discovery or to abandon the well. This can be done by:

- Periodic well logging
- Conducting VSP after drilling is completed
- Well testing using down hole wireline tools
- Production flow testing to the surface if required by the regulator

Flow testing of hydrocarbons to the surface is not as common a method. It may require flaring oil or gas for a number of days to test reservoir pressure decline over time. Mitigation measures can include:

- Using high efficiency burners (95–99%)
- Flaring during daylight hours
- Standby boats with oil spill response equipment
- Monitoring for combusted hydrocarbons

4.5 Drilling Unit

Exploration requires a stable platform from which to drill the well. Drilling units have an opening (moon pool) that allows the drill string to extend into the water below. A typical rotary drilling system with a top drive is used to turn the drill string. There are two types of drilling units that could be used for exploration drilling in Baffin Bay and Davis Strait: drillships (Figure 4.4) and semi-submersibles.

Photo credit: Stena Drilling

Figure 4.4 Floating Drillship designed and configured for arctic drilling

A drillship is a marine vessel specifically designed to drill in deep and ultra-deep water in water depths ranging from 600–3,000 m and drilling depths of more than 12,000 m. Drilling equipment is passed through the vessel's moon pool via a flexible riser pipe that extends from the drillship to the seabed. Drillships are differentiated from other offshore drilling units by their mobility and the ability to propel themselves from location to location. Drillships are susceptible to being agitated by waves, wind and currents; this can be a challenge when the vessel is actually drilling, because the vessel is connected to equipment that can be thousands of metres under the sea.

Semi-submersibles (Figure 4.5) are a more stable floating drilling unit and are often chosen for harsh conditions because of their ability to withstand rough waters. They can operate at water depths of 500–3,000m. While in transit, semisubmersibles are towed by tugs to a location and then partially lowered by filling the legs with water to provide stability.

Photo credit: Husky Oil

Figure 4.5 Semi-submersible drilling platform

A key requirement of the drilling system is its ability to maintain its position (referred to as station keeping) at the offshore well site location. The two most common station keeping methods used today are:

- Moored drilling systems that use pre-set anchors attached to the seafloor
- Dynamic positioning (DP) using a computer-controlled system to automatically maintain the drilling unit's position and heading by using its own propellers and thrusters

DP allows for operations in deep-water where mooring is not feasible because of water depth. A drillship may also combine DP with a mooring system that might have 8–12 mooring lines that could be installed at the drill site the year before drilling begins. This type of drilling unit maintains a fixed orientation to the wind, currents and ice flows. If ice conditions require the moored DP drilling unit to leave the drill site due to an approaching iceberg, it can safely suspend the well, disconnect from the moorings, and move off location under its own power.

Drilling units are large and expensive. A drillship can be 200+ m in length and 40+ m wide. At an initial cost to build of $500 million USD or more, their day rate can be $250,000–$400,000 USD/day depending on supply and demand. Similarly, semi-submersible hull dimensions can be 120 by 120 m and stand 40–50 m high when partially submerged. Semi-submersible rates are typically somewhat less than a drillship, in the order of $200,000–$250,000 USD/day. As demand and competition goes up, so do the day rates.

Drilling units typically come with a full complement of experienced workforce for that rig that are rotated on a set schedule. Whatever drilling unit is chosen, a Certificate of Fitness for the unit is to be issued from a recognized independent third-party certifying agency. The purpose is to certify the drilling unit is fit for purpose, functions as intended, and is in compliance with the regulations.

4.6 Drilling Support

The major components of an Arctic offshore drilling program in Baffin Bay/Davis Strait would be expected to include an Arctic-class drilling platform, icebreaking support vessels, ice-strengthened supply vessels, ice-strengthened fuel tankers, and possibly ice-strengthened wareships for offshore storage.

Most Arctic drilling operations would require one or two icebreaking support vessels (Figure 4.6). These support vessels would generally stay on station near the drilling unit and perform a wide range of operations including:

- Ice reconnaissance for a large area around the drilling unit
- Carry and deliver fuel and supplies including drilling materials to the drilling platform
- Install and retrieve pre-set anchors, if a tethered drilling platform is used
- Deploy and retrieve remotely operated underwater vehicles
- If necessary, support emergency response operations, including well control response, oil spill response, and firefighting and personnel evacuation[8]

[8] Accidents and Malfunctions are discussed in section 10.0

Photo Credit: Janine Beckett
Figure 4.6 Example of support vessel (icebreaker)

4.7 Ice-Strengthened Supply Vessel

Depending on the operator's logistics, waste management, oil spill response and well control plans, two or three ice-strengthened supply vessels might be used to ferry fuel, drilling materials, other supplies, waste products, and personnel between drilling unit vessels and shore facilities. If required, these vessels would also support well control operations and oil spill response operations, including boom and skimmer deployment.

Depending on the logistics plan for the exploration program, either a single large ice-strengthened fuel tanker, several small tankers, or a combination of both, could be used to supply fuel for the drilling unit, icebreaking support vessels and ice-strengthened supply vessels. Fuel tankers for use in an Arctic environment would be expected to be ice class double-hulled.

Deep-water drilling operations typically require a deep-draft port in the vicinity of the well site. If a port is not available, an offshore wareship may be stationed near the drilling rig and be used to:

- Carry fuel, drilling materials and other supplies
- Receive waste products for storage and shipment

- Provide areas for maintenance and repair operations
- Support helicopter, well control and oil spill response operations

In total a drilling program, particularly in the presence of ice, may require five to eight vessels in the vicinity (2–5 km radius) of the drilling unit, and farther afield (10–50 km) to monitor for approaching icebergs, or in transit back and forth to a shore-based facility.

Various shore-based facilities and services are typically needed to support offshore drilling. For the Baffin Bay and Davis Strait, drilling needs could come out of Nuuk (Greenland) or St. John's, Newfoundland and Labrador, as there is already an established infrastructure that specializes in the offshore oil and gas industry. If services and facilities were available in Iqaluit, these could be used as well, but it is unlikely that additional infrastructure would be purpose built specifically for offshore oil and gas, unless it was deemed to be more economical or practical than using existing infrastructure in Greenland or Newfoundland. The exception to this would likely be related to storage of emergency equipment at key locations in Nunavut.

Facilities could include:

- Office space
- Accommodations
- Heated warehouses
- Staging sites
- STORAGE yards
- A docking area
- storage facilities for emergency equipment such as oil spill response equipment and other emergency equipment

Services could include:

- Communications
- Land transportation services, primarily between the shore-base and airstrip
- Air transportation services (including a fixed-wing and helicopter aerodrome base with two or more helicopters stationed there during all offshore operations)
- Waste management services would include transporting wastes on supply vessels back to the shore-based facility, for disposal onshore or for storage prior to shipment out of the region, either overland or on a wareship following completion of the drilling program

4.8 Ice Management

Every operator is required to file an ice management plan with the regulator as part of the drilling operations authorization (Canada-Newfoundland and Labrador Offshore Petroleum Board et al. 2008). The plan is to describe:

- Design and operating limits of the drilling system for the anticipated ice conditions based on historical data on sea ice and size of icebergs
- Conditions and ice features that would constitute hazards to the drilling system
- How the hazards would be identified and located
- Range of ice detection options that might be used such as:
  - Aerial and marine vessel recon
  - Radar
  - Satellite
- Capability and reliability to predict and track ice bergs

- Mitigation measures in place when an ice hazard is predicted
- Ice management capability inside the designated safety zone, including:
  - Ability to use prop wash, tow, or use water cannon to deflect the iceberg
  - Ability to rapidly disconnect the drilling unit and move off location until the hazard is passed

4.9 Drilling Waste Management

The *Canada Oil and Gas Drilling and Production Regulations* (2009) (Government of Canada 2009) establish the requirement for an EPP, required is to address all "discharge streams". The NEB *Filing Requirements for Offshore Drilling in the Canadian Arctic* outline the information to be included in the EPP or a separate Waste Management Plan (WMP) pertinent to waste management in the Arctic offshore. The *Canadian Offshore Chemical Selection Guidelines for Drilling and Production Activities on Frontier Lands* (National Energy Board et al. 2009) and the *Canadian Offshore Waste Treatment Guidelines* (National Energy Board et al. 2010) supplement the EPP guidelines (NEB et al. 2011b) by providing a framework for chemical selection, and an aid to operators in the management of waste material and the discharge of chemicals in offshore areas. The NEB's stated goal for these guidelines is to reduce the potential for environmental impacts from waste management in offshore drilling and production operations.

Routine discharges from maritime operations could include domestic wastewater (greywater), sewage (blackwater), wash down and drainage from decks and exposed structures, cooling water, ballast water and bilge water. All vessels in a drilling program would be subject to international maritime law, including the *International Convention for the Prevention of Pollution from Ships (*MARPOL 73/78) and the provisions of the Arctic Shipping Pollution Prevention Regulations*,* the Arctic Waters Pollution Prevention Regulations and the *International Code for Ships Operating in Polar Waters* (Polar Code). All discharges must be approved as part of a program-specific WMP.

Water runoff into the sea, from the above-the-waterline structures of drilling platforms, cannot be avoided. Clean decks are necessary to prevent draining water from mixing with oil stains, chemical stains, granular or finer material, or other residue on the surface of the deck. Bilge water and any collected drainage water is normally processed through onboard oil-water separators and tested for oil concentration before release. Discharge of oily mixtures is prohibited in Canadian Arctic waters.

Greywater is discharged directly to the sea, as treatment of greywater is not required under MARPOL 73/78. Sewage and domestic wastes are normally processed through onboard treatment plants before being discharged as treated blackwater and macerated food waste.

Cooling water is generally part of a closed loop system. Seawater pumped on board for this purpose cannot be contaminated or mixed with water from other sources before it is returned to the sea during normal operations.

Ballast water discharges are governed by a Ballast Water Management Plan, which includes approved onboard treatment systems. Ballast water treatment systems and discharges would be expected to comply with applicable international and federal guidance specific to Canadian waters.

Drilling wastes, in the form of residual drilling fluids and cuttings, comprise the principal wastes generated during offshore well drilling. In Canada, other than residual base fluid retained on cuttings, no synthetic-based mud (SBM) or enhanced mineral oil-based mud (EMOBM) fluid, or any whole mud containing these constituents, should be discharged to the sea, and under no circumstances should oil base fluid or whole mud containing oil base fluid be discharged.

To minimize the quantity of oil discharged into the marine environment, the NEB recommends operators use water-based mud (WBM) or low polyaromatic hydrocarbon content, non-toxic and biodegradable SBM. The use of oil-based mud (OBM) is approved only in exceptional circumstances, when the use of WBM or SBM is not technically feasible.

The cuttings associated with SBM can be discharged to sea only after injection is shown not to be technically or economically feasible. Before discharge, cuttings must be treated with best available technology to reduce oil concentrations on wet solids. Operators may discharge untreated WBM and associated cuttings to the sea; however, all offshore discharges are subject to approval by the NEB. Prior to authorizing offshore waste discharges, the NEB will consider stakeholder concerns, potential environmental effects, waste volumes, and levels of contaminants in the waste.

The *Offshore Chemical Selection Guidelines for Drilling and Production Activities on Frontier Land* (NEB et al. 2009) and the *Offshore Waste Treatment Guidelines* (NEB et al. 2010) provide approaches to identify less toxic drilling mud additives and production chemicals and reduce potential environmental impacts of drilling mud/cuttings and produced water discharges. These guidelines are similar to that of the Oslo and Paris Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR Commission 2007)

The contents of a WMP for an offshore drilling program would include a summary of all applicable territorial, federal and international requirements. It would provide a listing of all waste products, including sources, volumes, treatment methods, handling and final disposal options. The WMP would also be expected to identify opportunities for eliminating, reducing and recycling waste, as well as best practices and technologies for waste management. The plan must specify procedures for documenting and tracking waste, and the sampling and analysis procedures to ensure regulatory compliance.

Waste materials and used chemicals would be removed from the drilling platform and transported by the supply vessels to a shore-based facility. Onshore, a qualified contractor would arrange for disposal onshore or for storage in preparation for shipping out of the region, either periodically during the drilling program or following drilling completion. Contracted waste management services would include equipment and personnel for handling waste generated at a shore-based facility and from offshore operations. These services would likely be located in Newfoundland and Labrador, where there are such facilities in support of the local oil and gas industry.

4.10 Air Emissions Management

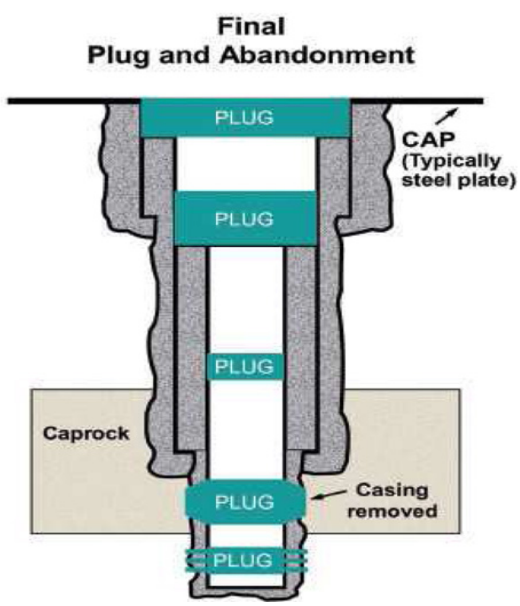
Air emissions from both exploration drilling and production operations contributes to localized changes in air quality in the immediate vicinity of the activities. The main sources of emissions are:

- Burning diesel fuel for electric power generation that creates carbon dioxide and nitrous compounds
- Methane and aliphatic volatile organic compounds (VOC) that are vented to the atmosphere from processes and fugitive emissions
- Flaring (as discussed under formation evaluation) and well testing that contribute to carbon dioxide, and small quantities of carbon monoxide, sulfurous and nitrous oxides and particulate matter
- Offshore loading of oil at loading buoys

For equipment like flares, turbines and generators required for specific project specifications, the operator will review manufacturers' emission factors to determine the best high-performance and efficient equipment to purchase during the design phase. Once installed and operational, the operator is required to report the annual quantities of greenhouse gas emissions to the regulator as per the *Canada Offshore Waste Treatment Guidelines* (NEB et al. 2010), while continuously assessing opportunities for reduction. Some of the best advances made over the past few decades have been made in burner technology with flaring, and a reduction in venting sources and fugitive emissions. If it is cost- effective and feasible, replacing diesel fuel or fuel gas with hydroelectric power from shore is an alternative technology that has been used in the North Sea and Middle East.

4.11 Well Abandonment

At the end of each drilling season, drilling activities would be suspended and the well secured until the next drilling season begins. Once a well has reached its target depth and all testing has been completed, it would be plugged and abandoned in accordance with NEB regulations. The abandonment process isolates subsurface formations from each other, thereby preventing the escape of any fluids from the wellbore and providing mechanical integrity of the plugged well (Figure 4.7). Cement and steel plugs are typically set at specific points along the wellbore. The cement is tested to determine if a proper seal exists. After the last plug is set and tested, the BOP is retrieved, and a corrosion cap installed over the wellhead. Monitoring an abandoned well may be completed if required by the NEB.



SOURCE: CO_2 Capture Project

Figure 4.7 Final Plug and Abandonment

5 ROUTINE DEVELOPMENT AND PRODUCTION ACTIVITIES

Once an oil or gas discovery is made and the extent of the reservoir is determined by 3D seismic, delineation and appraisal drilling, the operator will run reservoir models to simulate the reservoir fluid flow behaviour to optimize the field development plan. This helps determine the most cost-effective way to develop the field and maximize reservoir recovery. It will also support the economic assessment, accounting for revenue from production forecasts and the estimated development costs. If the required economic criteria are met, a business decision is made on whether to develop the field.

A field development plan establishes the following:

- Number of development wells to be drilled to reach optimum production
- Recovery techniques to be used to extract the oil or gas from the reservoir
- Type and cost of installations, both subsea and on the surface
- Oil and gas separation systems if needed

Unlike exploration drilling, development drilling can employ deviated wells, horizontal wells, and multi-drain wells. These additional technologies can reduce the surface footprint while increasing well productivity. Horizontal drilling has significantly advanced over the past decade, allowing a reduction in cost, less offshore structures and other field infrastructure, resulting in the drilling of less wells to deplete an offshore field. The present record for a horizontal well is at ExxonMobil's Sakhalin 1 project with an extended reach of 15,000 m (15 km).

There are a number of options available for production:

- Gravity-based Structure (GBS) with a topside, depending on water depth
- Subsea installations with tie back to a floating production platform
  - Floating Production, Storage and Offloading (FPSO) vessel
  - Floating Liquid Natural Gas (FLNG) vessel
- Subsea installations with tie back to a shore-based facility for processing via an undersea pipeline

In all cases the objective is to allow for production year-round if possible, which requires storage capability and the means to routinely move the product to market. The following describe several examples of different offshore production systems in use or planned.

5.1 Gravity-based Structures (GBS)

Gravity-based structures are generally constructed with concrete bases that sit directly on the ocean floor. They are suitable for use in shallow water (less than 300 m) with hard substrate on the seafloor to reduce potential shifting of the structure. Due to the weight and volume associated with these structures, they can withstand sea ice and storm conditions. An example of a GBS is the Hibernia platform (Figure 5.1) off Canada's east coast, which sits in 80 m of water approximately 300 km east of St. John's, Newfoundland and Labrador. First discovered in 1979, Hibernia underwent environmental assessment in 1986 and produced first oil in in 1997. It consists of three components:

- Topsides:
  - Two mobile drilling derricks
  - Producing system

  - Utilities
  - Living quarters for 185 people
  - Separation facilities to remove gas and water from the crude oil
  - Gas re-injection into the reservoir
  - Produced water treatment and discharge
- Gravity-based Structure:
  - Concrete structure designed to withstand the impact of an iceberg
  - 1.3 million bbls crude oil storage
- Offshore loading system for tankers

Photo credit: ExxonMobil

Figure 5.1 Hibernia Production Platform

The Lunskoye platform (Figure 5.2) in the Sea of Okhotsk, Russia, is an offshore natural gas production that sits in 50 m of water. The four-legged concrete GBS is designed to withstand heavy ice and an earthquake measuring 8.0 on the Richter scale. The rounded shape of the legs helps ice floes to slide around them or to edge up the legs and then fall backwards onto the frozen sea surface. The topsides are connected to the concrete legs using sliding joints. If an earthquake strikes, the topsides move independently from the legs in a pendulum motion to prevent damage.

Photo credit: Sakhalin Energy

Figure 5.2 Lunskoye Natural Gas Platform

Another type of GBS production platform was designed and installed in Russia's Prirazlomnaya offshore (Figure 5.3) oil field in 2013 and is currently the only hydrocarbon production platform on the Arctic shelf. It is located in the Pechora Sea, 60 km offshore in 20 m of water. This offshore fixed gravity platform is the first of its kind in Russia and was designed for extreme Arctic weather conditions. The platform (Figure 5.4) is used for all production operations, including well drilling, oil extraction, storage, treatment, offloading and water injection. The wellheads are located within the platform, and its foundation serves as a buffer zone between the wells and the open sea. A caisson was created from welded steel superblocks, then the topsides were installed and concrete cladding added. Once the platform settled into the seabed, a safety berm of aggregate was laid around its base. The two offloading lines used for transferring oil to tankers are provided with emergency shutdown systems that can be quickly activated.

Photo credit: GaspromNeft

Figure 5.3 Prirazlomnaya Oil Platform

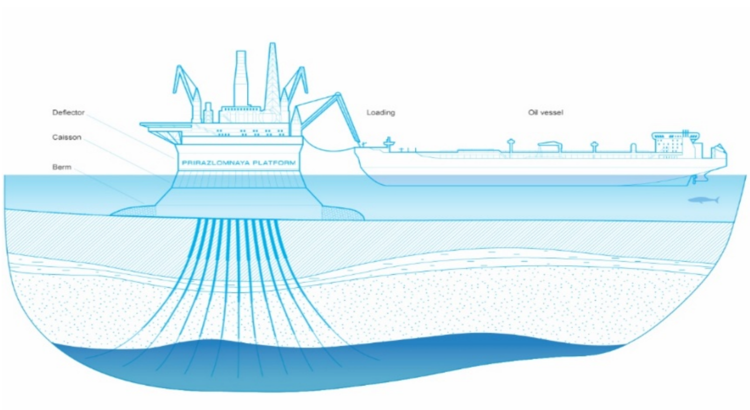


Photo credit: GaspromNeft

Figure 5.4 Schematic of the Prirazlomnaya Oil Production Platform

5.2 Subsea Installations with Tie Back to a Floating Production Platform

5.2.1 Floating Production, Storage and Offloading (FPSO) Vessel

An Floating Production, Storage and Offloading (FPSO) is a floating vessel that is designed to lift, process, store and offload hydrocarbons. FPSO vessels are essentially tankers with added hydrocarbon production and processing equipment. Their major advantage is in the development of fields located in deep waters where GBS structures cannot be installed. After processing, the produced hydrocarbons are stored until they can be offloaded to tankers. Associated gas can be re-injected into the field to maintain production or possibly processed into liquefied natural gas (LNG) for shipment. Floating Liquefied Natural Gas (FLNG) vessels are offshore LNG facilities designed to enable the development of offshore natural gas resources. FPSO and FLNG vessels are usually moored permanently at a specific location, but can be detached from their moorings in case of extreme weather conditions. FPSO and FLNG systems could be employed for seasonal use or for year-round operation in harsh Arctic environments.

Suncor Energy's Terra Nova oil and gas development, located 350 km southeast of the Island of Newfoundland, was the first offshore development in North America to use an FPSO (Figure 5.5) in an area with floating sea ice and icebergs. Since its start-up in 2002, Husky Energy has also used an FPSO to develop its White Rose oilfield in offshore Newfoundland and Labrador.

Photo credit: Suncor

Figure 5.5 Terra Nova FPSO

One of the largest FPSO vessels ever built, the Terra Nova is 300 m long and 45 m wide, approximately the size of three football fields laid end to end, and standing 18 stories high. The vessel can store 960,000 bbl of oil and accommodate up to 120 people. Oil production wells were pre-drilled by a semi-submersible drilling unit. Wellheads and production manifolds were placed in excavated drill centres in the sea floor to protect the equipment from scouring icebergs (Figure 5.6). A network of more than 40 km of flexible flow lines are used to convey hydrocarbons from the wells. Produced gas is separated from the oil and re-injected into the reservoir to support oil production and for possible future extraction. Crude oil is offloaded from the FPSO onto large shuttle tankers for shipment.

Photo credit: Suncor

Figure 5.6 Schematic of Terra Nova

The connection between the FPSO and the subsea flowlines is called a spider buoy. It provides the mooring point for the FPSO and is the pathway for oil that flows from the reservoir to the vessel. The spider buoy has a quick- disconnect feature, allowing the FPSO to safely disconnect and leave the area quickly in an emergency.

The Terra Nova FPSO is a double-hulled, ice-reinforced vessel. It has five thrusters and a global DP system that allows the vessel to maintain its heading while reducing the impact of ice and waves by allowing the FPSO to “weathervane” or change to a more favourable heading in high winds and storms.

The Goliat FPSO (Figure 5.7), in the Norwegian sector of the Barents Seas and developed by ENI, started production in 2017. It is a floating cylindrical production facility designed to withstand harsh Arctic storms in the region. Its design allows for the loading of oil on to shuttle tankers from any point on its circumference depending on wind and current conditions. Production takes place through a subsea system of 22 wells consisting of 12 oil producing wells, 7 water injection and 3 gas injection wells (Figure 5.8). It has a storage capacity of 1 million bbls.

Photo credit: ENI

Figure 5.7 Goliat Oil Production FPSO

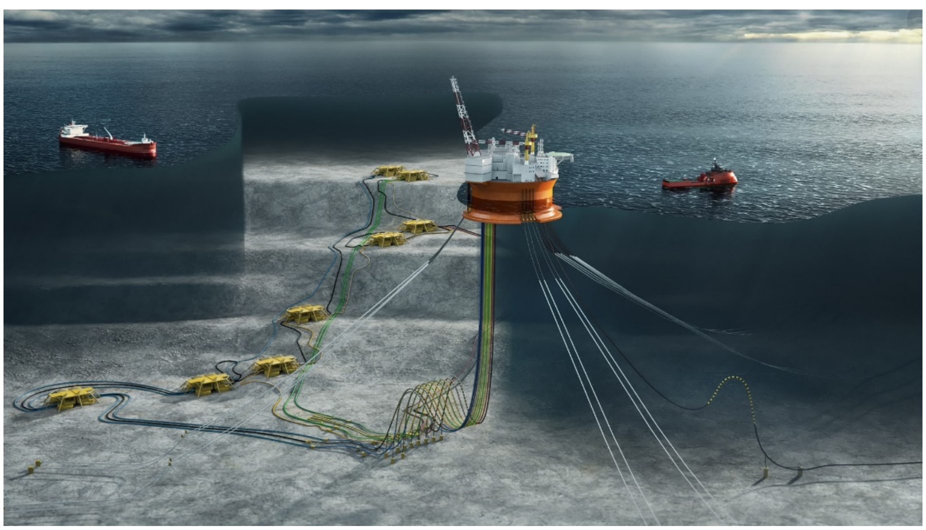
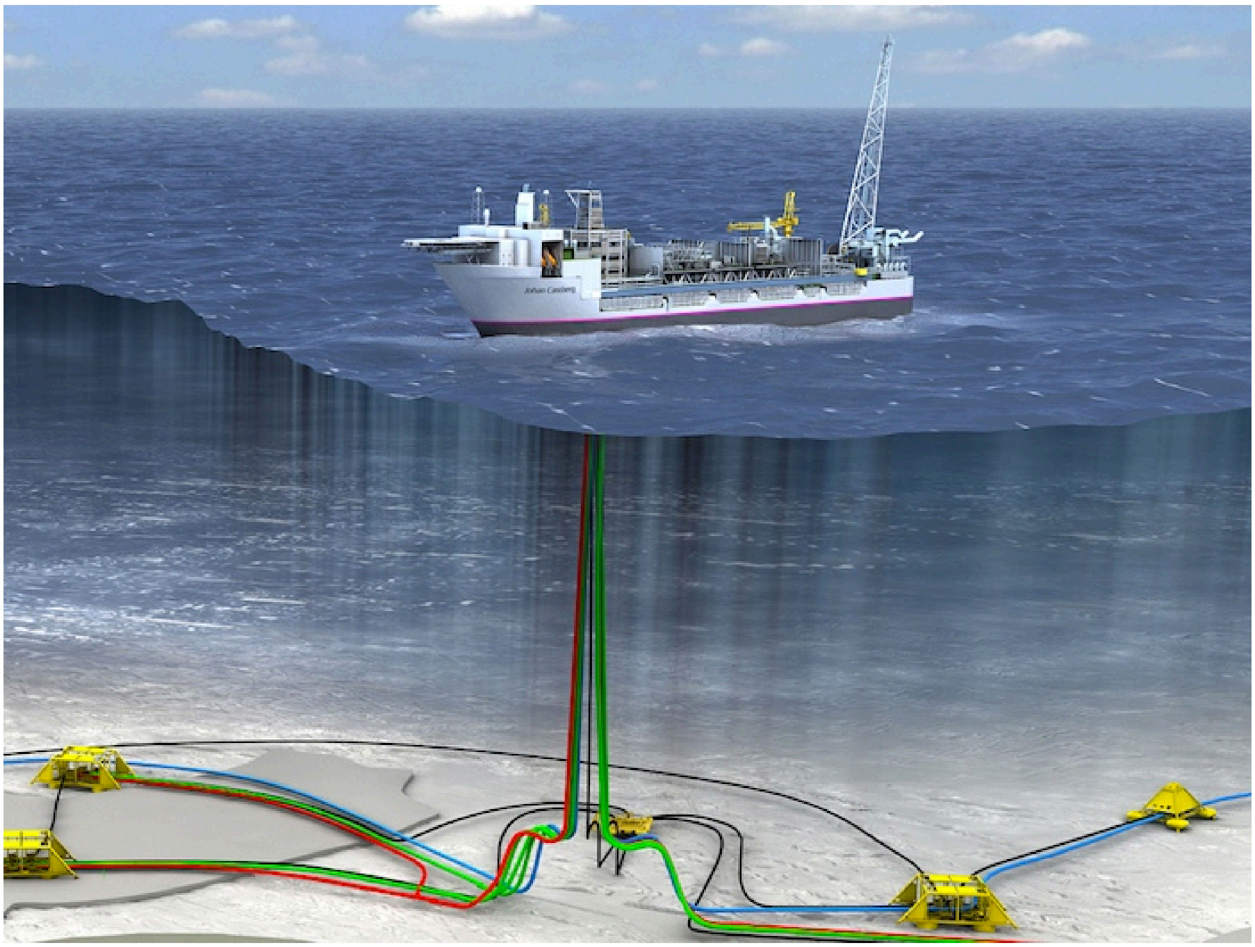


Photo credit: ENI

Figure 5.8 Schematic of Goliat Subsea System

Statoil is proceeding with the Johan Castberg FPSO project, which would be the most northerly field development on the Norwegian continental shelf of the Barents Sea. The project encompasses several earlier discovered separate fields in 350–400 m water depth, and will involve drilling 30 wells tied together in an extensive subsea development spread out over kilometres of the seafloor (Figure 5.9). This project is a good example of a series of smaller discoveries in a region being able to be developed through economies of scale. The target for first oil is 2022 with an expected life of 30 years. The project will include a supply and helicopter base on shore.



SOURCE: Statoil

Figure 5.9 Schematic of Johan Castberg FPSO and Subsea Collection System

In addition, Statoil and companies with other discoveries in the area are assessing the need for an onshore oil terminal to handle oil from a number of fields, yet to be developed, to allow for the use of larger oil tankers.

In addition to production offshore on a GBS or FPSO, oil can also be transported to shore by a subsea pipeline after being collected by flowlines from subsea wellheads. Oil pipelines are designed to meet the expected production rate from the field, and are typically 91.4–121.9 cm (36–48 in.) in diameter.

Seabed condition and composition is a primary factor in using a subsea pipeline (i.e., level surface, rock or sediment composition). Another important factor is whether the pipeline is laid on the seafloor or in a trench. Trenching is a common practice for the following reasons to:

- Avoid ice scour or iceberg gouging of the seabed
- Protect against landslides
- Protect against strong currents
- Protect against fisheries trawling and ship anchors

An onshore processing facility can include:

- Separation vessels to remove produced water
- Oil / gas separation if required
- Produced water disposal system
- Storage tanks
- One or more flare systems
- Fuel supply for power plant
- Crude desalting plant
- Sea water desalination system if required
- Utilities, maintenance and repair buildings
- Storage and laydown area
- Fire protection system
- Accommodations, telecommunications, airstrip and/or heli-pad
- Oil loading marine terminal

5.2.2 Floating Liquid Natural Gas (FLNG) Vessel

There are presently six FLNG vessels in service around the world, with more in design or under construction. There are no FLNG facilities yet in the Arctic, but there is extensive research and technology development to expand their use into harsh and cold environments.

As with FPSO, the FLNG vessel is moored directly above the natural gas field. The gas is then routed from the seabed to the vessel via risers. When it reaches the vessel, the gas is processed to separate it from liquids and condensate. The processed gas is then treated to remove any impurities and liquefied through freezing down to minus 160°C and stored in the hull. Ocean going LNG carriers off-load the liquid gas for delivery to LNG terminals around the world.

The advantages of FLNG include:

- All processing done at sea; no need to lay long pipelines to a shore base
- Well suited for fields with high production rates and far from land
- Can build at remote shipbuilding facility and start up faster than a shore-based processing facility
- Allows flexibility to move the vessel to a new location when the field is depleted
- Can be more economic than other alternatives

An example of a new FLNG is the Shell Prelude (Figure 5.10), which has been designed and built to stay moored in harsh weather conditions. It is the largest FLNG built to date at over four football fields in length.

SOURCE: Shell

Figure 5.10 Shell Prelude FLNG and LNG Tanker

There are some challenges to FLNG, such as:

- TNneed to fit every component onto a vessel that is one quarter the size of a conventional Shore-based processing facility
- Need to reduce wave action on the vessel so as to avoid sloshing of the liquefied gas in a partially filled tank
- Need to safely transfer the liquefied gas into a LNG tanker alongside the processing vessel

In addition to liquefied natural gas, dry gas can also be converted to compressed natural gas (CNG) at 2,900 psi. CNG tankers are less expensive to build than LNG tankers, but are considered more dangerous because of the high pressure. CNG systems are generally used for smaller to medium sized regional gas delivery and LNG tankers for long distances.

5.3 Subsea Installations with Tie Back to a Shore-Based Facility for Processing Via an Undersea Pipeline

The more conventional way to process natural gas is to pump the gas through a high-pressure pipeline to a shore-based processing facility for liquefaction (Figure 5.11) and then load on to an LNG tanker. Such shore-based facilities typically require a large footprint for safety reasons. As described above, the advantages of using a tie back to a floating production platform (FPSO or FLNG) are leading to more prevalent use of that option, especially in regions where the field may be far from shore and the construction and use of a subsea pipeline may not be practical or economical.

Photo credit: Shell

Figure 5.11 Shore-Based LNG Liquefaction Plan and Loading Terminal on Sakhalin Island, Russia

5.4 Transport of Production

Marine tankers would be required to transport produced crude oil and natural gas out of the Baffin Bay/Davis Strait region to an export destination. Tankers would meet applicable Arctic Class requirements, with double-hulls and latest navigation and communications equipment (Figure 5.12). Ballast water would be in segregated tanks on the vessel. A traffic control and ice management system would be in place to optimize the routing based on ice conditions and weather. The number of tankers and their frequency of transit would depend on production rates, storage capacity on the offshore or onshore facility, vessel capacity and destination locations. A typical large offshore oil production could require 200,000 dwt tankers loading every few days, with similar frequency of LNG tankers for a natural gas facility offshore or onshore.

Photo credit: Gazprom

Figure 5.12 Oil Tanker Approaching Prirazlomnoye GBS in Pechora Sea Russia

5.5 Support Infrastructure

The support infrastructure for development and production is similar to exploration activities described in Chapter 4 and would consist of a permanent fleet of supply and support vessels, icebreakers as required, and aviation support.

The time period for offshore hydrocarbon production (crude oil and natural gas) extraction can vary from 15–30 years, depending on the size of the discovery, and can be extended for 50 years or more for giant fields or tie-ins with new discoveries in the area. The lifetime of a reservoir is composed of different successive phases:

- Period of production increase (including additional drilling or tie-in with new fields in close proximity)
- Stabilization phase in which the production plateaus
- Injection phase (water, gas or chemicals) to assist hydrocarbon recovery
- Depletion period when production progressively declines

When the production rate becomes non-economical, the production is decommissioned, the facilities are dismantled, reclaimed and removed, and the wells are put into a permanent safe state. On occasion the field may be preserved such that, with new technology, the field could be re-commissioned to extract any residual hydrocarbons left in place.

6 ADDITIONAL FACTORS TO CONSIDER

There are inputs other than geological factors that should be considered to determine the commercial viability of an oil and gas project in the Baffin Bay and Davis Strait region.

6.1 Operating Environment Challenges

The oil and gas industry operates offshore worldwide, often in extreme conditions. To operate safely and manage risk associated with the extremes inherent to the offshore environment, innovative engineering, technology, and extensive planning are used. The Baffin Bay and Davis Strait operating environment is similar to other Arctic regions where oil and gas development currently occurs or has occurred in the past and would not pose any unique technical constraints or obstacles with respect to water depth, ice, or oceanographic or meteorological conditions.

Any company conducting marine seismic or exploration drilling will need to plan for the operating conditions in the region, which can affect timing of operations and periodic delays or suspension of activities. Seismic and exploration drilling requires open water conditions; these can change from year to year. Long or repeated delays could result in additional years added to a program to complete its objectives.

The icebergs that calve off the Greenland, Baffin Island, and Canadian Arctic Island glaciers and migrate south along the coast of Baffin Island pose the biggest challenge. Operators will be required to have a sound and flexible ice management plan (see Section 4.8).

The oil and gas industry has extensive experience in iceberg management from operating in the Grand Banks, offshore Newfoundland and Labrador. Icebergs are tracked in real time and their drift trajectory is forecasted as they approach a drilling rig or a production facility. Typically, a safety zone is established (20 km or more away) and icebergs (and sea ice) are managed to move them out of the safety zone. If ice management is not successful in keeping icebergs from a drill rig, there are emergency quick release mechanisms in place allow it to temporally disconnect from their anchor mooring system and move away from the threat. Ice management has been proven to be very effective in extending the drilling season as well as reducing the risk of downtime and disconnection.

A GBS is designed to withstand iceberg impacts. The Hibernia platform is designed to resist the impact of a one-million tonne iceberg with no damage. If the production facility is floating (FPSO or FLNG), it can disconnect and move off location.

Ice management procedures include support vessels for towing and deflection, onboard ice watch capability, iceberg data collection and detection resources such as radar, fixed wing aircraft and remote sensing satellites. The international Ice Patrol of the US Coast Guard and the Canadian Ice Service of Environment Canada both provide airborne surveillance along the east coast for international marine traffic, fishing industry and the oil industry.

Other operating challenges for Baffin Bay and Davis Strait include the lack of shore-based infrastructure and remoteness. These can be partially offset by the use of established infrastructures in Newfoundland and Labrador, as well as Greenland. As described in previous chapters it is increasingly common for production from offshore fields to be self-reliant and not require a large shore-based infrastructure.

Long-term trends from climate change in the Arctic may increase the frequency of icebergs while diminishing the ice pack. Climate change in the Arctic that results in less ice can allow for longer open water windows for routine vessel transits out of the region, an extended summer drilling season, and reduced risks from multi-year ice incursions. It can also increase the frequency and severity of open water storms. However, ice incursions can occur in any given year, which would still require an ice management program involving ice breakers and drilling and production systems designed for multi-year ice over the life of the project.

More frequent storms and severe fog due to more open water could result in restriction to aircraft operations and vessel traffic from shore base to offshore facilities.

6.2 Potential for Expansion and / or new Discoveries

It is difficult to project the potential for expansion when there has not been any initial development in the region.

What can be predicted from industry experience elsewhere is how future development projects are likely to begin and build-out over time. Most offshore development projects in remote areas begin with a single production platform. If the reservoir is relatively simple and not more than a few kilometres in aerial extent, it may be possible to recover hydrocarbon fluids from the entire reservoir through directional drilling from a single production platform. In the early stages of production, any associated natural gas produced with crude oil will likely be re-injected for pressure maintenance, as well as to conserve the gas for future possible exploitation.

Initial crude oil production can begin with the minimum number of wells required to operate a single treating train[9]. Production at the platform will be increased as additional wells are drilled, until all treating trains are at capacity and the platform is producing at its maximum capacity. Over time, additional production capacity is often installed to maintain production levels by adding additional tankage and treating equipment.

If the reservoir is complex or large in aerial extent, additional production platforms may be added to extend the reach of wells into producing zones that cannot be reached from the original platform. Some reservoirs may have two separate production zones, which are potentially too far apart to be reached from a single platform. In such cases, a second satellite platform would have to be installed either during initial field development or at a later date, once experience is available from operation of the first production platform.

Over the producing life of a field, additional infill production wells are drilled to allow for the conservation of hydrocarbon reserves from the entire reservoir. As production drops over time due to natural pressure reductions in the reservoir, additional water injection wells are also drilled as part of a pressure maintenance program. If the production from an individual well drops, a well workover[10] is done in an effort to restore production levels. Infield drilling, water flooding and well workovers are all measures taken to conserve the reservoir and maximize hydrocarbon recovery as required by the regulator.

[9] a sequence of equipment on the production platform that removes impurities, water, sulfur, separates out crude oil from natural gas and condensate (if present) before the crude is ready for market. As crude production increases the number of "trains" (i.e. equipment) can increase.

[10] Well workover refers to any downhole activity in the wellbore that can increase production

The primary incentive for additional exploration and development of new hydrocarbon reservoirs adjacent to anchor developments is to maintain or increase production and maximize the use and lifespan of project infrastructure. New discoveries can lead to expansion of commercial satellite fields, which can tie into an anchor field and be cost-effective.

Future discoveries in West Greenland could provide some benefits to integrate development between the two jurisdictions to allow for economies of scale, and reduce costs.

6.3 New Technologies and Operating Practices

Marine seismic data acquisition has changed considerably in the past decade with the drive to acquire higher quality data while reducing lost noise in the water column, including:

- Enhanced bandwidth and broader range of frequencies using deeper towed streamers
- Controlled-source electromagnetic survey on the seabed to provide better geologic images
- Use of marine vibrators that emit low levels of continuous energy in place of impulse energy (e.g., airguns)
- The use of autonomous underwater vehicles as a replacement to cables receivers
- Reducing signal loss by having the towed array go as deep as 50 m, thereby reducing noise levels in the water column

Drilling technology developments have focused on:

- Well control operating practices to prevent accidents or loss of fluids
- Faster drilling time with less shutdowns
- Technology that combines high quality modeling of physical parameters with well design
- Directional and horizontal drilling to limit the surface area of well site locations
- Coiled tubing drilling
- Reducing need for production flow testing
- More benign drilling mud components
- More efficient drilling waste treatment equipment that can reduce oil content on the discharged muds and cuttings
- Grind and injection options for cutting disposal
- The design and construction of new and upgraded ice-class drilling systems
- New designs for GBS platforms to accommodate multi-year ice and icebergs
- The design and construction of new icebreakers, including increased steel strength
- Alternatives to flaring, including a procedure called Formation Testing While Tripping[11] (FTWT)
- Development and placement of capping stacks around the world that can be rapidly broken down, transported by air or vessel, re-built, and deployed over a subsea well blowout
- Adding additional barriers to well control beyond the BOP shear rams, such as the injection of a liquid polymer resin and a liquid catalyst into a damaged BOP, resulting in an immediate solid polymer plug that seals and stops the flow
- Adding ability to inject oil spill dispersants directly into a damaged BOP on the seabed to increase the effectiveness of dispersion in the water column and reduce oil reaching the surface

[11] Taking samples of oil/gas that come to the surface in the drilling mud circulation while the drill string has been pulled out of the hole to add a new drill pipe.

The global trend in offshore development is submerged production at the seafloor to a floating vessel. The design includes:

- Automated control features
- Power cables to move oil or gas from wellheads to surface vessel
- Requiring materials and components strong enough to withstand water pressures at great depths
- Technologies to better install and dismantle after productive life
- Technologies below the surface to reduce impacts from weather
- Ability to shut down seabed wellhead flow immediately in event of iceberg presence
- Ability to move the vessel (FPSO or FLNG) off location quickly in event of iceberg presence
- Significantly reduce or avoid onshore footprint

6.4 Cost and Business Outlook

Costs and the business outlook are two of the most important factors that determine whether a project goes ahead. Current cost estimates for offshore exploration and development in water depths greater than 100 m are an order of magnitude greater than shallow waters and even greater in Arctic waters. Today's offshore Arctic development could require sustained and predictable oil and gas prices in the range of $80–100 USD/bbl and $8–10 USD/TCF (or greater), respectively. That threshold could start to come down in the future as more cost reduction opportunities are identified, and new research and technology develops. By comparison, in 2018, the cost threshold for most of the major oil companies' offshore projects globally is in the $40–50 USD/bbl range or higher.

The other critical factor relates to supply and demand. Today new offshore Arctic developments have to compete with lower-cost and more accessible discoveries in temperate and tropical environments. With better seismic survey data available, new discoveries are being made worldwide in offshore regions not previously explored, in addition to land-based production coming from oil sands and through the use of increased fracking technology. Demand for oil and gas is predicted to continue for the foreseeable future (International Energy Agency 2017) , with natural gas likely to increase in demand as a replacement for coal in power plants.

6.5 External Events

External events can have a significant impact on the timing of a project and the decision on whether or not to proceed. This is particularly true with projects in the Arctic offshore, with high costs and often limited or no infrastructure. At the global scale, such events can include:

- Political and regulatory stability and predictability
- Growing supply of worldwide oil and gas resources in more accessible areas and at moderate prices
- Increasing supply diversity such as shale resources
- New market storage availability
- Growing pipeline and marine transport capacity
- Continuing competition and reduction in costs for offshore exploration and development

In the case of Canada's Arctic offshore, the impact of political and regulatory uncertainty and predictability is a substantial risk to the oil and gas industry. For example, when acquiring an exploration licence, it is generally assumed that further exploration may be required in a region for an extended period to secure additional and sufficient discoveries for commercial economies of scale. Historically (such as North Sea), many exploration wells are required to be drilled in a region before a large discovery is made that would act as the anchor field or first commercial development. The 2016 US—Canada Joint Arctic Statement announcing Canadian Arctic waters as indefinitely off limits to new oil and gas licences, has increased the regulatory uncertainty for the oil and gas industry.

As discussed earlier, the Area of Focus does not have an extensive history of oil and gas exploration and development and is still in the early stages of analyzing and planning for how or if it could proceed in the region. It is likely that regulatory and policy factors will evolve as the planning process proceeds, which leads to additional uncertainty for the oil and gas industry. These factors may include:

- A new Canada Arctic Policy Framework
- Predictable and clear royalty rates over life of the project
- Shared Arctic Leadership
- Devolution of offshore oil and gas to the Nunavut and the other northern Territories
- Frontier and Offshore Regulatory Renewal Initiative
- Outcome of the Regional Strategic Environmental Assessment programs
- Amendments to the CPRA
- The need to weigh risks such as safety issues; environmental and social issues from routine activities (e.g., air emissions, underwater noise, discharges into water or drill cuttings, ship strikes, disturbance of fish and wildlife, effects on ice, changes in traditional life); and potential effects of accidents and malfunctions including oil spills or leaks, vs. benefits such as:
  - Northern security and sovereignty
  - Royalties regime of federal and regional governments
  - Government incentives or ownership
  - Northern and local taxes
  - Training and employment opportunities, including transferable jobs
  - Improved infrastructure
  - Mechanisms to manage marine traffic, including increases from tourism and other resource development in mining sector
  - Support for long term research and environmental monitoring opportunities
  - Diversification of the local economy and attraction of new opportunities

6.6 Alternatives

Mapping a region's geology can identify the estimated and speculated reserves potential of an area. Baffin Bay and Davis Strait have been systematically studied over the years, primarily by the Geological Survey of Canada. However, to identify the presence of an oil or gas reservoir, more intensive studies, including modern seismic data and, if necessary, exploratory drilling, would be required. Only by drilling a well is it possible to identify reservoirs, their hydrocarbon type, and their potential volumes. Exploratory drilling in a new basin with little or no previous data will more often come up empty (i.e., a dry well). If an initial discovery is made, it still does not identify the lateral extent of the reservoir and requires additional delineation drilling to determine the size. There may be situations where the reservoir properties are such (e.g., extremely high pressure) that development is not technically feasible.

Once a successful discovery is made, the most efficient and cost-effective way to develop the reservoir needs to be determined. For example, if the initial depletion rate is too high, much of the oil or gas will remain stranded, thereby reducing the ultimate recovery volumes. One option is to maintain pressure by water injection into the reservoir. As discussed in Chapter 5, there are several alternatives to bring a reservoir into production.

The main seismic survey alternatives are the use, duration and location of 2D vs. 3D surveys. For offshore exploration, it is generally recognized that 3D is required to best identify the preferred drilling location and total depth.

For drilling alternatives, other than the type of drilling rig, it may be possible to drill only to the first formation to secure an SDL, thereby reducing the time spent on location. If the drilling does encounter oil or gas, there are alternatives to flaring to determine the reservoir pressure. Other options for drilling (e.g., drill stem test) would require approval from the regulator.

For development, the single largest alternative is to reduce or avoid any type or location of landfall facilities or activities. Avoidance of landfall facilities and use of floating facilities increasingly is the preferred option.

6.7 No Activity Option

The decision to not allow exploration or development of oil or gas in the region is always an option that needs to be carefully considered by all stakeholders (e.g., governments, Indigenous people, local communities, the general public, and industry). This regional SEA is an important step in taking a holistic approach on all of the issues involved, weighing both positive (such as economics opportunities, employment) and negative effects (such as effects on wildlife harvesting).

There is no value to the hydrocarbon industry in making incremental decisions (e.g., marine seismic is approved, but no follow-up exploration drilling, or production drilling is allowed). The entire life cycle from initial awarding of an EL through to possible production has to be considered and understood in advance, recognizing that the regulatory process may in itself stop or restrict a project activity.

There are examples in Canada where a decision was made to place an offshore area in temporary (i.e., periodically reviewed) or permanent moratorium on oil and gas activities. In addition to the current ban on new licensing in all Canadian Arctic waters (including the Area of Focus), examples include Georges Bank off the coast of Nova Scotia, Queen Charlotte Sound and Hecate Straits off the British Columbia west coast, northern Hudson’s Bay in vicinity of Southampton and Coats Islands, and Lancaster Sound. The outcome is simply that the area off limits is not tested for its resources and economic potential, sometimes referred to by the industry as a stranded resource.

While the industry generally prefers keeping areas open for possible exploration, the impacts of closures on multinational companies is usually marginal at best, as international investments flow to regions of the world where oil and gas activities are encouraged and profitable. There is currently a high level of global competition for hydrocarbon production, as those areas of the world seeking such investments are increasing, not decreasing.

7 REALISTIC/TYPICAL LIFE CYCLE TIMELINES

7.1 From Exploration to Development

Initial interest in a region typically comes from an understanding of geological and hydrocarbon potential. Further data are typically acquired by geophysical companies in the form of 2D seismic surveys and are often underwritten by oil and gas companies. It can take many decades to acquire that understanding. Early data collection is often not necessarily of high quality and may require repeating with better technology and newer computer-assisted analysis and interpretation.

Such is the case for the Baffin Bay and Davis Strait region and the need for more advanced 2D seismic surveys. The timing to obtain such approval from NEB, including local and community consultations, can take years. Once approval is received, it takes time to carry out the field programs over such a large geographic area.

If there is interest, a company may request a call-for-nominations or the federal government may initiate a call-for-bids for a selected area. This process typically takes approximately one year and can lead to a decision to issue an EL (with conditions).

The successful EL rights holder may initially gather additional seismic data (typically 3D) to determine the best drilling location[s] in the EL. It can often take three to four-plus years before a preferred drilling location is identified. This typically includes planning and consultation; contracting a geophysical company with the necessary expertise and seismic vessel; securing a Geophysical Operations Authorization from NEB; conducting the field seismic program; and processing and interpreting the data.

Once a proposed drilling location is identified, a geohazard survey of the site can take 1–2 years to be carried out. Finally, if a decision is made to proceed with drilling, multiple years are required to contract a suitable drilling system; secure the required support vessels; make any vessel or equipment modifications as required to meet ice and weather conditions; and secure all approvals. The time to drill a single well can take 1–3 years depending on water depth, ice and weather conditions, total drilling depth, along with any unexpected delays such as stuck pipe in the well bore. Finally, the completed well will be permanently abandoned and any seabed cleanup undertaken.

The data acquired from the drilling program will determine if the company decides to drill any additional exploration or appraisal wells within the EL area, or terminate the program and let the EL expire if the work commitments under the licence have been met.

Presently the CPRA exploration licence term is 9 years, with some allowance for extensions. As noted above, INAC has initiated a review of the CPRA for the Arctic offshore which could result in a longer term for new EL's from 9 to 15+ years, similar to Greenland and other Arctic jurisdictions, which is a more realistic timeline. The Typical timeline for Exploration to Development is summarized in Table 7-1.

Table 7-1 Summary of Typical Timeline—Exploration to Development

ACTIVITY	TIMELINE
Initial interest in the region by company • can be driven by geology, government policies and incentives	N/A
2D speculation or funded marine seismic in a new region • Seismic interpretation and analysis • Decision to proceed / approach government re interest	 1–2 years 1–2 years
Call for Nominations by INAC (optional)	0.25 years
Call for Bids by INAC	0.75 years
Issuance of Exploration Licence (EL)	**[year 0]**
3D marine seismic survey (optional but usual) • Contract geophysical company / seismic vessel • Planning and consultation • Secure NEB Geophysical Operations Authorization • Field execution • Interpretation and analysis / identify drilling location[s]	 0.5 year 0.5 year 0.5 year 0.5 year 2–3 years
Seabed geohazard survey of proposed drilling location[s] • Contract survey company / vessel • Secure NEB Operations Authorization • Field execution • Data interpretation	 0.5 years 0.5 years 0.5–1 year 0.5 year
Offshore drilling rig and support vessels (icebreakers, tankers etc.) • Multiple contracts in place • Vessel and equipment modifications / upgrades to meet ice and weather conditions as required • Plan drilling program / establish support requirements • Public and regulatory consultations • Secure NEB drilling Operations Authorizations and other permits • Execution (per well) (ice dependent) • Well[s] permanent abandonment and cleanup • Well data interpretation	 0.5–2 years 0.5–2 years 1–2 years 1 year 1–2 years 2–3 years 1 year 1 year
Discovery[s] per EL • Application to NEB for a significant discovery declaration Secure SDL from government	 0.5 year 0.5 year

Total timeline range from EL to SDL: +/- 15–20 years

7.2 From Development to End of Production

If a discovery is made, a company can then apply for a significant discovery declaration from the NEB, a process that typically can take a year to complete as it requires a comprehensive technical assessment to determine the extent and dimensions of the reservoir. If successful, INAC then issues an SDL.

If the rights holder decides at some point to consider development, there is typically a period of internal review consisting of a reserves assessment, assessing market conditions, economic modeling, initial cost estimates, and risk assessment, often accompanied by a high-level feasibility study. This is followed by an application to the NEB for a commercial discovery declaration (CDD). Such internal reviews can often take two to four years or longer to carry out.

Changing global economic conditions can prolong the review. Once initiated, significant funding is required to continue, as offshore projects are typically measured in billions of dollars. Of note, there can be competition within a company's portfolio on where that funding is best invested for the highest return and lowest risk.

Typically, the first large expenditures are applied to front end engineering and development (FEED) studies, which includes detailed reservoir engineering; appraisal and development drilling and completions; development engineering; cost; and scheduling. FEED studies can take three to five years. Additional field work is often required at the site of the proposed offshore development, focused on seabed conditions and broader physical environmental studies such as ice conditions, both of which could affect design and operations.

The regulatory process leading to an NEB development plan approval (DPA), along with many other permits and authorizations, is usually a five-plus-year exercise. Once all approvals are in place, procurement and construction / new build of the platform can begin along with workforce training, facilities startup and commissioning. These activities can be in the order of 5–10 years. With a production licence in place from NEB, operations can continue for 20–40+ years, depending on the size of the producing field and if any new oil or gas can be brought on from nearby discoveries.

Taken together, the timeline from a significant, commercial discovery in the offshore through to end of production and decommissioning, based on actual projects in more temperate / tropical climate offshore areas, have been in the range of 25–50+ years, but can vary widely. It would be expected that such a timeline from start to finish in the arctic would be more like +/- 30–60 years. The Typical timeline for Development to end of production is summarized in Table 7-2.

Table 7–2 Summary of Typical Timeline – Development to End of Production

ACTIVITY	TIMELINE
Company determines discovery is commercially viable • Apply to NEB for CDD	1 year
Company commerciality review • Reserves assessment • Market conditions • Economic modeling • Cost estimates • Risk assessment • High-level feasibility study	1–3 years
FEED studies • Reservoir engineering • Drilling and completions • Development engineering • Cost and scheduling	3–4 years
Additional field studies • Sea bed geohazard surveys • Environmental studies (physical, biological and socio-economic)	2–3 years

Table 7–2 Summary of Typical Timeline – Development to End of Production

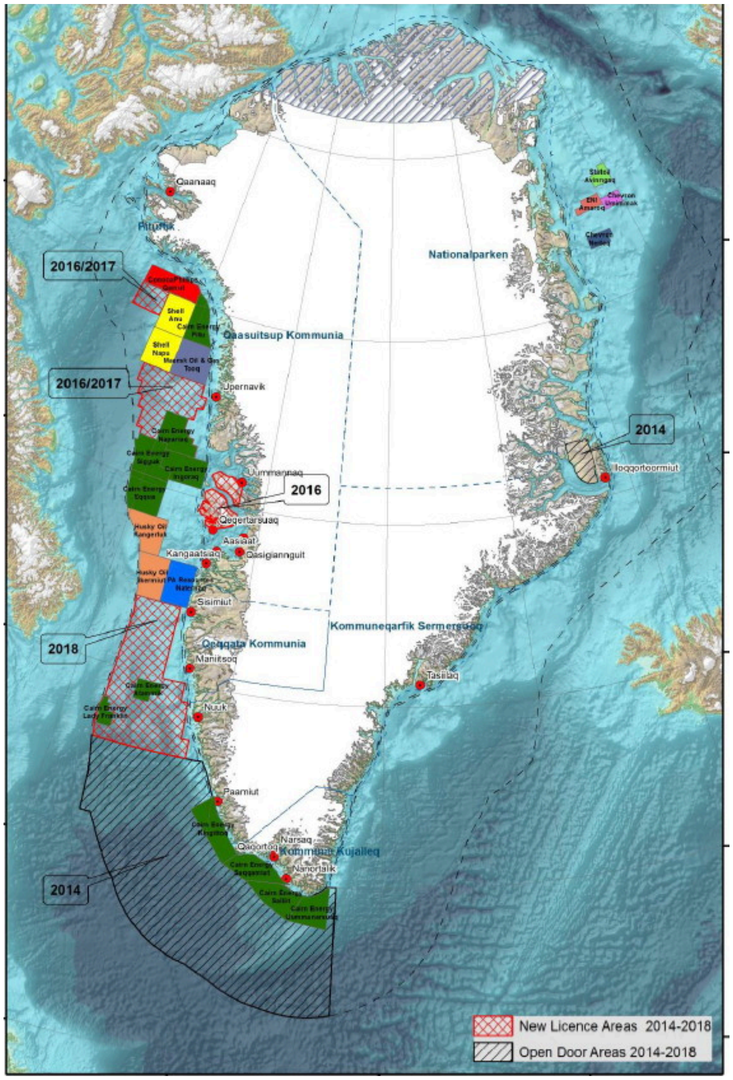
ACTIVITY	TIMELINE
Construction engineering design • Support facilities/marine base/aviation base • Telecommunications	2–3 years
Regulatory • Development plan preparation and submission to authorities • Environmental/socio-economic impact statements • Public review process/recommendations/conditions • NEB DPA • Governor–in–council Consent • Other permits (DFO, TC, ECCC, Nunavut)	2–4 years
Detailed Design and execution • Incorporate regulatory conditions • Procurement and infrastructure construction • Development drilling and vessel support • Procurement and facilities construction • Workforce and training • Final risk assessment/safety requirements • Facilities start-up/commissioning	4–6 years
Production operations • INAC PL • Regular maintenance and support • Expansion of facilities if required to bring in additional oil/gas discoveries • Decommissioning and cleanup	20–30+ years

Total timeline from commercial discovery declaration to decommissioning: +/- 30–60 years

8 ANALOGUE/EXAMPLES OF GLOBAL ARCTIC OFFSHORE EXPLORATION/DEVELOPMENTS

8.1 Offshore West Greenland

Offshore West Greenland waters provide a recent and close proximity analogue to possible future activities in the Canadian sector of Baffin Bay and Davis Strait. Following a series of government and industry funded speculative seismic programs in the 1990s and early 2000s, a number of licencing rounds were initiated by the Government of Greenland. Two Strategic Environmental Assessments were initiated in 2007 and 2009, covering waters in northeastern and southeastern Baffin Bay. An updated version of the strategic assessment for the Greenland portion of Baffin Bay was prepared and published in 2017. These SEAs helped to address issues and conditions for further 3D seismic and exploration drilling. Twenty-three licence blocks have been awarded to companies with 85,000 km of 2D seismic lines acquired and 14 exploration wells drilled (Figure 8.1). Many of these licence blocks have since been relinquished due to disappointing results from the initial exploration drilling programs.



SOURCE: Government of Greenland 2014

Figure 8.1 Western Greenland Oil Exploration Licencing

Cairn Energy was the most active explorer over the past decade, with large 3D seismic surveys (8km) (Figure 8.2 and Figure 8.3) and eight wells drilled. The following activities conducted by Cairn Energy are an example of the typical events conducted for a licence area.

Photo credit: Cairn Energy

Figure 8.2 3D Marine Seismic Vessel Operated for Cairn Energy in West Greenland

Photo credit: Cairn Energy

Figure 8.3 Support Vessels Assisting Seismic Survey in West Greenland

Prior to their operations, Cairn Energy carried out a series of engagements with stakeholders, including applicable government authorities, settlement and town administrations, harbour and airport administrations, local trade councils, and key potential contractors to discuss employment and business opportunities for local goods and services. The company established a local benefits agreement administered by a local authority, for education and community developments.

Cairn used two harsh environment drilling units, the Corcovado drillship (Figure 8.4), built in 2011, and the Leiv Eiriksson semi-submersible (Figure 8.5), built in 2001. The drilling units were scheduled so that only one rig would enter a hydrocarbon-bearing zone at any given time. Prior to and periodically during drilling operations, they conducted full testing of their BOP equipment, including testing by independent experts. Logistics was a major challenge, with supply and helicopter bases in Greenland, along with a base in northern Scotland.

Ice management was another key component of their operations. Their oil spill response procedures included equipment onboard their support vessels, access to additional equipment in the region, and access to worldwide equipment, aircraft and expertise at facilities in Southampton UK.

Photo credit: Ocean Rig

Figure 8.4 Corcovado Drillship Drilling in West Greenland

Photo credit: Ocean Rig

Figure 8.5 Leiv Eiriksson Semi-Submersible Drilling in West Greenland

Cairn Energy's exploration program showed that seismic and drilling operations can be carried out safely in a challenging physical environment, with limited impacts on the environment and positive benefits to people in the region. The company credited their success to:

- Having an experienced and high-quality team
- Using local knowledge and expertise, particularly understanding metocean and ice conditions
- Meticulous planning
- Early engagement with stakeholders
- Supportive government and people in the region

8.2 Sverdrup Basin in Nunavut High Arctic Islands

Panarctic Oils Ltd provides an early example in the search for oil and gas in the Canadian Arctic islands. Panarctic drilled its first exploratory well onshore in 1969, followed by 112 onshore wells and 38 offshore wells. The offshore wells were basically modified land rigs supported by floating, thickened sea ice platforms (Figure 8.6) constructed with thickened sea ice in water depths up to 600 m.

Photo credit: D.M. Masterson

Figure 8.6 Panarctic Ice Platform Drilling in Sverdrup Basin

Selecting drill locations required the collection of extensive 2-D seismic data over the land and ocean. Panarctic's 2D surveys totaled over 35,000 km, with 16,000 km collected over the offshore pack ice in late winter and spring.

Panarctic was a pioneer in Arctic exploration, contributing to new technologies and operations that were applied by the industry in other areas and jurisdictions, including the US and Canadian Beaufort Sea. These, included:

- Using satellite Earth stations for communications and weather predictions
- Positioning receivers on the ice and tracking changes in their position using five polar-orbiting satellites
- Constructing on-land drill sites, camps and airstrips under harsh conditions
- Building offshore ice islands as drilling platforms
- Adapting conventional rigs to a more modular design, totally enclosed against the weather and low temperatures, and easier to dismantle and move
- Developing Arctic rig matting
- Testing the performance of heat-traced insulated and un-insulated flowlines

Panacrtic drilled a well in 1969 at Drake Point on Melville Island, discovering a major gas field. In 1978, a production well was drilled and connected to a 1.2 km long subsea pipeline to shore to conduct a trial gas flow test (Figure 8.7). That pipeline was the first of its kind used in the Arctic. Its physical state is presently being investigated by the

National Research Council of Canada, as is the effectiveness of the measures adopted during its construction over 40 years ago to protect the line against ice action.

Photo credit: D.M. Masterson

Figure 8.7 Lowering Pipe Through the Ice at Drake Point In 1978

Panarctic discovered the Bent Horn oil field on Cameron Island in 1974 and Cisco, the largest oil field yet found to date (an estimated 500+ million bbl.), was discovered near Lougheed Island.

Sea lifts of equipment and supplies (Figure 8.8) from Montreal to Rea Point on Melville Island by oceangoing freighters and tankers, usually escorted by Canadian Coast Guard icebreakers, were a critical component of Panarctic's operations. Airstrips capable of handling twin otters, Hercules and helicopters were prepared near well sites. A large airstrip was built near the Rea Point camp to accommodate 727 and 737 jet aircraft. Crew changes could then fly directly from Edmonton to Rea Point. Highlighting the ongoing risks associated with exploration in the Arctic, a Lockheed Electra crashed near Rea Point in 1974 due to poor visibility with the death of 32 people.

Photo credit: D.M. Masterson

Figure 8.8 Panarctic Rea Point Sealift

8.3 Labrador Shelf

The Labrador Shelf is an example of early exploration through the 1970s that held much anticipated promise but has provided marginal results to date. Over 15 years of 2-D seismic surveys totaling approximately 120,000 km have been collected and 21 wells drilled. This resulted in six discoveries (all gas), one in the Saglek Basin in southern Davis Strait (present day Nunavut) and five in the Hopedale Basin. Poor drilling results, a region that appeared to be more gas-prone than oil-prone, and worsening economics resulted in the cessation of drilling activities in the early 1980s.

The Eastern Arctic Marine Environmental Studies Program (EAMES), which included the Labrador Shelf, was conducted in the late 1970s by the oil and gas industry (in co-operation with Federal Government), which provided baseline information on the physical and biological environment from Davis Strait south along the Labrador Shelf. A more recent Strategic Environmental Assessment for the Labrador Shelf was completed in 2008 by the C-NLOPB, and it is currently being updated in 2018.

Additional prospective regions have since been identified through seismic surveys and seep surveys involving coring samples. The C-NLOPB have issued and plan to issue new call for bids and issue ELs north of the Orphan Basin.

8.4 Grand Banks Region of Eastern Canada

The Grand Banks, particularly the Avalon and Jeanne d'Arc Basins offshore of the Island of Newfoundland, provides an example of the long timelines that typically are required from discovery to production. Exploration off Canada's east coast began in the 1966 and, other than one oil find in 1973, the first 40 wells on the Grand Banks were dry. Hibernia was discovered (80 m water depth) in 1976. Between 1980 and 1984, nine delineation wells were drilled to establish the field's recoverable reserves. Lengthy fiscal negotiations resulted in the Government of Canada becoming a partner in the field in 1988, resulting in an agreement on the development.

The Hibernia concrete production platform is a GBS design, with serrated outer edges designed to counter contact with icebergs. The GBS sits on the ocean floor with its topsides extending some 50 m above the surface. It is designed to withstand an inhospitable environment where rogue waves, fogs, ice and hurricanes are not uncommon. Hibernia achieved first oil in 1997, approximately 25 years after it was discovered.

Similar timelines occurred for other discoveries in the area. Terra Nova and White Rose where discovered in the mid-1980s and came on production in 2002 and 2005, respectively. The Hebron field was discovered in 1980 and started producing its first oil from a GBS platform (Figure 8.9) in December 2017, taking 35 years from discovery to production. Its expected production life is approximately 25 years.

Photo credit: ExxonMobil

Figure 8.9 Hebron Oil Platform Being Towed to Grand Banks

8.5 Canadian Beaufort Sea

After decades of exploration in the Mackenzie Valley and Delta, and with the discovery of oil and gas at Prudhoe Bay Alaska in 1968, industry interest moved into the Beaufort Sea. The first offshore well was drilled in shallow waters in 1973 on a man-made island; subsequent exploration drilling extended farther into deeper waters. Up to 1989, a total of 92 wells were drilled in the Beaufort, with one more well drilled in 2005 (Figure 8.10 to Figure 8.15). There has been no further drilling in the region since 2005, but several ELs have been awarded by INAC in the past 10 years, some in waters deeper than previously drilled. A number of companies have conducted large 3D marine seismic surveys over their licence area.

To date 48 SDLs have been issued in the Beaufort. There has been no development or offshore production from these discoveries.

Canadian Beaufort Sea exploration is best known for the unique variety of drilling systems and the technical innovations developed for water depths ranging from 2 to 100 m, as well as for landfast ice, out to moving first year and multi-year pack ice.

Photo credit: Dome Petroleum

Figure 8.10 Beaufort Drillship

Photo credit: Imperial Oil

Figure 8.11 Dredged Reinforced Artificial Island

Photo credit: Imperial Oil

Figure 8.12 Caisson Retained Island with Rubble Ice Field

Photo credit: Gulf

Figure 8.13 Mobile Arctic Caisson in Moving Ice

Photo credit: Gulf

Figure 8.14 Steel Drilling Caisson

Photo credit: IOL

Figure 8.15 Reinforced Ice Platform Island

The Beaufort Sea Oil Spill Co-operative was funded and managed by the major oil companies operating in the area in the 1970-1980s. The Cooperative had an inventory of oil spill response equipment. They also had a trained workforce to respond to large spills in the offshore that included approximately 20 Inuvialuit members. Each of the companies also had an inventory of their own equipment at their drilling locations, on board their vessels and at marine bases.

Much of the early field trials, specialized equipment and materials, such as fire-proof booms and aerial ignitors (designed to allow in-situ burning of oil on the open water and in ice conditions), were first developed and optimized in the Canadian Beaufort. Environment Canada and industry also funded and developed the Beaufort Environmental

Sensitivity Atlas (initially in hard copy and later digitized on-line), which was a valuable contribution to oil spill response planning for the area.

8.6 Offshore Norway

Norway has had an active oil and gas exploration and development program in its offshore waters since the 1960-era discoveries in the North Sea. Many of the developments included pipelines to shore for processing and transshipment to markets. More recently, the country has expanded its interests farther north into the Barents Sea, up to the permanent ice pack.

Today's developments in Norwegian waters are good examples of the trend towards limiting or avoiding landfall through the use of subsea development tied into FPSO vessels for oil production (see Section 5.2; Figure 5.6 and Figure 5.8).

8.7 Offshore Arctic Russia

The largest undeveloped Arctic oil and gas reserves are in Russia's offshore waters, from the Barents Sea in the west, across to the Kara Sea and Laptev Sea, and to the East Siberian Sea and Chukchi Sea in the east. While not strictly in the Arctic, the Sea of Okhotsk must deal with severe ice and cold temperature.

Exploration is a national priority, with Russian companies actively drilling in the Arctic offshore seas and off Sakhalin Island in the east (Figure 8.16 and Figure 8.17).

Photo credit: Rosneft

Figure 8.16 Drilling Platform in the Sea of Okhotsk, Russia

Photo credit: Rosneft

Figure 8.17 Drilling Platform in the Kara Sea, Russia

The Prirazlomnaya oil production platform is an example of a GBS system that was installed approximately 60 km offshore in the Pechora Sea in 2013. It is described in Chapter 5.

An example of a major discovery that has yet to be developed is Shtokman, one of the world's largest natural gas fields. Located in the Barents Sea, it is approximately 600 km north from the nearest land in 340 m of water. Discovered in 1988, it is estimated to contain 130 TCF of gas (by comparison the gas discovery in Davis Strait is estimated at 4 TCF). Two options have been considered; a FLNG or pipeline to shore. To date, there has been no development start due to the high costs, technical challenges and expansion of global supplies. However, the field may be economically developed in the next two to three decades.

9 HYPOTHETICAL OIL AND GAS SCENARIOS

The hypothetical scenarios consider approximate timelines, activities, financial feasibility, domestic policy and regulations, and climate to provide a baseline understanding of what the potential impacts and effects pathways could be if oil and gas exploration and/or development were to proceed in the Area of Focus. The scenarios are not associated with a specific location within the Area of Focus, but are intended to cover the full complement of oil and gas exploration and development activities that could occur in the Baffin Bay and Davis Strait region of Canada's eastern arctic offshore outside of the NSA. Although the sedimentary basin underlying the region is predominantly unexplored to date, the data that does exist suggests that the highest geological potential lies within southern Davis Bay (Figure 1.1). For the purposes of the hypothetical scenarios, it is assumed that oil and gas exploration and development would most likely be focused in southern Davis Bay. However; the activities and infrastructure described within the hypothetical scenarios and the associated potential effects would be similar throughout the Area of Focus.

It is important to note that the scenarios are not a prediction of what oil and gas activity is likely to occur in the Arctic. While the intent is to make them realistic, they are illustrative and do not predict an actual representation that reflects government or industry initiatives or interest. They are intended only as a basis for evaluating associated potential effects. A central premise of this approach is that as new information becomes available, the scenarios and the Strategic Environmental Assessment (SEA) should be adjusted.

As discussed in previous sections, there is variation in the way in which oil and gas exploration and development is carried out. For example, oil and gas exploration programs can vary depending on type of equipment, nature of survey, depth of drilling target, etc. The scenarios are intended to be broadly representative of what might occur.

If an oil and gas project was considered, a detailed project description would need to be developed to support the screening and assessment of environmental and socio-economic effects, and the preparation of required regulatory documents.

For additional details on the activities, timelines and regulatory requirements associated with the scenarios, refer to Sections 3 to 8 and for detailed information on accidents and malfunctions, refer to Section 10.

9.1 Scenario A: Exploration with Offshore Seismic Surveys

Initial interest in oil and gas resources in a region is generally based on an understanding of geological and hydrocarbon potential. Given that data on hydrocarbon potential in the Area of Focus is limited, additional seismic surveys would be required to determine the potential and composition of the recoverable hydrocarbons in the region, before any further oil and gas exploration would proceed. This data would initially be collected by completing a 2D offshore seismic survey. The results of this survey would provide a general understanding of the regional geological structure. The survey would cover a large area with survey lines spaced several kilometers apart. The 2D offshore seismic survey would be conducted during the open water season and could take 1–3 years to complete.

If results from the 2D seismic survey indicate potential hydrocarbon potential, and industry expresses interest in pursuing exploration of resources in the region, they would then solicit the federal government to put out a call for bids on specific lease areas. Once a company secures an exploration license, they would then conduct a 3D offshore seismic survey within that lease area to provide additional data on known geological targets. Survey lines would be spaced 200–400 m apart. The 3D offshore seismic survey would be conducted during the open water season and would be completed within 1 season.

For detailed information on activities associated with seismic surveys, see Section 4.1.

9.1.1 Potential Capital Expenditures

The cost to complete both a 2D survey and a 3D survey could range from $7 million USD[12] to $18.5 million USD[13]. Completion of a seismic survey requires a fully trained and experienced vessel crew and a fully trained and experienced seismic crew. The contracted vessels come with the full crew complement and very little onshore support is required. Local employment opportunities might include 6–10 seasonal positions as Marine Wildlife Observers (MWOs) on board seismic vessels to implement and monitor mitigation commitments. There also could be indirect employment opportunities associated with supplies and services from local sources.

9.1.2 Equipment and Infrastructure

- Seismic vessel (single air source array and single streamer for 2D survey and up to 2 air source arrays and 6–24 streamers for 3D survey)
- 1–2 support vessels (ice capable)

Requirements for onshore support would be limited (e.g., base for crew transfer, helicopter support) and would likely be provided from Nuuk (Greenland) or Newfoundland and Labrador where appropriate infrastructure is already in place. Crew transfer via helicopter could be based from the Iqaluit airport or any of the other communities in the region if it is feasible and in closer proximity to the location of the seismic survey.

9.1.3 Potential Accidents and Malfunctions

Potential accidents and malfunctions associated with offshore seismic surveys include:

- Fire and explosions
- Loss of life (falling off the vessel)
- Downed aircraft (helicopter)
- Vessel collisions
- Major weather and sea ice conditions
- Vessel strike with marine mammals
- Batch spills

Accidents and malfunctions during seismic surveys are uncommon given the slow speeds that seismic vessels must travel (4–5 knots), and international safety standards that the vessels adhere to (described in Section 10). Additionally, the Area of Focus is not heavily used commercially (e.g., commercial fishing vessels and gear, tourism, commercial shipping, etc.), which further reduces the likelihood for interactions that could lead to accidents or malfunctions.

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[12] Assumes completion of 2D and 3D seismic programs within two open water seasons with lower cost seismic vessel
[13] Assumes completion of 2D and 3D seismic surveys completed within four open water seasons with higher cost seismic vessel

9.2 Scenario B: Exploration Drilling

If the 3D seismic survey identifies promising hydrocarbon potential within the lease area and the lease holder decides that it is economically feasible to continue exploration, the next step is to drill into the reservoir to a certain distance below the seabed (referred to as the total depth [TD]) to confirm the presence and type of hydrocarbon and the vertical extent of the reservoir. Delineation drilling would be conducted to determine the horizontal extent of the field. Based on timelines to drill wells in offshore Newfoundland, it is assumed that the time to drill a well is 35–65 days. Exploration drilling would be conducted year round, but requires ice management and logistics support from icebreakers and other support vessels. The program would also require an ice management program (see Section 4.8), a drilling waste management program (see Section 4.9), and an air emissions management program (see Section 4.10) to comply with standard industry best practices, mitigations and commitments and regulatory conditions.

Prior to drilling the well, geotechnical and geohazard surveys would be completed to provide detailed information on the area immediately surrounding the well location. Methods to complete these surveys include:

- High-resolution multi-channel seismic data
- Side-scan sonar
- High-resolution sub-bottom profiles
- Seabed photography, magnetometer data and sediment grab samples

During drilling, formation evaluation will be conducted frequently to measure the formation properties, including the porosity and permeability of the rock and the reservoir fluid properties if oil or gas is encountered. Methods to complete formation evaluation include:

- Periodic well logging
- Vertical seismic profiling after drilling is completed
- Well testing using down hole wireline tools

For this scenario, it is assumed that flow testing would not be required.

At the end of each drilling season, drilling activities would be suspended and the well secured until the next drilling season begins. Once a well has reached its target depth and all testing has been completed, it would be plugged and abandoned in accordance with NEB regulations.

For detailed information on activities associated with exploration drilling, see Sections 4.2–4.11.

9.2.1 Potential Capital Expenditures

The cost to complete the exploration drilling program associated with this scenario could range from $100 million USD to $150 million USD.

Offshore exploration programs employ skilled and unskilled workers including engineers, welders, electricians, cooks, support staff, health and safety specialist, environmental specialists, helicopter pilots, technicians, geologists, and healthcare staff. Local employment opportunities might include full-time positions as environmental monitors on board the drilling platform and support vessel to implement and monitor mitigation commitments. With appropriate advance training, additional employment opportunities could be available for residents of Nunavut. There would also be indirect employment opportunities associated with supplies and services from local sources.

9.2.2 Equipment and Infrastructure

- Arctic class drilling platform (drillship or semi-submersible)
- 1–2 icebreaker support vessels
- 2–3 supply vessels (ice strengthened)
- 1–5 fuel tankers (ice strengthened)
- 1–2 wareships (ice strengthened) for offshore storage
- Onshore storage facilities in coastal communities for emergency equipment such as oil spill response equipment and other emergency equipment

Onshore support would be provided from Nuuk (Greenland) or Newfoundland and Labrador, where appropriate infrastructure is already in place. Crew transfer via helicopter could be based from the Iqaluit airport. Limited transits between Iqaluit and the drill site could occur, assuming that a deep-water port is available. With the exception of storage facilities for emergency response equipment, this scenario assumes that any onshore infrastructure and services required on Baffin Island to support a drilling program would be located in Iqaluit.

9.2.3 Potential Accidents and Malfunctions

Potential accidents and malfunctions associated with exploration drilling include:

- Fire and explosions
- Loss of life (falling off the vessel)
- Downed aircraft (helicopter)
- Terrorist threats
- Drilling rig loss of integrity
- Vessel collisions
- Major weather and sea ice conditions
- Vessel strike with marine mammals
- Batch spills
- Subsea blowout

9.3 Scenario C: Field Development and Production drilling

If a business decision is made to proceed with developing an oil or gas field, the operator will complete a field development plan and proceed with field development and production drilling. Although there are several options, this scenario assumes that the system would be similar to what has recently been used in Norway (see Sections 5.2 and 8.6). The drilling program would be designed to limit or avoid landfall through the use of subsea development tied into FPSO vessels for oil production or FLNG vessels. Production could take place through a subsea system of oil or gas producing wells, water injection wells and gas injection wells. The FPSO or FLNG vessels would be designed with large storage capacity and allow for the safe loading of oil or gas on to shuttle tankers for transport to an export destination. The number of tankers and their frequency of transit would depend on production rates, storage capacity on the offshore or onshore facility, vessel capacity and destination locations. A typical large offshore oil production field could require 200,000 dwt tankers loading every few days or similar frequency of LNG tankers. The assumed production life for this scenario is up to 30 years.

Ice management and logistics support from icebreakers and other support vessels would be required. The program would also require an ice management program, a drilling waste management program, and an air emissions management program to comply with standard industry best practices, mitigations and commitments and regulatory conditions.

When the production rate becomes uneconomical, the production would be decommissioned. Facilities are dismantled, removed and reclaimed, and the wells are put into a permanent safe state.

9.3.1 Potential Capital Expenditures

Capital costs associated with the field development scenario could be approximately $14 billion USD.

Offshore field development and production could employ skilled and unskilled workers including engineers, welders, electricians, cooks, support staff, health and safety specialist, environmental specialists, helicopter pilots, technicians, geologists, and healthcare staff. Local employment opportunities would likely include full-time positions as environmental monitors on board the drilling rig and support vessels to implement and monitor mitigation commitments. Additional opportunities for employment of Nunavut residents and business for Nunavut companies are also likely, due to the longer lead time for production activities. This could include a number of initiatives to train Nunavut residents to work on the production platform in some capacity, or on the supply vessels that support the platform. Other opportunities may include, but are not limited to, onshore support (e.g., supply base operations), aviation support, provision of supplies, offshore medical services, consulting, legal support, human resources and administration staff, logistics and customs brokers, catering, etc. Given the long lead time for production activities, development of procurement strategies by local businesses, training and apprentice programs, and support for local capacity building would help provide additional employment opportunities within Nunavut. The long lead time and duration of production activities makes it feasible and justifiable for local residents and businesses to invest in relevant training and business development initiatives.

9.3.2 Equipment and Infrastructure

- Arctic class semi-submersible drilling platform and FPSO
- 1–2 icebreaker support vessels
- 2–3 supply vessels (ice strengthened)
- 1–5 fuel tankers (ice strengthened)
- 1–2 wareships (ice strengthened) for offshore storage
- Onshore storage facilities in coastal communities for emergency equipment such as oil spill response equipment and other emergency equipment

The support infrastructure for development and production is similar to that described in Scenario B and would consist of a permanent fleet of supply and support vessels, icebreakers as required, and aviation support. A supply and helicopter base could be located in Iqaluit. With the exception of storage facilities for emergency response equipment, this scenario assumes that any onshore infrastructure and services required on Baffin Island to support a drilling program would be located in Iqaluit.

9.3.3 Potential Accidents and Malfunctions

Potential accidents and malfunctions associated with field development and production drilling include:

- Fire and explosions
- Loss of life (falling off the vessel)
- Downed aircraft (helicopter)
- Terrorist threats
- Drilling rig loss of integrity
- Vessel collisions (e.g., with other vessels or icebergs)
- Major weather and sea ice conditions
- Vessel strike with marine mammals
- Batch spills
- Subsea blowout

9.4 Scenario D: No Offshore oil and Gas Activity

If through planning, consultation and regulatory decision-making processes, the Area of Focus is deemed to not be an appropriate region for oil and gas activities, then hydrocarbon resources would remain undeveloped and activities associated with the exploration and development of these resources would not occur.

9.4.1 Potential Capital Expenditures

None

9.4.2 Equipment and Infrastructure

None

9.4.3 Potential Accidents and Malfunctions

None

10 NON-ROUTINE ASPECTS OF OIL AND GAS EXPLORATION AND DEVELOPMENT

Non-routine events (also referred to as accidents and malfunctions), while unlikely to occur, require contingency planning to reduce or avoid impacts on workers, public safety and the environment, and to bring the incident under control as quickly and effectively as possible. As such, the operator will have contingency plans in place for all potential accidents, such as:

- Uncontrolled hydrocarbon release
- Fire and explosions
- Loss of life
- Medical evacuations
- Downed aircraft
- Terrorist threats
- Drilling platform loss of integrity
- Vessel collisions
- Major weather and sea ice conditions

Companies are required to undertake a risk evaluation on all of their activities from design through to completion of operations, with intent to prevent a non-routine event from occurring and ability to respond if one occurs. In the OA application, the NEB requires the operator to describe the risk assessment methodology and management processes used to identify threats and hazards, and prepare mitigative measures should an unexpected incident occur.

The following section provides a description of general containment and treatment measures that are commonly used to respond to oil spills in the offshore environment. These measures are tools that are available to the responding organizations and are generally used in combination with each other based on the specific circumstances of the spill and the resources that are to be protected. The effectiveness of response measures for the Area of Focus would be contingent on multiple factors such as environmental conditions, technology, infrastructure and capacity. Spill response planning should consider the variables unique to the region, such as environment, cultural values, local infrastructure, current technology and best practices, and capacity.

10.1 Types and Likelihood of Spills

An unplanned release of chemicals or hydrocarbons has the potential to create the most impact on the environment. Unplanned releases can result from batch spills or blow-outs.

Batch spills are instantaneous and typically of short duration and small volume (a few litres) before they are contained, and the source stopped. Batch spills can include:

- Diesel oil (during rig/platform fueling)
- Hydraulic and lubricating fluids
- Synthetic- or water-based whole muds
- Chemical constituents that make up drilling muds
- Cleaning agents

Batch spills can occur during routine use, storage and transfer on the rig, production platform or supply vessels. Occasionally a subsurface release can occur through a crack in the flex joint, riser or lines due to leaking or equipment malfunctions. Bottom release can occur due to an emergency riser disconnect event.

Blowouts are continuous events that can last for hours, days or weeks if left uncontrolled, and involve the discharge of potentially large volumes of crude oil into the surrounding waters and associated gas into the atmosphere. Potential blowout scenarios can include both topside and subsea release points and a combination of different flow paths such as through the drill string, annulus or an open hole for both oil and associated gas.

There have been many statistical reports on blowouts over the years based on the worldwide database (SINTEFF 2017), some of which include trend adjustments based on technological and operational improvements over the last decades. In addition to using historical data, some reports also develop scenario-based models to cover specific conditions or regions of the world.

Large offshore blowouts are very rare events. There have been in the order of 50,000 exploration wells drilled worldwide to date, with two blowout events rated as extremely large (greater than 150,000 bbl): the Ixtoc one incident in the Mexican sector of the Gulf of Mexico in 1979; (3M bbl.) and the Deep Water Horizon accident in 2010 (4 M bbl)

The probability of blowouts varies depending on well characteristics, well pressure, water depth, operating conditions, and whether it is an exploration, appraisal or development well. As part of a project specific spill response plan, operators submitting a regulatory application to drill a well would include a risk assessment that considers the factors that apply to the design of their exploration or production activity. The risk is typically reduced as drilling moves from exploration to development phases, as there is an increase in knowledge of the area and the reservoir properties. The use of probability statistics also varies depending on how the historical data was analyzed and interpreted, including data from countries where drilling regulations may be less rigorous or small-time operators have less experience. Estimates of the probability of well blowouts, measured as the frequency per well, vary by different areas of the world. Such estimates vary from 0.001 to 0.005 per well, with a mean blowout probability for exploratory wells at 0.025 per well. Analysis of international data indicates that if a blowout does occur, there is a greater than 50% chance of it lasting two days or less from natural bridging and a 15% change of it lasting longer than two weeks.

In preparing an environmental impact statement prior to opening a large area for exploration and development, regulators can also develop large-scale hypothetical WCSs to assess the likelihood of a blowout event happening over the life of the area. For example, a reference that is often quoted is a hypothetical scenario for the entire Outer Continental Shelf of Alaska. This was prepared by the US Bureau of Ocean Energy Management (BOEM) in 2015, involving eight production platforms and associated pipelines and more than 500 wells producing over 4 billion bbl of oil. In this scenario, they estimated a 75% chance of one or two spills of more than 1,000 bbl over a 77-year period. BOEM acknowledged that even with this hypothetical scenario, the data suggested that a large spill in the exploration phase was very unlikely.

10.2 Worst Case Scenario

References to worst case scenario, also referred to as worst case discharge scenario (WCDS), are found in:

- Inuvialuit Final Agreement 1984—sec. 13(11) (b) "an estimate of the potential liability of the developer, determined on a worst-case scenario…"
- NEB Filing Requirements for Offshore Drilling in the Canadian Arctic 2014—4.18 Spill Contingency Plan—"describe the worst-case oil spill scenario for a major loss of containment of oil from a well"
- NEB Financial Viability and Responsibility Guidelines 2013—"the applicant will provide an estimate of implementing its oil spill plan for a worst-case scenario, including compensation to affected third parties"
- It is typically assumed for offshore oil and gas activities that the WCS would be a surface or subsea major crude oil blowout at the drilling rig location of a certain rate and duration. Typically, "realistic and credible" are used when developing the scenario to put some boundaries and probability around the event.
- There are guidelines on calculation of worst-case discharges from the Society of Petroleum Engineers, which are focused on the prescriptive requirements from the US BOEM. Regulations from some other countries (Norway and UK) are more general in nature.

The NEB has taken a goal-based approach wherein the operator provides a credible WCS based on an actual drill well that meets the intent of assessing a worst case spill, and defends such during the regulatory process.

To develop a project- or drill well-specific WCS, a number of inflow (oil and gas flow from the reservoir to the wellbore) and outflow (from wellbore to its exit into the water column) performance parameters are required, including:

- Representative crude oil type (taken from previously drilled wells in region and/or Environment Canada's crude oil database, including density, viscosity, interfacial tension, pour point and flash point)
- Well flow rate(s) over time based on reservoir permeability and net pay thickness
- Duration of flow including natural bridging
- Reservoir characteristics such as pore pressure, fluid properties, porosity and permeability
- For a subsea blowout, the probability of formation of hydrates by the natural gas released at the sea floor depending on water depth and temperature

Other input parameters that are required for a WCS include:

- Specific drilling location
- Specific wellbore geometry
- Specific drilling event including:
  - Partial penetration
  - Open hole vs. drill pipe in hole
  - Obstruction[s] in wellbore including:
    - Long duration / low flow rate with no bridging
    - Short duration / high flow rate with bridging
  - Flow restrictions in the BOP
- Iterative process requiring flow rate over time
  - Erosion modeling to establish flow over time
  - Inflow / outflow to determine velocities causing erosion
- Met ocean data for the time of occurrence

As discussed later in this report, a number of spill modelling tools are available to predict the potential trajectories and fate of released hydrocarbons, including in the water column, on the water surface, in the atmosphere and onshore. These tools are useful in predicting potential environmental effects of spills.

A realistic WCS requires a number of assumptions to be made that could include, but not limited to:

- Entire hole section is drilled with over-balanced mud weight
- Oil enters the well when tripping out of the hole
- Attempts to control annular flow fails
- Shear rams activated by leak in the drilling riser
- Marine riser is disconnected
- Drilling rig is moved away from the well
- Drill string remains partially or entirely in the hole

Developing an accurate and credible WCS is a very detailed undertaking for a specific set of circumstances. Preparing a hypothetical WCS has limited value as it may not be indicative of a credible situation based on an actual project.

10.3 Measures to Regain Well Control

In Canada, the NEB requires a company to demonstrate the capability to drill a relief well[14] to kill an out-of-control well during the same drilling season, referred to as the Same Season Relief Well (SSRW) policy. The intent of the policy was to reduce the risk that a blowout would continue into the winter months, thereby reducing impacts on the environment. Spill response, when there is ice present, would have limited ability to secure the well and clean up the spill in or under ice.

The NEB undertook a review of the SSRW policy in 2010-2011 as part of its broader Arctic Offshore Drilling Review. The SSRW policy was retained, but the NEB added the statement that an applicant wishing to depart from this policy would have to demonstrate how they would meet or exceed the intended outcome. NEB's intent was to review each applicant's SSRW alternatives submission on a case-by-case, project-by-project basis.

Surface intervention equipment and response techniques have improved, with a number of systems now available and new ones under development. Surface intervention includes re-establishing the primary barrier by circulating fluids or performing a dynamic kill to restore a sufficient column of drilling mud to overcome formation pressure. Surface intervention can start immediately at time zero of a blowout event to mitigate or stop the flow from the well before a capping stack is deployed.

If required, a secondary BOP barrier (i.e., capping stack) can be brought to the site and installed within a few weeks. The industry has stockpiled capping stacks and supplementary equipment at strategic locations around the world, including USA, UK, Norway, South Africa and Brazil, and with fast deployment by air and ship and logistical plans in place for transporting these to well sites.

[14] a relief well is drilled to intersect an oil or gas well that has experienced a blowout. Specialized liquid, such as heavy (dense) drilling mud followed by cement, can then be pumped down the relief well in order to stop the flow from the reservoir in the damaged well.

Most blowouts are brought under control within hours or a few days through surface intervention (referred to as dynamic kill procedures) or natural bridging or depletion. A realistic response time from start of incident to a capped well, assuming pipe in hole and shear rams closed, can range from a few days to two to three weeks:

- 1–2 days for assessment of damage of the wellhead by a Remote Operated Vehicle (ROV)
- Up to 7 days to pump-in seawater and plug with cement, or if required
- From 14 to 21 days to bring in a capping stack from outside region, move to location and deploy capping stack and secure well
- Final well kill may be required after a well is secured and flow has stopped, but can occur in a subsequent year when it is safe to do so and a rig is available

Taken together the duration and volume discharged for a specific WCS is dependent on bridging, success of surface intervention and capping stack deployment (Figure 10.1) as required to secure the well and stop the flow. Drilling of a relief well is a last resort and not a primary option to stop the flow, but may be required to provide a final and permanent abandonment of the original well, as was the case with Deep Water Horizon.

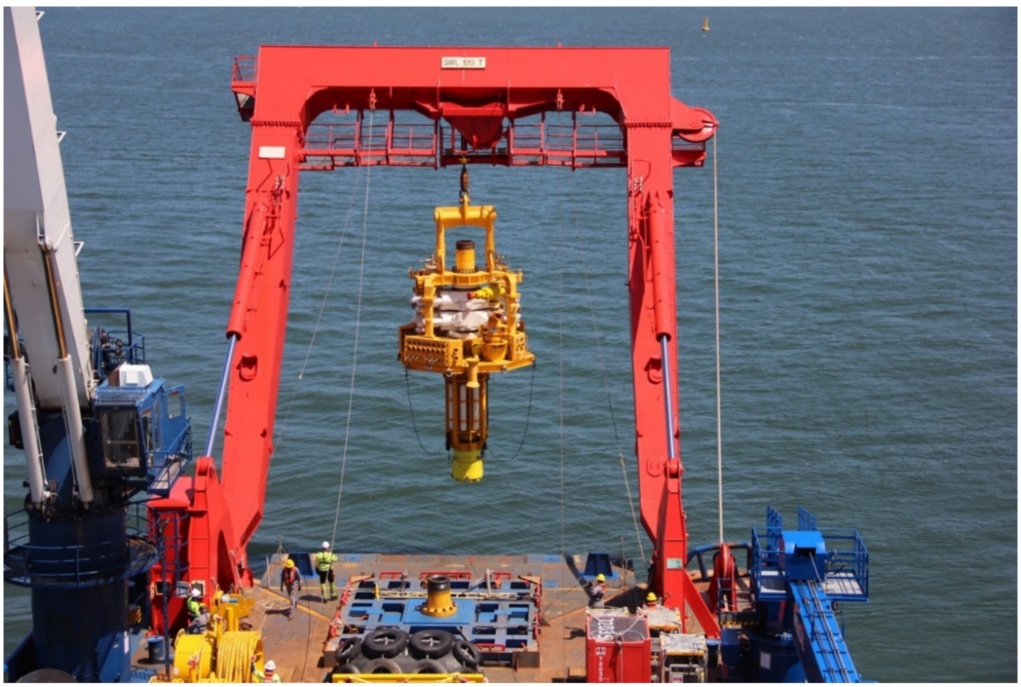
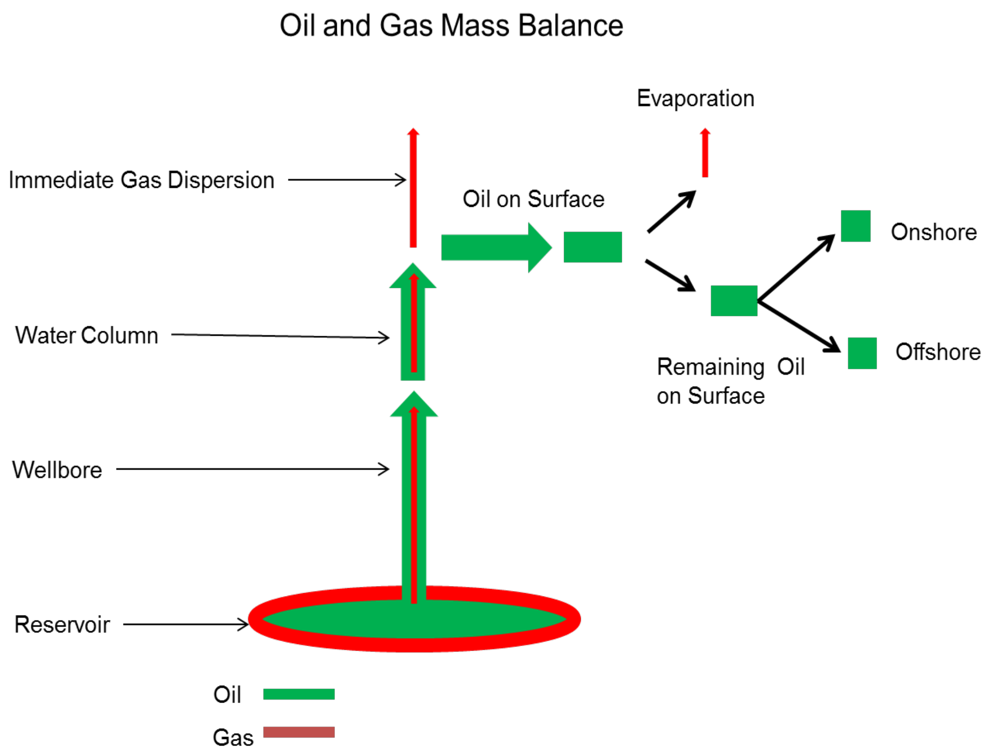


Photo credit: Oil Spill Response Limited (OSRL)

Figure 10.1 Deploying a Capping Stack on to the BOP on Sea Floor

10.4 Oil Spill Fate and Behaviour

An oil spill (and accompanying gas) can be viewed in the context of a mass balance (Figure 10.2), whereby oil exits the underground reservoir through the wellbore and is released (in the case of a subsea blowout) into the water column. Natural gas is typically rapidly dispersed into the surrounding atmosphere below the lower explosive limit. Oil is mostly spread onto the water surface where it undergoes various fates, the most significant often being evaporation.

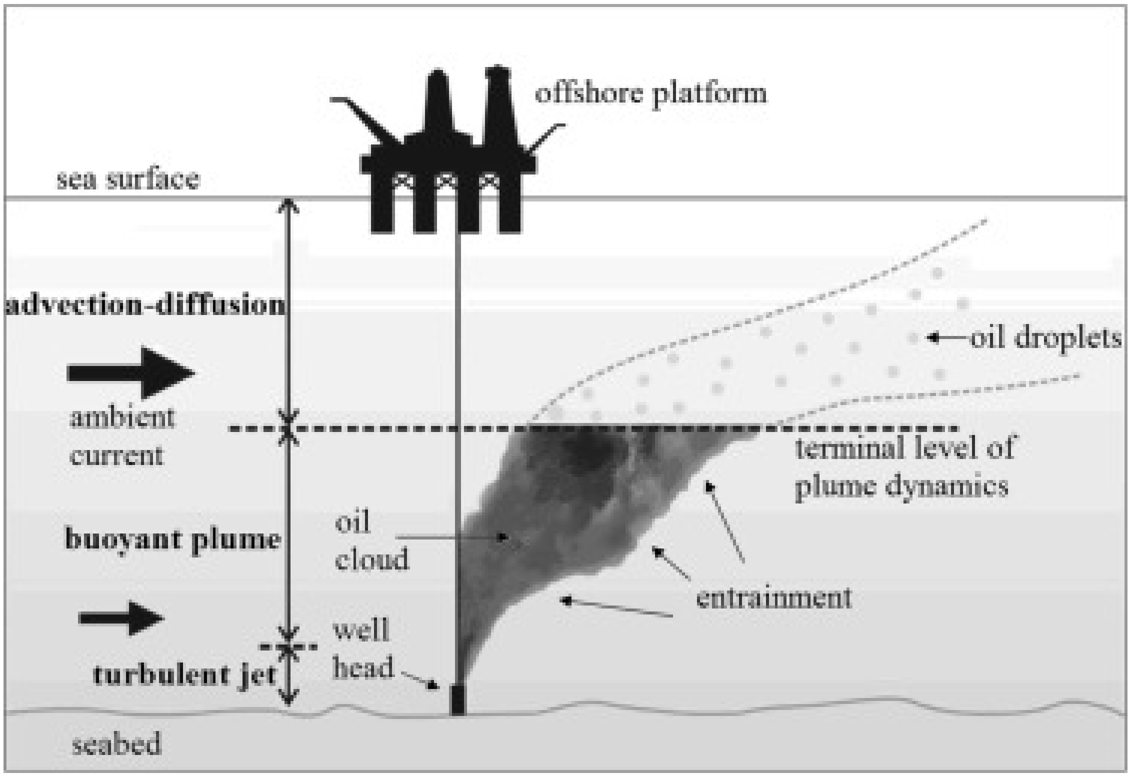


SOURCE: ExxonMobil

Figure 10.2 Oil and Gas Release into the Environment Mass Balance

A large crude oil spill might involve a subsea blowout, with oil and gas from the reservoir being released into the water at the seabed. The blowout plume formed by the discharge of the oil and gas mixture forms an inverted cone in the water column above the wellhead. As the mixture is forced up into the water column, it entrains sea water, which increases the plume diameter and slows its vertical ascent. Seawater entrainment also reduces the concentration of oil and gas in the plume. The gas is in the form of bubbles of varying sizes that expand as they rise through the water due to a continual drop in water pressure. The gas also dissolves into the seawater as the plume rises, potentially accounting for the fate of a significant fraction of the overall gas discharge.

The oil is carried along in the plume in the form of small droplets (Figure 10.3). Higher rates of discharge and velocities of the gas/oil mixture exiting the wellhead result in smaller oil droplets. Low velocity subsurface currents will cause little horizontal displacement of the plume, but significant currents can bend the plume in the flow direction and displace the location of the top of the plume and the location of the flux of oil and gas at the sea surface.



SOURCE: Chen Haibo et al, Ocean Engineering

Figure 10.3 Subsea Oil Plume

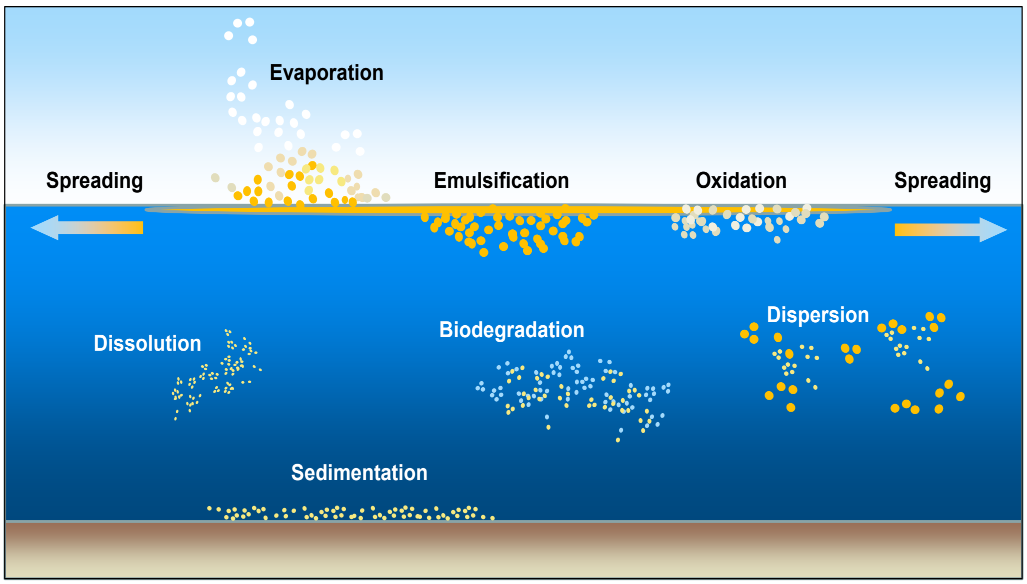
If the water depth is greater than approximately 450 m, the natural gas may start to react with the deep, cold water to form gas hydrates. If the water depth is substantially less than 450 m, the gas bubbles will not form hydrates and much of both oil droplets and gas bubbles will be brought quickly to the surface by the water entrained by the rising gas bubbles. If the water depth is appreciably greater than 450 m, a significant percentage of the gas bubbles will either dissolve or form hydrates. This causes the buoyancy of the plume to decrease as it rises, until the average density of the cold bottom-water plume equals the surrounding warmer surface water plume.

When the density of the plume equals that of the surrounding water, the plume ceases to rise as a coherent mass, and the plume is said to “stall” or “terminate”. At this termination height above the sea floor, the oil droplets and remaining gas bubbles delivered to the top of the plume will be free to rise through the water column based on the buoyant force on each individual droplet and bubble. The gas bubbles remaining at the termination height will rise to the surface, albeit more slowly than in the coherent plume. Approximately 10% to 20% of the volume of gas released from the BOP would be expected to reach the surface as bubbles, almost directly above the BOP in a circular area with a diameter of approximately 80–100 m.

In general, oil droplets less than 100 µm in diameter do not have sufficient buoyant force to bring them to the sea surface. The fraction of the discharged oil in this size range and smaller may be transported long distances by subsurface currents and would be subject to diffusion, biodegradation and dissolution.

The oil droplets that surface will coalesce into a slick that spreads (transported by wind and currents), evaporates, naturally disperses and eventually emulsifies. With wave action, some surface oil will be entrained. Over the longer term, some components of the surface oil could be oxidized by sunlight while others could dissolve in the seawater. The naturally dispersed oil droplets will be transported by water currents, become entrained, diffuse in the water column, biodegrade, and undergo sedimentation as a result.

Over time, dispersed oil is biodegraded with the help of resident microbes in the Arctic's open waters under both summer and winter conditions (Deppe et al. 2006). Figure 10.4 illustrates these processes in open water conditions and on ice, under ice, between ice and within ice.



SOURCE: ExxonMobil

Figure 10.4 Oil Spill Fate and Behavior in Open Water

Over the duration of a subsea blowout, approximately 40–50% of the oil droplets released will typically evaporate into the atmosphere. The maximum amount of oil in the water column will be approximately 50-60% of the oil volume discharged (consisting of oil droplets at the discharge site that are too small to surface and ongoing natural dispersion of surface oil slicks by wave action). This maximum volume will occur on the last day of the release, when the well ceases to flow. The amount of oil in the water column will decrease over time from this point in a cyclical manner, due to resurfacing of dispersed oil in calmer seas and being re-dispersed in higher sea states, and the effects of biodegradation. In an extended blowout scenario, approximately 50 days after stopping the well flow, the oil remaining in the water column represents 20–30% of the total volume released. At this point, a portion of the oil released has been biodegraded in the water column. The maximum amount of oil on the water surface in the form of a slick at any time is approximately 15–20% of the oil volume-discharged. At the end of the scenario, a small amount of oil will continually move between the water surface and upper part of the water column due to winds and wave-induced oil entrainment.

Trajectory and fate modeling is an important tool when developing an oil spill contingency plan for a specific project. The biggest deficiency with modeling is that it does not always take into account mitigative measures (i.e., response to a spill that can reduce the spatial and temporal size and the corresponding effects) and therefore can result in an unrealistic scenario. Some recent modelling tools have included mitigation measures in determining the trajectory and fate of oil. There are two types of modeling that are typically done for an oil spill:

- Stochastic approach, in which hundreds of individual trajectories are run on the same type of release under varying environmental conditions (e.g., different wind and current historical database)
- Deterministic approach, in which modeling is done on a single release at a given location and time, requiring specific oil properties that will predict oil concentrations, thickness, weathering and overall mass balance

The challenge with running such models for the Baffin Bay/Davis Strait SEA, is it requires input of site-specific data (similar to what goes into a WCS), along with historical data sets on weather and sea conditions. Given the limited past drilling in the region, there are few examples of wells to use as a basis for predicting the properties of hydrocarbons from the study region. The only reference well data in Davis Strait was a gas discovery. Qualitatively one can assume, based on the current regime, that an oil spill in the region will result in surface and subsurface oil moving south by the Baffin Island and Labrador currents. The resulting slick would have the potential to get caught in the northward moving West Greenland, North Atlantic, and Hudson Strait currents, while undergoing spreading, evaporation and dispersion in the water column and other mass balance fates.

10.5 Offshore Oil Spill Response

Accidents and malfunctions which could introduce hydrocarbons into the environment are considered to be the biggest risk to biophysical and socio-cultural receptors. While medium or large oil spills or blowouts are unlikely to occur given the types of safeguards used in modern oil and gas exploration and development, effects of oil spills are adverse. The effectiveness of oil spill response and its ability to reduce damage to environmental receptors depends on exposure, seasonal and environmental conditions, and oceanographic conditions (e.g., currents, water temperature, extent and type of ice cover). The proximity of the spill to shorelines, and the vulnerability of shorelines to spills is also important (e.g., likelihood that shoreline to be exposed to oil, the shoreline types, the biological communities that they support, the use of these areas by traditional harvesters, communities and others users).

Response to oil spills in an Arctic environment introduces additional operational and logistical challenges to be considered including the remoteness, limited available infrastructure, and environmental variables (e.g., limited daylight hours in winter, extreme cold, sea ice and icebergs). Given the increasing interest in developing in Arctic regions, recent research has focused on methods and technologies for effectively responding to oil spills in the Arctic environment (DF Dickens Associates 2017). The following sections discuss some of the tools that are available for oil spill response. Used in combination and depending on the environment and the circumstance of the spill, these methods have been demonstrated to be effective in open water and coastal environments. Where sea ice is present, some techniques may be more effective than others. For example, mechanical recovery in sea ice environments may be less effective than use of dispersants or in-situ burning because access to remote ice-covered areas may not be practical for the equipment and vessels that are required to undertake mechanical recovery. Recent and ongoing research focused on oil spill response and recovery in remote and ice-covered regions has extended capabilities and developed new strategies and confirmed that effective oil spill response in the Arctic is possible (DF Dickens Associates 2017).

10.5.1 Mechanical Containment and Recovery

Containment and recovery is often viewed as the preferred response strategy to remove oil from the surface of water by containing the oil in a boom (Figure 10.5) and recovering it with skimmers (Figure 10.6). However, there are operational and practical limitations to solely relying on mechanical containment and recovery systems for large spills at sea; these limitations can become even more critical in the Arctic. Sea state is an important consideration where booms are required, as oil is often entrained beneath or splashed over in any wind-wave exceeding 1 m. Increasing wave heights also make equipment deployment and retrieval difficult, reduces the effectiveness of skimmers, and can result in unsafe working conditions. High-capacity skimmers often recover large quantities of water along with the oil, and along with emulsification, can result in very large offshore storage demands and on-land disposal requirements.

Overall, performance of containment and recovery is typically low; it accounted for an estimated 5% of the total oil volume discharged during the Deep Water Horizon blowout in the Gulf of Mexico (note that this does account for the oil portion that is not recoverable due to evaporation into the atmosphere or dissolution into the water column).

SOURCE: SL Ross

Figure 10.5 Oil Spill Boom Collection System

SOURCE: SL Ross

Figure 10.6 Large Ocean Skimmer Device

10.5.2 Controlled In-Situ Burning

Based on large Arctic and ice field trials and validations in Canada, USA, and Norway, as well as actual oil spills from tanker accidents, and more recently during the Deep Water Horizon blowout, it is generally accepted that in situ- burning (ISB) (Figure 10.7) can be a very effective way of removing oil from the environment. It can be especially effective in Arctic regions where the presence of ice can aid in concentrating the oil between ice flows or in melt pools. The effectiveness of burning on the water surface is dependent on an oil thickness with a minimum value of 3–5 mm. This can be enhanced with the use of fireproof booms and herding agents, as well as the use of aerial ignition systems such as the heli-torch. Burn removal rates have ranged from 60–80% efficiency, with some trials in Norway achieving 95% removal. All the major oil spill response organizations maintain ISB equipment for rapid response.

Environment Canada has computer models that can be used to predict safe distances from downward smoke concentrations to eliminate risk to responders or local populations.

SOURCE: SL Ross

Figure 10.7 In-Situ-Burning

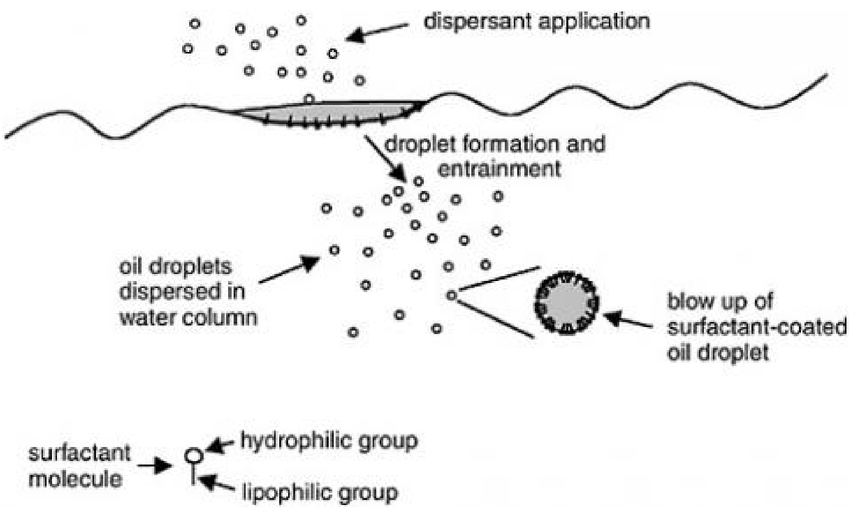
10.5.3 Oil Spill Dispersants

Oil spill dispersants products are used to rapidly break up oil slicks on the water surface and disperse the oil into the water column using the mixing energy of waves. They work much like household dish soap and contain a surfactant molecule with a solvent carrier that attaches one end of the molecule to the oil (lipophilic) and the end to the water (hydrophilic) (Figure 10.8). This reduces the surface tension of the oil / water interface, thereby breaking the oil up into micron-sized droplets.

Dispersants do not remove oil from the environment; they transfer the oil from the surface into the water column. This can aid in increasing microbial degradation of the oil particles by bacteria. Arctic waters contain such oil-consuming bacteria and it would be expected such bacteria are present in the Baffin Bay/Davis Strait waters due to the natural seeps in the area. If oil is removed from the surface, the potential for contact with seabirds is lessened, as well as shoreline contact. It is a tradeoff, as the process can increase the potential for contact with animals that live in the water column (e.g., fish, invertebrates, marine mammals). However, with dilution into large bodies of water like Baffin Bay and Davis Strait, the toxicity of the oil can be rapidly reduced to below acute toxicity levels.

The most efficient way to apply dispersants is by aerial application. There are such aircraft available worldwide that are specially equipped for the job. Other methods include spraying onto the oil slick by vessels, and for a subsea blowout, applying the dispersant by a hose from a surface vessel directly into the oil as it escapes from the damaged wellhead.

There are regulations in Canada that control the type and use of oil spill dispersants (Government of Canada 2016). They require an authorization from the NEB once a Spill Impact Mitigation Assessment (SIMA) (previously referred to as a Net Environmental Benefit Analysis) has been conducted to determine if they should be used.



SOURCE: ExxonMobil

Figure 10.8 Oil Spill Dispersant Process

10.5.4 Shoreline Response

A shoreline response program would consider both nearshore protection of sensitive coastal areas and shoreline cleanup for any oil that might be stranded on the coast. The development of a response strategy would be a part of the assessment process that evaluates oil pathways, resources at risk, and seasonal sensitivities and vulnerabilities of habitats and resources. Shoreline protection priorities would be developed based on pre-spill strategies for specific areas of importance. Planning would involve community engagement to incorporate traditional knowledge and current resource harvesting practices.

If oil reaches the coast and is stranded, a SIMA would be used to determine the best overall options and the target treatment endpoints to apply to shoreline response. This analysis would be based on a shoreline cleanup and assessment technique (SCAT) survey to determine the location and character of any stranded oil. All treatment recommendations, including operational priorities, generated by this survey would be submitted to the Unified Command[15] for review and considered in the context of the overall response operation.

Typically, a shoreline response strategy involves the initial removal of bulk or heavy oiling that could be remobilized to affect adjacent areas. Further treatment phases would be based on the SIMA, and the development of treatment endpoints would follow guidelines established by Environment Canada to avoid causing unnecessary additional impacts. The shoreline treatment options would vary depending on shore zone types (e.g., sand beaches, mixed sediment gravel beaches, tundra) and the degree of oiling. The treatment options are described in the Environment

[15] An authority structure that includes share command by two or more individuals from different responding agencies or jurisdictions

Canada *Field Guide to Oil Spill Response on Marine Shorelines* (Environment and Climate Change Canada 2016) and their applicability to and implementation for different Arctic shoreline types would follow those recommendations. The treatment options that would be considered include:

- Natural recovery
- Flushing and recovering bulk oil
- Sediment mixing
- Sediment relocation
- Burning oiled sediments, peat and logs
- Bioremediation

Guidelines and strategies are available for oil spill wastes generated during a shoreline cleanup. The use of portable burners and incinerators for waste management or in situ shoreline treatment techniques are preferred options, particularly in remote areas. Shoreline equipment caches would need to be established that can be readily transported by helicopter to protect shoreline areas that are determined to be the most vulnerable or to treat those with the highest initial priority for onshore oil recovery.

10.5.5 Tracking and Surveillance

Detection, monitoring and tracking of oil on water and in ice conditions in real time are key requirements for the appropriate allocation of resources during an oil spill. Forecasting the future movement of oil allows responders to adjust response plans for site-specific factors, adapt to weather conditions and to identify resources at most risk.

The use of airborne remote sensing technologies, in addition to visual observations collected by trained observers, is the most effective way to identify the presence of oil on water and in some situations to detect oil among ice. The main technologies include:

- Satellite radar imagery
- Side-looking airborne radar (SLAR)
- Synthetic aperture radar (SAR)
- Infrared cameras

Additional research is ongoing to evaluate and test next generation ground penetrating radar (GPR), acoustics sonar, gas detectors and nuclear magnetic resonance.

As part of Transport Canada and Fisheries and Oceans Canada (DFO) response organizations, the federal government's Marine Aerial Reconnaissance Team (MART) for the Arctic, based in Ottawa and Iqaluit, owns a Dash 8 equipped with the latest state-of-the-art surveillance equipment.

10.5.6 Tiered Oil Spill Response

In the 1980s, the oil and gas industry developed a three-tiered model to describe an escalating magnitude of spill response capability. The tiered levels of preparedness describe how appropriate resources can be rapidly mobilized to respond effectively to spills of varying size.

Tier 1 involves a small spill up to 100 bbl that occurs at or near a company's vessels or offshore platform and is of very limited geographic extent. This type of spill might involve fuel spilled from a hose during vehicle refueling. The operator is expected to respond to the spill with their own onboard resources. A robust and dedicated mechanical containment and recovery capability that can be rapidly deployed using local resources would be in place for Tier 1 spills. In addition to this capability, in situ burning and the use of dispersants could be considered for a Tier 1 response. Vessels with International Maritime Organization-compliant protocols would have a Shipboard Oil Pollution Emergency Plan and the necessary equipment on board for a Tier 1 spill response.

Tier 2 involves a medium-scale spill that usually extends beyond the Tier 1 response area. In addition to the operator, a broader range of responders could be involved in the response. A Tier 2 response capability involves regional resources such as the Eastern Canada Response Corporation, which is owned by several of the major oil companies. A response organization could provide equipment, vessels, storage, and most importantly, locally trained spill response teams. Equipment, such as booms (fire and shoreline protection), skimmers, controlled in situ burning equipment and dispersants could be stockpiled and strategically located at various sites, offshore and onshore.

Tier 3 involves a large-scale spill, potentially having major environmental or socio-economic effects, which require substantial resources to cleanup. Response resources might be provided by a number of national and international oil spill response organizations, equipment manufacturers and suppliers, and third-party providers (e.g., logistics and aviation companies).

Tier 3 response constitutes a scaled-up Tier 2 in situ burning and dispersants response. In a Tier 3 response in the offshore waters of Baffin Bay and Davis Strait, a mechanical containment and recovery response strategy would likely play only a minor role, if at all. The logistics of delivering deployment, storage and handling equipment for a large-volume spill would not be possible or effective. Mechanical containment and recovery equipment could be used in some circumstances. A Tier 3 response would typically involve bringing in equipment and expertise for some combination of in situ burning and aerial dispersant application from national and international stockpiles located at Eastern Canada Response Corporation in St. John’s, and organizations such as Oil Spill Response Limited in Southampton UK.

The Canadian Coast Guard can provide assistance for both a Tier 2/3 sized spill incident with vessels, equipment and expertise (Figure 10.9).

SOURCE: Canadian Coast Guard

Figure 10.9 Canadian Coast Guard vessel with side-sweep boom

Canada is signatory to a number of agreements respecting cooperation in the event of an international oil spill event, including the 1983 Canada-Denmark (Greenland) Marine Pollution Contingency Plan and the 2013 Arctic Council Agreement on Cooperation on Marine Oil Pollution Preparedness and Response in the Arctic, as well as the more recent 2016 Operational Guidelines as prepared by the Arctic Council Emergency Prevention, Preparedness and Response (EPPR) Working Group.

If applicable, individual oil companies would also set up mutual aid agreements with one another if they are operating in the same region or in close proximity.

It would be expected that any company operating in Baffin Bay / Davis Strait would be a member of the Eastern Canada Response Corporation (ECRC), as well as a standing member in one or more international oil spill response organizations.

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