

# STRATEGIC ENVIRONMENTAL ASSESSMENTS

- of the entire hydrocarbon option
- on île d'Anticosti

Consultation document



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# 1. Introduction

## 1.1 Background

On May 30, 2014, Minister of Energy and Natural Resources Pierre Arcand and Minister of Sustainable Development, the Environment, and the Fight Against Climate Change David Heurtel announced the government's Hydrocarbon Action Plan.

The plan is comprehensive, coherent, integrated, and specific in its approach. It contains multiple steps, many of which have already been carried out while others are under way. In it, the government states the following:

- While it is in favor of developing the oil and gas industry, it puts people and the environment first—it will only take action once the right conditions are in place.
- Before any development can be authorized, its potential must be confirmed, its profitability must be known, and best practices must be established.

In August 2014 the government adopted the Water Withdrawal and Protection Regulation with the goal of protecting drinking water sources. It also introduced a bill, passed in June 2014, renewing the permanent ban on oil and gas development in the St. Lawrence Estuary, the moratorium in place in the Gulf of St. Lawrence, and other restrictions.

With regard to hydrocarbon transport, the government is keeping watch over pipeline project developments. The governments of Québec and Ontario have jointly established seven guiding principles in this regard and set up a permanent hydrocarbon oversight body, which released its first report in June 2015 on the Enbridge Line 9B Reversal Project. The government has also taken a firm stance on TransCanada's Energy East Project, imposing a number of conditions. The Project will be subject to public hearings by Bureau d'audiences publiques sur l'environnement (BAPE) in 2016.

The government also wishes to ensure the right conditions are in place before considering any oil and gas exploitation. In view of that, An Act to implement the accord between the Government of Canada and the Government of Quebec for the joint management of petroleum resources in the Gulf of St. Lawrence, for which there is an equivalent bill at the federal level, was tabled at the National Assembly on June 11, 2015. These bills followed intense negotiations on the joint management arrangements to be put in place.

As part of the government's Hydrocarbon Action Plan, two (2) strategic environmental assessments (SEA) have also been announced by the Québec government—one general in nature and the other specific to Île d'Anticosti. The purpose is to review our current knowledge and document the environmental, social, economic, and safety challenges associated with oil and gas extraction and transportation so the government can determine the best course of action. The objective is to:

- Get a better idea of the economically exploitable oil and gas potential in the area
- Address the lack of information on the techniques used, in particular fracking and offshore hydrocarbon exploration and development
- Analyze environmental hazards and establish measures to minimize them and manage them properly
- Study consultation and cooperation mechanisms conducive to community approval and sustainable land use
- Identify best practices to apply in conjunction with partners and the industry

- Examine oil and gas needs
- Compare risks associated with various transport methods
- Have the legislative and regulatory framework updated

To achieve this goal, five steering committees have been struck to look into five different issues: the environment, society, the economy, transportation, and technical matters. Each committee is composed of government representatives and academic experts.

Phase 1 of the SEA on hydrocarbons produced a report on current knowledge of hydrocarbon exploration and development processes. With the report's release on April 2, 2015, it became evident that more study was needed in some areas. To address this requirement, Phase 2 of the SEA was instituted to develop an Additional Knowledge Acquisition Plan (AKAP) and will feature sixty four (64) new studies.

To date, the government has conducted three strategic hydrocarbon environmental assessments:

Offshore:

- SEA1 – St. Lawrence Estuary and northwestern Gulf of St. Lawrence (July 2010)
- SEA2 – Anticosti and Magdalen basins and Chaleur Bay (September 2013)

Onshore:

- SEA on shale gas (January 2014)

The Bureau des Audiences publiques (BAPE) has also done research on the subject:

- Seismic surveys in the St. Lawrence Gulf and Estuary (March to August 2004)
- Sustainable development of the shale gas industry in Québec (September 2010 to February 2011)
- Effects of natural resource exploration and extraction on groundwater in Îles-de-la-Madeleine (May to October 2013)
- Development of the shale gas industry (March to November 2014)

The AKAP studies will support SEA objectives by furthering development of a new legislative and regulatory framework for oil and gas in Québec.

In addition, SEA work on Île d'Anticosti will help the government decide whether to approve the use of fracking there.

The government is also working on a new energy policy for 2016–2025 to replace the 2006–2015 policy. These ongoing studies will thus build on round table discussions by experts from various energy industries as well as public input.

The new energy policy will consider the place of hydrocarbons on the Québec energy landscape. The SEA studies will help determine how best to regulate hydrocarbon exploration, development, and transportation, if at all, as well as how to spread the benefits and minimize the negative effects as long as these resources continue to figure prominently in Québec's energy balance. In that sense, these efforts all feed into each other.

## 1.2 The process

In summer 2014 a steering committee (committee) was formed to oversee the two SEAs. The committee—co-chaired by Christyne Tremblay, Deputy Minister of Sustainable Development, the Environment, and the Fight Against Climate Change, and Gilbert Charland, Deputy Minister of Energy and Natural Resources—includes six

independent university representatives as well as representatives from four ministries: Affaires municipales et Occupation du territoire, Finances, Sécurité publique, and Transports (see member list in Appendix 1).

Also working on the committee are Ministère de la Forêt, de la Faune et des Parcs, Ministère de la Santé et des Services sociaux, and Secrétariat aux affaires autochtones.

The process is divided into four phases, each of which will run in parallel for both the general and Île d'Anticosti SEAs.

- Phase 1: Current knowledge report. Released on April 2, 2015. Based on this report and the priorities the committee identified, and to respect deadlines, an Additional Knowledge Acquisition Plan (AKAP) was developed and published at the same time.
- Phase 2: This document presents the results of the AKAP studies. Note that any studies that were not yet complete when the document was drafted were still included when possible, as some of the preliminary findings and observations had already been discussed with the coordinators and experts from each steering committee.  
  
Studies per subject area are listed in Appendix 2 along with a progress report.
- Phase 3: Public consultations on AKAP findings are planned for fall 2015.
- Phase 4: Final report for each SEA.

### 1.3 Additional knowledge acquisition plan (AKAP) studies

In Phase 2 of the SEAs, 64 studies were conducted by teams of researchers from different backgrounds. Of these 64, 43 had been completed at the time of this consultation document.

This document summarizes the new knowledge acquired through the AKAP studies identified in spring 2015, the primary findings and issues raised in the five subject areas, and best practices for regulating hydrocarbon exploration and development.

The final reports will cover all the studies, review public consultation results, and deliver on SEA objectives.

## 1.4 Oil and gas in Québec

### Demand

No fossil fuel extraction is currently taking place in Québec. To meet its needs in 2013, Québec imported 137 million barrels of oil (MMbbl) and 7.7 billion cubic meters of natural gas (Whitmore and Pineau, 2014) from other provinces, the United States, and elsewhere.

Hydrocarbons account for more than half of Québec energy consumption. Over the last 25 years, total demand for oil has grown about 1% per year. Oil and natural gas have therefore maintained their share of the energy pie at around 40% and 15% respectively.

From 1999 to 2011, total energy consumption in Québec rose by 14%, largely due to an increase in population and GDP. The almost fully oil-fueled transportation sector experienced the strongest growth (37%).

Despite initiatives and measures aimed at improving energy efficiency, the National Energy Board (NEB, 2013) and Régie de l'énergie (2014) expect oil consumption in Québec to stagnate in the coming decade. As for natural gas, NEB forecasts a 0.25% yearly increase until 2035 while Régie de l'énergie (2014) foresees a 2% yearly increase until 2030. However, today's fight against climate change where a number of states—such as Québec—are providing strong leadership and adopting environmental and energy policies could put lie to these predictions.

### Supply

While in 2012 most oil consumed in Québec came from overseas, mainly Africa, the situation changed in 2013; Québec refineries are now largely supplied by North American producers (Western Canada and the United States). Until recently nearly all natural gas came from Western Canada, but with its expanding shale gas industry the United States has increased its share.

Québec and Ontario distributors are looking to increase access to this new supply source. Its relative proximity means lower transport costs. In 2013 Québec imported \$13.5 billion in oil and gas, which is equivalent to 61% of its trade deficit.

Imported oil is carried by train, ship, and pipeline and then refined into products like gasoline, diesel, and jet fuel as well as fuel oil, asphalt, petrochemical feedstock, and other derivatives.

Québec has two refineries: Suncor in Montréal and Valéro in Lévis. Together they account for nearly 20% of Canada's production of refined petroleum products. In 2013 Québec exported a net 12.6 million barrels a day (MMbbl), contributing roughly \$200 million to its GDP (MERN, 2014).

Every year, Québec imports around six billion cubic meters of natural gas, exclusively by pipeline. Gaz Métro and Gazifère handle most distribution in the province, operating the main gas pipeline networks.

A portion of the natural gas coming into Québec is liquefied (LNG) and stored for use in winter when demand peaks. LNG is also used to supply the Blue Road, a network of refueling stations for vehicles in Eastern Canada, as well as various industrial clients not connected to the gas pipeline distribution network, thereby contributing to a reduction in GHG emissions. Côte-Nord, Nord-du-Québec, Bas-Saint-Laurent, Gaspésie, and some regional county municipalities (RCM) have not yet been integrated into the natural gas distribution network, presenting both economic and environmental challenges for the industrial sector.

Some plant and pipeline projects are currently under development and are aimed at exporting and distributing LNG or supplying Côte-Nord businesses with natural gas.

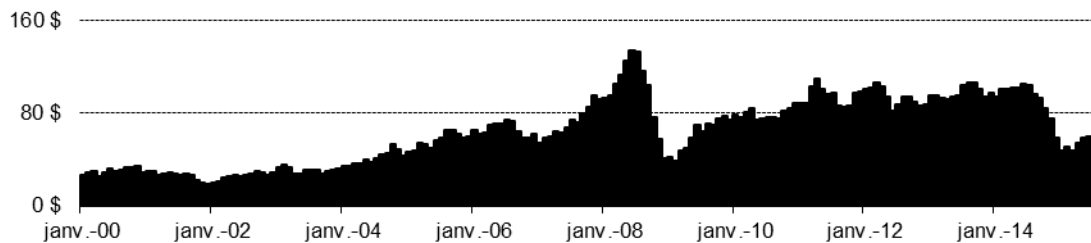
Québec has over 600 petrochemical companies, making it a main industry player in Canada alongside Ontario and Alberta. Their operations are mostly concentrated in east-end Montréal where the Suncor refinery and the Chimie Parachem, Indorama PTA Montréal, and Selenis Canada plants are located, as well as the Port of Montréal and an extensive rail and pipeline network.

## Prices

Oil prices (WTI, current \$US) have fluctuated significantly in recent years, rising steadily from \$30 a barrel in the early 2000s to a peak of \$145 in July 2008 (Table 1). The global economic crisis then completely upended the market in the months and years that followed. Oil prices once again hit a low of \$30 a barrel in December 2008 before gradually rebounding.

The American shale oil boom expanded the market supply substantially, contributing to a drop in prices. In the last few months, oil prices have fluctuated considerably.

**Table 1 WTI oil prices, January 2000 to August 2015 per barrel (current US dollars)**

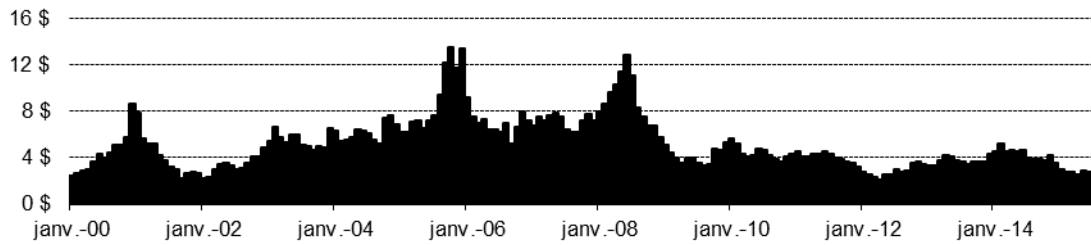


Source: EIA, September 2015

The price of natural gas followed a similar pattern to that of oil from 2000 to 2008, rising from about US\$2 per cubic foot in January 2000 to \$13 in June 2008 before plummeting as a result of the global economic downturn (Table 2).

However, unlike oil prices, natural gas prices never recovered after 2008. Actually, they continued to fall, dropping below US\$2 per cubic foot in April 2012. This can be explained by the fact that the natural gas market is continental—unlike the oil market, which is global—so American shale gas development had a tremendous impact on the North American market.

**Table 2 Natural gas prices, January 2000 to August 2015 per cubic feet (current US dollars)**

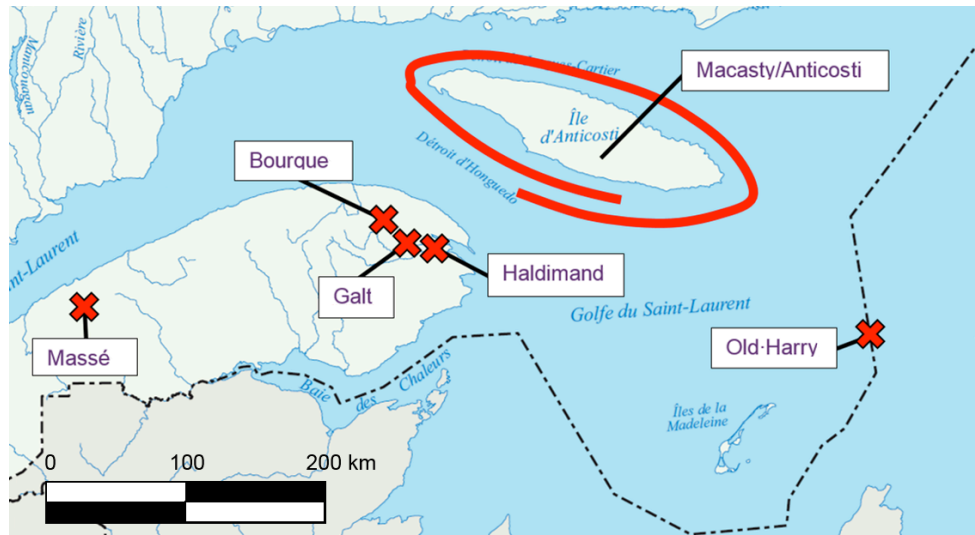


Source: EIA, September 2015 Québec's potential

There is a long history of hydrocarbon prospecting in Québec—nearly a thousand wells have been drilled since 1860. However, no large-scale development has ever taken place.

Onshore oil and gas exploration is concentrated in five major geological regions found in the sedentary basins of southern Québec: the St. Lawrence Lowlands, Gaspésie, Île d'Anticosti, and Bas-Saint-Laurent. Offshore exploration is focused on the Old Harry field in the Gulf of St. Lawrence.

**Figure 1 History**



Exploration is ongoing, and certain basins are recognized as potentially harboring hydrocarbon deposits. Some could even enter into production should their geological and economic potential be confirmed.

Analogues have been identified for each geological structure (see Table 3). These analogues are crucial to our studies as they help identify best practices for exploring and developing such structures and determining their economic potential once there is enough data on hand.

Despite the small scale of oil and gas exploration in Québec at the moment, a number of prospecting companies have their head offices in the province (e.g., Pétrolia, Junex, Squatex Energy and Resources), and other purveyors of goods and services to the industry (drilling, geophysical surveying, helicopters, etc.) are present as well. These companies and suppliers are generally based in the Montréal and Québec City areas.

In 2014 the *Hydrocarbures Anticosti* (HA SEC) partnership was established to explore and, if successful, extract hydrocarbons on Île d'Anticosti. The government, through *Ressources Québec*, a subsidiary of the government corporation *Investissement Québec*, has a 35% stake in the partnership. In 2014 and 2015, HA SEC carried out 12 stratigraphic surveys on the island that basically consisted of extracting core bedrock samples. These surveys should provide more information as to the presence of oil and gas.

**Table 3 State of knowledge on potential oil and gas resources in Québec**

NAME	TypologY - Québec	Analogue	typologY - Analogue
Galt	Gas and oil in fractured low primary-porosity Devonian limestone in a double plunge anticline in the Upper Gaspé Limestone Formation	Anadarko Basin, mainly in the states of Oklahoma and Kansas	Gas and oil in fractured low primary-porosity Mississippian limestone in the Mayes Group—the oil is in the fracture network and the gas in stratigraphic traps
Bourque	Gas and oil in fractured low primary-porosity Devonian limestone in the Upper Gaspé Limestone Formation		
Haldimand	Fractured low-porosity Devonian sandstone in the York River Formation	Oriskany sandstone found primarily in New York, Pennsylvania, and West Virginia	Gas in fractured variable-porosity Devonian sandstone in the Oriskany Formation
		Middle Bakken in Williston Basin in the states of North Dakota and Montana and the provinces of Manitoba and Saskatchewan	Oil in calcareous sandstone and fractured, low-porosity dolomitic siltstone in the Upper Devonian–Lower Mississippian middle Bakken member
Massé	Gas and oil in hydrothermal dolomitic limestone in the Silurian Sayabec Formation	Slave Point Formation in Alberta	Gas in hydrothermal dolomitic Devonian limestone and reefs in the Slave Point Formation
Old Harry	Carboniferous fluvial sandstone in the Bradelle and Ile Brion formations	Carboniferous sandstone in the south of the North Sea	Carboniferous fluvial sandstone in the Schooner Formation
Anticosti	Shale in the Macasty Formation	Point Pleasant Formation in Ohio and Utica Formation in Pennsylvania and Ohio	Gas and oil in source rock shale in the Point Pleasant and Utica formations

This document presents the results of the AKAP studies and will be used for the public consultation the government will be conducting to:

- Collect, analyze, and consider stakeholder concerns and expectations
- Validate findings (impact, mitigation measures, observations) and obtain feedback

## 2. Biophysical environment

### 2.1 Scope

This section documents the main biophysical features of the environments covered by the strategic environmental assessments (SEAs), namely Gaspésie, Bas-Saint-Laurent, and Île d'Anticosti. These regions were selected as they fall within this assessment's study area. Their main biophysical characteristics are described in this section, with particular attention given to Île d'Anticosti.

It should be noted that the St. Lawrence Lowlands (SLL) were covered in the shale gas SEA, and there are no plans to update that data as part of this study. However, some aspects of it were used in this study, especially industry-related information.

### 2.2 Gaspésie

#### Climate

As with nearly all areas of southern Québec, Gaspésie features a cold and humid continental climate, except the Chic-Chocs Mountain peaks, which are continental subarctic.

The region's rugged terrain makes for varied weather. Municipalities along the north shore—which are typically located in coves at river mouths—enjoy a more maritime climate. Such areas have average annual temperatures of 3.5°C—a far cry from the subzero averages in the Chic-Chocs range. Chaleur Bay is aptly named, featuring the highest average annual temperatures in the region at 4°C.

Average annual precipitations vary from 950 mm to 1,300 mm. The Chic-Chocs Mountains get more snow than anywhere else in Québec, with average accumulation of 675 cm a year. The north shore, Matapédia Valley, and the far end of Chaleur Bay receive the least precipitation, while the Appalachians and eastern tip of the region get the most. That last area is the one most affected by maritime depressions from the U.S. East Coast.

#### Geology

The geological features of Gaspésie, Bas-Saint-Laurent, and Île d'Anticosti are presented in detail in the report on the geology and hydrocarbon potential of sedimentary basins in southern Québec put together as part of these SEAs (Institut national de la recherche scientifique, Centre Eau Terre Environnement, 2015).

Gaspésie was shaped by two main orogenies: the Late Ordovician Taconic Orogeny and Middle Devonian Acadian Orogeny. As a result, the region features two mountain groups, the Taconian Belt in the north and southeast (Maquereau-Mictaw inlier), and the Acadian or Gaspé Belt (Bourque et al., 1995) in the center and south of the peninsula. The Salinic Orogeny (Van Staal et al., 2009), which mainly affected the Appalachians in New Brunswick, also had remote effects in the north on the rocks of the Gaspé Belt (Bourque et al., 2001; Bourque, 2001; Malo, 2001; Pinet, 2010).

The nature and age of source rocks in the region suggest that oil and natural gas could be present. In the past decade, many oil and gas discoveries have been made across the northwest of the peninsula, (estimates on the size of these deposits are available), but the hydrocarbon potential of the peninsula as a whole remains unknown for the most part.

A review of the geological qualities (diagenesis, porosity, permeability, structure, etc.) of seals and natural discontinuities should give us some clarity in this regard.

## Hydrogeology

The hydrogeology of the Appalaches (Gaspésie and Bas-Saint-Laurent) consists of fractured sedimentary (or volcanic) rocks covered in a thin layer of glacial sediments. Valleys run NW–SE and have slopes with thick unconsolidated sediments (Figure 2). Water is recharged primarily on these slopes and at the bottom of these valleys, but also to a lesser extent in upland shear zones.

Little has been done to assess the hydrogeology of Gaspésie, and few piezometers have been installed. However, a study was conducted in the Haldimand sector near Gaspé (CIRAIG, 2014). This study (Raynauld et al., 2014) revealed that the drinking water aquifer located 40 meters below the surface is 700 meters of rock away from the oil reservoir.

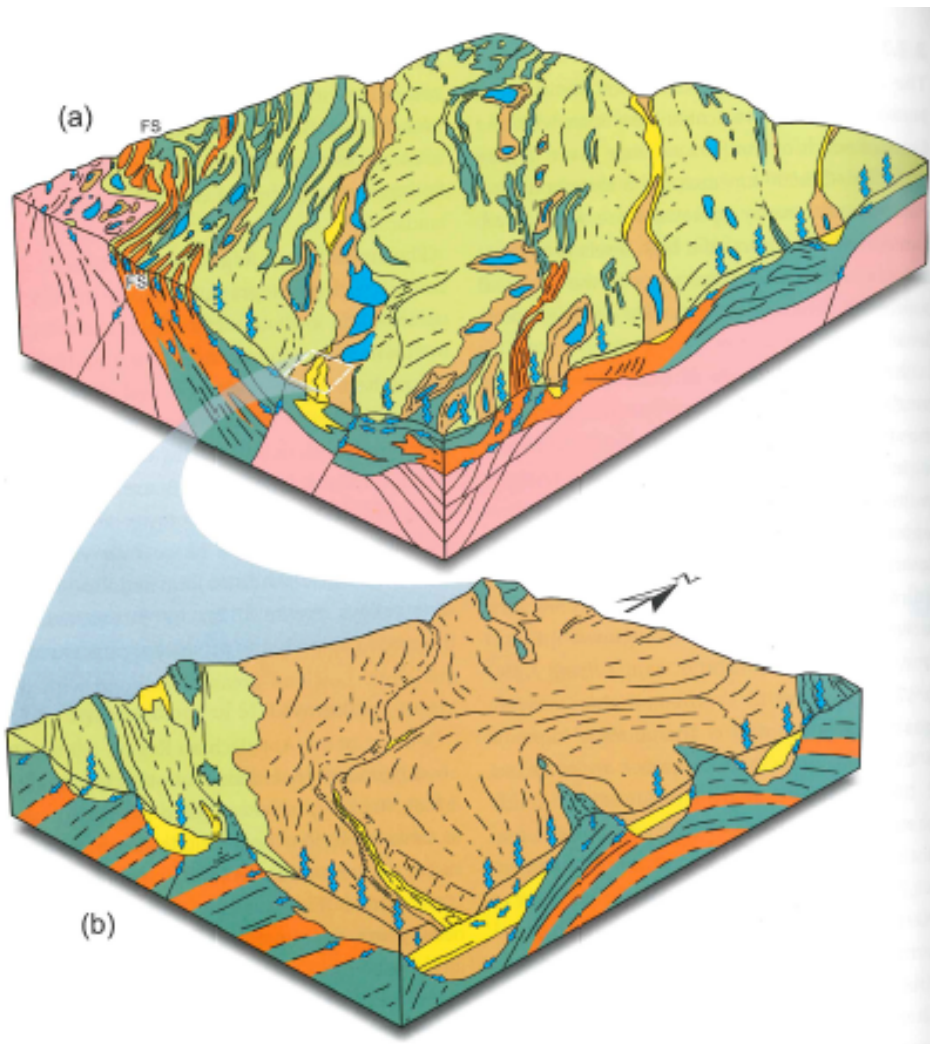
An aquifer is a geological formation, consolidated or not, from which a usable volume of water can be extracted. To be considered an aquifer, the formation must therefore have a sufficient volume of water, and this water must be usable, i.e., not too salty and not containing too many dissolved solids.

It can be difficult to determine how deep aquifers are as in the great majority of cases, water wells are only drilled deep enough to provide the required volume of water.

All aquifers are particularly vulnerable to contamination: confined aquifers are generally better protected against surface contamination than unconfined aquifers, and aquifers in discharge areas are less vulnerable than aquifers in recharge areas.

Caprock protects aquifers from hydrocarbon contamination. The presence of liquid or gas hydrocarbons implies the presence of an impermeable geological feature; otherwise the hydrocarbons (which are less dense than water) would have surfaced or been oxidized long ago.

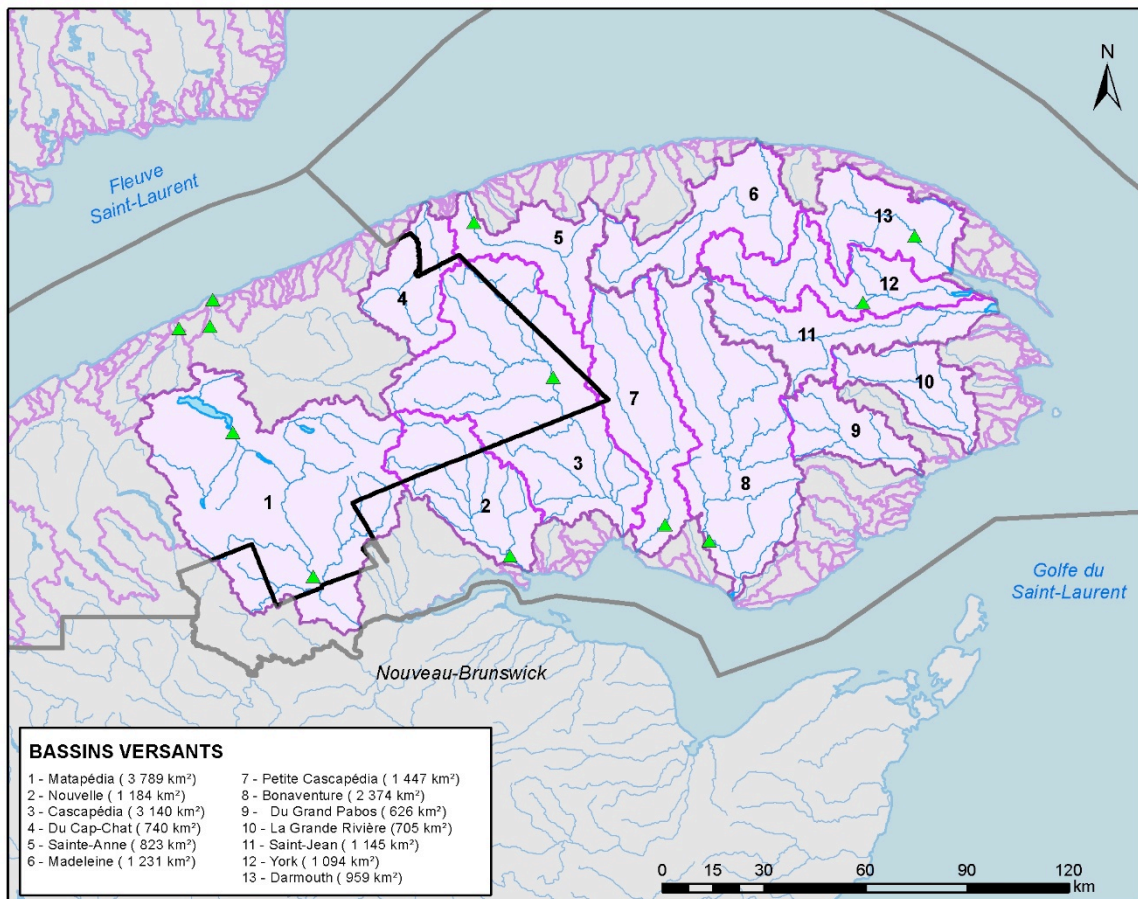
**Figure 2 Hydrogeology of the Appalaches (Gaspésie and Bas-Saint-Laurent)**



## Hydrography and hydrology

Gaspésie is bounded by the salt waters of the St. Lawrence Estuary in the north, the Gulf of St. Lawrence in the east, and Chaleur Bay in the south. The region features a number of rivers that flow north or south but lakes are uncommon and tend to be small (Figure 3). Watersheds in the north of the peninsula are generally smaller and steeper than those in the south. There are three major watersheds in the region, each of them south-flowing and over 2,000 sq km in size, namely those of Rivière Matapédia, Rivière Cascapédia, and Rivière Bonaventure. Straddling Québec and New Brunswick, the Restigouche River acts as a natural boundary between the two provinces for a good 100 km. The river also serves as the outlet for a 12,820 sq km watershed—a bit over half of which is in Québec, including Rivière Matapédia—which drains into Chaleur Bay.

**Figure 3 Location and size of the main Gaspésie watersheds**



Note: The green triangles mark the locations of active Centre d'expertises hydriques du Québec (CEHQ) hydrometric stations that gauge river discharge in real time

Gaspésie has several working hydrometric stations on various rivers. Seven-day low-flow discharges for 2-year recurrence intervals ( $Q_{2,7}$ ) range from about 2 to 4 L/s per sq km, i.e., a bit higher than that of the St. Lawrence Lowlands and Bas-Saint-Laurent (CEHQ, 2008). Average annual runoff is also slightly higher, with discharges of around 25 to 30 L/s per sq km. Flood discharges for 2-year recurrence intervals, meanwhile, are

on the order of 200 to 350 L/s per sq km. The spring freshet generally takes place in mid May.

## Ecology

This ecological overview is of the Gaspé Peninsula natural region, an ecological unit under Québec's Ecological Reference Framework (QERF)<sup>1</sup> developed by MDDELCC (Figure 4). This natural region belongs to the Appalachians natural province and falls within two Québec administrative regions: Gaspésie–Îles-de-la-Madeleine and Bas-Saint-Laurent. Covering an area of 25,000 sq km, the peninsula is bounded on three sides by the Gulf of St. Lawrence and is cut off from the rest of the continent in the west by the Matapédia and Matane River Valleys.

The region features a vast plateau 300 to 600 meters in altitude. Its surface is dissected by multiple deep and winding valleys such as the Cap-Chat and Sainte-Anne River Valleys in the north and Cascapédia and Bonaventure River Valleys in the south. Mountains dominate the landscape with peaks typically reaching 800 m to 1,100 m. The two main mountain ranges are the Chic-Chocs, which run from Rivière-Matane to Mont Albert, and the McGerrigles, which feature the highest peak in Gaspésie, Mont Jacques-Cartier, at 1,270 m. Composed of more erosion-resistant rock (metabasalts, ophiolites, granites), the nearly horizontal crest line of these peaks and the Mont Albert and McGerrigle plateaus bear witness to an ancient and now-eroded peneplain.

The peninsula's bedrock is primarily made of sedimentary rock (sandstone, mudrock, limestone, and conglomerates) deposited on the continental shelf or in marine basins over a series of oceanic episodes 330 to 615 million years ago. Volcanic (basalt) and magmatic (granite) rock are also present in small quantities, as is ultramafic rock in Mont Albert.

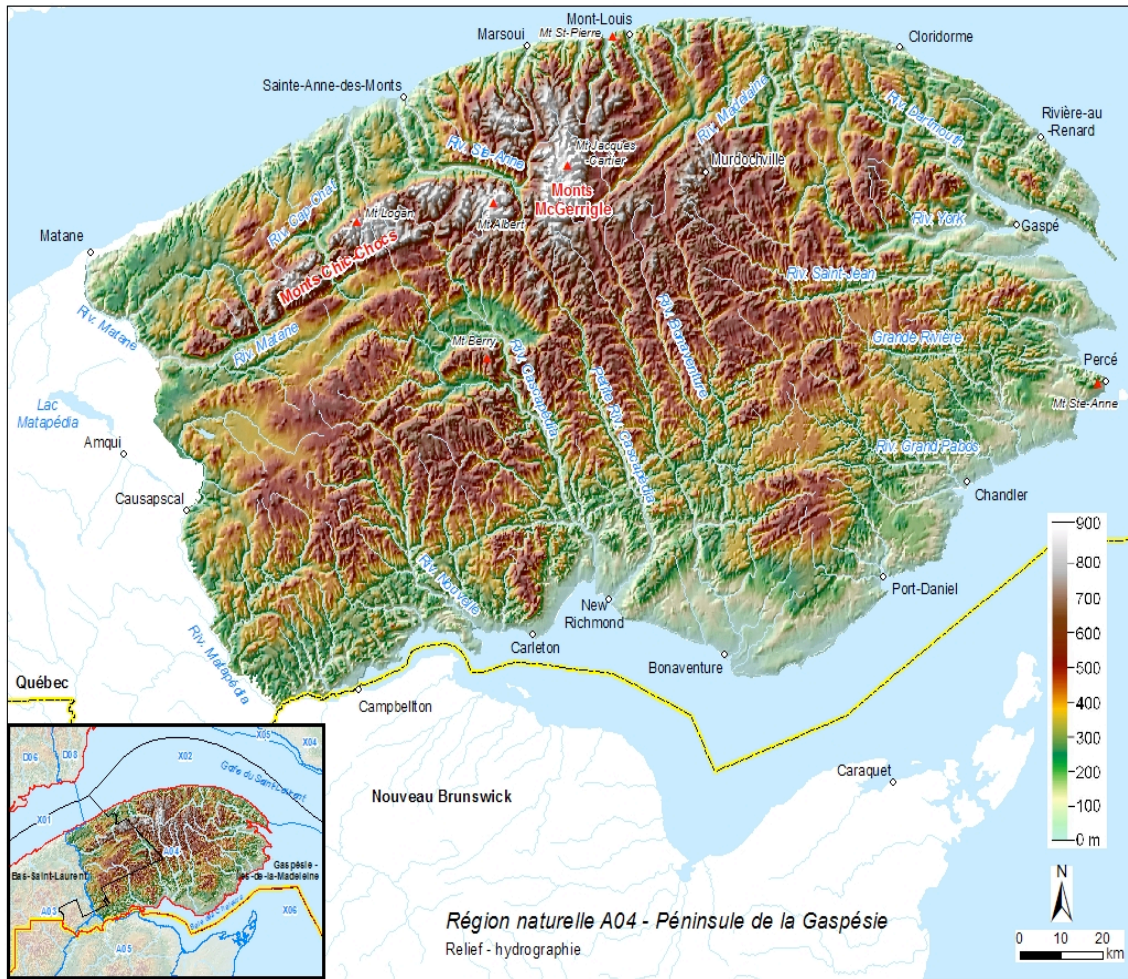
The surface deposits covering most of the Gaspé Peninsula are alteration and colluvial deposits. Glacial deposits (till) are uncommon, and the rest of the region is more or less evenly divided between fluvio-glacial, alluvial, glaciomarine, and organic deposits.

Aside from the coast, the region is sparsely inhabited and forests stretch across the land. Protected areas account for 5.5% of the natural region's territory (*Registre des aires protégées du Québec*). Efforts are being made to expand protection and meet government objectives for protected areas.

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<sup>1</sup> Reference: [http://www.mddelcc.gouv.qc.ca/biodiversite/cadre-ecologique/rapports/cer\\_partie\\_1.pdf](http://www.mddelcc.gouv.qc.ca/biodiversite/cadre-ecologique/rapports/cer_partie_1.pdf)

**Figure 4 Location of the Gaspé Peninsula natural region**



**Usable water sources and their quantities and watercourses unable to provide the volume the industry requires**

The environmental knowledge report (CIRAIG, 2014) concluded that it was impossible to say whether Gaspésie aquifers were productive enough to provide the water required for hydrocarbon development as knowledge of the region’s hydrogeology is lacking at the moment.

As for surface water, although there is enough overall water in Québec to meet hydrocarbon exploration and development requirements (Gangbazo, 2013), no study on Gaspésie watercourses has been conducted to determine which ones would be unable to provide the amount of water the industry needs.

In the event that the hydrocarbon industry were to locate in Gaspésie, a detailed analysis of regional watershed discharge rates would have to be conducted.

## 2.3 Bas-Saint-Laurent

### Climate

As with nearly all areas of southern Québec, Bas-Saint-Laurent has a cold and humid continental climate. Featuring a low-lying terraced landscape (under 250 m), the coastline up to Matane in the east borders the St. Lawrence Estuary, resulting in a more maritime climate. This means that average annual temperatures in the lowlands are rather uniform spatially, varying from 3 to 4°C. These temperatures are comparable to those found further south and are 2 to 3°C higher than those recorded in Abitibi, despite being at the same latitude. Temperatures drop gradually, down to 2 to 2.5°C, the higher up you go and farther away you are from the river.

Average annual precipitations vary from 950 mm on the coast to 1,200 mm inland.

### Geology

As with the Gaspésie region, Bas-Saint-Laurent was shaped by two main orogenies: the Late Ordovician Taconic Orogeny and Middle Devonian Acadian Orogeny.

Deep wells and quality seismic surveys have been rare in the region. Its complex geology and lack of outcrops and data on exploitable subsurface areas have caused it to be ignored for a long time. Source rock definitely seems to be present at depth, but its characteristics are still a matter of speculation. However, recent developments suggest that there is real potential for oil and gas in the region and that it should be thoroughly reexamined using new geological models and exploration methods.

Exploration in this long-neglected region could be given new life by synthesizing the data available, updating geological models and exploration methods, and collecting more data. A recent discovery and multiple publications justify such efforts.

### Hydrogeology

The hydrogeology of Bas-Saint-Laurent was discussed earlier in the Gaspésie section and will therefore not be described here.

Knowledge of Bas-Saint-Laurent groundwater is inadequate and fragmented. No hydrogeological mapping project had been carried out or even started in the region until 2012 (Université du Québec à Rimouski, 2012).

Since then, a groundwater knowledge acquisition program has been under way (PACES). This study, led by *Université du Québec à Rimouski* in partnership with the *INRS Centre Eau Terre Environnement* (INRS-ETE) is targeting the northeastern portion of Bas-Saint-Laurent. The purpose is to take stock of hydrogeological conditions (groundwater quality, quantity, and vulnerability) across the watershed.

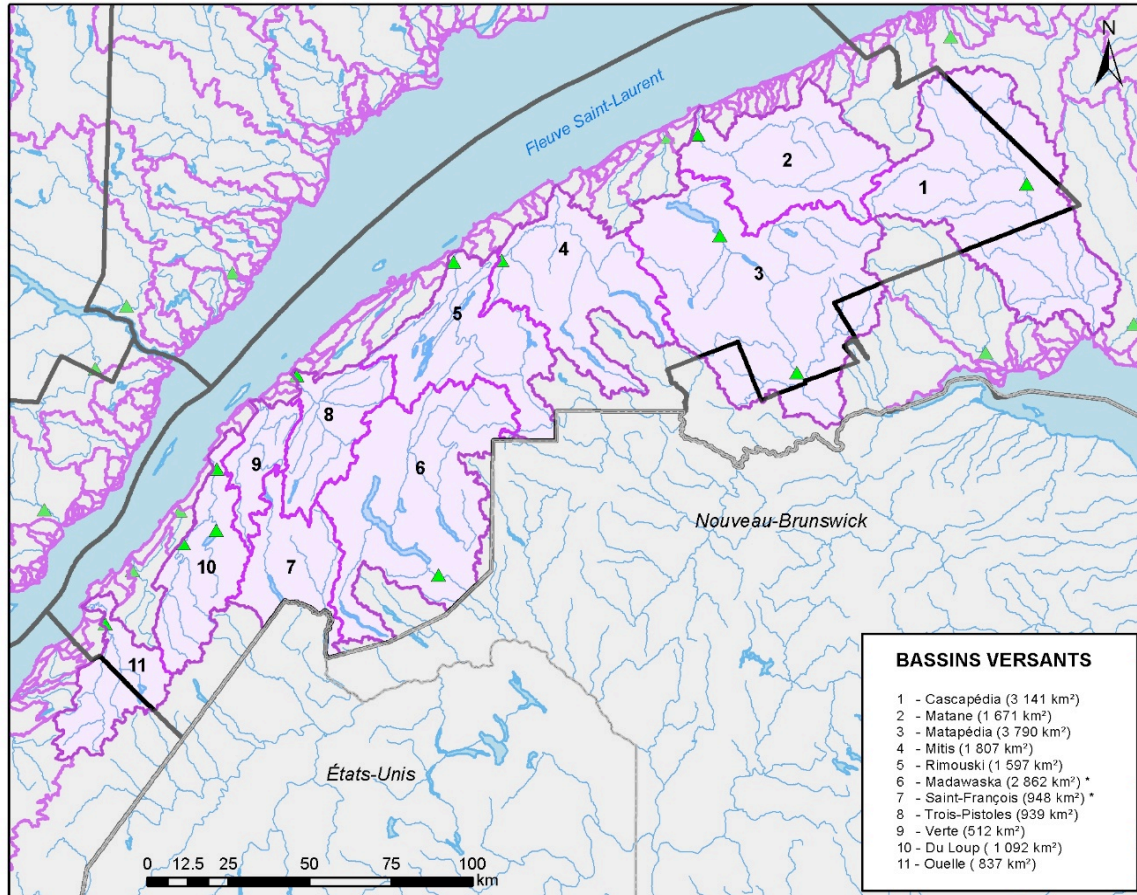
### Hydrography and hydrology

The Bas-Saint-Laurent region is bordered in the northwest by the Middle and Lower St. Lawrence Estuaries. From the tip of Île d'Orléans to the mouth of the Saguenay, the water is brackish and contains a lot of suspended sediments. The lower estuary starts at the mouth of the Saguenay, where saltwater mixes with freshwater and tides are high.

Bas-Saint-Laurent has several watersheds in the Appalachian geological province, most of them average in size. Lakes are typically small (90% under 20 ha), but the region does feature two bigger ones: Témiscouata (66.82 sq km) and Matapédia (38.07 sq km). Some watersheds drain northwest into the fluvial estuary (Figure 5); these belong to

hydrological region 02 - Saint-Laurent sud-est. In the south, Rivière Madawaska and Rivière Saint-François flow south into the St-Lawrence River St. John River. The latter flows through the State of Maine in the United States before traveling through New Brunswick and discharging into the Bay of Fundy. In the east, the Matapédia and Cascapédia empty into Chaleur Bay.

**Figure 5 Location and size of the main Bas-Saint-Laurent watersheds**



Note: The black lines in the above figure indicate the boundaries of the Bas-Saint-Laurent region. For the Madawaska and Saint-François river watersheds, only Québec drainage areas are shown. The green triangles mark the locations of active *Centre d'expertises hydriques du Québec* (CEHQ) hydrometric stations that gauge river discharge in real time.

Several hydrometric stations gauge the watersheds flowing into the estuary and the Matapédia watershed. The average annual discharge is about 20 to 25 L/s per sq km. Seven-day low-flow discharges for two-year recurrence intervals ( $Q_{2,7}$ ) typically range from 1 to 3 L/s per sq km. Flood discharges for two-year recurrence intervals ( $Q_2$ ) are on the order of 150 to 250 L/s per sq km, and the spring freshet generally takes place toward late April.

**Usable water sources and their quantities and watercourses unable to provide the volume the industry requires**

As with Gaspésie, knowledge on Bas-Saint-Laurent hydrogeology is lacking at the moment, so much so that we cannot determine whether regional aquifers are productive enough to provide the water required for hydrocarbon development (CIRAIG, 2014).



formed: the Taconic and Acadian ranges. Compared to neighboring natural regions, very few volcanic and magmatic rocks are present.

While the region was successively covered by two types of glaciers, first continental and then regional, glacial deposits have hardly moved. A thin till covers mountain tops and becomes thicker in slopes and valleys. In many areas north of the 48th parallel, deposits are a direct result of bedrock alteration. Fluvioglacial deposits are abundant in the valleys, especially in the Lac Témiscouata area. Glacial lacustrine sediments can also be found in the Grand Falls valleys (New Brunswick) up to Squatec. Most of the St. Lawrence coastline is covered in glaciomarine, coastal, and organic deposits, a byproduct of the advance and retreat of the Goldthwait postglacial sea.

This natural region is part of the eastern balsam fir–yellow birch bioclimatic domain. However, there are sugar maple bushes and other hardwood species in well-drained areas under 400 m in altitude, where the average annual temperature is above 2°C. Mixed and coniferous forests are more common in valley floors and poorly drained depressions. As for fauna, wildfowl can be found on the flats along the river, as can big game, like moose, in large wooded areas.

Areas with conservation status account for 1.9% of the region's territory (*Registre des aires protégées du Québec*), not even close to the conservation target set by the Québec government. Efforts are being made to expand the protected areas and meet government objectives in this regard. Striking a balance between conservation and permits issued in the area—such as oil or gas permits, which cover a broad swath of the region—remains a challenge.

## 2.4 Île d'Anticosti

At 7,943 sq km, Île d'Anticosti is the largest island in Québec. It is located in the natural province of the St. Lawrence Gulf and Estuary.

### Climate

Four automatic stations operated by Environment Canada and SOPFEU (*Société de protection des forêts contre le feu*) are present on the island.

According to its most recent weather records, Île d'Anticosti clearly has a cold and humid continental climate, as does nearly all of southern Québec.

The island is strongly influenced by the Gulf of St. Lawrence, which surrounds it and gives it a particularly maritime climate. The fact that the island is also quite flat—its highest points barely reaching 300 m in altitude—means that the climate is very consistent throughout the region, with average annual temperatures around 3.5°C and total annual precipitation of about 900 mm.

### Geology

Île d'Anticosti constitutes the bulk of the Anticosti platform land surface. The platform developed in a Paleozoic sedimentary basin along the Precambrian craton margin. The island's sedimentary sequence is made up of Lower Ordovician (Tremadocian) to Lower Silurian (Llandoveryan) deposits mainly composed of calcareous shale and carbonates.

Small-scale deep exploratory drilling and seismic surveys have been conducted on the island. These confirmed the presence of conventional reservoirs—albeit with more saltwater than hydrocarbons. Oil-prone source rock has been found in areas of low thermal maturity and gas-prone source rock has been discovered in the southwest of the

island where thermal maturity is greater. More recently, new studies have begun on the non-conventional potential of the source rock. Shale exploration is under way but it is still too early to tell for certain whether its development would be economically viable. It should, however, be noted that the AECN01 and AECN02 studies have identified various development scenarios that could be profitable.

Aside from some old seismic lines, the Anticosti Basin in the north is essentially virgin ground for exploration. Its hydrocarbon potential is still up in the air but seems promising in the sense that the Macasty Formation—an oil-prone source rock—should be present through much of the basin.

## **Soil**

Performing initial soil characterization on Île d'Anticosti was deemed unnecessary for this SEA as it is the developer's responsibility, as set out in Section 2.2 of *Lignes directrices provisoires sur l'exploitation gazière et pétrolière* (MDDELCC, 2014b): "the applicant must, before carrying out its project, conduct soil and groundwater characterization." Characterization studies are regulated by the three documents below:

- *Guide de caractérisation des terrains* (Ministère de l'Environnement, 2003)
- Caractérisation physico-chimique de l'état initial des sols avant l'implantation d'un projet industriel (in progress at MDDELCC)
- Revision of the parameters analyzed and measurements taken with respect to soil radioactivity (study GENV27)

*Guide de caractérisation des terrains* addresses land characterization in general whereas *Caractérisation physico-chimique de l'état initial des sols avant l'implantation d'un projet industriel* elaborates on the activity in question. For its part, the GENV27 study (MDDELCC, 2015) lists the parameters to analyze when characterizing soil radionuclides.

## **Soil stability**

According to the AENV21 study (Fournier & Deschênes, 2015), the data available on surface deposits in Anticosti is rather incomplete. Analysis was based on a surficial geology map produced by the Geological Survey of Canada (GSC) as well as aerial photographs, specifically pictures taken in 1975 with a scale of 1:40,000.

The Geological Survey map indicates that surface deposits are primarily found on the island's periphery while the bedrock shows on the surface in the center. Clay soils are present on the island, particularly in the south between Rivière Sainte-Marie and Rivière Galiote. These deposits are landslide hazards—appropriate precautions will have to be taken wherever they are present.

In light of this information, aerial photographs were examined—specifically those taken in areas where clay deposits were indicated on the map. As a result of this analysis, what seems to be the scar from a major landslide was discovered in the clay deposits. This type of landslide, which can run several hundred meters, is typical of sensitive clay deposits.

## Water characteristics

### Hydrogeology

The hydrogeology of Île d'Anticosti is complex due to the presence of karst areas. These geological formations—which are present on the surface—are composed of chemically soluble rock with special, extremely variable and disparate hydrogeological features and they are particularly vulnerable to contamination. Contaminants can easily travel through karst aquifers and spread quickly over long distances.

In the 1980s a research team from *Université de Sherbrooke* conducted a series of studies and identified two major karst areas—Jupiter and Saumon—featuring many sinkholes (round landforms engendered by the dissolution of rock), dissolution-enlarged joints, losses in streams, and major resurgences. In these areas, lake water levels can fluctuate by many meters a week when sinkhole ice melts in early summer. The Patate Cave is another manifestation of the karst phenomenon.

University of Ottawa researchers have also identified a source of brine and methane near Rivière Chaloupe, not far from the surface projection of the Jupiter fault. This source is associated with a carbonate mound about 1 m high and 30 m in diameter. Early indications are that the methane emanating from it is at least partly thermogenic in origin and is coming from an underground reservoir never identified in the island's sedimentary succession.

More knowledge will be required to better understand the origin of the fluids and their path through the caprock.

No groundwater resource map is currently available for Île d'Anticosti, and there are no gauging stations monitoring groundwater on the island (CIRAIG, 2014). Key scientific data is therefore missing on the hydrogeology of the island and the geochemical composition of its groundwater. This precludes any assessment of the natural connectivity between deep regions and surficial aquifers.

In February 2014 Pétrolia announced a hydrogeological study on Île d'Anticosti (Pétrolia, 2014) by *INRS Centre Eau Terre et Environnement* (INRS-ETE). The study, which will take three years to complete (see Figure 7), has the four following objectives:

1. Establish 14 monitoring wells at 10 different sites and take samples of the groundwater to determine its quality
2. Characterize the current geological and hydrogeological conditions in detail
3. Monitor changes in water quality as Pétrolia conducts its operations and set up a system to detect and correct any potential issues
4. Incorporate all results and make recommendations aimed at minimizing the potential impact of oil operations on groundwater

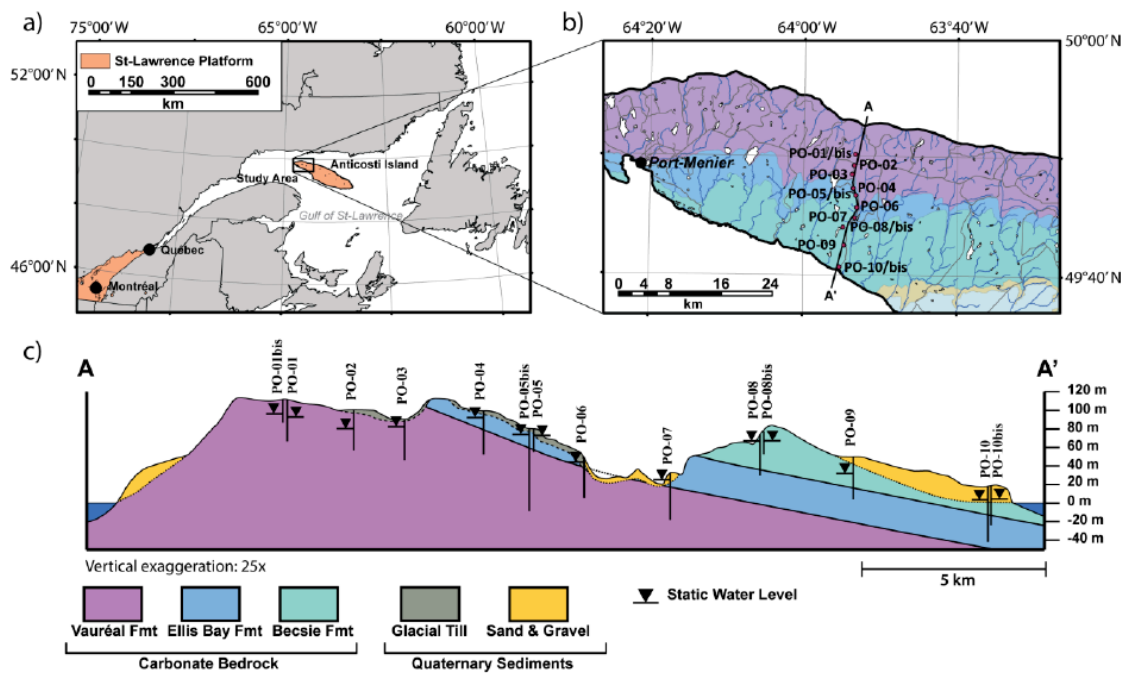
Early results based on data collected in 2014 show the following:

- In the area where the company carried out its work, the flow system is mostly topography-dependent and has rather low hydraulic conductivity ( $2 \times 10$  to  $5 \times 10 - 6$  m/sec).
- The surface geochemistry (20 to 102 m deep) mostly follows a carbonate dissolution and calcium-sodium ion exchange pattern, and all water sampled has

been of the Ca-HCO<sub>3</sub> or NA-HCO<sub>3</sub> variety (which is similar to the results obtained by the *Université de Sherbrooke* team in the Jupiter section of the karst lakes). These hydrochemical signatures provide information on changes in the water and its movement patterns. Flow patterns seem to be defined by recharge and discharge areas, which are mainly determined by topography.

- Sample analyses have not revealed any volatile organic compounds or hydrocarbons in the water. However, gas was detected in the air sections of wells. Methane could not be identified by the instruments in place.
- The aquifer system is a fractured carbonate system dominated by horizontal fractures with fewer and fewer fractures the deeper you go. Water most likely circulates vertically from the surface toward the depths along natural vertical fractures on Anticosti.

**Figure 7 Illustration of the work INRS-ETE carried out for Pétrolia on Île d’Anticosti in 2014**



Note: a) Île d’Anticosti location b) Piezometer layout c) Geological cross section and piezometric levels

The obligation to conduct hydrogeological studies prior to oil and gas drilling, as set out in Chapter 5 of the *Water Withdrawal and Protection Regulation (WWPR)* (c. Q-2, r. 35.2), will make it possible to document the groundwater situation on Île d’Anticosti.

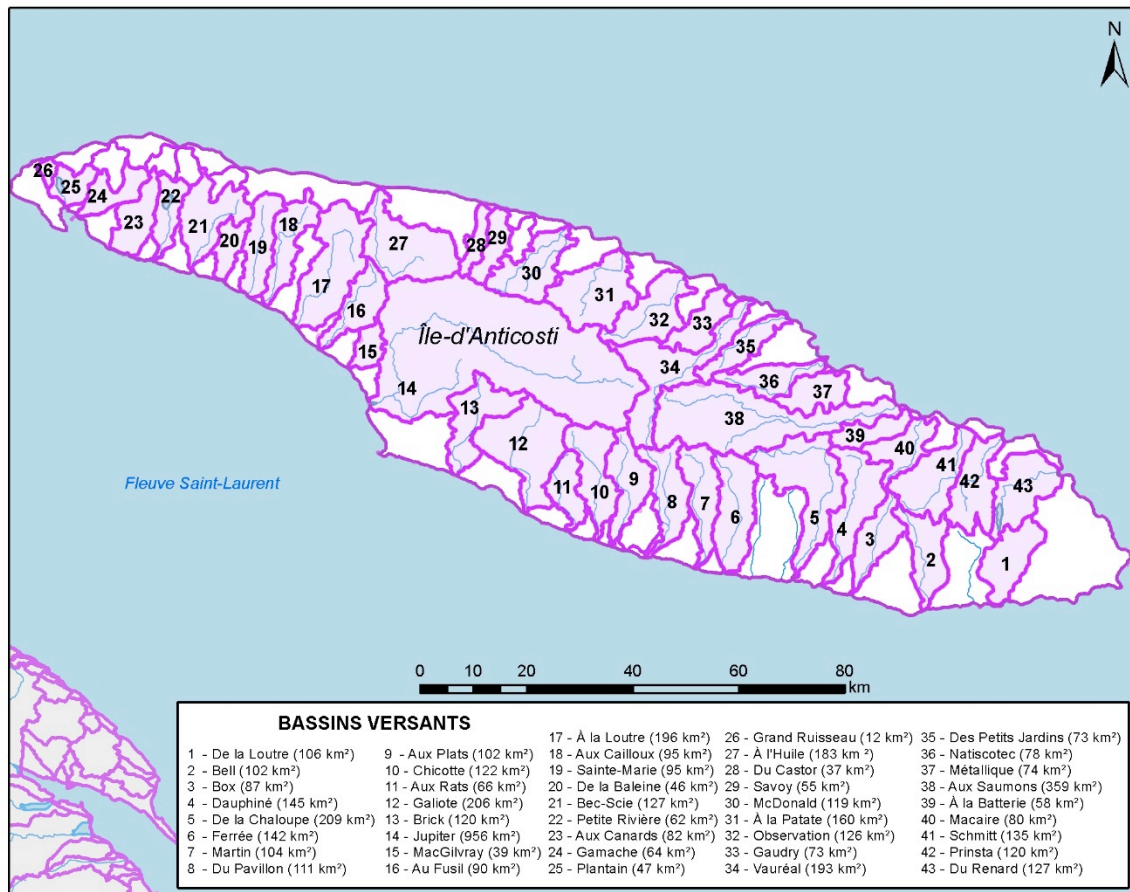
### Hydrography and hydrology

Île d’Anticosti features many small watersheds (typically under 200 sq km) (Figure 8). The Rivière Jupiter and Rivière aux Saumons watersheds are exceptions, covering 956 sq km and 358 sq km respectively—the largest watersheds on the island. Most watersheds are elongated and perpendicular to the shore. The island has multiple karst areas that can interact with surface water.

The island has had no hydrometric station for years now. Two such stations—one at Rivière à l’Huile (135201) and the other at Rivière Jupiter (132901)—were shut down in 1993.

As part of this SEA, an analysis of the data from these stations was conducted and raised doubts as to the reliability of their flood and low-flow data. The fact that these stations had unstable monitoring areas and that few measurements were taken during low flows and floods has resulted in inaccurate rating curves, which are to calibrate discharge fluctuations based on the water levels recorded. Nevertheless, the data from Rivière à l’Huile Station was deemed reliable enough to be used for low-flow analysis. Based on this data, the  $Q_{2.7}$  low-flow discharge has been estimated at 0.94 L/s per sq km; this value has been transposed to all other watersheds on the island. Compared to other values typically recorded in Québec, this is rather low, but it is similar to low-flow values observed in some Estrie and Montérégie watersheds where low values are more common, especially in the latter region. Beyond that, little is known about surface runoff on the island.

**Figure 8 Location and size of the main Île d’Anticosti watersheds**



### Watercourses

There are nearly 10,000 km of rivers on Île d’Anticosti. The island’s drainage density is 1.23 km/sq km. In comparison the natural provinces of southern Québec have higher densities of 1.5 to 1.8 km/sq km (Table 4).

**Table 4 Drainage density in natural provinces of southern Québec**

Natural province	Drainage density (km/sq km)
A- Appalachians	1.6
B- St. Lawrence Lowlands	1.8
C- Southern Laurentians	1.5

The island has around a hundred type 1 watersheds (discharge into the Gulf). The area covered varies tremendously from one river to another (Table 5). The Rivière Jupiter watershed is by far the largest on the island, covering an area of 956 sq km, nearly three times the size of the next largest basin, that of Rivière aux Saumons. For comparison's sake, here is a list of the Anticosti watersheds and that of the main rivers of southern Québec—the latter are much larger.

**Table 5 Surface area of the 10 biggest Île d'Anticosti watersheds in relation to a few southern Québec watersheds**

Area	River	Watershed area (sq km)
Southern Québec	Saint-Maurice	42,651
	Yamaska	4,798
	Batiscan	4,683
	Du Chêne	803
	Saint-Charles	544
Anticosti (10 biggest watersheds)	Jupiter	956
	Aux Saumons	359
	Chaloupe	209
	Galiote	206
	À la Loutre	196
	Vauréal	193
	À l'Huile	183
	À la Patate	160
	Dauphiné	145
	Ferrée	142

### Lakes

Water covers about 214 sq km of Île d'Anticosti, or 2.7% of its area. Water surface area can be broken down as follows: large streams and rivers (16%), lakes (76%), and ponds (9 %) (Table 6, Figure 9). These are spread unevenly across the island. Most ponds are located in the east, which is full of bogs.

Many lakes and ponds are not connected to the surface water network. Two very different areas feature such lakes:

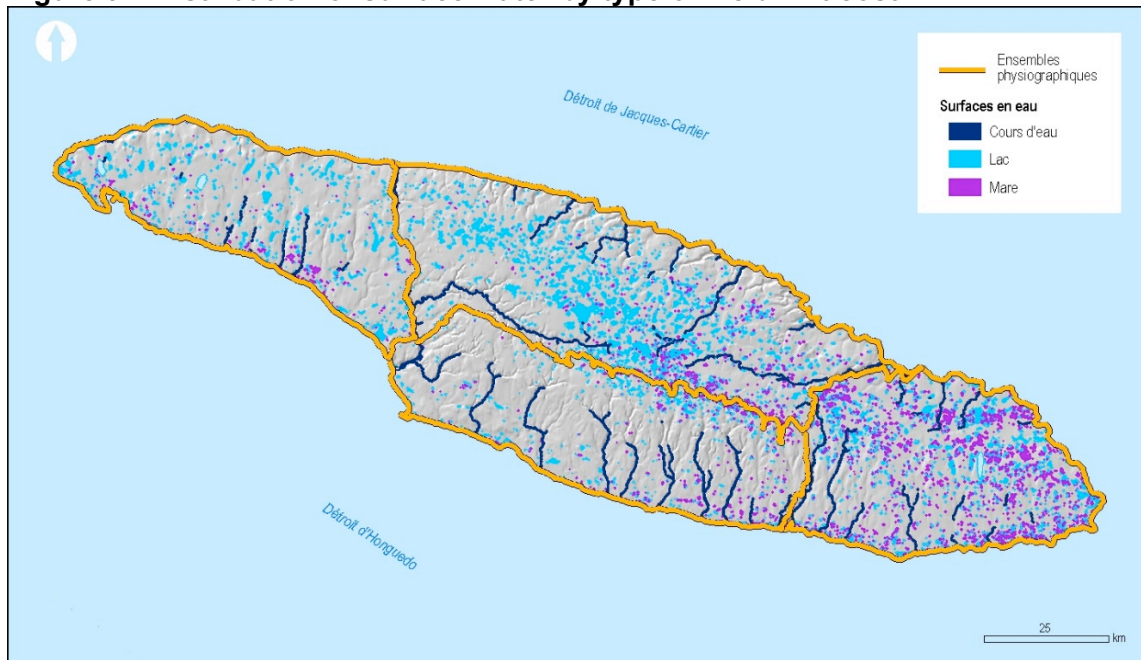
- The eastern tip of the island features a number of wetlands. Many lakes in the area lie in organic soil (bogs), giving them access to the water network through the ground. These are concentrated downstream from watersheds.
- The central area of the island features unconnected lakes closer to watershed sources lying on shallow alteration deposits.

**Table 6 Breakdown of surface waters on Île d'Anticosti**

Description	Number	Area (sq km)	Water area (%)
Large rivers and streams	134	33.37	16
Lakes	5,281	162.30	76
Ponds	7,398	18.79	8
Total	12,813	214.46 sq km	

Lake dynamics are often influenced by karst phenomena. Hydrogeomorphic analyses have allowed us to document phenomena associated with major fluctuations in lake water levels in the central part of the island. Sinkholes in the area's lacustrine environments and highly permeable limestone have brought about major variations in water levels controlled by surface hydrology, evaporation, and especially water table fluctuations and the underground karst network (Côté, Dubois, Héту, & Gwyn, 2006).

**Figure 9 Distribution of surface water by type on Île d'Anticosti**



**Usable water sources and their quantity and watercourses unable to provide the volume the industry requires**

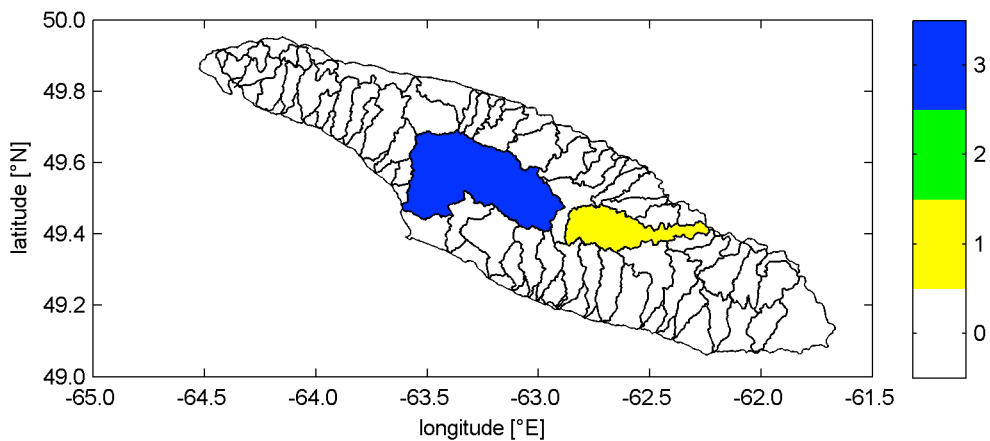
At the time this document was written, the industry had not yet decided if it would use water or other methods (propane, nitrogen, or carbon dioxide [CO<sub>2</sub>]) for fracking on Île d'Anticosti. Furthermore, there is currently no information on groundwater availability and very little for surface water.

Given the lack of information, it is difficult to ascertain whether surface water on the island would be able to replenish itself and be enough to meet industry needs without hurting the environment. As with the study on shale gas water consumption requirements in the St. Lawrence Lowlands, hypotheses and simplification are key here<sup>3</sup>.

<sup>3</sup> Given that hydrocarbon operations require about as much water as shale gas fracking, it can be concluded that a total volume of at least 1,670 cubic m of water would be needed per fracking phase (horizontal segments about 120 m long). For typical 1,600 m long horizontal wells, the water volume required for all

Considering the uncertainties above, the AENV02, AENV03, and AENV06 studies (Kirby et al., 2015) have shown that only two Anticosti watersheds would be able to support withdrawals of 38.7 L/s: the Rivière aux Saumons (359 sq km—yellow area in Figure 10) and Rivière Jupiter (956 sq km—blue area in Figure 10) watersheds. At best, these watersheds could meet the needs of one or three multiwell drilling sites operating simultaneously in their respective areas.

**Figure 10 Illustration of the maximum number of multiwell drilling sites that watersheds on Île d’Anticosti could simultaneously support in view of consumption requirements of 38.7 L/s and maximum withdrawals equal to 15% of each watershed’s  $Q_{2,7}$ .**



As such, a better understanding of Île d’Anticosti’s natural environment is required, specifically its river water regime and its ecosystem water needs, so as to better understand and manage the cumulative impacts of withdrawing water from a given watershed’s rivers.

The *Water Withdrawal and Protection Regulation* (WWPR) (c. Q-2, r. 35.2) has been in effect since 2014. Under Section 31.75 of the *Environment Quality Act* (EQA) (R.S.Q., chapter Q-2), approval is now required to withdraw 75,000 liters a day or more of surface or groundwater. Consequently, when surface water withdrawal projects are examined, the impact on the environment and other users must be taken into account. To this end, in addition to regulatory requirements, it has been determined that a cumulative criterion of 15% of the  $Q_{2,7}$  should be used in conjunction with other criteria to prevent negative impacts in watercourses subject to repeated withdrawals.

Should the government approve hydrocarbon development on the island, MDDELCC will require additional knowledge before it can appropriately process water withdrawal authorization requests or know which specific data to request from applicants

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13 phases would therefore be 21,710 cubic m. Based on shale gas studies, two fracking phases a day has been assumed. This would require 3,340 cubic m of water a day, meaning that water would have to be withdrawn at an average rate of 38.7 L/s for the entire time of fracking at any given drilling site. For the shale gas industry, standard drilling platforms are defined as having 10 horizontal wells, so total fracking time is 39 days.

## Water quality

The AENV09 study (Hébert & Pelletier, 2015) was conducted as part of this SEA to obtain data on Anticosti water quality.

Six samples were collected from nine stations across eight rivers on the island during ice-free periods between October 2014 and August 2015 so as to characterize the water's physicochemical quality. The analysis parameters were drawn from the list in Appendix 2 of the *Water Withdrawal and Protection Regulation* (WWPR) (c. Q-2, r. 35.2). They included conventional water quality criteria as well as natural elements that could be affected by drilling and fracking operations. They also included contaminants likely to be produced by such activities. The water's overall quality was assessed using the bacterial and physicochemical quality index (BPQI), a water quality index that, for this study, takes into account total phosphorus, nitrites and nitrates, ammonia nitrogen, and suspended solids.

Results show that all rivers monitored on the island have very high quality water, with BPQIs ranging from 94 to 99 depending on the station (the highest possible score is 100). Phosphorus, nitrite/nitrate, and ammonia nitrogen concentrations are very low—well below the quality criteria for protecting bodies of water from eutrophication (0.030 mg/L of phosphorus) and for protecting aquatic life (2.9 mg/L for nitrites/nitrates and 0.21 to 1.8 mg/L for ammonia nitrogen). The island's river water is crystal clear: turbidity varies from 0.1 to 2.8 NTU, and concentrations of suspended solids are well below the reference value of 13 mg/L—the dividing line between fair and marginal water quality as defined by the BPQI. Given how clear the water is and how low the concentrations of nutrients are, Anticosti rivers would be very sensitive to any supplementary nutrients (phosphorus or nitrogen) or suspended solids.

The water is alkaline, with pH levels ranging from 7.6 to 9.5 and alkalinity levels from 58 to 146 mg/L ( $\text{CaCO}_3$ ). The rivers are also resistant to acidification (Nagpal, 1995). Water hardness varies between 75 and 169 mg/L ( $\text{CaCO}_3$ ). Quality criteria for metals influenced by water hardness are relatively high (Table 7). Dissolved organic carbon (DOC) concentrations were between 2.1 and 11 mg/L, but Rivière Trois-Milles, Rivière Bell, Rivière Sainte-Marie, and Rivière de la Chaloupe contain higher concentrations than the others. As DOC has been recognized as an important factor in mitigating the toxicity of some metals, these rivers should be more resistant to metal contamination. Anticosti rivers have very low concentrations of metals, even for aluminum, iron, and manganese, which are usually quite common in the Earth's crust and surface waters. Due to their hardness, Anticosti rivers, much like the rivers draining the Gaspé Peninsula and St. Lawrence Lowlands, are more resistant to metal contamination than rivers draining the Southern and Central Laurentians, Lower North Shore Plateau, Appalachians, Abitibi Lowlands (Table 7), Mistassini Highlands, and Ungava Bay Basin.

Activity concentration recorded for radium-226 ranged from < 0.003 Bq/L to 0.015 Bq/L, with most measurements below 0.006 Bq/L. These values are low and similar to activity concentrations recorded for natural surface and groundwater. In a study on the presence of radionuclides in surface water at 13 locations in Canada chosen due to their susceptibility to high radionuclide concentrations, the activity concentrations recorded for radium-226 varied from 0.001 Bq/L to 0.013 Bq/L (Baweja, Joshi, & Demayo, 1987). Furthermore, a Health Canada study on radionuclide concentrations in water drawn from 53 New Brunswick communities showed average activity concentrations of 0.0032 Bq/L, which corresponds to the background level in Canada (Santé Canada, 2009).

**Table 7 Quality criteria for protecting aquatic life**

<b>Metal</b>	<b>Anticosti chronic effect criterion (µg/L)<sup>†</sup></b>	<b>Abitibi chronic effect criterion (µg/L)<sup>‡</sup></b>
Arsenic (AS)	150	150
Boron (B)	5,000	5,000
Barium (Ba)	322–765	38–272
Beryllium (Be)	1.15–9.02	0.041–0.774
Cadmium (Cd)	0.22–0.40	0.049–0.18
Cobalt (Co)	100	100
Chromium (Cr) <sup>‡‡</sup>	10.6	10.6
Copper (Cu)	7.3–14.6	1.3–6.1
Iron (Fe)	1,300	1,300
Manganese (Mn)	1,498–3059	255–1,304
Molybdenum (Mo)	3,200	3,200
Nickel (Ni)	40.9–81	7.4–36
Lead (Pb)	2.2–6.2	0.19–1.5
Selenium (Se)	4.6	4.6
Antimony (Sb)	240	240
Strontium (Sr)	21,000	21,000
Uranium (U)	14	14
Vanadium (V)	12	12
Zinc (Zn)	94–187	16.8–81

<sup>†</sup> Criteria vary based on hardness: barium, beryllium, cadmium, copper, manganese, nickel, lead, and zinc values were calculated using the minimum and maximum hardness recorded, i.e., 75 and 169 mg/L.

<sup>‡</sup> Criteria vary based on hardness: barium, beryllium, cadmium, copper, manganese, nickel, lead, and zinc values were calculated using the minimum hardness used to calculate the criteria (10 mg/L except for beryllium: 20 mg/L) and the maximum hardness recorded, i.e., 64 mg/L.

<sup>‡‡</sup> The criterion associated with hexavalent chromium (CrVI) was used.

In the event of hydrocarbon development on Île d'Anticosti, it would be appropriate to establish two regular water quality monitoring programs in order to document the impact of these activities on the aquatic environment: a spot monitoring program using water samples and a continuous monitoring program using probes (temperatures, pH, dissolved oxygen, conductivity, turbidity). The spot monitoring program would document changes in water quality and the impacts of hydrocarbon development in relation to baseline conditions while the continuous monitoring program would help identify changes in water quality relating to incidents or spills, making for quicker response time.

### **Benthic macroinvertebrates**

MDDELCC does not currently have a regular benthic macroinvertebrate monitoring program for Île d'Anticosti rivers. That said, as part of this SEA, the AENV10 study (Hébert & Pelletier, 2015) in fall 2014 characterized the initial state of benthic macroinvertebrate communities in eight rivers on the island. They were monitored at the same stations used to monitor initial surface water quality (AENV09 Study). As with the study on water quality, this study will help determine how vulnerable environments are to various contaminants.

In Pennsylvania the 59 stations of the Remote Water Quality Monitoring Network (RWQMN) are supervised by the State-owned Susquehanna River Basin Commission (SRBC) and are located where drilling and fracking in the Marcellus Shale are most active, as well as areas in which no exploration activities are planned, to determine baseline conditions (SRBC, 2014). The monitoring program is funded by the industry, water use royalties, and public bodies.

In British Columbia the Horne River Basin Water Project was launched in 2008 by the shale gas-producing Horne River Basin Producers Group in partnership with an NPO and the British Columbia Ministry of Natural Gas Development (Salas, Murray, & Davey, 2014).

In the event of hydrocarbon development on Île d'Anticosti, it would be advisable to establish regular benthic macroinvertebrates monitoring program in order to document the impact of development activities on the aquatic environment.

## Ecology

### Wetlands

Wetlands cover over 25% of the island. The great majority of them are open (75%) or wooded bogs (11%) (Table 8). Wetlands are particularly concentrated in the eastern parts of the island (Figure 11).

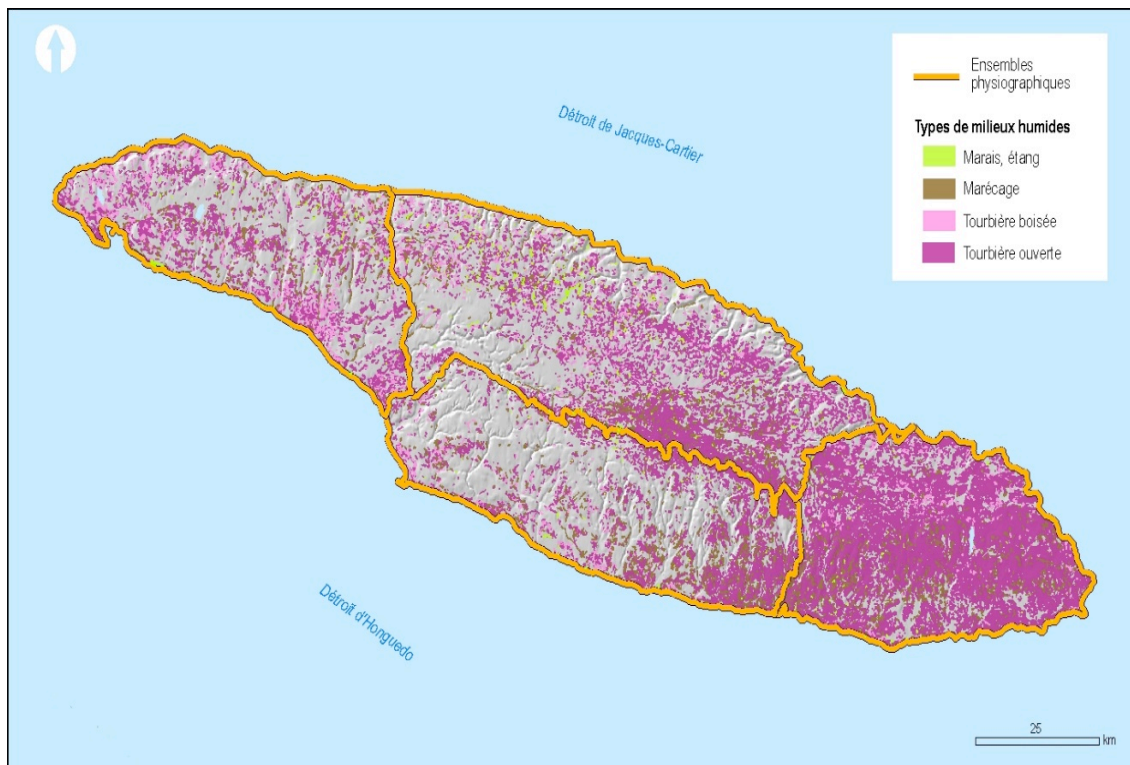
Such environments are subject to regulations that reflect their biological importance. Their soil is very peculiar (poor drainage, low bearing, compaction risk) and poses constraints to infrastructure and drilling projects.

**Table 8 Distribution of wetlands on Île d'Anticosti**

Wetland type	Area	
	Sq km	Percentage <sup>†</sup>
Marshes, ponds	15	0.8
Swamps	253	12.6
Wooded bogs	216	10.8
Open bogs	1,517	75.8
Total	2,002	100.0

<sup>†</sup> Percentage of wetland area

**Figure 11 Distribution of wetlands on Île d'Anticosti**



### **Vegetation and plant species with special status**

Île d'Anticosti is dominated by coniferous forests. The introduction of white-tailed deer over a hundred years ago dramatically changed the island's vegetation, the distribution of which is presented in Table 9 and Figure 12. Browsing favors white spruce—the species spread at the expense of balsam fir and now covers 40% of the island. Fir forests are now quite old and cover less than 20% of the island.

In addition to deer-related disturbances, there have been insect outbreaks, wind throw, and logging. Forest fires are particularly common on the island's large central plateau and help renew black-spruce moss and heath forests or convert them into more open black-spruce stands or very rocky lichen or moss tundra (regression). Old forests are still standing and occupy nearly 40% of the island.

Île d'Anticosti is home to over 700 plant species, 31 of which are already or could potentially be designated as threatened or vulnerable. Its phytogeography is quite special, featuring both arctic and southern elements, a truly distinctive phenomenon in Québec. For instance, two arctic plants—the low braya (*Braya humilis*) and arctic bladderpod (*Physaria arctica*)—can be seen here, over a thousand km south of their usual range. Conversely, the ram's-head lady's-slipper (*Cypripedium arietinum*) also grows in the region, over a thousand km away from its main distribution zone in Outaouais. Some valleys on the north shore also feature white pine, while other areas feature isolated populations of maidenhair fern (*Adiantum pedatum*) and many-headed sedge (*Carex sychnocephala*), two more southern plants well outside their typical range. The presence of so many isolated species suggests that their genetics may be different from that of others growing in Québec.

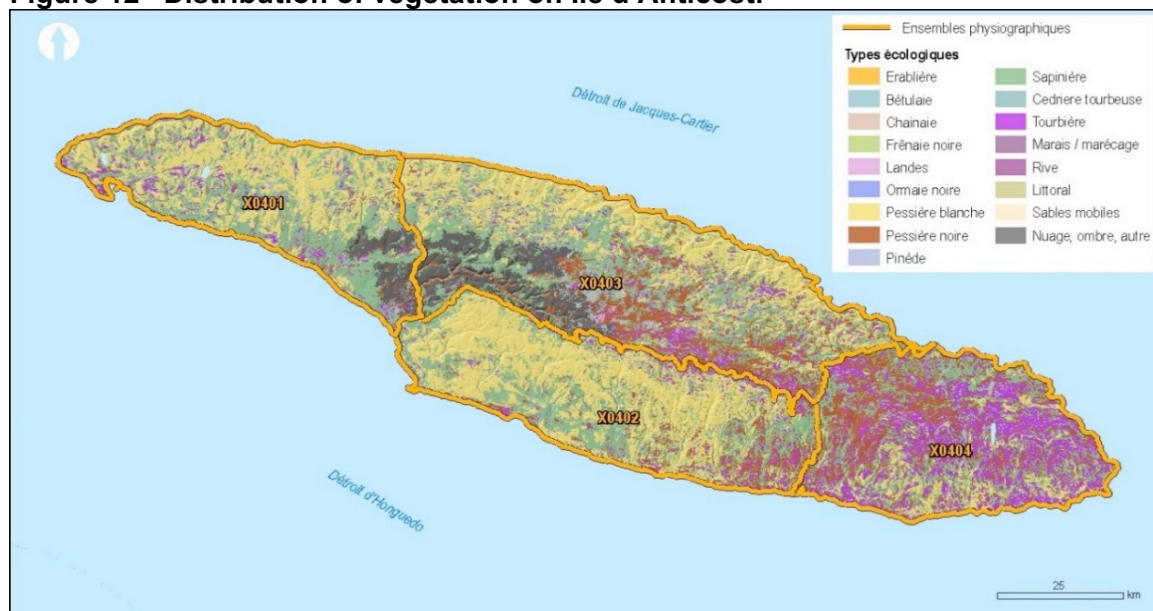
**Table 9 Distribution of vegetation on Île d'Anticosti**

Vegetation type	Sq km	Area	Percentage <sup>†</sup>
Browsing-induced white spruce forests	3,186.2		40.2
Black spruce forests	1,553.3		19.6
Black-spruce moss and heath forests	540.6		6.8
Black-spruce sphagnum forests	302.2		3.8

<sup>†</sup> Percentage of island land area

There are currently 31 species on the island designated as threatened, vulnerable, or liable to be identified as such: 6 nonvascular species (6 occurrences) and 25 vascular species (138 occurrences). Only two species have official status under the *Act respecting threatened or vulnerable species*: the Anticosti aster (threatened) and ram's-head lady's-slipper (vulnerable). Some species grow practically nowhere else in Québec, such as the slender-spire orchid (*Platanthera unalascensis*), the low braya, and arctic bladderpod. Others are only native to Anticosti and Îles Mingan, such as the dwarf club rush (*Trichophorum pumilum*) and the Laurentian dandelion (*Taraxacum laurentianum*).

**Figure 12 Distribution of vegetation on Île d'Anticosti**



### Wildlife habitats

The Québec government included provisions in the *Act respecting the development and conservation of wildlife* aimed at protecting wildlife habitats that meet certain conditions. The *Regulation respecting wildlife habitats* defines these habitats and specifies those covered by plans. A list of activities (forestry, mining, oil and gas development, dam operation and maintenance, recreational site development, farming) requiring no approval when conducted in accordance with recommendations is also included.

On Île d'Anticosti five types of terrestrial habitats have been legally designated under the *Act respecting the development and conservation of wildlife* (Table 10; Figure 13). Due to its large population of white-tailed deer, the entire island aside from the village of Port-Menier has been designated as a confinement area for the cervid. Many aquatic

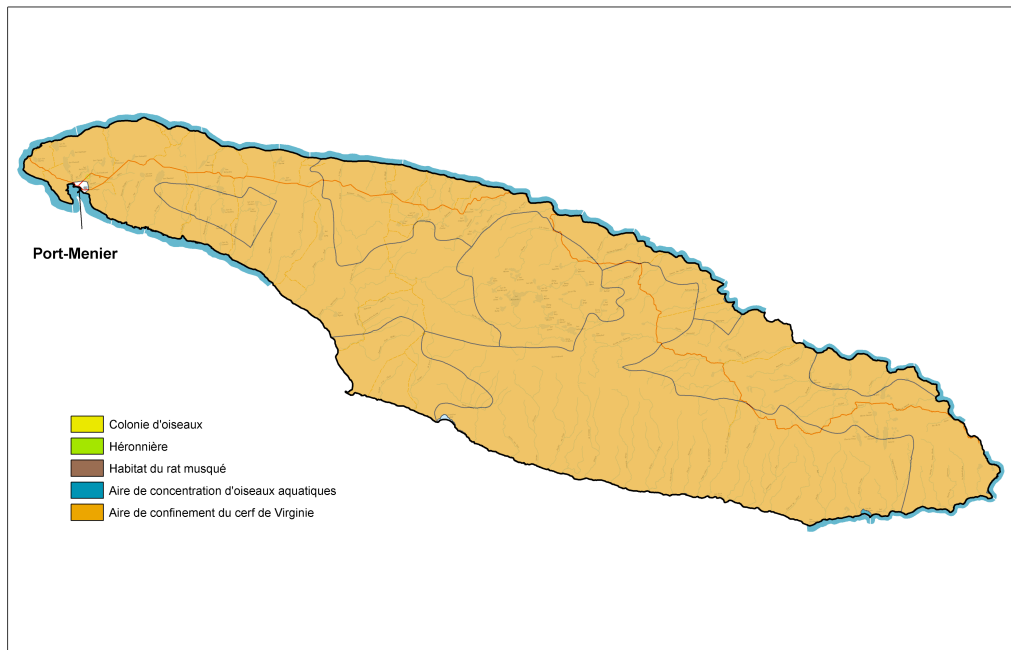
bird staging grounds and colonies are found on the island's shores, indicating how rich the environment is for avifauna. The island also features a heronry with 14 active nests, as per the latest survey, in addition to a muskrat habitat, both within the boundaries of Port-Menier.

**Table 10 Wildlife habitats on Île d'Anticosti protected under the Act**

Habitat	Number of legally recognized habitats	Area (sq km)	Location
White-tailed deer confinement areas	8	7,836	Entire island except Port-Menier village
Aquatic bird staging grounds	19	458	Over 50% of the island's coastline
Heronry	1	0.3	Within the limits of Port-Menier
Cliffside bird colonies	4	0.6	Northeastern cliffs (between Cap-de-la-Table and Pointe-Heath)
Muskrat habitat	1	0.7	Lac Saint-Georges, within the limits of Port-Menier

*respecting the development and conservation of wildlife*

**Figure 13 Legally designated wildlife habitats on Île d'Anticosti**



Note: Due to their small size, some habitats can barely be seen on the map.

## Aquatic wildlife

The cold, clear waters of Île d'Anticosti are perfect for salmonids. Common fish species include Atlantic salmon, brook trout, American eel (likely to be designated as threatened or vulnerable), three-spined stickleback, and banded killifish. Rainbow smelt, alewife, American shad, and ninespine stickleback are also seen occasionally. Rainbow trout has been spotted in some rivers from time to time. Two fish species are subject to sport fishing: Atlantic salmon and brook trout<sup>4</sup>.

The characteristics of salmon populations vary from one region, river, and season to another. Île d'Anticosti salmon belongs to a genetically distinct group of salmon. Its small size and grilse proportions in particular set it apart from the rest. These peculiarities have made the island a salmon management farming zone in Québec.

Atlantic salmon is the second biggest animal species in terms of economic activity on Île d'Anticosti. Twenty-four rivers on the island are official salmon rivers (Figure 14). Over 50% of the island's watersheds are drained by such rivers, the main ones being the Jupiter, aux Saumons, and de la Chaloupe watersheds.

Figure 15 illustrates the evolution of sport fishing data on Île d'Anticosti from 1984 to 2014. It shows that the number of unreleased salmon has gone down, the number released has shot up, and fishing success rates have varied tremendously from year to year. Since water conditions in the island's rivers have such a great impact on the likelihood of catching salmon, success rates are not reliable indicators of the number of spawners.

The Atlantic salmon situation on Île d'Anticosti is a concern. It is not unique to the island but is felt more strongly in the region due to its small salmon population. According to Canada's Species at Risk Public Registry, Anticosti Atlantic salmon is endangered. Its decline in population has been attributed in large part to low survival rates at sea.

To maintain the quality of these habitats, any activity in the watersheds of the island's salmon rivers will have to limit water heating, erosion-derived sediment input, and contamination (Beaupré et al., 2004; MEF, 1998b).

Île d'Anticosti features 24 Atlantic salmon rivers (*Salmo salar*), five of which are used for recreational fishing. Rivière Jupiter alone contains about 30% of the breeding and rearing habitats, in addition to accommodating nearly 30% of the adult salmon population.

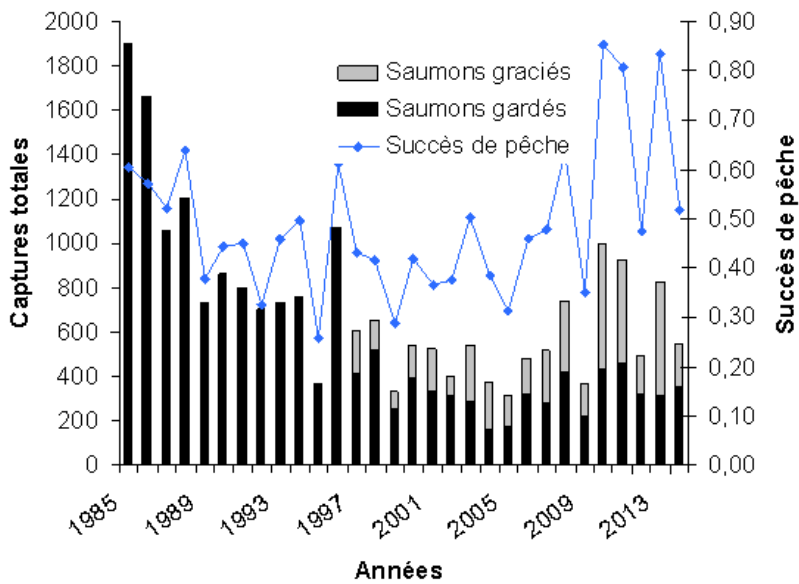
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<sup>4</sup> Both the lake and anadromous forms of brook trout are found on Île d'Anticosti (the latter is commonly known as sea trout). Most of the rivers are home to anadromous populations of brook trout, a species prized by anglers. Rivière Jupiter, Rivière la Loutre, Rivière du Brick, and Rivière Bec-Scie are known for their anadromous brook trout. A good 20 lakes or so also support brook trout fishing.

**Figure 14 Location of the 24 salmon river watersheds on Île d'Anticosti**



**Figure 15 Total number of salmon caught and sport fishing success rate on Île d'Anticosti (Salmon fishing zone Q10)**



**White-tailed deer**

White-tailed deer are without a doubt the most iconic animals of Anticosti. The initial 200 brought to the island in the late 19th century have grown to an estimated herd of 166,000 based on the latest aerial survey conducted in 2006 (Rochette & Gingras, 2007). Even without a survey, by monitoring a number of population trend indicators we can safely estimate that deer density levels are close to 20/sq. km. Despite high mortality rates in some winters, the population can quickly rebound over a season or two, so long as adverse conditions are not recurrent (Potvin, Breton, & Gingras, 1997).

These numbers can be explained by the white-tailed deer's adaptability, a lack of natural predators, and limited hunting taking place on the island.

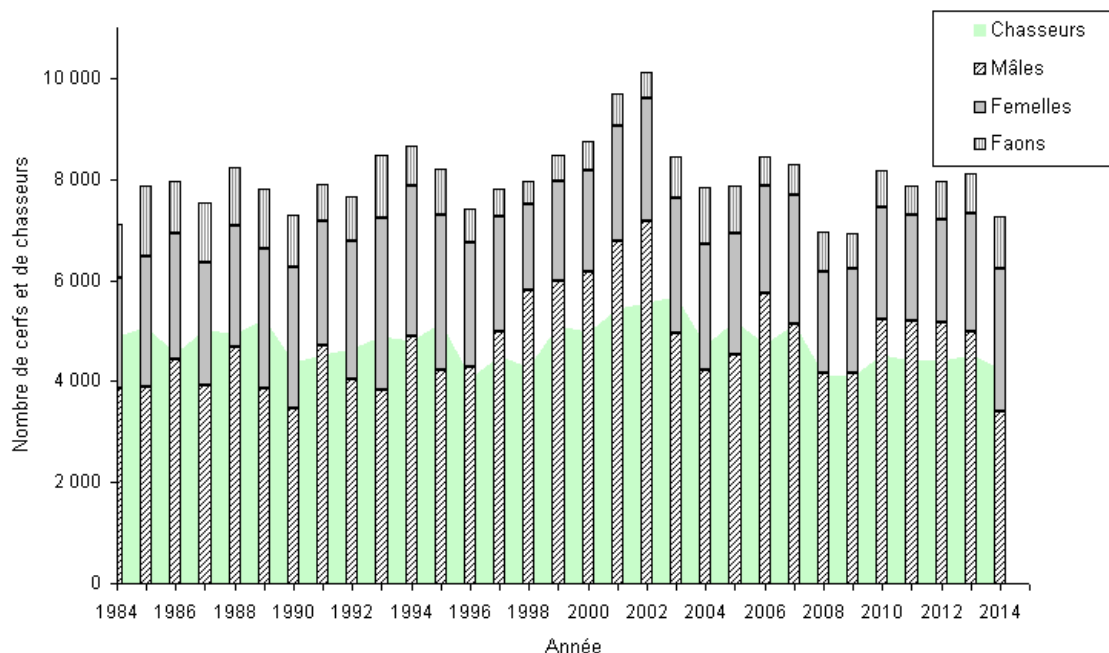
Thanks to this abundance of deer and lack of major predators, outfitters have thrived on the island, providing top-notch hunting products. White-tailed deer hunting mainly takes place from September to December. Since outfitters first arrived in 1984, some 4,500 hunters have hunted an average of 8,500 deer a year (Figure 16).

Due to their high concentrations, white-tailed deer have radically modified the environment, which has had consequences on other species. Extensive browsing in fir forests—their primary winter habitat, providing food and shelter—prevents the latter from regenerating. Since deer were introduced to the island, the proportion of fir forests has gone down by 50%, being gradually replaced by white spruce, which has little nutritional value for deer.

In the short term, winter food should still be available after the loss of senescent fir forests (Lefort, 2002). In the long term, it is unclear whether the deer will be able to maintain their numbers with such a small proportion of fir and such a large proportion of white spruce in their diets (Thibault, Tremblay, Dussault, Huot, & Côté, 2004). A reduction in population is feared. The major challenge will be to manage the land in such a manner as to maintain solid deer population levels and quality habitats for the long term (Huot & Lebel, 2012).

White-tailed deer hunting is the main outfitting activity on the island. The industry provides nearly a hundred jobs, mostly on a seasonal basis.

**Figure 16 Annual number of sport hunters and deer harvested on Île d'Anticosti from 1984 to 2014**



### Other wildlife species

Many other animal species can be found on Île d'Anticosti, including moose, black bears (part of the island's large wildlife), small wildlife, furbearers, birds, amphibians, reptiles, and marine animals.

The island has a small moose population estimated at a few hundred heads. The moose are not evenly distributed. According to an aerial survey conducted in the mid 80s—the only such survey ever carried out—more than a third of them are concentrated in less than 10% of the land. Moose are not native to the island; Henri Menier introduced about twenty of them at the turn of the 20th century. Despite a three-month hunting season and the permission to hunt any segment of the population, moose hunting is rather uncommon.

Black bears figure prominently in the island's history. Their presence in the area is brought up in texts dating back to the 16th century. Authors from the second half of the 19th century, in particular before Henri Menier had arrived, wrote about memorable bear encounters and hunting experiences. Bears were a common sight back then, but based on current information, their numbers began to decline around the 1920s, when the white-tailed deer population got so large that it destroyed part of the island's vegetation through extensive browsing.

Small wildlife is a term used to designate a multitude of undersized animals such as small mammals, chiroptera (bats), herpetofauna (frogs and reptiles), and birds. These species are at the bottom of the food chain and have many predators. They can be divided into two categories: small game, which is hunted for sport, and the rest. Aside from birds, the island's small wildlife is not particularly diverse.

Furbearers are mammals trapped for their fur. These include the red fox, beaver, river otter, and muskrat. While the American marten was still quite common in the early 20th century, it appears to have disappeared around 1936. Trapping is a minor activity on the island. Aside from the red fox, which was the object of a population survey, very little information is available on the island's furbearers.

Birds are the most diverse form of fauna on the island. A total of 221 species spread across 21 families were identified during an island-wide knowledge acquisition study conducted in preparation for the establishment of Parc national d'Anticosti. A sample plot survey carried out for the Québec Breeding Bird Atlas added another 10 species to the list.

Before Henri Menier started introducing various animals to Île d'Anticosti over a century ago, the place was completely devoid of reptiles and amphibians. Today, the green frog, leopard frog, and mink frog are the only amphibians on the island.

More than half the mammals found on the island and along its coast are marine mammals. Fourteen species ply the waters of Anticosti: the beluga, white-beaked dolphin, Atlantic white-sided dolphin, orca, long-finned pilot whale, harbor porpoise, fin whale, minke whale, blue whale, humpback whale, right whale, harbor seal, harp seal, and gray seal.

### **Wildlife species with special statuses**

The CDPNQ database (*Centre de données sur le patrimoine naturel du Québec*) currently counts 59 occurrences of animal species associated with Île d'Anticosti (Table 11). A lack of occurrences does not mean that the species is not there—its presence in an area may just be poorly documented. For instance, it is estimated that 25 at-risk vertebrate species are present on Île d'Anticosti at some point in their lifecycles, but only 6 species are currently listed in the database. That is without counting the invertebrate species on the island, for which there is virtually no information.

Of all endangered animal species on the island, bald eagles are the most numerous. According to the 2006–2008 survey, Île d'Anticosti lays claim to 24% of all bald eagle nesting territories in Québec. Along with the Mingan Archipelago, it features the highest

concentration of breeding pairs. Nests can be found along the coast up to 1 km from shore, often near river mouths.

**Table 11 Occurrences of wildlife species on Île d’Anticosti according to the CDPNQ**

Species	Occurrences
Golden eagle	5
Barrow’s goldeneye (eastern pop.)	1
Horned grebe	1
Black bear (Anticosti pop.)	1
Bald eagle	50
Leatherback sea turtle	1
Total	59

Île d’Anticosti is home to a rich and diverse fauna. Its large population of white-tailed deer—one of the species introduced in the late 19th century—has made it a popular hunting destination. Over 4,000 hunters visit the island every year, providing more than \$12 million a year in business to local outfitting operations.

### Areas under restriction

The AENV04 and AENV05 studies (Bazoge, 2015) show that many legal, regulatory, and other constraints limit or regulate hydrocarbon industry infrastructure on Île d’Anticosti. These include the *Natural Heritage Conservation Act*, the *Act respecting threatened or vulnerable species*, the *Environment Quality Act* (s. 22, paragraph 2), the *Regulation respecting petroleum, natural gas and underground reservoirs*, the *Regulation respecting wildlife habitats*, and the *Water Withdrawal and Protection Regulation*.

Natural resource development on Île d’Anticosti goes through an integrated resource management process in which the various users coordinate their efforts so as to ensure that activities are environmentally and economically balanced.

### Protected areas

A total of 1,063.6 sq km of Anticosti and its surroundings are currently protected under the register of protected areas, or 7.6% of the island’s overall area (Table 12). In 2015 the government set a target of 12% for protected areas, so further conservation efforts will be required. MDDELCC also asked community stakeholders to join the protected area designation process in their respective regions. In response, a roundtable was set up in the Côte-Nord region. An initial meeting was held in November 2012 bringing together 33 participants representing various areas of interest. In winter and spring 2013, information sessions were held in every Côte-Nord regional county municipality (RCM) to collect proposals for protected areas from citizens.

Five proposals were submitted for the land portion of Anticosti. A regional roundtable task force examined these proposals as well as the nine MDDELCC areas of interest to pick areas to recommend to the government so as to protect the island’s most representative natural environments. After reviewing all proposals, the task force and regional roundtable identified three study areas for protection. The first one is an area covering 124 sq km in the west end of the island (land portion)<sup>5</sup>; the second is an area

<sup>5</sup> This study area corresponds in part to a proposal from the Île d’Anticosti municipality and the Minganie RCM. It also corresponds to an expansion project for *Parc national d’Anticosti*, which the government would

covering 82 sq km in the east end of the island (land portion)<sup>6</sup>; and the third one is an area covering 1,104 sq km around Rivière Jupiter and the southwestern tip of the island.<sup>7</sup> The three areas represent 16% of the total Anticosti land area once current protected areas are added to them.

**Table 12 Size of Anticosti areas protected under the Québec register of protected areas (terrestrial or aquatic)**

Designation	Area (sq km)
Québec national park	566.2
Wildlife habitat	456.2
Ecological reserve	40.98
Exceptional forest ecosystem	0.19

### Areas under legal or regulatory restriction

Many laws and regulations impose conditions on activities such as oil and gas exploration and development.

For purposes of analysis, legal and regulatory constraints prohibiting industrial activity are presented separately from those subjecting such activities to government approval. The legal and regulatory constraints concerning hydrocarbon development on Île d'Anticosti are presented in Table 13. These are legal or regulatory provisions that impose restrictions on the oil and gas industry in order to protect certain natural features. Assessments were based on the data available at the time of the AENV04 and AENV05 studies (Bazoge, 2015).

The results are presented in Figure 17 and Table 14. They show that current regulations prohibit oil- and gas-related drilling on at least 36% of the island's territory. The rest of the island is designated as a wildlife habitat and is therefore subject to the *Regulation respecting wildlife habitats*. Activities in these habitats can be subjected to government approval. Under Section 22 of the *Environment Quality Act*, approval is also required for any work conducted in wetlands.

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like to see granted biodiversity reserve status. While the municipality and RCM proposal did not include Colline Makasti, it was added to the study area due to its conservation value.

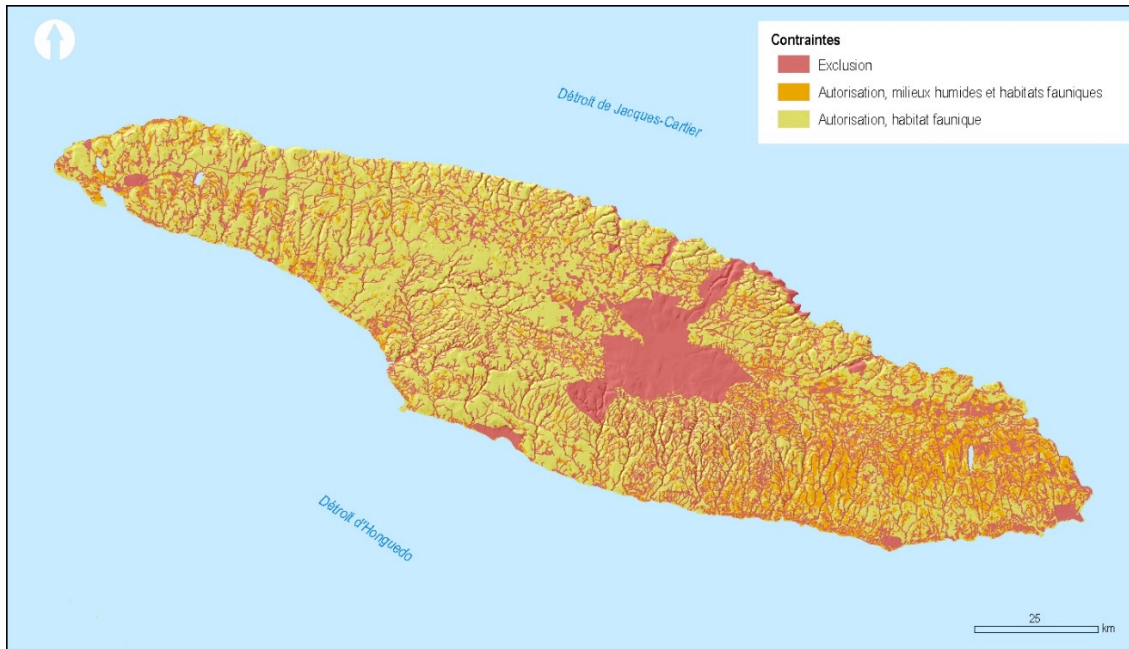
<sup>6</sup> This study area, delineated by *Ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques*, is intended to safeguard a representative sample of the X0404 physiographic unit and to provide supplementary protection to the Pointe-Heath ecological reserve.

<sup>7</sup> This study area was proposed by the Committee and delineated by *Ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques* so as to protect one of the best-known Anticosti salmon rivers as well as a site deemed to be of conservation importance (Pointe-Sud-Ouest).

**Table 13 Legal and regulatory constraints concerning hydrocarbon development on Île d'Anticosti (studies AENV04 and AENV05)**

Law or regulation by type of constraint	Ministry concerned	Designation
<b>Prohibition</b>		
<i>Natural Heritage Conservation Act</i> (protected areas)	MFFP	Exceptional forest ecosystem – included in register of protected areas
	MFFP	Québec national park – included in register of protected areas
	MDDELCC	Ecological reserve – included in register of protected areas
	MFFP	Wildlife habitat – included in register of protected areas
<i>Water Withdrawal and Protection Regulation</i>	MDDELCC	Remote protection area (category 1 and 2 withdrawals)
		Within 500 m of a withdrawal site providing water for human consumption and food processing
<i>Regulation respecting petroleum, natural gas and underground reservoirs</i>	MERN	Within 100 m of a public highway, as defined in the <i>Highway Safety Code</i> (chapter C-24.2)
		Within 100 m of high water mark on land
<i>Regulation respecting wildlife habitats</i>	MFFP	Within 1,000 m of an airport
		Wildlife habitat – not included in register of protected areas
<b>Approval</b>		
<i>Act respecting threatened or vulnerable species</i>	MDDELCC/ MFFP	Occurrence of threatened or vulnerable species
<i>Environment Quality Act</i> (s.22, paragraph 2)	MDDELCC/ MFFP	Wetland

**Figure 17 Overview of Anticosti areas where activities are banned or subject to approval**



**Table 14 Breakdown of Île d'Anticosti land area by type of legal or regulatory constraints**

Type of constraint	Percentage of Île d'Anticosti territory
Prohibition	36
Approval (outside exclusion zones) broken down as follows:	64
• Wetlands and wildlife habitats	14
• Wildlife habitats	50

Drilling is banned through much of Île d'Anticosti due to various regulatory measures. Additional constraints can also apply, in particular for operations conducted in wetlands. As such, development is restricted in many ways and will require approval under the *Environment Quality Act*.

#### Areas of interest for conservation

Many regions of Île d'Anticosti have special biological and ecological features, which has led various experts and local and regional authorities to designate them as ecologically significant. These include exceptional forest ecosystems (not included in the register of protected areas), salmon rivers (with 60 m buffer zones), occurrences likely to be designated as threatened or vulnerable, potential habitats for threatened and vulnerable forest plant species, and areas of interest for bird conservation.

No legal measures are currently in place to restrict oil and gas development activities in these areas. Approval processes will have to take them into account, and if hydrocarbon operations are ever established on the island, mitigation measures will have to be implemented. As indicated in Table 15, 5% of the island's territory is subject to more than five constraints, 39% is subject to two to four, and 56% is subject to only one.

**Table 15 Breakdown of Île d'Anticosti land area by number of conservation-related constraints**

Number of constraints	Percentage of Île d'Anticosti territory
One constraint	56
Two to four constraints	39
More than five constraints	5

The challenges associated with conserving species and ecosystems on Île d'Anticosti are many. Most items of interest are concentrated in four specific areas: 1- the eastern tip of the island, including the Pointe-Heath ecological reserve and the area just north of it; 2- the Rivière Jupiter area; 3- the coastline, especially in the northeast; 4- the entire west end of the island.

### Air quality

The MDDELCC Air Quality Monitoring Program (AQMP) records and monitors air quality at various locations across Québec. MDDELCC uses a network of stations to measure air contaminant concentrations. The majority of these stations are located in the south of the province. Unfortunately, not a single air quality monitoring station is active on Île d'Anticosti at the moment. Nevertheless, comparisons with other Québec regions can provide reasonable estimates as to the concentrations of various contaminants on the island. Concentrations of total suspended particulates (TSP), fine particulates (PM<sub>2.5</sub>), sulfur dioxide (SO<sub>2</sub>), nitrogen dioxide (NO<sub>2</sub>), and ozone (O<sub>3</sub>) have all been established using measurements taken from AQMP stations in similar environments to that of Anticosti (largely unaffected by local and regional pollution).

**Table 16 Stations used to estimate initial air quality on Île d'Anticosti**

Contaminant	Station name	Station location
TSP	Route-385	On the north shore of the St. Lawrence about 75 km southwest of Baie-Comeau and 15 km inland
PM <sub>2.5</sub>	Auclair	On the south shore of the St. Lawrence about 60 km east of Rivière-du-Loup
SO <sub>2</sub>	Saint-Anicet	In the far south of the province about 60 km southwest of Montréal
NO <sub>2</sub>	L'Acadie	In Vallée du Richelieu about 7 km west-southwest of Saint-Jean-sur-Richelieu
O <sub>3</sub>	Mingan	On the Gulf of St. Lawrence about 50 km north of Port-Menier

### Total suspended particulates (TSP)

Table 17 presents descriptive statistics on recorded TSP concentrations. The average annual concentration is 6 µg/m<sup>3</sup>. The 98th and 99th percentiles for daily concentrations are on average 16 µg/m<sup>3</sup> and 17 µg/m<sup>3</sup> respectively.

**Table 17 Average daily concentrations of total suspended particulates (TSP) at Route-385 Station (Forestville)**

Year	-----Percentiles-----						Maximum
	Arithmetic mean ( $\mu\text{g}/\text{m}^3$ )	Median ( $\mu\text{g}/\text{m}^3$ )	75th ( $\mu\text{g}/\text{m}^3$ )	95th ( $\mu\text{g}/\text{m}^3$ )	98th ( $\mu\text{g}/\text{m}^3$ )	99th ( $\mu\text{g}/\text{m}^3$ )	
2011	6	6	7	14	17	17	17
2012	6	4	8	12	13	14	15
2013	6	5	7	14	18	19	20
<b>Average</b>	6	5	7	13	16	17	17

24-hour standard:  $120 \mu\text{g}/\text{m}^3$

**Fine particulates (PM<sub>2.5</sub>)**

Table 18 presents descriptive statistics on PM<sub>2.5</sub> concentrations. The average annual concentration is  $3.4 \mu\text{g}/\text{m}^3$ . The 98th and 99th percentiles for daily concentrations are on average  $12 \mu\text{g}/\text{m}^3$  and  $13 \mu\text{g}/\text{m}^3$  respectively.

**Table 18 Average daily concentrations of fine particulates (PM<sub>2.5</sub>) at Auclair Station**

Year	-----Percentiles-----						Maximum
	Arithmetic mean ( $\mu\text{g}/\text{m}^3$ )	Median ( $\mu\text{g}/\text{m}^3$ )	75th ( $\mu\text{g}/\text{m}^3$ )	95th ( $\mu\text{g}/\text{m}^3$ )	98th ( $\mu\text{g}/\text{m}^3$ )	99th ( $\mu\text{g}/\text{m}^3$ )	
2011	3.5	3	5	9	11	13	18
2012	4.8	3	5	9	11	12	16
2013	2.9	2	4	8	13	15	87
<b>Average</b>	3.4	3	5	9	12	13	40

24-hour standard:  $30 \mu\text{g}/\text{m}^3$

**Sulfur dioxide (SO<sub>2</sub>)**

Table 19 presents descriptive statistics on SO<sub>2</sub> concentrations. The average annual concentration is 0.6 ppb. The 98th and 99th percentiles for hourly concentrations are  $12 \mu\text{g}/\text{m}^3$  and  $13 \mu\text{g}/\text{m}^3$  respectively. The 98th and 99th percentiles for daily concentrations are 5 ppb and 6 ppb respectively.

**Table 19 Average hourly and daily concentrations of sulfur dioxide (SO<sub>2</sub>) at Saint-Anicet Station**

Year Period	-----Percentiles-----						Maximum (ppb)
	Arithmetic mean (ppb)	Median (ppb)	75 <sup>e</sup> (ppb)	95 <sup>e</sup> (ppb)	98 <sup>e</sup> (ppb)	99 <sup>e</sup> (ppb)	
2011							
1 h	0.7	0	1	3	6	9	39
24 h		0	1	3	4	5	8
2012							
1 h	0.6	0	1	3	6	11	45
24 h		0	1	3	4	6	16
2013							
1 h	0.6	0	0	3	8	12	57
24 h		0	1	4	6	7	10
<b>Average</b>							
<b>1 h</b>	0.6	0	1	3	7	11	47
<b>24 h</b>		0	1	3	5	6	11

4-minute standard: 400 ppb—this value can be exceeded up to 0.5% of the time on an annual basis but cannot exceed 500 ppb  
 24-hour standard: 110 ppb  
 Yearly standard: 20 ppb

**Nitrogen dioxide (NO<sub>2</sub>)**

Table 20 presents descriptive statistics on recorded NO<sub>2</sub> concentrations. The average annual concentration is 3.3 ppb. The 98th and 99th percentiles for hourly concentrations are 13 ppb and 16 ppb respectively. The 98th and 99th percentiles for daily concentrations are 9 ppb and 11 ppb respectively.

**Table 20 Average hourly and daily concentrations of nitrogen dioxide (NO<sub>2</sub>) at L'Acadie Station**

Year Period	-----Percentiles-----						Maximum (ppb)
	Arithmetic mean (ppb)	Median (ppb)	75 <sup>th</sup> (ppb)	95 <sup>th</sup> (ppb)	98 <sup>th</sup> (ppb)	99 <sup>th</sup> (ppb)	
2011							
1 h	3.5	3	4	9	13	16	25
24 h		3	4	7	9	10	14
2012							
1 h	3.5	2	4	11	15	18	30
24 h		3	5	8	10	12	16
2013							
1 h	2.8	2	3	8	12	15	29
24 h		2	3	6	9	10	14
<b>Average</b>							
<b>1 h</b>	3.3	2	4	9	13	16	28
<b>24 h</b>		3	4	7	9	11	15

1-hour standard: 220 ppb  
 24-hour standard: 110 ppb  
 Annual standard: 55 ppb

## Ozone (O<sub>3</sub>)

Tropospheric ozone (or ground-level ozone) is a secondary contaminant created as a result of photochemical reactions between nitrogen oxides and volatile organic compounds.

Table 21 presents descriptive statistics on recorded O<sub>3</sub> concentrations. The average annual concentration is 25.5 ppb. The 98th and 99th percentiles for hourly concentrations are 45 ppb and 46 ppb respectively. The 98th and 99th percentiles for 8-hour concentrations are 44 ppb and 46 ppb respectively.

**Table 21 Average 1-hour and 8-hour daily concentrations of ozone (O<sub>3</sub>) at Mingan Station**

Year Period	-----Percentiles-----						Maximum (ppb)
	Arithmetic mean (ppb)	Median (ppb)	75th (ppb)	95th (ppb)	98th (ppb)	99th (ppb)	
2010							
1 h	25.5	27	36	42	44	44	54
8 h		26	35	41	43	44	47
2011							
1 h	25.5	26	35	43	47	49	54
8 h		26	34	43	46	48	51
2012							
1 h	25.6	28	34	41	44	45	55
8 h		27	33	41	43	45	51
<b>Average</b>							
<b>1 h</b>	25.5	27	35	42	45	46	54
<b>8 h</b>		26	34	42	44	46	50

1-hour standard: 82 ppb

8-hour standard: 65 ppb

Air quality on Île d'Anticosti is similar to that found in regions largely unaffected by local or regional pollution. Air contaminants emitted by certain facilities in the west end of the island (thermal plant, airport, port, and oil depot) may affect local air quality.

## Noise

Given that Île d'Anticosti is still in a "natural" state, it was deemed unnecessary to conduct a study on its initial soundscape.

## 3. Environment

### 3.1 Scope

The overall objective of the environment focus area is to outline the issues related to hydrocarbon development in Québec and its on- and offshore environmental impacts. As part of the Anticosti SEA, the environment focus area was to look at hydrocarbon development in terms of its environmental impacts on the island.

#### **Comprehensive SEA on hydrocarbons**

The specific objectives of the environment focus area are to determine:

- The potential environmental impacts of hydrocarbon development, especially on the quality of the water, air, soil, and St. Lawrence marine environment, on ecosystems, and on overall greenhouse gas (GHG) emissions
- Whether these impacts differ depending on the technologies used, specifically hydraulic fracturing, or the receiving environments (offshore and onshore) and their carrying capacity
- The best ways to reduce impacts to acceptable levels or even eliminate them altogether

#### **Anticosti SEA**

The following objectives were identified:

- Establish the state of geological and hydrogeological knowledge on environments targeted for hydrocarbon exploration and extraction
- Determine the vulnerability of surface water and groundwater based on the withdrawal volume required for drilling and fracturing operations and the risks of contamination by well or transport infrastructure
- Identify sensitive sectors
- Assess GHG emissions potentially caused by hydrocarbon extraction on Anticosti and their impact on Québec's GHG emissions balance and the carbon market
- Identify waste management and treatment issues (drilling mud and waste water)
- Propose an approach to determine the baseline state of each environment, in order to be able to measure the impact of exploration and extraction (on surface water and groundwater, flora, fauna, air quality, etc.)
- Recommend prevention and mitigation measures to balance hydrocarbon exploration and extraction with the protection of species and their habitats
- Recommend monitoring programs designed to identify negative impacts (on the water, air, or soil) as quickly as possible

To address these matters, a knowledge survey was produced and published in April 2015. In light of the survey findings, it was determined that 35 studies would be needed to complete the acquisition of environmental knowledge as part of the Additional Knowledge Acquisition Plan (AKAP). These studies are presented in Appendix 2.

This section covers the potential impacts of hydrocarbon exploration and extraction on on- and offshore environments, the regulatory framework, and future needs pertaining to the acquisition of environmental knowledge.

### 3.2 Potential impacts of hydrocarbon exploration and extraction on the onshore environment

This section covers the potential impacts of hydrocarbon exploration and extraction on the onshore environment, in this case in Gaspésie, in Bas-Saint-Laurent, and on Île d'Anticosti. Potential impacts bear on water, soil, air and greenhouse gases, fauna and habitats, and noise.

#### Impacts on the aquatic environment

Hydrocarbon exploration and extraction on Île d'Anticosti could have negative impacts on the water. These impacts depend on the number of facilities, the technology used, the nature of the waste and spills, and the characteristics of the receiving environments.

For oil and gas activities, projects are analyzed in accordance with the requirements of the provisional guidelines for oil and gas exploration (*Lignes directrices provisoires sur l'exploration gazière et pétrolière* [MDDELCC, 2014b])<sup>8</sup>. This document includes rules and monitoring measures and specifically covers optimal water management and protection of the aquatic environment. For occasional oil and gas wastewater discharge, specific requirements were established based on the nature of the inputs, the geochemical characteristics of the deposit, and the sensitivity of the receiving environment. Specific effluent discharge objectives (EDOs) (MDDEP, 2008) may be combined with the requirements of the provisional guidelines.

#### Surface water

##### Decrease in the amount of surface water available

The volume of water necessary for hydrocarbon exploration and extraction depends on multiple parameters: hydrocarbon type (Table 22), geological formation type (Table 23), well depth, well completion methods, fracturing fluid properties, length of horizontal wells, and operator's level of experience (Lary, Fabriol, Moretti, Kalaydjian, and Didier, 2011; Nicot and Scanlon, 2012; Veil, 2010).

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<sup>8</sup> The provisional guidelines for oil and gas exploration (*Lignes directrices provisoires sur l'exploration gazière et pétrolière*) provide a **framework** for drilling work and fracturing operations authorized under the *Mining Act* (CQLR, c M-13.1) for the purposes of finding oil or gas (Section 22 of the EQA and Subsection 6 of Section 2 of the *Regulation respecting the application of the Environment Quality Act* [CQLR c Q-2, r 3]). The guidelines do not have the force of law or regulation, but were developed based on the existing body of regulations at MDDELCC.

**Table 22 Quantity of water required for extraction by hydrocarbon type**

Hydrocarbon type	Quantity of water required	
	Average (m <sup>3</sup> /mJ)	
Conventional oil†	367 (primary extraction: 5, secondary: 222, tertiary: 140)	
Conventional natural gas††	~ 0	
Shale gas	4.7	
Oil shale†††	n/a	

† Water is commonly used to increase the amount of oil extracted—described as the secondary and tertiary phases (in the form of steam).

†† Conventional natural gas extraction requires only a small amount of water to prepare the drilling mud and does not require hydraulic fracturing.

††† According to two studies consulted by CIRAIG (2014).

Source: CIRAIG (2014)

**Table 23 Water use by U.S. company Chesapeake Energy by gas field type**

Gas field type	Activity (water demand)		Total (m <sup>3</sup> )
	Drilling (m <sup>3</sup> )	Fracturing (m <sup>3</sup> )	
Barnett formation	950	14,450	~ 15,000
Fayetteville formation	250	18,600	~ 19,000
Haynesville formation	2,300	19,000	~ 21,000
Marcellus formation	325	20,900	~ 21,000

Source: Mathis (2011)

Water withdrawals for well fracturing are generally done over a short period (approximately one week) and the water is stored onsite while the well is being completed (stimulation), which takes about three weeks. Withdrawing water over a short period of time may reduce the flows of smaller bodies of water (Nicot and Hayes, 2010; U.S. EPA, 2010). Moreover, all uses of the body of water must be balanced, including protection of aquatic ecosystems. (CSR, 2012; Nicot and Scanlon, 2012; National Energy Board, 2009; Healy, 2012).

The risks of removing too much water as compared to the water source capacity is higher during low water level periods, when the flows of certain bodies of water can be very weak. This also applies during periods of drought, as we experienced in Québec in summer 2012.

The industry is experimenting with fracturing techniques that are more water-efficient, partially due to the rising cost of water management. For instance, in British Columbia's southern Montney basin, the industry is carrying out so-called "energized" fracturing treatments that include nitrogen or carbon dioxide and only use 150 m<sup>3</sup> of water per fracturing step, which is one-tenth what slickwater-based fracturing treatments use (Johnson and Johnson, 2012).

Water withdrawals in Québec have been subject to the Water Withdrawal and Protection Regulation (WWPR) (c Q-2, r 35.2) since August 2014. Under Section 31.75 of the Environment Quality Act (EQA) (CQLR, c Q-2), authorization is required for withdrawals of surface water or groundwater with a flow rate of over 75,000 liters per day. Those withdrawing the water must submit a study signed by a professional or someone with a university degree in biology on the location of the natural environments, the flora and fauna affected by the water withdrawal, and the scenario for the entire planned water

withdrawal. With WWPR requirements, the possibility the hydrocarbon industry could withdraw more water than the source capacity is slim to none.

As a result, when analyzing projects that include water withdrawal, the impact on the environment and on other users must be considered. To that end, in addition to the WWPR requirements, MDDELCC has decided that a cumulative criterion of 15% of Q<sub>2,79</sub> should be used along with other criteria to prevent the negative impacts of multiple withdrawals on the same body of water.

### Surface water contamination

Flowback water from hydraulic fracturing operations generates significant volumes of contaminated water. Depending on the conditions, flowback water may come into contact with and lead to the contamination of surface water. There are six specific incidences that can lead to surface water contamination (CIRAIG, 2014):

- Leaking of holding ponds on drilling sites
- Spilling of wastewater during transport to a treatment facility
- Spilling during wastewater treatment
- Water runoff on drilling sites
- Contamination after wastewater treatment
- Contamination of aquifers that feed the surface water during low water periods (this point will be covered in the next section)

Hydraulic fracturing generates roughly 2,000 vehicle roundtrips per well (CSR, 2012; Leteurtois, Durville, Pillet, and Gazeau, 2012). All of the material and equipment needed for the activities associated with hydraulic fracturing, including water and chemical products, are transported onsite by truck (U.S. EPA, 2011). Moreover, wastewater from operations is usually transported by tankers to treatment facilities or to another well for reuse.

The use of pipes to divert water to the site greatly reduces road traffic and should be encouraged when permitted by the deployment of platforms, their relative placement, and the topography.

After spills and leaks of any kind, a number of contaminants (fracturing additives, motor oil, petroleum-derived hydrocarbons, effluent, etc.) may be found underground and reach the surface water (Gosman, Robinson, Shutts and Friedmann, 2012; Leteurtois et al., 2012). Leaks may also be caused by a breakdown of equipment—e.g., pumps and pipes carrying chemical products.

The potential persistence in the environment, the bioaccumulation potential in aquatic organisms, and the toxic potential for aquatic organisms of fracturing inputs were assessed based on the indicators used in the literature (MDDEFP, 2013b). Missing information for the various compounds is also indicated.

The U.S. EPA (2015a) established the intrinsic characteristics of 453 of the 1,076 compounds identified, providing a general idea of their propensity to disperse into the

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<sup>9</sup> Q<sub>2,7</sub> is the seven-day low-flow discharge for a two-year recurrence interval.

environment. A number of them have a propensity to bind to soil and organic matter. The U.S. agency also reported on the availability of toxicity thresholds established to protect human health. MDDELCC reported on the availability of quality criteria (toxicity thresholds) to protect aquatic life and prevent contamination of fish for the 110 compounds likely to be used in Québec.

Generally speaking, compounds that can be used as fracturing inputs (shown in Table 25 of Chapter 3) and for which information is available are biodegradable and break down relatively quickly. A few are categorized as being environmentally persistent and may have a bioconcentration potential in aquatic organisms. Some compounds that can be used as fracturing inputs are toxic or highly toxic for aquatic organisms, although the majority of compounds for which information is available have low lethal or sublethal toxicity to these organisms.

Therefore determining certain characteristics of fracturing inputs (persistence in aquatic environments, bioaccumulation potential in aquatic organisms, and toxicity) is the first step in defining the risks associated with these substances.

Drilling and hydraulic fracturing of wells disturb the soil surface. These processes require the deforestation of 1.2 to 1.6 hectares of land for the site, in addition to a surface area of up to 2.3 ha for the access road, ponds, truck parking lots, equipment storage, etc. (Johnson, 2010). Since these surfaces remain barren indefinitely, runoff carries contaminants on top of the soil toward bodies of water, which could have a negative impact on water quality and aquatic ecosystems. According to some estimates, a site with no rainwater management measures in place can produce 85 to 100 tons of sediment per hectare per year (Schueler, 2000; U.S. EPA, 2007).

The provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière [MDDELCC, 2014b]) contain measures for limiting runoff. Runoff from sites with a high risk of contamination from oil and gas operations must be drained or pumped to a structure collecting gas and oil wastewater. The drainage ditch encircling the site must be designed not to collect runoff from outside the exploration site.

### **Specific impacts on Île d'Anticosti**

Currently there is no plan to develop hydrocarbon on Île d'Anticosti. Nevertheless, Study AENV11 (Cloutier, 2015) qualitatively assessed the potential impacts of hydrocarbon development on the aquatic environment based on the results of multiple studies that were conducted as part of this SEA. It appears that:

- The quantity of water available for the dilution of effluent into the rivers is a limiting factor. The assimilative capacity for waste disposal into the Jupiter and Saumons rivers could decrease significantly if water were withdrawn from these rivers for well fracturing.
- If oil and gas wastewater must be treated and disposed of into the environment, the solution with the least environmental impact seems to be to set up a centralized water treatment plant with ocean disposal.
- Intense development of the industry on the island may have major impacts on the aquatic environment, because of deforestation, road and pipe construction-related sedimentation, higher water temperatures, and habitat fragmentation. Mitigation measures must be taken to reduce these impacts.
- The draft assessment on the potential impacts of hydraulic fracturing on drinking water by the U.S. Environmental Protection Agency (U.S. EPA, 2015a) provides

useful information on the causes of various spills that have occurred. This information could be used to tighten the guideline requirements to better prevent spills.

Hydrocarbon exploration and extraction on Île d'Anticosti (and elsewhere in Québec) could have negative impacts on the aquatic environment. These impacts depend on the number of facilities, the technology used, the nature of the waste and spills, and the characteristics of the receiving environments. But the potential impacts can be mitigated by applying measures tailored to the project and surrounding environment. MDDELCC assesses the potential impacts of a project on the aquatic environment as part of its analysis. This assessment is based on the technical aspects of the project as well as specific aspects related to the project setting.

If gas wastewater must be treated and disposed of on Anticosti, the solution with the least impact seems to be to set up a centralized water treatment plant with ocean disposal. Disposing of treated water into the rivers does not seem possible given the fragility of the environment. However, since certain chemicals used in hydraulic fracturing can potentially impact water quality, measures must be taken to reduce the risk of leaks and spills as much as possible.

Study AENV11 recommends conducting studies on:

The phenomena of karst flows on Île d'Anticosti

The river water regime and ecosystem water needs

Updating surface water quality criteria for certain contaminants present in drilling or fracturing wastewater, especially for bromides and total dissolved solids, fluorides, and nitrites

## Groundwater

There are significant concerns regarding the risk of groundwater contamination from oil shale and gas exploration and extraction activities. Three types of contaminants should be considered: chemical additives used for hydraulic fracturing, liquid hydrocarbons, and methane and other substances found in shale.

The three major potential sources of groundwater contamination are:

- Structural defects (in concrete or steel casings)
- The migration of fracturing fluids or hydrocarbons via induced or naturally occurring cracks
- The migration of methane (INSPQ, 2010; Leteurtois et al., 2012)

For the first source, it should be noted that hydraulic fracturing in shale requires the well to be under high pressure. If the pressure is too great, it can compromise the integrity of the casing, which may cause chemical products or hydrocarbons to leak into the groundwater outside the well (Gosman et al., 2012).

The second source of groundwater contamination considered comes from the potential channeling, via natural or induced cracks, of injection fluids containing fracturing additives into fresh water aquifers. There have been few, if any, reported cases. Even when methane contamination is detected in a well, water analyses do not reveal the presence of fracturing additives. This comes as no surprise, since the groundwater collected by the wells comes from the first 100 meters below the surface, while fracturing injections are done over 1,000 meters deep. Once the injection pressure at the surface is relieved, the flow is toward the well, not toward the surface and aquifers. The injected products are absorbed by the clay present in the rock. The shale in the Utica formation, which is not saturated with water, absorbs this and the contaminants.

The third potential source is the migration of methane, which, while not toxic, could affect groundwater quality. Here again, the use of casings and cement along with pressure testing greatly minimizes the risk of leaks. Well monitoring, required under WWPR, will reveal the presence of serious leaks, which must be repaired according to the requirements of the Regulation respecting petroleum, natural gas and underground reservoirs (RPNGSR).

### **Industrial wastewater**

Based on drilling and fracturing wastewater data obtained in Québec and analyses of U.S. data, Study E3-5, conducted as part of the shale gas strategic environmental assessment (MDDEFP, 2013b), confirmed the list of contaminants indicated in the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière [MDDELCC, 2014b]), identified contaminants of concern, and designated those for which exploratory monitoring would be necessary.

Since the MDDEFP study, other studies have been published in which new compilations of fracturing wastewater data have allowed the authors to clarify the profile of this water. Information updated based on recent literature (2013–2015) sheds new light and reduces uncertainties about certain parameters. Most of these studies, including the study by the U.S. EPA (2015a), were able to identify the contaminants that are of the most concern by comparing the concentrations measured in the hydraulic fracturing water to the maximum acceptable concentrations established for drinking water. In this section, wastewater characterization data was compared to two wastewater quality indicators:

The effluent requirements in the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière [MDDELCC, 2014b])

Quality indicators pertaining to the risk of impacts to aquatic life and the aquatic environment<sup>10</sup>

### **2013 Québec data and observations**

A number of studies were compiled to broaden the spectrum of potential concentrations contained in this water and the number of contaminants covered. Table 24 shows the characteristics of drilling and fracturing wastewater from the Utica shale in Québec (2007–2010) and fracturing fluids from the Marcellus shale in the U.S., the maximum measured concentrations of which exceed wastewater quality indicators. The Study AENV16 report (Guay and Caron, 2015) includes all of the contaminants for which the minimum, median, and maximum concentrations were calculated.

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<sup>10</sup>The quality indicators measuring the risk of impacts on the aquatic environment are the effluent final acute value, 100 times the chronic aquatic life criteria and 100 times the aquatic organism contamination prevention criteria, as defined in the *Critères de qualité de l'eau de surface* (MDDEFP, 2013a) document.

Despite uncertainty about the data, untreated gas wastewater from the Utica shale in the St. Lawrence lowlands is characterized by (Table 24):

- High concentrations of organic contaminants, as shown in the results of the five-day biochemical oxygen demand (BOD5) and the chemical oxygen demand (COD)
- The routine presence of ammonia nitrogen and frequent presence of other forms of nitrogen
- High ion concentrations (total dissolved solids), while clearly lower than those observed in the flowback water in the U.S.
- High total metal concentrations, especially for barium, while staying well below the concentrations reported for water from the Marcellus shale
- The presence of organic compounds such as oil and grease, petroleum-derived hydrocarbons (expressed in C10-C50), and a few volatile organic compounds typical of hydrocarbon exploration
- The presence of a few phenolic substances
- A high concentration of suspended solids (SS)

Two additional observations can be made:

- Hydraulic fracturing wastewater proved to be highly toxic in acute toxicity tests performed on daphnia (water fleas)
- Certain compounds contained in fracturing inputs could be found in the wastewater. Although used in the process, most of the contaminants considered to be of concern in this wastewater were of natural origin

No data is currently available on drilling or hydraulic fracturing wastewater from the Macasty shale.

**Table 24 Characteristics of drilling and fracturing wastewater for contaminants presenting maximum concentrations exceeding wastewater quality indicators**

Contaminants	Untreated fracturing wastewater from the Utica formation in Québec †				Untreated fracturing wastewater from the Marcellus formation in the United States ‡			
	Min. (mg/L)	Median (mg/L)	Max. (mg/L)	Detection frequency	Min. (mg/L)	Median (mg/L)	Max. (mg/L)	No. or detection frequency (Reference)
<b>General contaminants</b>								
Total ammonia nitrogen	0.16	4.5	15.8	36/36	29.4	90	242	19 (2)
Bromides					0	445	1,190	19 (2)
Chlorides	80	2,295	16,380	34/34	18	34,000	196,000	141 (1)
Cyanide	< 0.003	—	0.041	5/11	0.0019	0,1	0.954	86 (1)
BOD5	4	160	675	17/17	37.1	144	1,950	19 (2)
Fluorides	< 1	—	6	2/5	0.009	1.7	58.3	86 (1)
SS	7	39.9	643.3	18/18	10.8	102	3,220	19 (2)
Nitrites	< 0.1	—	24	1/2	0.034	2.5	146	91 (1)
pH	6.36	8.04	9.71	35/35	4.9	6.6	11.6	138 (1)
Total dissolved solids	2,480	6,390	7,190	5/5	221	55,000	345,000	141 (1)
Sulfites	—	—	—	—	2.5	—	38	19 (3)
<b>Total metals</b>								
Silver	< 0.02	—	< 0.02	0/5	0.0005	0.05	0.1	216 (1)
Barium	< 1	1.95	3	8/10	0.005	164	13,900	220 (1)
Beryllium	< 0.5	—	< 0.5	0/5	0.00021	0.04	0.08	216 (1)
Boron	1.3	2.5	12	6/10	3.14	12.05	97.9	18/18 (2)
Cadmium	< 0.001	—	< 0.05	0/16	0.00019	0.012	0.1	218 (1)
Chromium	< 0.01	—	< 0.5	2/15	0.00084	0.025	0.704	220 (1)
Copper	< 0.003	—	0.5	2/15	0.0025	0.13	116	219 (1)
Iron	< 0.5	2.5	9.1	8/12	0.025	29.7	574	233 (1)
Lithium	—	—	—	—	10.6	42.75	153	18/18 (2)
Manganese	< 0.5	—	< 0.5	0/5	0.0025	2.2	29.4	220 (1)
Mercury	< 0.0001	—	0.002	1/12	0	0.0002	0.065	185 (1)
Molybdenum	< 0.5	—	< 0.5	0/5	0.0009	0.0317	0.147	15/18 (2)
Lead	< 0.002	—	0.4	5/16	0.0005	0.03	0.97	212 (1)
Selenium	< 0.5	—	< 0.5	0/1	0.0025	0.05	0.35	196 (1)
Strontium	—	—	—	—	345	1,080	4,830	19 (3)
Thallium	< 1	—	< 1	0/5	0.001	0.1	1	192 (1)
Zinc	< 0.016	0.25	7.5	8/16	0.005	0.12	247	220 (1)

Contaminants	Untreated fracturing wastewater from the Utica formation in Québec †				Untreated fracturing wastewater from the Marcellus formation in the United States ‡			
	Min. (mg/L)	Median (mg/L)	Max. (mg/L)	Detection frequency	Min. (mg/L)	Median (mg/L)	Max.3 (mg/L)	No. or detection frequency (Reference)
Organic contaminants								
Benzene	< 0.0002	—	0,0091	2/7	0.00025	0.005	2	142 (1)
Benzo(a)pyrene	—	—	—	—	0.0005	0.002	0.19	111 (1)
Chloroethylene	< 0.0002	—	< 0.0002	0/2	0.0005	0.005	2	87 (1)
Dibromochloromethane	—	—	—	—	0.00025	0.0005	2	148 (1)
Ethylbenzene	< 0.0001	—	0.0028	3/7	0.00025	0.005	2	127 (1)
Total petroleum hydrocarbons C10 - C50	0.19	2.4	100	21/21	0.21	—	0.21	1 (2)
Naphthalene	—	—	—	—	0.0048	0.022	3.1	16 (2)
Pentachlorophenol	< 0.001	—	< 0.001	0/5	0.00125	0.0095	0.94	111 (1)
Tetrachloromethane	< 0.0002	—	< 0.0002	0/2	0.00025	0.005	2	128 (1)
Toluene (methylbenzene)	< 0.0005	—	0,0112	4/7	0.00025	0.005	6.2	143 (1)
1,2,4-Trichlorobenzene	—	—	—	—	0.00025	0.005	2	152 (1)
1,1,1-Trichloroethane	< 0.0002	—	< 0.0002	0/2	0.00025	0.005	2	128 (1)
1,2,4-Trimethylbenzene	—	—	—	—	0.0044	0.005	1.2	8/19 (4)
Xylenes	< 0.0004	—	0.0059	3/7	0.0005	0.0015	6.5	87 (1)

† Results of untreated wastewater characterization from the drilling or fracturing of 18 shale gas wells in Québec (2007–2010)

‡ Results of untreated wastewater characterization in the United States from (1) Abualfaraj,

Gurian, and Olson (2014); (2) Hayes and Severin (2012); (3) Hayes (2009); (4) URS Corporation (2010)

## 2015 U.S. data and observations

### General contaminant

- The median and maximum concentrations observed in the Marcellus shale wastewater are higher than the concentrations observed in the wastewater from the Utica shale in Québec for all parameters, although to varying degrees.
- The high concentrations of BOD5 and SS point to the need for an organic and inorganic compound treatment facility.
- Among the various forms of nitrogen, ammonia nitrogen emerges as being the most problematic, followed by nitrites.

### **Total dissolved solids and ions**

In all studies, total dissolved solids emerge as being the most challenging contaminants because of their high salt concentration, which makes them harder to manage (USGS, 2013).

Bromides with high maximum concentrations (> 1,000 mg/L) are among the contaminants of concern in this sector. They were the cause of the water quality issues observed at the time of chlorination (MDDEFP, 2013a).

### Metals

- Although they present a maximum value that is higher than the quality indicators, certain heavy metals (Ag, Be, Cd, Cr, Hg, Mo, Pb, Se, Th) have, for the most part, median concentrations below mg/L. The metals of the highest concern, with maximum concentrations that may exceed 100 mg/L, are barium (> 10,000 mg/L), boron, copper, iron, lithium, strontium, and zinc. Barium, strontium, and zinc are all subject to an effluent requirement in the guidelines (Table 20).
- Barium, strontium, and bromide are signature ions found in fracturing and production wastewater (Haluszczak, Rose, and Kump, 2013). Strontium, boron, and radium are also known to be tracers for this type of contamination (Vengosh, Jackson, Warner, Darrah, and Knodash, 2014).

### Organic compounds

- For volatile and semi-volatile organic compounds, the handful of contaminants that repeatedly emerge in different studies are benzene, toluene, ethylbenzene, and xylene, along with certain PAHs, especially naphthalene and benzo(a)pyrene. Despite low detected concentrations, benzo(a)pyrene emerges because the quality indicator is very low based on its carcinogenic potential.
- Total petroleum hydrocarbons in the United States were not characterized. They emerge due to the maximum data obtained in Québec and quality indicators pertaining to petroleum hydrocarbons like diesel and fuel oil (MDDEFP, 2013a).
- The presence of surfactants and glycols likely reflects the fracturing fluid composition.

## Radionuclides

Despite still-incomplete data (Abualfaraj et al., 2014), data available in the United States shows occasionally high concentrations and, more importantly, concentrations that exceed the maximum acceptable values for drinking water for certain radionuclides in flowback water.

The composition of hydraulic fracturing flowback water changes according to its residence time in the well. Concentrations increase over time and reach asymptotic values a few days or weeks after fracturing. Studies have shown that, while initially the chemical characteristics of the flowback water from hydraulic fracturing is similar to the chemical makeup of the fracturing fluid that was injected, it becomes more similar to the geochemical composition of the fractured rock formation (U.S. EPA, 2015a).

Study AENV16 (Guay and Caron, 2015) also touches on the compounds contained in fracturing inputs that can be found in oil or gas wastewater. Although their presence appears to be increasingly insignificant, at least after a certain time has passed, the data collected by Soeder et al. (2014) shows that as many as 132 different compounds related to inputs could be measured in oil and gas wastewater in the United States.

### **Contaminants of concern for the environment**

Table 25 shows the contaminants that are of highest concern, i.e., those whose maximum or median concentrations (taken from the compilation of U.S. data) exceed or just meet the technological requirements for treated effluents as set out in the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière [MDDELCC, 2014b]), or just meet one of the wastewater quality indicators established based on surface water quality criteria (MDDEFP, 2013a). The information in Table 25 indicates that the list of contaminants subject to the guidelines' effluent and monitoring requirements is accurate.

Uncertainty remains over the potential effects of a number of organic or inorganic compounds contained in this water due to variability in concentrations and compounds between studies, the absence of quality indicators for some (radionuclides, bromides), the sheer number of unanalyzed compounds, and a lack of available data. Similarly, multiple compounds or their derivatives contained in inputs used for drilling or fracturing can be found in this wastewater. The chronic toxicity of the wastewater effluent should be routinely monitored to verify all risks due to these contaminants being present at the same time.

**Table 25 List of the 20 components most often used to fracture oil wells in the United States**

Compound		CAS	Use
French name	English name		
Acide acétique	Acetic acid	64-19-7	Scale inhibitor
Butoxy éthanol, 2-	Butoxy ethanol	111-76-2	Acidifying agent
Chlorure d'hydrogène	Hydrochloric acid	7647-01-0	Acidifying agent
Distillats de pétrole (C9-C16) (2x)	Distillates, petroleum, hydrotreated light	64742-47-8	Friction reducer, thickening agent
Éthylène glycol	Ethylene glycol	107-21-1	Enzyme breaker
Glutaraldéhyde	Glutaraldehyde	111-30-8	Biocide
Gomme de guar	Guar gum	9000-30-0	Gelling agent
Hydroxyde de sodium	Sodium hydroxide	1310-73-2	Stimulation fluid
Méthanol	Methanol	67-56-1	Anti-corrosive agent, acidifying agent
Persulfate d'ammonium	Ammonium persulfate	7727-54-0	Breaker
Propane-2-ol	Isopropanol	67-63-0	Corrosion inhibitor, non-emulsifier, reflux stimulant, acidifying agent, stimulation fluid
Prop-2-yne-1-ol	Propargyl alcohol	107-19-7	Corrosion inhibitor
Solvant Naphta aromatique lourd	Heavy aromatic Naphtha	64742-94-5	Anti-corrosive agent, acidifying agent
Hydroxyde de potassium	Potassium hydroxide	1310-58-3	Crosslinker, buffer
Chlorure de sodium	Sodium chloride	7647-14-5	Breaker, friction reducer, scale inhibitor, clay stabilizer, biocide
Éthanol	Ethanol	64-17-5	Surfactant, biocide
Acide citrique	Citric acid	77-92-9	Iron control
Résines phénoliques	Phenolic resin	9003-35-4	Propping agent

Additional knowledge is required on:

The characteristics of water from the Macasty shale in terms of naturally occurring contaminants (radioactive elements, salinity) and the toxicity and persistence of certain compounds used as fracturing inputs.

Then effluent water quality criteria will need to be established.

## Impacts on soil

### Seismicity

The Canadian Association of Petroleum Producers is one association that acknowledges that hydraulic fracturing induces low-magnitude earthquakes (under 3 on the Richter scale) (CAPP, 2012), a claim questioned by the Seismological Society of America. A study conducted by Ellsworth et al. (2011) showed an increase by a factor of six in the frequency of earthquakes magnitude 3 or higher (4–6) on the Richter scale in the central United States from 2001 to 2011. Research to pinpoint the cause led researchers to the conclusion that such an increase could not have been from natural causes outside a volcanic area. The increase in frequency coincided with the shale gas industry's arrival in the region. However, although the authors attributed the increase to the industry, there were unable to determine the exact cause. Was it related to the method used (hydraulic fracturing) or the quantity of gas extracted?

The British Columbia Oil and Gas Commission (2012) investigated the occurrence of anomalous seismic activity (magnitudes ranging from 2.2 to 3.8 on the Richter scale) in the Horn River Basin between April 2009 and December 2011. The investigation concluded that the earthquakes were induced by hydraulic fracturing activity near pre-existing faults. The factors determined to significantly contribute to seismicity included pump rate, fracturing pressure, and proximity to pre-existing faults. The consensus in the literature seems to be that the most intense seismicity (magnitude 3) is largely due to the disposal of fracturing wastewater by injecting it into deep wells, a common industry practice, while seismicity directly linked to hydraulic fracturing is much more rare and induces lower magnitude events (National Research Council of the National Academies, 2015).

Mitigation measures suggested in Study ATVS01 include producing seismic event reports, studying the relationships between hydraulic fracturing parameters and seismic activity, improving seismograph accuracy, developing a national inventory of faults and shale stress zones, creating a program to monitor seismicity before, during, and after fracturing activities, and learning more about the characteristics of underground reservoirs.

### Contamination of soil by drilling mud, fracturing fluid, and flowback water

According to the International Reference Centre for the Life Cycle of Products, Processes and Services (CIRAIG), the extent of soil contamination depends on the quantity and composition of hydrocarbons, drilling mud, fracturing fluid, and flowback water that infiltrate the soil. This 2014 study revealed that:

- Drilling mud contains a number of non-toxic and synthetic substances whose composition remains unknown. However, these substances are not generally considered “dangerous.” High in calcium carbonate, drill cuttings are even reused via landspreading in some locations.
- The fracturing fluid contains a number of toxic and synthetic substances whose composition remains unknown. Yet it is difficult to assess the actual effects of these substances considering their low concentration; fracturing fluid is 99% water and salt.

Québec's provisional guidelines require that a waterproof membrane be installed at the drilling site, which effectively resolves this issue.

## Impacts on air quality

According to CIRAIG (2014), in addition to greenhouse gases, hydrocarbon exploration and extraction can potentially emit a variety of air pollutants, particularly those listed below (SNC-Lavalin, 2013):

- Nitrogen oxides (NO<sub>x</sub>)
- Sulfur dioxide (SO<sub>2</sub>)
- Carbon monoxide (CO)
- Dust and fine particles (e.g., PM<sub>2.5</sub>)
- Volatile organic compounds (VOCs)
- Hydrogen sulfide (H<sub>2</sub>S)
- Polycyclic aromatic hydrocarbons (PAHs)
- Aldehydes (formaldehyde, acetaldehyde, acrolein, etc.)

The impact on air quality from the emission of air pollutants associated with hydrocarbon exploration and extraction can be assessed using atmospheric dispersion modeling. An air quality impact assessment was performed for the St. Lawrence lowlands.

Atmospheric dispersion modeling of the contaminants associated with shale gas exploration and extraction in the St. Lawrence lowlands was performed (SNC-Lavalin, 2013) as part of the shale gas SEA.

The air pollutants considered in the model were nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), carbon monoxide (CO), total suspended particulates and particulate matter (TSP, PM<sub>2.5</sub>), volatile organic compounds (VOCs), hydrogen sulfide (H<sub>2</sub>S), polycyclic aromatic hydrocarbons (PAHs), aldehydes (formaldehyde, acetaldehyde, acrolein, etc.), and ozone (O<sub>3</sub>). Two emission scenarios were considered in the lowlands model: a base case scenario and a scenario with mitigation measures.

Combustion engines replicating early-2000s technology were primarily used in the base case scenario. For the mitigation measures scenario, combustion engines using more recent technology were simulated and the NO<sub>x</sub> and particulate emissions were significantly lower than with the older engines. The modelled atmospheric concentrations were compared to air quality criteria and standards (MDDELCC, 2014c) for both scenarios.

In the results of the base case scenario model, several contaminants exceeded air quality criteria and standards, specifically for nitrogen dioxide (NO<sub>2</sub>), fine particles (PM<sub>2.5</sub>), formaldehyde, BTEX, hydrogen sulfide (H<sub>2</sub>S), and total PAHs. Generally speaking, the degree to which the pollutants exceeded the standards depended on the project phase (drilling, hydraulic fracturing, production testing, etc.). Moreover, these exceedances were sometimes significant at the edge of sites and could extend up to a few hundred meters or even a few kilometers for certain contaminants. Finally, the modeling also showed that, in some situations—for instance, when meteorological conditions were unfavorable to emissions dispersion—odors exceeding the complaint threshold could be detected in the area around platforms and gas treatment centers.

In the results of the model that took into account the implementation of a number of mitigation measures, exceedances of air quality criteria and standards appeared to be limited to NO<sub>2</sub> and formaldehyde near platforms and the gas treatment center. In addition, with the mitigation measures studied, the impact of the odor around the platforms appeared to diminish considerably as compared to the base case emissions scenario.

In conclusion, the modeling results show that the small- or large-scale development of shale gas in the St. Lawrence lowlands could have a marked impact on local air quality from distances of hundreds of meters up to one kilometer from the sites and on regional air quality in sub-regions with higher implementation density. The study also concludes that large-scale development could have a major impact on the province's NO<sub>x</sub> emissions, a precursor to the creation of photochemical ozone (smog).

### **Île d'Anticosti**

A second modeling study specific to Anticosti is underway (Study AENV08).

The provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière), published by MDDELCC, set out the requirements for authorizations, air emissions, air quality, and monitoring.

### **Greenhouse gases**

#### **Nature and sources of greenhouse gas emissions**

Greenhouse gases (GHGs) are gaseous components that absorb infrared radiation emitted by Earth's surface and that contribute to the greenhouse gas effect. The increase in their concentration in Earth's atmosphere is a factor in climate change.

The most common greenhouse gases naturally occurring in the atmosphere are:

- Water vapor (H<sub>2</sub>O)
- Carbon dioxide (CO<sub>2</sub>)
- Methane (CH<sub>4</sub>)
- Nitrous oxide (N<sub>2</sub>O)
- Ozone (O<sub>3</sub>)

In addition to the gases listed above, industrial greenhouse gases include halogenated compounds like:

- Chlorofluorocarbons (CFCs)
- Hydrochlorofluorocarbons (HCFCs)
- Tetrafluoromethane (CF<sub>4</sub>)
- Sulfur hexafluoride (SF<sub>6</sub>)
- Nitrogen trifluoride (NF<sub>3</sub>)

The global warming potential of greenhouse gases varies. In reality, each greenhouse gas has a different residence time in the atmosphere and a different capacity to absorb infrared radiation emitted by Earth's surface.

The global warming potential (GWP) concept was developed to help researchers compare the capacity of each greenhouse gas to trap heat in the atmosphere relative to the amount trapped by carbon dioxide (CO<sub>2</sub>)—which is the baseline unit, with a GWP of 1, over a given period. The emissions from various greenhouse gases are calculated based on the quantity of carbon dioxide that would be required to produce a similar warming effect over a given period. This is called the carbon dioxide equivalent (CO<sub>2</sub>e) and it can be obtained by multiplying the amount of gas by its associated GWP.

Before 2013, the GWPs used for GHG emission inventories in Canada came from the second IPCC assessment report (IPCC, 1996). Since then, the United Nations

Framework Convention on Climate Change (UNFCCC) has stipulated that the GWP values on which member countries must base their GHG emission inventories are those contained in the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC, 2007). Therefore Québec’s 1990–2013 emissions inventory will use the GWPs in effect in Canada and set out in international agreements as stipulated in the fourth report.

Note that methane GWPs have been increased in the most recent IPCC report (IPCC, 2013), but they are not yet in effect.

Table 26 shows global warming potential values for certain greenhouse gases for a time horizon of 100 years.

**Table 26 Global warming potential values for certain greenhouse gases for a time horizon of 100 years**

Greenhouse gases	Formula	Sources		
		IPCC (1996)	IPCC (2007)	IPCC (2007)
Carbon dioxide	CO <sub>2</sub>	1	1	1
Methane	CH <sub>4</sub>	21	25	34
Nitrous oxide	N <sub>2</sub> O	310	298	298
Sulfur hexafluoride	SF <sub>6</sub>	23,900	22,800	
Nitrogen trifluoride	NF <sub>3</sub>	-	17,200	

The main greenhouse gases (GHGs) associated with hydrocarbon exploration and extraction are carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and, to a lesser extent, nitrous oxide (N<sub>2</sub>O).

- The primary sources of greenhouse gas emissions from this industry include:
- Internal combustion engines that run on diesel fuel, including generators
- Internal combustion engines that run on natural gas
- Mobile equipment
- Flares and incinerators
- Venting and leaking of methane into the atmosphere
- Fugitive emissions from fuel tanks and micro-leakage in processes
- Hydraulic fracturing flowback storage tanks

## **GHG emissions estimates**

### **For the Anticosti Basin**

Greenhouse gas emissions estimates for Île d’Anticosti were calculated as part of Study AENV01 (MDDELCC, 2015e). Given that hydrocarbons are not being extracted on the island at this time, an analogy was drawn between the Macasty formation on Anticosti and the Point Pleasant formation in Ohio to produce a preliminary GHG emissions assessment. While subject to uncertainty and limitations, the most important being related to hydrocarbon recovery percentages, this assessment provided an order of magnitude for the GHG emissions that could result from hydrocarbon extraction on Anticosti. It also showed that the hydrocarbons in the analogous geological formation are composed of approximately 20% liquid hydrocarbons and 80% gas—a parameter that

has a major impact on GHG emissions. Moreover, it appears that the timeline for installing gas recovery infrastructure is the determining factor with respect to potential GHG emissions from future hydrocarbon extraction on Anticosti.

### **For other geological basins**

For the geological basin of the St. Lawrence lowlands, GHG emissions estimates were drawn up as part of the 2013 shale gas strategic environmental assessment. This SEA was performed by CIRAIG based on the lifecycle approach<sup>11</sup>. As part of the same assessment, SNC-Lavalin submitted a study on determining the rates of emissions, specifically GHGs, stemming from shale gas exploration and extraction activities<sup>12</sup>. MDDELCC filed a report summarizing the different studies performed and the impact of future development of shale gas in the St. Lawrence lowlands on Québec's GHG emissions balance<sup>13</sup> in 2013.

For the geological basins of the Bas-Saint-Laurent, Gaspésie, and Gulf of St. Lawrence regions, a greenhouse gas emissions intensity assessment is presented in Study GENV-30. This assessment was based on the study of analogous geological structures targeted by INRS for their hydrocarbon potential in Report GTEC01 available at the time this study was drawn up.

Given the current state of knowledge and the fact that there is no data on hydrocarbon recovery potential for these geological structures, absolute GHG emissions could not be assessed as they could be for Anticosti and for shale gas in the St. Lawrence lowlands. However, based on the geological analogies presented in the INRS study, GHG emissions intensity—i.e., the relationship between GHG emissions and the amount of energy produced for each structure—could be estimated. Intensity can be used to compare the carbon footprints of different geological structures and could lead to an assessment of absolute GHG emissions if hydrocarbon extraction data were to become available.

### **On the lifecycle**

According to the review of the literature performed by CIRAIG as part of this SEA (CIRAIG, 2014), the two phases of hydrocarbon development that contribute the most to GHG emissions are the extraction and refining phases, which account for over 90% of total emissions (excluding hydrocarbon combustion). Transport to refineries and end consumers only represents a very small proportion of total emissions.

Table 27 shows the GHG emissions released during the entire hydrocarbon lifecycle, from the extraction of raw materials to the transport to end users just before consumption. For petroleum, this means total emissions from the well to the refinery, and for natural gas, it means total emissions from the well to the consumer. With respect to onshore shale gas, the emissions estimates include intentional emissions resulting from normal equipment operation and unintentional emissions produced from equipment wear or breakage due to poor design.

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<sup>11</sup> CIRAIG, 2013. *Analyse du cycle de vie et bilan des gaz à effet de serre prospectifs du gaz de schiste au Québec.*

<sup>12</sup> SNC-Lavalin, 2013. *Détermination des taux d'émission et modélisation de la dispersion atmosphérique pour évaluer l'impact sur la qualité de l'air des activités d'exploration et d'extraction du gaz de schiste au Québec.*

<sup>13</sup> MDDELCC, 2013. *Rapport synthèse des résultats du Centre interuniversitaire de recherche sur le cycle de vie des produits et services (CIRAIG) sur l'impact des émissions de gaz à effet de serre de la filière du gaz de schiste au Québec.* GES (Study GES1-2).

**Table 27 GHG emissions associated with the hydrocarbon exploration lifecycle**

Hydrocarbon type	GHG emissions estimate† (g CO <sub>2</sub> eq./mJ)
onshore	
Conventional oil	12–47 (probably between 20 and 30)
Conventional natural gas	7–21 (probably between 15 and 21)
Shale gas	7–34
Oil shale‡	9–13
offshore	
Conventional oil	10–28
Conventional natural gas‡‡	7

† Does not take into account uncontrolled emissions escaping from natural faults or emissions after well closure.

‡ Based on a limited amount of data and the shale gas being sent to the flare.

‡‡ Based on only one set of questionable data.

Source: CIRAIG (2014)

For the geological basins of the Bas-Saint-Laurent, Gaspésie, and Gulf of St. Lawrence regions examined in Study GENV-30, Table 28 shows GHG emissions intensities in the lifecycle of different geological structures, including hydrocarbon production and processing. Note that the types of hydrocarbon contained in the analogous geological structures presented in Study GTEC01 may not be the same as the hydrocarbon types present in geological structures studied for Québec. But GHG emissions intensities represent the closest possible approximations based on the current level of knowledge. Without taking into account the portion of the Galt structure that contains liquid hydrocarbons and on which assessments are still underway, GHG emissions intensities may vary from 9.12 g CO<sub>2</sub> eq/mJ to 21.15 g CO<sub>2</sub> eq/mJ, with the highest intensity associated with the Haldimand structure. Overall and in light of information currently available, the Old Harry and de Massé structures appear to be emitting the least GHGs per megajoule produced, while the three other geological structures are in the average range for shale gas and oil shale emissions intensities in North America.

**Table 28 Summary of characteristics and GHG emissions intensities on the lifecycle of certain geological structures in the Bas-Saint-Laurent, Gaspésie, and Gulf of St. Lawrence basins**

Characteristics of geological structures				Hydrocarbon extraction	Hydrocarbon processing	Total GHG emissions	
Geological structure (basin)	Primary analog hydrocarbon type	Analog drilling type	Geological analog	(g CO <sub>2</sub> eq/mJ)	Gas liquefaction or (petroleum refining) (g CO <sub>2</sub> eq/mJ)	(g CO <sub>2</sub> eq/mJ)	(t CO <sub>2</sub> eq/B OE)
Massé (Bas-Saint-Laurent)*	Gas (with liquid hydrocarbons)	Conventional vertical	Slave Point formation Ladyferm gas field (northeastern British Columbia)	7.09	5.2– 6.4	12.29– 13.49	0.077 – 0.084
Galt (Gaspésie)	Gas	Horizontal without hydraulic fracturing	Fractured limestone of Mississippian age from the Anadarko Basin in Oklahoma and Kansas	13.5	5.2– 6.4	18.7– 19.9	0.117 – 0.124
Galt (Gaspésie)*	Liquid hydrocarbons	TBD	TBD	TBD	TBD	TBD	TBD
Bourque (Gaspésie)	Gas and condensate	Directional drilling	Idem, Galt structure	13.5	5.2– 6.4	18.7– 19.9	0.117 – 0.124
Haldimand (Gaspésie)	Oil	Horizontal without hydraulic fracturing	Sandstone from the Bakken Formation in North Dakota and Saskatchewan	9.76	11.39 (oil refining)	21.15	0.132
Old Harry (Gulf of St. Lawrence)	Gas	Conventional vertical	Carboniferous sedimentary sandstone in the south of the North Sea	3.924	5.2– 6.4	9.12– 10.32	0.057 – 0.065

\*: At the time this report was published; GHG emissions figures for this formation are to be determined. They will be presented in Study GENV30.

### Impacts of hydrocarbon exploration and extraction on Québec greenhouse gas emissions

Québec's goal is to keep its GHG emissions below 68 million tons of CO<sub>2</sub> equivalent in 2020, a 20% reduction from 1990 emissions levels.

According to the CIRAIG study produced in 2013 as part of the SEA on shale gas in the St. Lawrence lowlands, annual GHG emissions were estimated at 2.5 million tons of CO<sub>2</sub> equivalent for a small-scale development scenario and 19.1 million tons of CO<sub>2</sub>

equivalent for a large-scale development scenario. For instance, the GHG emissions for these two scenarios could represent an increase of 4% and 28% respectively over Québec's 2020 GHG emission targets.

As for Anticosti, the preliminary GHG emissions estimates for the Macasty formation were assessed using the "More" scenario from the economy focus area and data from a geological formation analogous to the Macasty formation—the Utica shale in Point Pleasant, Ohio. Therefore, assuming the gas recovery infrastructure is in place when extraction begins in 2020, annual GHG emissions would be approximately 1.4 million tons of CO<sub>2</sub> equivalent during the peak well development period. These emissions could represent an increase of 2% over Québec's 2020 GHG emission targets. They must be considered as an order of magnitude and do not include emissions from transporting produced hydrocarbons.

According to SEA data, since no hydrocarbon extraction is planned in the St. Lawrence lowlands or on Anticosti before 2020, there would be no impact on the 2020 GHG reduction target in the event hydrocarbon is ultimately extracted in these two geological basins. Future hydrocarbon extraction would likely have an impact on Québec's next GHG reduction targets. No matter what the case, the industry will have to make a decisive move and quickly implement mitigation measures to reduce GHG emissions from its activities.

### **Wildlife and habitats**

Generally speaking, the construction of roads and pipelines and the increase in road transportation can degrade and destroy important habitats and interfere with the behaviors and lifecycles of certain animals (WWF, 2014). Hydrocarbon exploration and extraction may impact wildlife and animal habitats in a number of ways (Noël, 2012), including:

- Altering, fragmenting, and reducing the size of habitats
- Decreasing water resources (water withdrawals from surface water can reduce their flow and spoil fish habitats)
- Exposing them to contaminants
- Destroying natural forest cover and replacing it with invasive plant species
- Interfering with animal activities and behavior due to dust and particle emissions, increased noise and light, and heavier traffic flow

### **Specific impacts on Île d'Anticosti**

#### **Impacts on Atlantic salmon**

Concerns were raised regarding the potential impacts on salmon from accidental hydrocarbon spills if oil and gas extraction were to be developed on Anticosti. Study AENV18 (Valiquette, 2015) showed that, although the scientific literature specifically covering the effects of hydrocarbon exposure on Atlantic salmon is limited, there are ample studies on the Salmonidae family.

In the early life stages of Salmonidae, exposure to sublethal concentrations of hydrocarbons generally delays growth, diminishes energy reserves, causes cardiovascular disease, and suppresses the immune system, which can have indirect effects on individuals' survival at sea. Although adults seem to be less affected by hydrocarbons, their ability to find their way back to spawning grounds and their physical capacity to reproduce may be compromised. The lethal and sublethal effects of Salmonidae exposure to petroleum-derived hydrocarbons may negatively impact the

preservation and long-term survival of fish populations affected by a spill. In the event of a major oil spill, the Atlantic salmon on Île d'Anticosti could suffer a severe demographic decline, which could threaten the metapopulation given the smaller local population size.

The lethal and sublethal effects of Salmonidae exposure to petroleum-derived hydrocarbons may negatively impact the preservation and long-term survival of fish populations affected by a spill. A severe local demographic decline could threaten the entire metapopulation of Atlantic salmon on Île d'Anticosti.

### **Impacts on white-tailed deer**

Study AENV19 (Drolet, Dussault, and Côté, 2015) was not able to determine with certainty the impacts oil and gas activities could have on the white-tailed deer population on Île d'Anticosti because there have been no studies to assess the direct impact. However the potential impact of oil operations on white-tailed deer on Anticosti can be summarized based on a review of the literature on the impacts of anthropic disturbances on ungulates (including white-tailed deer) and specific data collected on Anticosti's white-tailed deer.

Studies performed on intermittent and cumulative disturbances all demonstrate negative impacts on ungulates. The two major impacts are an increase in movement rates and avoidance of human infrastructure (indirect loss of habitat). Other impacts observed include an increased mortality rate from collisions and a lower fawn survival rate. There may also be physiological responses, like faster heart rates and higher stress levels. These responses may increase disturbed animals' energy expenditure and reduce their survival rate.

The scope of the impacts oil and gas activities would have on white-tailed deer depends on a number of factors. The density of anthropic disturbances in the landscape and the volume of traffic will determine the increase in the movement rate of ungulates (including white-tailed deer) and the size of their avoidance zone. The season during which the work is done will affect white-tailed deer's behavioral and physiological responses. A number of studies have also found that females with fawns are the most sensitive population group. Finally, ungulates' tolerance for and ability to adapt to disturbances may also modulate the impacts.

Mitigation measures must be implemented to limit the effects of development projects on fauna and flora, specifically the species designated above. The legal framework regulating unconventional oil and gas extraction needs to be more clearly defined. Measures should be implemented to ensure the industry does not have negative impacts on Anticosti's ecosystems with legal conservation status.

Particular attention must be given to concentrated areas of aquatic birds on the coast, specifically with respect to the future construction of port and hydrocarbon transport infrastructure. Mitigation measures (habitat characterization, facilities placement, additional protection measures, offsetting, etc.) should be included in all certificates of authorization. (ATVS01)

### **Noise**

According to the shale gas strategic environmental assessment committee (CEES, 2014), the main sources of noise caused by development of the shale gas industry, i.e., road and production site construction and hydraulic fracturing operations, may cause significant stress on certain residents, especially those living in rural areas or occupying

homes closest to noise sources. For instance, noise has an impact on sleep quality, which can in turn lead to fatigue, stress, and difficulty concentrating.

The transport of machinery during construction and the use of large amounts of water during fracturing also increase noise levels and decrease road safety. The elderly and the mentally ill are the individuals most affected by these disturbances. Hearing damage, aggravation of cardiovascular diseases, and stress-induced extreme behavior are other related effects that have been linked to this industry by researchers like those with the Oil and Gas Accountability Project.

In Québec, noise control is subject to the criteria applied by MDDELCC, not regulatory standards. These criteria vary depending on the noise source, be it a construction site, stationary source, or road.

MDDELCC applies Memorandum of Instruction 98-01 to noises emitted by a fixed source, e.g., an industrial site. This memorandum (MDDELCC, 2015 g) establishes daytime and nighttime noise criteria to be met and differentiates between four zones based on their level of sensitivity (Table 29). Zone I is the most sensitive and includes single-family homes, schools, and hospitals. Zone IV is the least sensitive and includes areas zoned for industrial and agricultural use. Many municipalities regulate noise disturbances based on the criteria contained in this memorandum of instruction.

Québec’s sectoral policy on community noise applies to noise emitted by construction sites, while road noise disturbances are subject to recommendations based on the ambient noise before construction.

**Table 29 Maximum permissible noise levels by category**

Zone	Night (dBA)	Day (dBA)
I	40	45
II	45	50
III	50	55
IV	70	70

Source: MDDELCC (2015 g)

Whether taken individually or cumulatively, noise impacts caused by the shale gas industry vary according to the development phase underway, its duration, and its intensity. The industry can follow existing noise control best practices and can adapt mitigation measures and acoustic treatments based on the specific needs of a site.

Noise dispersion modeling was carried out to gain a better understanding of the noise impacts of shale gas development in the St. Lawrence lowlands (Soft dB, 2013).

First the study defined scenarios according to the shale gas development project type and development scenarios 3 and 5 from the SEA committee. Noise from increased road traffic was also factored in. Each operational phase was linked to specific noise sources (equipment and activities) and a number of (heavy or light) vehicles. Individual sources were identified (e.g., excavators, trucks, compressors, pumps, derricks) and assigned a sound power level (in dBA) based on a review of the literature.

The model used conservative environmental conditions: flat, non-absorbent soil without buildings, vegetation, or other barriers. Calculations were based on two scenarios for each phase of work—one in which the equipment was used around the clock (100% of the time) and another with a normal equipment use factor. Two meteorological conditions were considered for each of these scenarios, i.e., conditions favorable to the propagation of sound during the day and at night. Noise from traffic on an access road and a main country road was modeled using software according to the type of traffic

indicated in the literature as being commonly found on shale gas exploration sites. The sound level of each source was combined and distributed equally over the total site area and the noise was calculated from the site perimeter. Key findings are summarized below.

### **During construction**

Sounds impacts from components introduced during preliminary work, especially from transporting heavy machinery and other equipment, are in line with those from other construction projects.

Soil preparation activities for the construction of access roads, well sites, and central stations are some of the noisiest. These activities may last about 20 days but do not usually involve night construction. A number of mitigation measures can be applied to markedly reduce the amount of noise, but choosing an appropriate site is still the best way to avoid undesirable effects.

Taken individually or cumulatively, impacts from trucking can be considered minimal. Duration may range from one to two weeks for a single site and stretch out to as much as a few months if multiple sites are involved. The sound level of this phase is usually tolerable since operations are temporary and mostly done during the day. The noise may not be compatible with the nature and use of the receiving environment in residential, recreational, or tourist areas.

Much would be gained from mitigation measures like studying the condition of roads before the start of work, signing a usage agreement between the developer and municipality or private owner establishing the terms of road use, and choosing the geographical location and work schedule with the least impact on the environment and regional economy.

For large-scale development scenarios, the variable factors that could have a greater impact on the noise level are the total number of multiwell sites, the total number of central facilities, and the volume of traffic on the roads in general if development takes place in a single area. These construction activities generate the most noise, but since the distance between two multiwell sites is 4.3 km (running northwest/southeast), there is no cumulative effect and they do not contribute to the sound impact. Running southwest/northeast, where the distance is 900 m, a plot of land located on the border between the two multiwell sites could expect a level of noise 3 dB higher than from a single site.

Mitigation measures should definitely include planning the transport of chemical products and emergency services in the event of a spill or accident, and preferably include avoiding large trucking distances when transporting raw materials.

### **During drilling and fracturing**

The literature and sound simulations indicate hydraulic fracturing is the noisiest operation.

Generators and compressors—the noisiest equipment—run continuously during well fracturing. This can be very disturbing to neighbors. For instance, to comply with the nighttime noise criteria set out in Memorandum of Instruction 98-01 by MDDELCC, a minimum distance of 5,110 m for Zone I (the most sensitive zone), 3,430 m for Zone II, 2,450 m for Zone III, and 560 m for Zone IV must be maintained between the noise source (fracturing) and dwellings. Implementation of mitigation measures can significantly reduce these distances (note that fracturing work is not usually done at night).

The individual sound impact can be considered moderate but the cumulative sound impact can be considered high. These operations usually range in duration from four to six weeks, but on the regional scale they may last a few months. Researchers have indicated there is a risk of sleep disturbance for neighboring residents.

To minimize these impacts, the presence of nearby dwellings should be taken into account during site selection and natural or constructed obstacles should be used to reduce noise dispersion.

### **During natural gas production and transport**

During the production phase, transport by truck for the construction of compressor stations, treatment units, and dehydration units induces impacts that, individually and cumulatively, are considered weak and short-term.

Here again, preferred mitigation measures include planning drilling sites to streamline transportation and the use of heavy machinery.

For the transportation and distribution phase, gas pipeline construction generates noise, but this process only lasts a few weeks. The individual and cumulative impacts are minor.

According to the literature, there are no specific mitigation measures to be implemented in the transportation and distribution phase. The permanent closure phase requires mitigation measures similar to those in the construction phase.

### **Île d'Anticosti**

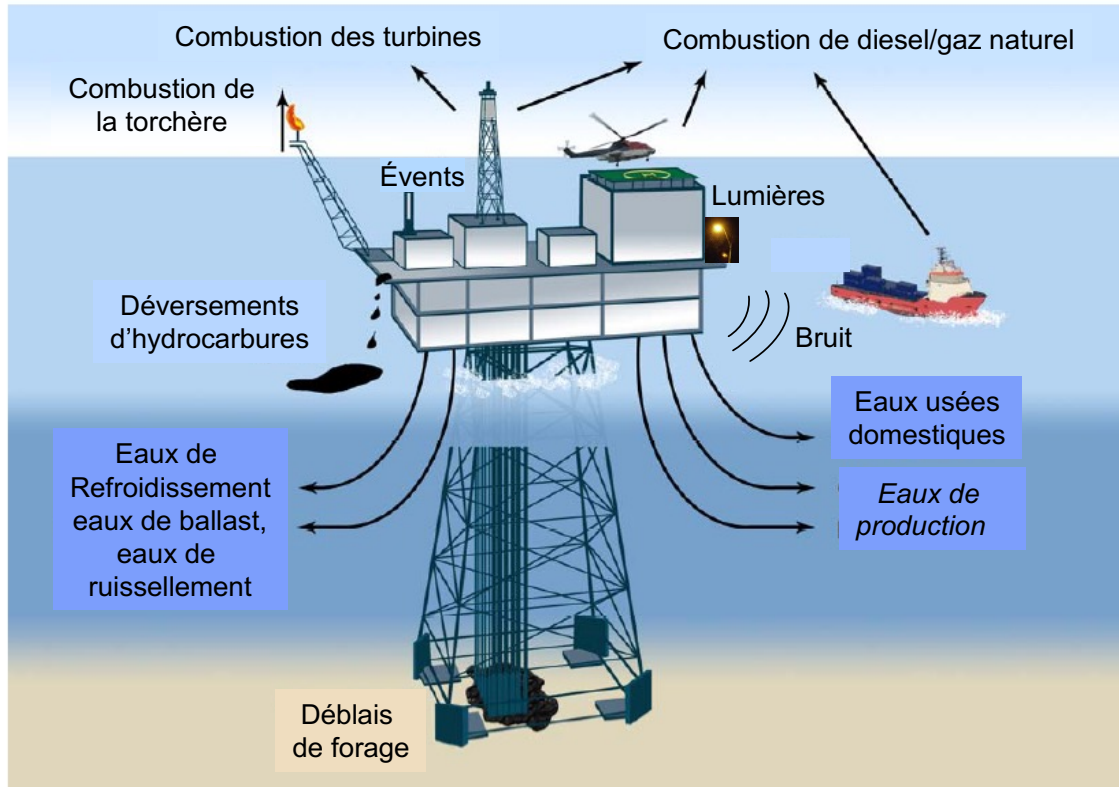
Study AENV07 on the noise impacts associated with petroleum exploration and extraction activities on Île d'Anticosti is still underway. For now, the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière) published by MDDELCC set out the requirements for noise emissions and monitoring. The guidelines are mainly based on the memorandum of instruction on noise from stationary sources and the criteria for community noise.

More research is needed to better understand the scope of the impact of drilling noise on white-tailed deer on Île d'Anticosti. (AENV19, p. 10)

## **3.3 Potential impacts of hydrocarbon exploration and extraction on the offshore environment**

This section covers the potential impacts of hydrocarbon exploration and extraction on the offshore environment from the Bonton et al. (2014) report and Study GENV25. It is a deliverable in the knowledge acquisition program on the Gulf of St. Lawrence launched by MDDELCC in 2012. Note that the potential impacts of accidental hydrocarbon spills in the offshore environment and prevention, preparation, and intervention measures are presented in Section 3.4 and Chapter 7. Hydrocarbon exploration and extraction facilities in offshore environments use inputs and power and emit waste into the environment on a daily basis (Figure 18). They may discharge various contaminants into the marine environment—e.g., from runoff water flowing on the surface of the facility, drill cuttings generated during the exploration phase, or produced water released during the production phase. These inputs and waste may have direct and indirect impacts on ecosystems, particularly the marine ecosystem.

**Figure 18 Main waste from hydrocarbon exploration and extraction activities in a marine environment (based on OSPA 2009)]**



There are six impact sources from day-to-day hydrocarbon exploration operations in an offshore environment (Table 30):

- Land use, or the physical occupation of the marine environment by exploration and extraction units
- Discharge of wastewater, particularly produced water
- Air emissions, or the emission of associated gases and combustible contaminants necessary for the operation of drilling and production facility operation and the transportation of hydrocarbons
- Discharge of waste, particularly drilling waste
- The use of resources such as construction materials, chemical products used for drilling and production, and the power required for the production and transportation of hydrocarbons
- Noise and light emissions such as the noise from exploration drilling

**Table 30 Classification of the main sources that impact the marine environment in the hydrocarbon exploration and extraction lifecycle**

Category	Source of impact
Land use	Exploration and extraction facilities, pipelines
Wastewater	Produced water, ballast water, runoff water, cooling water, household wastewater
Air emissions	Engine combustion, flaring, venting
Waste	Drill cuttings, drilling mud, well completion fluids, blowout preventer (BOP) fluids, food waste, production sand, construction materials
Use of resources	Power, structural materials, chemical products, saltwater
Noise and light	Seismic waves, light from platforms, noise from exploration, production, and transportation facilities

### Impacts on the aquatic environment

According to Study GENV25 (CEAEQ, 2015c), a number of studies assessing the expression of various biomarkers after exposure to treated produced water from oil and gas platforms have been described in the literature. Many studies highlighted a lack of expression of biomarkers (activity of glutathione S-transferase and acyl-coenzyme A oxydase, as well as the presence of DNA adducts, biliary metabolites, or a loss of membrane integrity) at distances farther than 500 m from drilling platforms. However, other studies have shown significant induction of two biomarkers involved in the organism detoxification process—the activity of ethoxyresorufin-O-deethylase (EROD) and Cyp1A—for fish living less than 200 m downstream of the produced water discharge point. Detection of these two biomarkers indicates exposure to contaminants but does not necessarily mean the presence of a biological effect. Instead they are seen as indicating the presence of a contaminant inside an organism or as a biological reaction induced by an environmental change or stress. Note that biomarkers are defined as observable or measurable changes at the molecular, biochemical, cellular, or physiological level that reveal past or present exposure of a living organism to a chemical substance.

For pelagic organisms, acute and sublethal toxic effects were reported in the laboratory in fish and invertebrates exposed to treated produced water in concentrations exceeding 1%, corresponding on average to a distance of less than 50 m from the platform. In addition to diminished reproductive success and death in the most sensitive aquatic organisms, endocrine disruption effects were measured in certain fish at concentrations of over 1%, indicating that they could only be observed near platforms, i.e., no more than 50 m from the structure. Environmental effects were only observed in the immediate vicinity of platforms after exposure lasting several weeks or even months.

### Wastewater discharge from offshore installations

Average produced water discharge from the Terra Nova, Hibernia, and White Rose oil facilities off Newfoundland in 2009 were estimated at between 0.5 and 1 m<sup>3</sup> of water per m<sup>3</sup> of crude oil produced (Stantec, 2012). In 2011, average concentrations in produced water discharge for an oil property in the North Sea were 12.5 mg/L of petroleum-derived hydrocarbons and 13.1 mg/L of BTEX, equivalent to an annual load of 17.6 tons of hydrocarbons and 18.4 tons of BTEX (OSPAR, 2013).

The oil facilities off Newfoundland discharged ammonia, total phosphorus, ethylene glycol, phenolic substances, methanol, and BTEX into the marine environment (INRP, 2014). In 2011, the Hibernia facility discharged 84.4 tons of BTEX at a concentration of

17 mg/L, 163 kg of PAHs (32 µg/L), 56 tons of phenolic substances (11.2 mg/L), and 79 tons of ethylene glycol (15.7 mg/L) (CNLOPB, 2014; INRP, 2014). The Sable Island facility discharged 289 tons of ethylene glycol into the ocean in 2011 (INRP, 2014).

The discharge of ballast water for storing crude oil at the Hibernia facility is equal to the crude oil production, or an average of 20,000 m<sup>3</sup>/j (Stantec, 2012). Their hydrocarbon concentrations varied from 0 to 3.1 mg/L between 2007 and 2009. The concentrations of hydrocarbon in the ballast water used to store crude oil from production facilities in the North Sea were 1.8 mg/L on average in 2011, for an average of 5.0 tons per extraction site and a production of 7,200 m<sup>3</sup>/j (OSPAR, 2013).

Additional knowledge is required on:

- The characteristics of Macasty shale wastewater with respect to naturally occurring contaminants (radioactive elements, salinity)
- The toxicity and persistence of certain compounds used as fracturing inputs
- Then effluent water quality criteria will need to be developed.

### Land use

During each lifecycle stage, the maritime territory is occupied by a certain number of exploration and extraction units and vessels such as geophysical survey vessels, drilling and production platforms, and dismantling facilities for decommissioning. Drilling and production platforms may occupy the maritime territory for a number of years and drastically alter the natural habitats of marine fauna and flora and the movement of fish and mammals while also hindering maritime transport and fishing activities.

One of the primary sources of impact associated with land use is the presence of drilling and production platforms, underwater production equipment, and pipelines. Occupation of the marine environment by these facilities can disturb the natural habitat of organisms living on the seafloor and in the water column and displace marine mammals and other aquatic organisms in the exploration or extraction zone. The presence of facilities may create an artificial reef that can attract or scare off certain species of fish, crustaceans, and mollusks, and create areas of high organism concentration (Genivar, 2011).

Platforms are trawl-free zones, providing a refuge for coral and other epifauna organisms that attach themselves once the structure is built. The effect over time of adding a hard substrate is that the structure is colonized by species that would otherwise not be present in natural sandy areas or muddy ground. The presence of platforms also creates a habitat conducive to the establishment of communities of fish that seem to be attracted as much by the hard substrate offered by the structure as by the increase in potential prey. This colonization appears to occur relatively soon after the platform is installed. It may take two years for the ecosystem to develop completely, depending on the species (CEAEQ, 2015c). There is also a risk that the installation of exploration and extraction facilities will impact birds, which may be attracted by the light being emitted and collide with platforms (Fraser, Russell, and Von Zharen, 2006). The presence of facilities in offshore environments can create conflicts between hydrocarbon development, maritime transport, and fishing users. It can also increase the risk of vessel collision.

**Table 31 Main sources of impact from land use during the hydrocarbon exploration and extraction lifecycle in offshore environments (based on Genivar, 2011)**

Step	Source of impact
Geophysical surveys	Presence of seismic survey vessels Generation of seismic waves (noise in the water)
Exploration drilling	Seabed disturbance (anchoring, exploratory wells, drill cuttings piles) Presence of drilling facilities and support vessels
Construction	Seabed disturbance (anchoring, production wells, injection wells, underwater equipment, pipelines) Presence of support vessels, pipe-laying vessels
Production	Presence of production facilities and underwater equipment Presence of storage, hydrocarbon transport, and pipeline vessels Increased risk of various spills
Decommissioning	Presence of dismantling facilities Presence of dismantled facility left on the seafloor

Note that the authors of the 2011 Genivar studies did not consider the increase in maritime transport in the Gulf of St. Lawrence.

#### Potential impacts of land use in the Gulf of St. Lawrence

The potential presence of hydrocarbon exploration and extraction facilities in the Laurentian Channel, specifically in the Old Harry Prospect, may potentially impact the benthic habitats present at the site such as soft coral, sponges, and certain benthic fish like codfish, redfish, and sole (Corridor Resources, 2013; Genivar, 2011). The installation of an oil or gas pipeline to transport hydrocarbons to a distribution site could have a local impact on the benthic habitats and communities of the Gulf and the ecologically and biologically significant area bordering the Laurentian Channel (Genivar, 2011).

#### Air emissions

Table 32 shows the main sources of air emissions in the offshore hydrocarbon exploration and extraction lifecycle. Some air emissions come from combustibles (natural gas, diesel) used for hydrocarbon drilling, extraction, treatment, and transport. These combustibles are used to operate various generators and engines. In the production phase, air emissions come from the associated gases present in the extracted hydrocarbons. Some of these gases are lost as they go through the venting and flaring systems. For gas fields, some of the associated gases that are collected during natural gas processing can be injected into underground formations.

The main compounds emitted into the air by venting or flaring systems are carbon dioxide, hydrogen sulfide, methane, carbon monoxide, nitrogen oxides, sulfur oxides, particulate matter, and volatile organic compounds. The combustion efficiency of gases in a flare vary from 80 to 98% (Lee et al., 2011). Flares also emit gases other than CO<sub>2</sub> into the atmosphere after incomplete combustion. These compounds may play a role in the greenhouse gas effect, be toxic to human health and ecosystems, and create pollutants emanating from the odors produced. Unlike in the previous section, where a quantitative assessment of GHG emissions was performed, the same assessments cannot be carried out to evaluate the significance of these emissions in Québec's greenhouse gas balance given the current state of knowledge.

Nitrogen and sulfur oxides and carbon monoxide are the most dangerous components associated with local or regional pollution. The impact on human health of air emissions from Canada's offshore facilities has not been given much attention, given their distance

from the coasts and the dispersion of emissions by marine winds (Lee et al., 2011). Methane and carbon dioxide are the primary greenhouse gases emitted during hydrocarbon exploration and extraction. Methane emissions occur during normal extraction operations, routine maintenance, and oil and gas facility disturbances (GMI, 2011).

Table 33 presents air emissions from offshore facilities in 2011:

- The Hibernia facility emitted (stack emissions) 559 tons of carbon monoxide, 987 tons of nitrogen oxides (expressed in NO<sub>2</sub>), 118 tons of fine particles (< 2.5 microns), and 387 tons of VOCs into the air in producing 56 million barrels of crude oil.
- The Terra Nova facility emitted 469 tons of carbon monoxide, 2,375 tons of nitrogen oxides, 130 tons of particles (< 2.5 microns), and 60 tons of VOCs into the air in producing 15.8 million barrels of crude oil.
- The White Rose facility emitted 513 tons of carbon monoxide, 2,444 tons of nitrogen oxides, 138 tons of particles (< 2.5 microns), and 60 tons of VOCs into the air in producing 12.8 million barrels of crude oil. The Hibernia, White Rose, and Terra Nova facilities produced between 0.4 and 0.6 Mt in CO<sub>2</sub> equivalent in greenhouse gases in 2011 (CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O).

**Table 32 Main sources of air emissions from offshore hydrocarbon exploration and extraction (based on Genivar, 2011)**

Step	Source of impact
Geophysical surveys	Engines of seismic survey vessels and other geophysical surveys, generators, boilers
Exploration drilling	Support vessel engines, generators, boilers, flaring, venting, operation of drilling facilities (drilling string rotation, fluid injection, drilling waste treatment), fugitive gas emissions
Construction	Same as for exploration drilling, pipelay vessel engines, power for the installation of underwater equipment
Production	Transport vessel engines, production facility position maintenance, generators, production facility operation (extraction, fluid injection, separation, crude oil processing, natural gas processing, natural gas compression, produced water treatment), power to transport hydrocarbons, gas emitted by flaring, gas emitted by venting, boilers
Decommissioning	Engines of vessels for dismantling and transporting materials (steel, cement), generators, operation of dismantling facilities (removal of pipelines and underwater equipment, blowout preventers)

**Table 33 Air emissions from offshore facilities in 2011**

Facility	Carbon monoxide (t/year)	Nitrogen oxides (t/year)	Fine particles (t/year)	VOCs (t/year)	GHGs (Mt CO2eq/year)
Terra Nova	469	2375	130	58	0,6
Hibernia	559	987	118	387	0,5
White Rose	513	2,444	138	60	0,39

Sources: Environment Canada(2013); INRP (2014)

## Waste

When discharged into the marine environment, water-based mud and cuttings tend to disperse easily, unlike synthetic-based muds. The primary transport mechanisms governing the behavior of drilling waste in marine environments are advection-dispersion, aggregation, decantation, depositing on the ocean floor, consolidation, and erosion.

- The offshore discharge of drilling waste has a variety of potential impacts on the environment:
- Creation of a sediment plume in the water column
- Creation of hypoxic or anoxic zones
- Toxicity to organisms of components present in drilling waste
- Bioaccumulation of certain metals and hydrocarbons in organisms
- Burying of the benthic community by seafloor sediment deposition
- Displacement of mobile benthic organisms

The deposition of drilling waste on the seafloor may cause a local decrease in the abundance and biodiversity of fauna and flora, along with an increase in opportunistic species populations (Caenn, Darley, and Gray, 2011). Biological effects can generally be observed up to 1,000 meters from the facility for drill cuttings from water- and synthetic-based mud (Lee et al., 2011). However these effects are usually limited to a range of about 500 m from the structure (CEAEQ, 2015c), especially when the mud is water-based. The impact on benthic populations is generally observed over a distance farther from the platform than the impact observed on pelagic populations. It is estimated that the offshore environment is recolonized by benthic communities within a year, to eventually regain a community structure close to the original state as the amount of contaminants in the deposits decreases (Caenn et al., 2011; Lee et al., 2011). The U.S EPA (2000) estimates that three to five years after cessation of discharge of drill cuttings contaminated with synthetic-based mud, the concentrations of contaminants will have fallen low enough and oxygen concentrations will be high enough for living conditions to be acceptable to benthic communities.

## Light and noise

The main sources of light are the drilling, production, and transport units necessary for night navigation or night work and flaring to burn unrecovered gases (Table 34). Marine birds may also be attracted to light emissions from such sources. Birds migrating at night are especially drawn to the lights of offshore facilities, but the reasons for this remain unclear (Poot et al., 2008). The impact of light emission on birds has been documented, and incidences of birds colliding with structures have been observed (OSPAR, 2012).

Birds' attraction to light sources may also have indirect impacts, like depleting their energy reserves (Poot et al., 2008). The distance of influence on birds from light emitted from offshore platforms in the North Sea has been estimated at between 3 and 5 km from the light source (Poot et al., 2008). Some species of plankton and pelagic fish may also be drawn to light sources and be vulnerable to increased predation at the water's surface (Lee et al., 2011).

**Table 34 Main sources of noise and light emissions from offshore hydrocarbon exploration and extraction**

Step	Source of impact
Seismic surveys	Sound waves (air guns, sparkers, etc.)
Exploration drilling	Noise from drilling facilities and vessels Light from facilities
Construction	Noise from construction facilities Light from facilities
Production	Noise from production facilities and hydrocarbon transportation vessels Light from facilities
Dismantling	Noise from dismantling and transport vessels

Seismic surveys in the exploration phase are the main source of noise. Other than seismic surveys, rising underwater sound levels are caused by vibrations in the water column from pile driving into the seafloor during platform construction (Environnement Illimité, 2006; Hildebrand, 2009). Other vessels (support vessels, hydrocarbon transportation vessels, etc.) and airborne units also emit noise.

Exploration and extraction facilities also emit vibrations underwater and in the air from thrusters and surface machinery (e.g., turbines, pumps, compressors, generators) (GENESIS, 2011; NCE, 2007). Underwater noise emissions from machinery are primarily caused by structural vibrations rather than noise emissions into the air. Most of the underwater noise emitted by an exploration and extraction facility is caused by the thrusters that hold the platform in place (NCE, 2007). The noise from a drilling platform is approximately 200 dB at 1 m away from the sound source—comparable to the passing of a bulk carrier vessel. By comparison, the average ambient noise in the Laurentian Channel (primarily from maritime transport) ranges from 81.6 to 104.6 dB (Genivar, 2011).

Noise emissions may impact fish and marine mammals in a variety of ways, inducing behavioral reactions, masking other sounds, and causing avoidance behavior, stress, and hearing loss (Environnement Illimité, 2006).

### 3.4 Legal and regulatory framework

On Anticosti, as elsewhere in Québec, MDDELCC's provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière) set out the measures developers must take to reduce the environmental impacts of their onshore activities as much as possible.

The guidelines outline what information developers must provide for their certificate of authorization application to be considered for projects subject to the requirements (Section 22 of the Environment Quality Act and Subsection 6 of Section 2 of the Regulation respecting the application of the Environment Quality Act [CQLR c Q-2, r 3]) and clarify certain scientific and technical data they must submit mid-project. This information is required under the Regulation respecting the filing of information on certain drilling and fracturing work on gas or petroleum wells (CQLR c Q-2, r 47.1).

The guidelines also cover other related authorizations under the EQA, in addition to the certificate of authorization to which some projects are subject. The guidelines must be used to authorize all oil and gas exploration and fracturing projects, no matter what the geological formation.

Requirements not stemming from the laws and regulations in effect in Québec are largely based on regulations applicable to other industrial sectors having similar impacts or on requirements applicable to the oil and gas industry outside Québec. Finally, some requirements are inspired by the principles of prevention and precaution when there is a lack of information or when the environmental stakes are too high to proceed otherwise. MDDELCC's expectations are that, when issued a certificate of authorization, developers will commit to meeting these requirements.

The current guidelines reflect MDDELCC's major priorities in terms of protection of the environment, specifically:

- Accountability of developers, who are subject to specific rules and follow-up measures
- Optimal water management. In a sustainable development context, optimal water management is reflected in the adoption of strategies aimed at limiting water contamination and reducing the amount of water withdrawn, primarily through reuse
- The protection of receiving environments, by taking into account the Environmental Discharge Objectives (EDOs) applicable to the discharge of wastewater into surface water and by compliance with air quality criteria near facilities that emit contaminants into the air
- Water protection and conservation, particularly water withdrawals to be used for human consumption or food processing
- Optimal waste management through source reduction, reuse, recycling, and other forms of recovery
- Disposal must be seen as a last resortThe protection of human and animal populations from disturbances (e.g., noise, vibration, light) caused by oil and gas explorationSoil protection and site remediation through proper land rehabilitation, safe well closure, and appropriate post-closure monitoring
- The fight against climate change by helping attain the goal of reducing greenhouse gas emissions through the use of best available technology and the implementation of measures to minimize greenhouse gas emissions
- Protection and conservation of the natural heritage, habitats, and biodiversity

The full provisional guidelines are available on the MDDELCC website at:

<http://www.mddelcc.gouv.qc.ca/industriel/hydrocarbures/Lignes-directrices.pdf>.

With respect to GHG emissions, oil exploration and extraction are primarily governed by two GHG emissions regulations. The Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere (RMRCECA) requires companies to report their GHG emissions if they exceed the annual threshold of 10,000 metric tons of CO<sub>2</sub> equivalent. (AENV-01)

The Regulation respecting a cap-and-trade system for greenhouse gas emission allowances (C&T system) applies to businesses whose GHG emissions meet or exceed

the annual threshold of 25,000 metric tons of CO<sub>2</sub> equivalent (Government of Québec, 2015). The C&T system is an economic tool aimed at reducing the GHG emissions of the largest emitters, which must procure emission allowances on the carbon market to cover all GHG emissions associated with their operations. The current C&T system covers the oil and gas development, natural gas distribution, and natural gas pipeline transportation sectors. The Regulation does not provide free emission allowances for these sectors. Moreover, the threshold applies to all of a business's operations, not to each individual location as is the case for the industry as a whole. Emitters must cover all of the GHG emissions resulting from their activities. The C&T system has also applied to businesses that distribute fuel and combustibles since January 1, 2015. (AENV-01).

### **Water management**

Excluding the processing of wastewater for reuse, all pretreatment and treatment systems must be approved by MDDELCC. A separate certificate of authorization must be issued for any project to recover wastewater for purposes other than drilling and fracturing (e.g., road ice removal, dust control).

The use of surface water sources or of water unfit for human consumption must be prioritized in supplying water for drilling and fracturing activities. All gas and oil wastewater, as well as site runoff, if any, must be collected separately in leak-proof equipment. The water should be transported through pipes as much as possible to reduce the repercussions of trucking.

Unless MDDELCC deems a different measure provided for in the water management plan to be acceptable, gas and oil wastewater must be treated, recycled, or disposed of within three months of the end of drilling or fracturing work, as applicable.

Under no circumstances will dilution be considered an acceptable form of pretreatment or treatment.

Runoff water must be treated onsite, while gas or oil wastewater can be treated on- or offsite. Based on drilling and fracturing wastewater data obtained in Québec and, when available, in the U.S.,

Study E3-5, conducted as part of the shale gas strategic environmental assessment (MDDEFP, 2013b), also confirmed the list of contaminants indicated in the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière [MDDELCC, 2014b]), identified contaminants of concern, and designated those for which exploratory monitoring would be necessary.

### **Air emissions management**

Applicants must comply with the air emissions requirements in the Clean Air Regulation (CAR) (CQLR c Q-2, r 4.1) and the requirements of the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière [MDDELCC, 2014b]) for the duration of operations. These requirements are summarized below. For further information, refer to the referenced documents. Application for a certificate of authorization:

#### **Air emissions component**

Section 22 of the Environment Quality Act (EQA) stipulates that a certificate of authorization must be obtained before certain work or activities may begin. Section 48 of the EQA also imposes an obligation to obtain authorization before installing a device or piece of equipment designed to prevent, reduce, or prevent the release of contaminants into the air. A list of information to be included with the certificate of authorization

application is provided in the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière).

### **Monitoring: Air emissions component**

#### **Monitoring and reporting of uncontained fugitive emissions and liquid leaks:**

The applicant must monitor all uncontained fugitive emissions and liquid leaks (e.g., gas, wastewater, petroleum, and fracturing fluid) that are observed on the oil or gas development site. Under Section 21 of the EQA, the minister must be notified of the accidental presence in the environment of a contaminant without delay.

#### **After shutdown:**

Applicants who would like to temporarily or permanently close their well must ensure that there is no risk of leakage in the surface casing vent (temporary closure) or migration of gases and hydrocarbons and that the well does not contaminate the groundwater.

### **Ambient air quality management**

This section summarizes the section of the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière) (MDDELCC, 2014b) dealing with air quality (ambient air). For further information, refer to the referenced documents.

As a reminder, MDDELCC requirements pertaining to air quality around oil and gas development facilities are aimed at protecting human health, minimizing pollutants, and minimizing impacts on ecosystems. These requirements largely center on compliance with air quality standards and criteria around exploration facilities. The air quality standards are laid out in the Clean Air Regulation (CAR), while air quality criteria are established by MDDELCC by virtue of Section 20 of the EQA for unregulated contaminants. It should be noted that these air quality criteria and standards are in addition to the emissions standards set out in the CAR.

### **Application for a certificate of authorization: Air quality component**

Oil and gas exploration project developers must file an application for a certificate of authorization from MDDELCC. Certain information and documents are requested in order to analyze certificate applications. This primarily includes a description of air contaminant emissions that will be produced at different stages of the project and an assessment of the impact these emissions will have on air quality locally and regionally.

Compliance with air quality standards and criteria must be assessed when the application is filed using an atmospheric dispersion modeling study. The study must cover all contaminants emitted by the exploration operations, specifically particulates (TSP, PM<sub>2.5</sub>), NO<sub>x</sub>, CO, SO<sub>2</sub>, VOCs, PAHs, and other contaminants, as well as the secondary contaminants (O<sub>3</sub>) formed downstream of the site.

### **Air quality monitoring requirements**

Under Section 22 of the EQA, MDDELCC may require developers to monitor contaminants revealed by the modeling study as having a concentration in the ambient air of at least 80% of the norm or, where applicable, of the corresponding air quality criteria. If a developer's certificate of authorization includes an obligation to monitor air quality, this monitoring must be carried out in accordance with the developer's air quality monitoring plan approved by MDDELCC in advance. In the event monitoring demonstrates that an air quality standard or criteria has been exceeded, the applicant

must implement mitigation measures to remedy the situation (EQA, Section 20). Other requirements: Oil and gas development project developers must also comply with the following requirements: When carried out on public land, exploration activities must not exceed air quality standards and criteria at a distance of 300 meters or more from the exploration site, or where sensitive receivers have been placed if they are located within the aforementioned 300-meter zone. If storage containers are used to store fracturing fluid, manipulations (venting or pulverizing) of fracturing fluids having repercussions on the emission of contaminants into the air are prohibited (EQA, Section 20).

In the event of well-founded air quality complaints or proven issues (dust, odors, etc.) around exploration sites, developers must implement corrective measures without delay and use the necessary means to verify their effectiveness (EQA, Section 20).

### **Other requirements**

Oil and gas development project developers must also comply with the following requirements:

- When carried out on public land, exploration activities must not exceed air quality standards and criteria at a distance of 300 meters or more from the exploration site, or where sensitive receivers have been placed if they are located within the aforementioned 300-meter zone.
- If storage containers are used to store fracturing fluid, manipulations (venting or pulverizing) of fracturing fluids having repercussions on the emission of contaminants into the air are prohibited (EQA, Section 20).
- In the event of well-founded air quality complaints or proven issues (dust, odors, etc.) around exploration sites, developers must implement corrective measures without delay and use the necessary means to verify their effectiveness (EQA, Section 20).
- Developers must prevent the emission of dust by spraying water or using dust suppressants certified according to the NQ-2410-300/900 standard at the site and on access roads.

### **Noise monitoring requirements**

With respect to monitoring acoustic emissions, applicants must comply with sound mitigation measures and the requirements set out in the provisional guidelines (MDDELCC, 2014b), as summarized below. For further information, refer to the referenced documents.

Developers must prevent the emission of dust by spraying water or using dust suppressants certified according to the NQ-2410-300/900 standard at the site and on access roads.

### **Sound mitigation measures**

A number of more specific sound mitigation measures can also be implemented, as follows:

- Use the mineral soil or topsoil from scraping work to form windrows around the site
- Follow a regular daily schedule for activities generating the most noise
- Keep equipment well-maintained and outfitted with effective silencers and properly functioning noise control devices
- Install sound enclosures for compressors, pumps, generators, saws, jackhammers, and other equipment

- Use acoustic shields on hydraulic and pneumatic drills
- Use low-noise blades on concrete saws
- Install compressor condensate discharge silencers
- Keep temporary access roads and traffic routes on sites well maintained and limit traffic speeds
- Construct routes so that trucks do not have to back up as much (backup alarms)
- Use backup alarms that automatically adjust their output to the ambient noise
- Prohibit the use of engine brakes on access roads and sites
- Use the transportation route with the lowest noise impact

### **Monitoring requirements**

For the duration of operations, applicants must comply with monitoring requirements, specifically those set out in sections 2.4.4.3 and 3.2.8.7 of the guidelines. The requirements are outlined below.

Applicants must implement sound monitoring programs in sensitive areas affected by activities at the oil or gas exploration site for each step of a project. This monitoring program must have been approved in advance by MDDELCC when the certificate of authorization was issued.

If sound monitoring detects an exceedance of the sound limits set out in Memorandum of Instruction 98-01, the administrative practice on road noise, or the guidelines for construction sites, applicants must implement the required corrective measures and verify their effectiveness.

Applicants must conduct a noise impact study on the planned post-construction oil or gas exploration activities covered by the guidelines, i.e., well drilling and completion activities, production tests, and well closure and facility dismantling activities, and indicate in the study the mitigation measures they plan to take to ensure that noise levels at sensitive points of reception comply with MDDELCC noise criteria at all times. The noise impact study must include the initial noise measurement, the assessment criteria, and a noise impact model.

### **Greenhouse gas monitoring requirements**

#### **Greenhouse gas emissions monitoring and control**

The requirements pertaining to the control of GHG emissions are summarized below. For further information, refer to the associated regulations—the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere* (RMRCECA) and the *Regulation respecting a cap-and-trade system for greenhouse gas emission allowances* (C&T system) presented in Section 2.4.6.3 of the guidelines.

#### **Greenhouse gas emissions reporting**

Section 6.1 of the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere* (c Q-2, r 15) requires applicants to report their GHG emissions if they exceed the threshold of 10,000 metric tons of CO<sub>2</sub> equivalent. For oil and gas emitters, the reporting threshold applies to all activities carried out within a calendar year by a single business in Québec.

#### **Emissions report verification statement**

Under Section 6.6 of the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere* (c Q-2, r 15), when they file their emissions report,

applicants that report GHG emissions equal to or higher than 25,000 metric tons in CO<sub>2</sub> equivalent must file an emissions report verification statement with the minister's office prepared by a verification body accredited by a member of the International Accreditation Forum in accordance with ISO 14065 no later than June 1. Verification must comply with sections 6.6, 6.7, 6.8, and 6.9 of the Regulation (c Q-2, r 15).

### **Greenhouse gas monitoring by developers**

With respect to GHG emissions monitoring requirements, the measures are set out in sections 2.4.6.4 and 2.4.8.3 of the provisional guidelines for oil and gas exploration (Lignes directrices provisoires sur l'exploration gazière et pétrolière) (MDDELCC, 2014b). These measures are summarized below. For further information, refer to the referenced documents.

### **Composition of hydrocarbons coming out of the well**

Applicants must characterize the hydrocarbons coming out of the well—specifically crude oil and natural gas—once drilling and, where applicable, fracturing operations have been completed to assess the concentration of the compounds most susceptible to being emitted into the air. In order to report their GHG emissions and meet the requirements of the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere* (c Q-2, r 15), applicants must ensure they take the necessary measures to assess the composition of the gases emitted into the air at that time, as set out in Section QC.33.4 of Protocol QC.33 of the Regulation (c Q-2, r 15).

The report demonstrating the results of the composition of crude gas and petroleum coming out of the well must be filed with MDDELCC within two months of the start of production tests. The characterization results must be entered in the register.

### **Register of emissions released into the air**

The register for monitoring uncontained fugitive emissions in the air must include, for each piece of equipment and each gaseous contaminant sampled, the inspection or observation date, the quantity emitted, the concentrations measured, an estimate of the amount of VOCs emitted, corresponding hourly meteorological data on temperature and wind (speed and direction), and any actions that were taken to prevent or stop leaks.

### **Annual report**

Applicants must submit an annual report to MDDELCC indicating, for each equipment category, the uncontained fugitive emission and liquid leak monitoring results obtained with the leak detection and repair program and a report of repairs that were made. The nature of the contaminants and an estimate of the amount of contaminants released into the environment must be included as well.

## 4. Technical Aspects

### 4.1 - Scope

The Technical Aspects steering committee's mandate is to determine the best industry practices and the main risk factors associated with hydrocarbon exploration and extraction and propose appropriate monitoring, mitigation, and response measures. Its purpose is also to document the main technical aspects of hydrocarbon development so that the Québec government can have a better understanding of the risks and benefits associated with onshore and offshore development of this industry.

Three of the 12 knowledge surveys already carried out are more directly involved with this theme, namely:

- Geology and hydrocarbon potential of sedimentary basins in southern Québec
- Comparison between the Macasty Formation, Île d'Anticosti, Québec, and a few hydrocarbon source rocks in North America
- Summary of existing knowledge on current and emerging practices in the oil and gas industry

Once these surveys were completed, to fill in the gaps in knowledge revealed by this exercise, it was agreed to conduct other studies (presented in Appendix 2) under the Additional Knowledge Acquisition Plan (AKAP), namely:

- Five studies on good geophysical surveying and drilling practices to adopt
- Four studies on good practices appropriate to the geological context specific to certain structures already known for their hydrocarbon potential or the physical environment of their surroundings

This section deals with the geological aspects of hydrocarbon exploration and extraction and good practices associated with these activities in onshore and offshore environments.

### 4.2 Geological aspects

Geological structures showing hydrocarbon potential in the Bas-Saint-Laurent (Massé site) and Gaspésie (Bourque, Galt, and Haldimand sites) regions and the Gulf of St. Lawrence (Old Harry sector) were considered in Study GTEC01 and the "Risks" component of Study GTEC02 (Malo et al., 2015).

Study GTEC01 presents current geological knowledge on each sedimentary basin where such structures are located and identifies their analogue. It does not, however, deal with the Macasty Formation, as the "Comparison between the Macasty Formation, Île d'Anticosti, Québec, and a few hydrocarbon source rocks in North America" study was conducted as part of the knowledge summary.

The "Risks" component of Study GTEC02 presents an analysis of specific risk factors for the various geological structures and the Macasty Formation.

The geological analogue involved here is a known, well-documented geological environment with a production history and has basic geological similarities to the Québec geological environment, about which we have little knowledge. A number of criteria help identify the analogue, including the age, composition, porosity, structure,

level of thermal maturity, and total organic carbon content of the formation. Defining such analogues in the Québec context has many advantages. For example, the characteristics of analogues help establish the criteria for determining high-potential sectors that share geological attributes and thus take into account the hydrocarbon potential of a given sector in land use planning.

From a technical standpoint, identifying geological analogues helps define design, development, and integrity issues so that quality, performance, and safety can be optimized in a similar context. The geological and technical information provided by the analogue study makes it possible to perform a more informed analysis when processing permit applications and to better monitor and control activities.

From an economic standpoint, when the quantity and quality of available information allows, identifying an analogue is the first step toward developing simple production scenarios, which may be adjusted as data on the geological structure becomes available. The Economy section of this document addresses this aspect in the Québec context.

The term “geological hazard” or “geohazard” is used here to refer to a geological surface or subsurface element inherent in the nature of the land that may lead to incidents or even accidents in response to natural phenomena (e.g., landslides) or human activity (e.g., hydraulic fracking). If such a hazard is not factored into work planning, it could jeopardize the environment and the safety of people and property and prevent optimal recovery of the resource.

During hydrocarbon exploration and extraction, soil stability and the presence of major faults, shear zones, and overpressure zones involve geological hazards that must be factored into the development of programs to provide for appropriate mitigation measures.

Based on current available information, the work under the Technical Aspects theme provides a better understanding of the geological hazards associated with structures showing a potential for discovery of hydrocarbons in Québec. It also makes it possible to present some of the best practices to adopt, and specify the areas of the territory and the activities where applying specific regulations would be justified. Figure 19 shows the relative position of each geological structure analyzed.

**Figure 19 Position of geological structures**

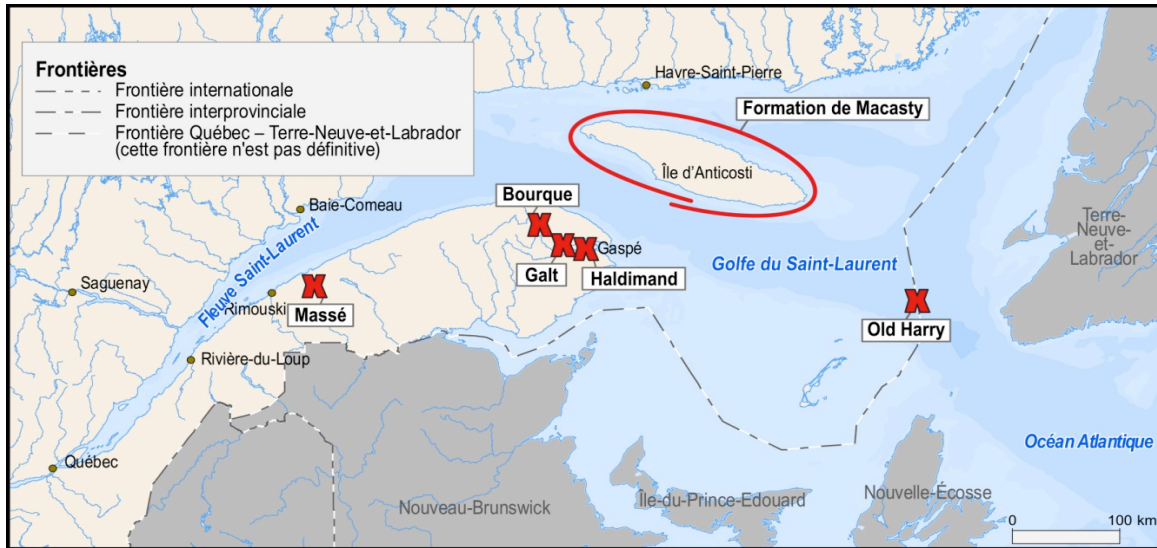


Table 35 shows a results summary of the work performed under Study GTEC01 and the “Risks” component of Study GTEC02, which deals with the analogue and the identification of risk factors by structure. Good practices associated with these risks are presented in Section 4.3.

**Table 35 Results summary of work performed under Study GTEC01 and the “Risks” component of Study GTEC02 (Malo et al., 2015)**

		Massé	Galt	Bourque	Haldimand	Old Harry	Anticosti
<b>Analogue</b>		Slave Point dolomites	Mississippian lime within the Anadarko Basin	Mississippian lime within the Anadarko Basin	Oriskany Formation Median member of the Bakken Formation	Southern part of the North Sea	Point Pleasant Formation
	<b>Surface</b>	Sedimentary cover	5 to 25 m	3 to 28 m	0 to 10 m	1 to 21 m; impermeable	4 to 20 m; pelagic zone
	Surface well	8 to 88 m deep	None	None	None	None	None
	Water features	Little information available	Sulfur water	Fresh or salt water, locally contains hydrocarbons	Fresh or salt water, locally contains hydrocarbons	Little information available	Fresh or salt water, locally contains hydrocarbons
	Surface fracturing	At least 243 m	At least 235 m	Little information available	Over 20 m	Little information available	At least 70 m, karst
	Oil seeps	No	Yes	No	Yes	Yes	Yes

		<b>Massé</b>	<b>Galt</b>	<b>Bourque</b>	<b>Haldimand</b>	<b>Old Harry</b>	<b>Anticosti</b>
<b>Subsurface</b>	Fluids	Methane, brine, condensates, heavy oil	Methane, brine, condensates, light oil	Gas and condensate, light oil	Brine, gas and condensate, heavy and light oil	Little information available	Fresh or salt water, locally contains gas or other hydrocarbons
	Pressure	Little information available	Little information available, a case of overpressure	Little information available, a case of loss of circulation	Light on reservoir overpressure	Little information available	Little information available, overpressure in some cases
	Structure	No clear association between faults and fractures with overpressure zones or hydrocarbon occurrences	No clear association between faults and fractures with overpressure zones or hydrocarbon occurrences	Major fracturing in the reservoir and the Bras-Nord-Ouest fault Low-permeability host rock	No clear association between faults and fractures with overpressure zones or hydrocarbon occurrences Fractured reservoir	Little information available	No clear association between faults and fractures with overpressure zones or hydrocarbon occurrences
	Clay	Little information available	Little information available	Interstratified I/S and smectite in a survey	Interstratified I/S and contains smectite	Little information available	Interstratified I/S locally
	Seismic risks	No clear association	No clear association	No clear association	No clear association	No clear association	No clear association

### Risks of induced seismicity

A distinction should be made between the risks of natural seismicity and those associated with induced seismicity.

Natural seismicity refers to naturally occurring earthquakes. It is monitored by a network of seismograph stations that record waves associated with earthquakes, even those of very low amplitude. This network is under the responsibility of the Geological Survey of Canada<sup>14</sup> (CSC). In general, southern Québec has relatively low seismic activity. In the regions where hydrocarbon extraction is being considered, particularly in the St. Lawrence Lowlands, natural seismicity is sporadic.

<sup>14</sup> See <http://www.earthquakescanada.nrcan.gc.ca/zones/eastcan-eng.php>.

A distinction should also be made between magnitude and the intensity felt on the ground. Magnitude corresponds to the amount of energy released by an earthquake. This is usually expressed by the magnitude of the seismic moment. The intensity felt on the ground corresponds to the severity of movement observed on the surface and may be expressed using the Modified Mercalli Intensity Scale, which matches the effects observed on the surface with the energy of an earthquake. The intensity felt thus depends on numerous factors, such as the depth of focus, the types of materials the energy passes through, etc., and not just the magnitude.

In general, the hydraulic fracturing process used for oil and gas wells induces only faint earth tremors (microseismicity) caused by the creation of fractures associated with the injection of fluids and fracture proppants.<sup>15</sup> The magnitude of microearthquakes is generally less than 2, although occurrences of up to 3 have been documented (Ellsworth, 2013<sup>16</sup>; Skoumal et al., 2015<sup>17</sup>). It is unlikely that these events are felt by residents as the energy generated through pumping is too low.

However, in some regions, such as the Horn River basin in northeastern British Columbia,<sup>18</sup> the injection of fluids during hydraulic fracturing near pre-existing faults has caused earthquakes ranging in magnitude from 2.2 to 3.8 on the Richter scale. Following such earthquakes, British Columbia adopted the following measures:

- Presentation of reports on the microseismicity measured during hydraulic fracturing
- Establishment of a notification and consultation procedure
- Study on the relationship between the parameters of hydraulic fracturing and seismicity
- Improvement of the seismograph network

In the literature there seems to be a consensus that more intense induced seismicity (magnitude 3) is primarily related to the disposal of wastewater in a deep underground repository—which is common practice in the industry—as induced seismicity directly related to hydraulic fracturing is much rarer and generates lower magnitudes (National Research Council of the National Academies, 2015<sup>19</sup>).

### 4.3 Good practices

For both onshore and offshore environments, the main activities covered by the studies conducted stem from geophysical surveys, well drilling with or without fracking, temporary and permanent closures, corrective work, monitoring and control activities, drilling waste management, reuse of frac water, wastewater management, the dismantling of facilities, and the rehabilitation of sites.

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<sup>15</sup> Sand or ceramic materials injected with fluids to keep fractures open.

<sup>16</sup> William L. Ellsworth. "Injection-Induced Earthquakes," *Science* 341 (2013), DOI: 10.1126/science.1225942.

<sup>17</sup> Robert J. Skoumal, Michael R. Brudzinski, Brian S. Currie. "Earthquakes Induced by Hydraulic Fracturing in Poland Township, Ohio," *Bulletin of the Seismological Society of America* (2015), DOI: 10.1785/0120140168.

<sup>18</sup> BC Oil and Gas Commission. "Investigation of Observed Seismicity in the Horn River Basin," August 2012. <https://www.bcogc.ca/node/8046/download>.

<sup>19</sup> <http://www.nap.edu/read/13355/chapter/1#iii>

The studies conducted under the Technical Aspects theme helped determine the best practices to apply and the geological hazards present. They can contribute to the development of rules for hydrocarbon exploration and extraction in Québec.

#### **4.3.1 Onshore environment**

The reference points with physical environments similar to those of Québec that were chosen for establishing good practices for the onshore environment are British Columbia, Alberta, New Brunswick, New York, Ohio, Oklahoma, Texas, and Great Britain.

Good practices developed by the following independent organizations or industrial associations were also analyzed:

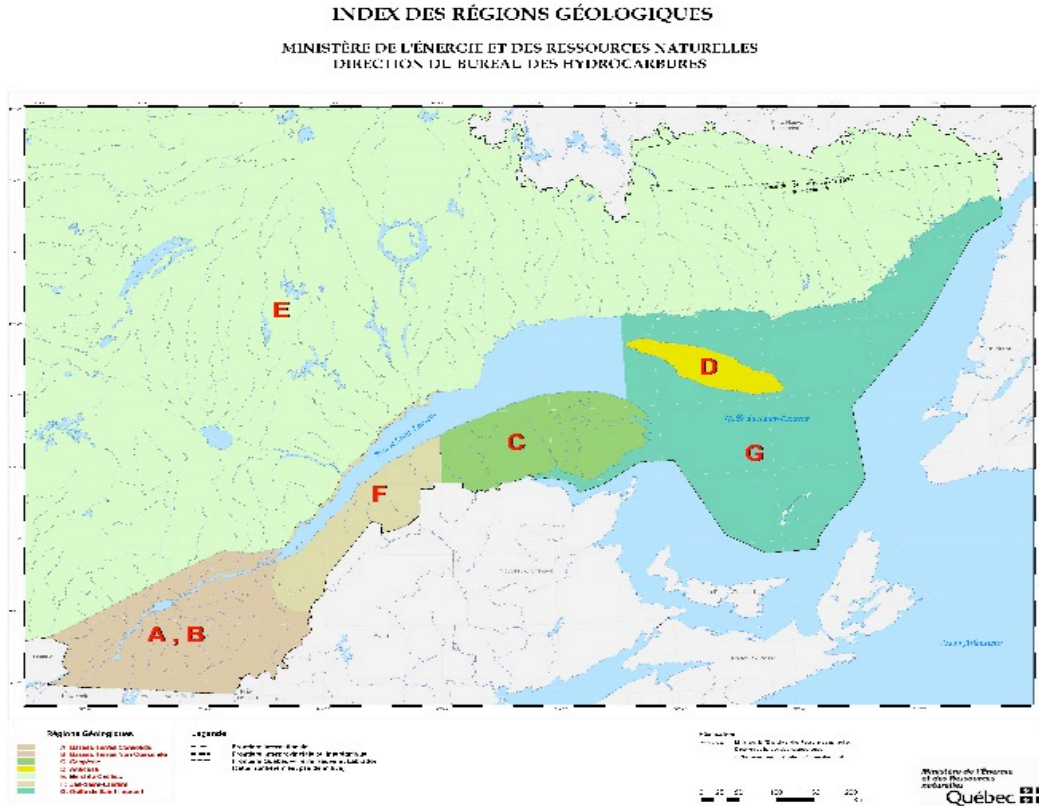
- Canadian Association of Petroleum Producers (CAPP)
- American Petroleum Institute (API)
- Safety Association for Canada's Upstream Oil and Gas Industry (ENFORM)
- State Oil and Gas Regulatory Exchange (SOGRE)
- Interstate Oil and Gas Compact Commission (IOGCC)

Sedimentary basins in Nord-du-Québec were not considered for the various studies conducted under the Technical Aspects theme because they are not subject to hydrocarbon exploration and extraction.

Furthermore, the "Good Practices" component of Study GTEC02 deals with good practices to consider based on the geological hazards mentioned that are specific to the Québec context.

Figure 20 shows the seven main geological regions of Québec.

**Figure 20 Index of the geological regions of Québec**



### Onshore seismic surveys

The onshore component of Study GTEC05 (Dupuis and Fillion, 2015) provides an overview of good seismic acquisition practices for onshore hydrocarbon exploration and extraction.

Study GTEC05 mentions that onshore seismic surveys can be conducted with minimal impact on the environment because they consist of one-time exploration whose impact is essentially temporary. Nevertheless, some risk factors may have environmental impacts.

Among the environmental impacts mentioned in the study, we note the risk of introducing invasive species of plants or insects or pathogens via surface equipment. Mitigation of this risk factor involves cleaning equipment before it is transported. British Columbia regulates the cleaning of such equipment and performs monitoring once work is completed.

The land clearing required to conduct seismic surveys, particularly for access road construction and line cutting, may affect erosion and the stress level of wildlife and lead to contamination of waterways through accidental spills, to waste generation, and to potential disturbances to heritage sites. As in the previous case, businesses must comply with certain conditions and restrictions applicable to this context and use various mitigation measures.

Some risk factors are from signal sources used during seismic surveys. Vibrator trucks and explosive charges are the two types of sources generally used for onshore surveys; they are documented in Study GTEC05. Precise measurements regarding separation distances to be observed and the size of explosive charges to be used are established by the authorities quoted in this study.

Separation distances and the size of explosive charges are regulated to protect the integrity of certain property, such as residences, buildings, and structures with concrete foundations, as well as drinking water wells, observation wells, piezometers, gas and oil pipelines, telecommunication infrastructures, monuments, retention basins, dams, cemeteries, and domestic septic fields.

As for sources using explosive charges, safety measures regarding the placement of charges are suggested, particularly shot hole drilling and the procedures to follow in the event of a misfire.

In general, the reference authorities (here, Alberta and British Columbia) provide for a regulatory framework that determines the minimum setback distances applicable to most potentially sensitive structures that may be found near a seismic survey. These minimum distances may require adjustments depending on the specific conditions at the survey site.

If blasting nevertheless causes damage, the authorities whose provisions were analyzed require the company responsible for the work to take immediate measures to prevent further damage and repair the damage already caused.

The use of explosives is strictly regulated and the provisions of each of the authorities concerned with regard to transportation, storage, and use apply. The use of explosives poses occupational health and safety risks, but it helps minimize the environmental footprint of seismic surveys, particularly by reducing the size of the line cutting required when a company uses vibrator trucks.

For the two reference authorities, shot holes must be filled and marked in the field. For explosive charges that misfire, two types of measures were identified. In some cases, the company in charge of the work must destroy the charge using a new charge (Alberta and British Columbia) or bury the charge by filling in the hole (British Columbia). However, the company is responsible for ensuring public safety and taking all measures necessary to prevent the situation from posing a risk to people or property.

In the event a shot hole results in a water blowout, the company in charge of the work must cease drilling and stop the leak immediately. If this is not possible, it must agree on a plan to control and manage the water flow with the owner and notify the competent authorities.

In the event a shot hole results in a gas blowout, the promoter must confine the leak to prevent any harm to people, the environment, property, or public safety.

Vibrator trucks require a wider access road than the one needed when a company uses explosive charges. They therefore have a greater impact on line cutting. The risk of jeopardizing the integrity of various structures is nevertheless similar to any other risk associated with the use of equipment that has a vibrating source.

In addition to the good practices mentioned in Study GTEC05, the authors of the “Good Practices” component of Study GTEC02 considered good practices applicable to seismic surveys based on the geological risks mentioned in the “Risks” component of Study GTEC02.

Based on this study, the authors point out that conducting seismic surveys involves deploying a team in the field and using vibrator trucks or explosive charges as a source of energy. In the case of explosive charges, the energy produced by detonations is too low to reactivate faults even if such faults reach the surface, as is the case in the eastern part of Île d’Anticosti and the vicinity of the structures studied. The only risk common to the geological structures analyzed that can be contemplated is the presence of explosive charges that have not detonated (misfires). In general, however, these charges are quickly deactivated and destroyed, and the current version of the Regulation respecting

petroleum, natural gas and underground reservoirs (RRPNGUR) contains specific provisions in this regard. Regardless of the energy source used, the main risk associated with seismic surveys seems to be the local presence of clay soil in sloped areas. This type of landform is present in a few confined regions of Île d'Anticosti (study GTEC02, "Risks" component).

The "Good Practices" component of Study GTEC02 suggests adapting seismic survey parameters to the local context with regard to landslides, particularly when clay soil in a slope is found in an area where a survey must take place.

Study AENV21 (Fournier and Deschênes, 2015), which makes a preliminary assessment of the risk of soil and rock movements associated with hydrocarbon exploration and extraction on Île d'Anticosti, mentions that the possible presence of sensitive clay could cause a major landslide due to the local geology and the main rupture mode observed there.

Although seismic surveys do not include permanent facilities, it is recommended that facilities be placed outside zones potentially exposed to this hazard.

To avoid triggering such ground movements, hydrocarbon exploration and extraction operations should respect buffer strips near clayey slopes to avoid compromising the equilibrium conditions of slopes through excess weight at the top of slopes, clearing or excavation at the base of slopes, and concentrations of water toward slopes.

With regard to rock movements, the authors of Study GENV21, like the authors of the "Good Practices" component of Study GTEC02, conclude that the risks of a major rock slide caused by hydrocarbon exploration and extraction are very low. Work performed on the edge of a cliff could at most cause ruptures where stability is already precarious. As for the risks of a karst collapse, this phenomenon must be taken into account to ensure the safety of people and equipment.

To monitor natural or induced earthquakes, the Geological Survey of Canada (GSC) set up a seismicity monitoring system on Île d'Anticosti. New seismographs deployed in summer 2015 should soon be fully operational. This new system will help ensure better monitoring of seismic phenomena on the island and in the surrounding area.

### **Onshore drilling**

Study GTEC03 (Malo et al., 2015) helped record and establish good practices for hydrocarbon exploration and extraction operations resulting from onshore drilling. Operations resulting from drilling include activities related to well drilling, completion with or without fracking, various types of testing, corrective work, closures, the dismantling of facilities, the rehabilitation of sites, and monitoring and control that must be carried out by companies and the legislator during work and once work has been completed. Furthermore, the work of the "Good Practices" component of Study GTEC02 builds on the work of Study GTEC03 by integrating good practices associated with the geological risks mentioned in Study GTEC02.

Good practices for the following activities were analyzed:

- Separation distances
- Multiwell pads
- Well design and construction
- Well design and construction (casings)
- Well design and construction (casing cementing and evaluation)
- Drilling fluids
- Liquid blowout prevention and control system
- Wellhead
- Pressure and leak testing
- Drillstem testing
- Well deviation control
- Perforation prevention and control
- Injectivity testing
- Fracturing stimulation
- Stimulation other than by fracturing
- Extraction and production testing
- Leak and migration monitoring
- Corrective measures
- Onsite hydrocarbon processing
- Temporary well closure
- Permanent well closure
- Site restoration and rehabilitation
- Orphan wells
- Surface equipment management
- Drilling discharge and water management and disposal
- Flowback water reuse, management, and disposal

### Separation distances

The authors of Study GTEC03 mention that in order to protect residents and drinking water resources, separation distances between wells drilled for hydrocarbon exploration and extraction and areas at risk are established by the various reference authorities. Areas at risk include buildings (private or public), infrastructures other than buildings, and drinking water supply sources.

Given this, it is suggested that minimum distances be established between wells and areas at risk.

The distances suggested by the various authorities are quite similar, but some are better adapted to the Québec context, which is the case of the distances proposed by Alberta and British Columbia, for example.

The summary of separation distances proposed by the reference authorities under Study GTEC03 is presented on pages 22 and 23 of the study.

To ensure the safety of people and property and protection of the environment, Section 22 of the Regulation respecting petroleum, natural gas and underground reservoirs provides for separation distances with regard to the location of oil and gas wells. Under this section, a well may not be drilled:

- less than 100 m from a public highway within the meaning of the [Highway Safety Code](#) (c. C-24.2), a railway line, a pipeline, a high voltage transmission line carrying more than 69,000 volts, any dwelling or public building; in the case of an artificial underground reservoir or of drilling the depth of which does not exceed 15 m under the layer of unconsolidated deposits, the distance may vary from 50 to 100 m;

- onshore, less than 100 m from the high-water mark; however, in the case of an artificial underground reservoir or of drilling the depth of which does not exceed 15 m under the layer of unconsolidated deposits, the distance may vary from 50 to 100 m;
- on water-covered land, less than 1,000 m from the high-water mark on the seacoast, or less than 400 m from the high-water mark of the St. Lawrence River;
- less than 1,000 m from an airport;
- less than 1,600 m from any existing underground reservoir with respect to which the licensee holds no right.

The Water Withdrawal and Protection Regulation (WWPR) has been in effect since 2014 to regulate hydrocarbon exploration and extraction to ensure water is protected. In accordance with this regulation, it is prohibited to construct a drilling site or conduct a stratigraphic survey:

- in a floodplain having a flood recurrence interval of 20 years;
- in the identified floodplain of a lake or watercourse unless the 20-year and 100-year flood recurrence intervals have been distinguished;
- less than 500 m from a site where water is withdrawn for human consumption or food processing. It should be noted that the distance of 500 m may be increased to the distance set in a hydrogeological study showing that this distance does not minimize risks of contamination of the sites where water is withdrawn for human consumption or food processing that are located on the territory covered by the study;
- in the outer protection zone for category 1 or 2 groundwater withdrawals;
- in the intermediate protection zone for category 1 or 2 surface water withdrawals.

To protect aquifers during hydraulic fracturing stimulation, separation distances are also established by the WWPR. In Québec, therefore, hydraulic fracturing is prohibited less than 400 m below the base of an aquifer. The base of an aquifer is set at 200 m under the surface of the ground, unless the hydrogeological study provided for in [Section 38](#) of the WWPR shows that the base of the deepest aquifer presenting a total dissolved solid content less than 4,000 mg/l is located at a different depth.

For separation distances, the authors feel it is necessary to establish minimum distances between drilling sites and areas at risk. For this purpose, the results of Study GTEC03 and the separation distances presented in the RRPNGUR and WWPR must be reconsidered.

Section 2.3.4.3 of Study GTEC02 also mentions that although the WWPR requires a safe distance to be maintained between a hydraulic fracturing operation and the base of any aquifer, no distance is specified in the case of a fault or natural fractures. The authors feel these aspects must be taken into account when planning hydrocarbon exploration and extraction.

They believe it would be reasonable to take a performance obligation approach for the various separation distances to be established in Québec for hydraulic fracturing. An intermediate approach could consist of initially setting conservative separation distances, validating them during work or through interpretation of data collected

during work (onsite or modelled), then gradually reducing these distances as data becomes available or justifies reduction.

### **Multiwell pads**

Study GTEC03 mentions that according to the Canadian Society for Unconventional Resources (CSUR), a multiwell pad allows several wells (deviated or remote vertical wells) to be drilled from a single location. Placing a number of deviated wells on the same pad significantly limits the surface footprint and impacts that several vertical wells a few kilometers away would have.

To ensure the safety of people and property, protection of the environment, and optimal resource recovery in the design of multiwell pads, the authors of Study GTEC03 suggest applying:

Directive 080: Well Logging issued by the Alberta Energy Regulator (AER)

Alberta's Interim Directive ID 81-3: Minimum Distance Requirements Separating New Sour Gas Facilities from Residential and Other Developments and British Columbia's Drilling and Production Regulation

Given the possible economic and environmental benefits of using multiwell pads, it is suggested that the potential of horizontal drilling for a single site (multiwell pad) be anticipated and planned when considering separation distances.

### **Well design and construction (casings)**

Casings are steel tubes that, when cemented in place, help protect (isolate) aquifer formations from contamination during drilling, completion, and extraction operations. Below are the main types of casings:

Conductor casing enables a well to function as a conduit and facilitates control during drilling of the borehole into which surface casing will be introduced.

Surface casing is placed inside conductor casing. It is a permanent well structure that extends from the surface to a specific depth. Its main function is to protect non-saline groundwater.

Intermediate casing is placed inside surface casing. It is used to ensure control of wells, protect non-saline groundwater, and prevent the risk of deeper fluids migrating toward shallower permeable horizons.

Production casing is used to isolate production zones and contain the pressure of formations in the event of a leak.

With regard to casings, the authors of Study GTEC03 suggest using the API 5CT Specification for Casing and Tubing and AER Directive 010: Minimum Casing Design Requirements because they present the most comprehensive practices for casing design and installation. These documents cover all aspects of the minimum pressures (burst, collapse, tension, force) that the various types of casings must be able to withstand. They also cover design aspects of vertical, deviated, and horizontal wells related to their integrity to ensure the protection of people, property, and the environment and optimal resource recovery.

The "Good Practices" component of Study GTEC02 indicates that in Québec, the RRPNGUR requires the length of surface casing to be no less than 10% of the total

depth of a well. This same study mentions that Minister's Order AM-2014 is even more precise and specifies that in the case of stratigraphic surveys performed on Île d'Anticosti, such casing must exceed the depth corresponding to the aquifer base by at least 30 meters.

Given that the lower limit of aquifers is often not accurately defined and freshwater aquifers are largely unknown and generally difficult to delineate (GTEC02, "Risks" component), particularly their maximum depth, in addition to the opinion of Study GTEC03, the authors of the "Good Practices" component of Study GTEC02 believe that surface casing depth should take into account these uncertainties, as in Minister's Order AM-2014, and also consider the risk of encountering losses of circulation in the first 350 meters below the surface.

### **Well design and construction (casing cementing and valuation)**

For casing, the role of cement is to ensure wells are leaktight so that aquifer formations are protected (isolated) from potential contamination. Cementing also helps prevent casing corrosion. The cement used during hydrocarbon exploration and extraction is customized to the type of formation, temperature, depth, completion technique, etc.

With regard to this activity, the authors of Study GTEC03 suggest applying API Recommended Practices (RP) 10 and 65 and AER Directive 09: Casing Cementing Minimum Requirements because the guidelines they provide are the most comprehensive and the most appropriate in the industry for cementing methods.

The "Good Practices" component of Study GTEC02 reports that in Québec, circulation losses are often recorded in the first 350 meters below the surface. The authors believe that this shallow interval may require special measures to control losses, such as partial cementing of the interval before resuming drilling. The same applies to slightly overpressure or underpressure intervals that may be encountered at a greater depth. This practice may help reduce the risk of leaks or subsequent migrations by isolating problematic intervals for the first time very early on in the drilling process and then a second time during installation and cementing of the casing planned for drilling.

The authors also point out that the quality of control logging results may be affected by the presence of low-permeability intervals such as shale. They therefore believe that special care must be given to the quality of recording and analyzing such logs. The Interim Guidelines on Oil and Gas Exploration (Guidelines) produced by MDDELCC mention, like the RRPNGUR, that companies must perform control logging. This practice should be encouraged and systematically adopted when necessary, particularly for wells intended for hydraulic fracking and production.

### **Drilling fluids**

Drilling fluids are compounds used during drilling to cool and lubricate the drill bit. After reaching the drill bit, the fluids generally come back up to the well surface, where the drilling waste (solid and liquid debris) can be removed. The "Drilling waste management and disposal" section of this chapter deals with this aspect. Drilling fluid is also used to maintain sufficient pressure in the well to prevent penetration of other fluids (hydrocarbons and formation waters). The volume of fluid that comes back to the surface

is monitored and if an increase or decrease in volume is observed, drilling fluid density or viscosity or both are adjusted. There are various types of drilling fluids, which are classified according to their main composition: water-based, waterless, and gas.

Each type is associated with a specific function and performance. A number of substances are found in drilling fluids, and their concentration varies according to the geological context of each well. When work is completed, drilling waste is recovered for processing. According to the literature review on the environmental impacts of hydrocarbon development in Québec, produced by the Centre for the Life Cycle of Products, Processes and Services (CIRAIG, 2014), the substances used in drilling fluids are:

- Simple substances
- Water
- Barite
- Calcium carbonate
- Bentonite
- Sawdust
- Limestone
- Potassium silicate
- Sodium hypochlorite (bleach or NaOCl)
- Lignite
- Bicarbonate of soda
- Sil Soap
- Calcium nitrate
- Polymers
- Magnafloc 24
- Biocide
- Drillpac LV/HV polymer
- SAAP
- MF-VIS-TM
- MF STAR TM
- MF-PAC-R TM
- Hyperdrill AF 247RD
- DefoamX
- Aqua Star
- TKPP
- MF RIGMATE TM
- MF Silfloc
- 

Water-based drilling fluids are the most commonly used because they have a minimal impact on the environment and can be easily processed before being discharged or reused for further drilling. However, for more difficult drilling situations (e.g., reactive shale intervals that swell upon contact with water, deep wells, and horizontal wells), water-based drilling fluids do not always provide optimum performance. Hydrocarbon-rich formations may not be compatible with water, and drilling fluid may enter the formations and block the path of the hydrocarbons sought. In these specific cases, companies use primarily oil- or hydrocarbon-based drilling fluids. These types of drilling fluids are more efficient but must be handled and managed more carefully. This aspect is addressed later on in this chapter in the “Flowback water reuse, management, and disposal” section.

With specific regard to drilling fluids, the authors of Study GTEC03 suggest applying *API RP 13: Specification for Drilling Fluids – Specifications and Testing* because it is widely followed by all the reference authorities in terms of drilling fluids and respects the environment.

**The authors of the “Good Practices” component of Study GTEC02 also mention that in Québec, the Guidelines address drilling fluids and the products and by-products brought to the surface (drilling waste). This aspect is addressed later on in this chapter in the “Flowback water reuse, management, and disposal” section.**

In addition, the Guidelines recommend encouraging the use of surface water or water unsuitable for human consumption as a water supply for drilling activities.

## Liquid blowout prevention and control system

To ensure the safety of people and property and protection of the environment during hydrocarbon exploration and excavation, it is necessary to prevent liquid influxes and blowouts, even with continuous adjustments of drilling fluid density and viscosity, by using a well pressure control system. Fluid influxes in wells can occur during drilling when the pressure on the fluid in the geological formation is higher than the pressure generated by the column of drilling fluid from a neighboring geological formation. A blowout is an uncontrolled flow of fluids from a reservoir (water, oil, or gas) toward a drilling well, whether or not such fluids reach the surface.

AER Directive 036: Drilling Blowout Prevention Requirements and Procedures and API RP 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells should be taken into account because they are a reference for a number of authorities for blowout prevention systems (GTEC03, Malo et al., 2015).

For Québec, the “Good Practices” component of Study GTEC02 notes that even if severe overpressure is not documented or anticipated in the structures examined in Eastern Québec, slightly overpressure and underpressure intervals may alternate in the same well. The authors of this study believe that the provisions of the RRPNGUR currently in effect with regard to blowout prevention systems, combined with the general opinion stated above, are sufficient to cover this type of risk.

## Wellhead

A wellhead is composed of a series of valves and pipes used to control pressure. A wellhead can also be equipped with a “Christmas tree,” i.e., an assembly of valves that help control hydrocarbon production or fluid injection.

During drilling operations, pressure is controlled by drilling fluids and the blowout preventer, a main component of the blowout prevention system. Throughout drilling the design of the wellhead changes, and once well completion work is finished, the wellhead helps control the pressure of fluids (saltwater, frac flowback water, hydrocarbons, etc.) coming out of the well. The wellhead may be used, for example, to control the injection of gas or water into a well that is not in production in order to increase the hydrocarbon production rate in other wells. It also allows a mechanism to be installed to perform logs or corrections. When wells are brought into production, the wellhead valves are opened and hydrocarbons are allowed to flow through the production tube.

For the wellhead, it is recommended that API RP 6A: Specification for the Wellhead and Christmas Tree Equipment be followed because it is the recommended practice most followed in this regard by the reference authorities (GTEC03).

## Pressure and leak testing

A well pressure test consists of establishing the resistance of a geological formation to pressure and the maximum permitted pressure that can be used during drilling to prevent drilling fluid from leaking into neighboring formations and damaging them.

With regard to the leaktightness of cement and casings, logging is generally used to verify well integrity. This work is performed during well cementing operations. After cementing, pressure tests help ensure the integrity of the work, the rocky formation, and various assemblages.

For pressure and leak testing, it is suggested that the directives proposed by the AER be followed because they are a reference for most of the authorities:

- Directive 017: Measurement Requirements for Oil and Gas Operations
- Directive 005: Calculating Subsurface Pressure via Fluid-Level Recorders
- Directive 034: Gas Well Testing, Theory and Practice
- Directive 040: Pressure and Deliverability Testing Oil and Gas Wells

The authors of the “Good Practices” component of Study GTEC02 mention that the history of data collected during drilling operations for a given sector helps optimize drilling parameters so that the hydrocarbon reservoir and its cap rock, if any, are not damaged. For sectors for which there is still little data, the authors believe that fluid pressure profiles and maximum injection pressures would be better known if pressure tests were systematically performed on formations during initial exploratory drilling. Formation pressure test results should be standardized and included in the drilling completion reports required under the RRPNGUR.

### **Drillstem testing**

When the presence of hydrocarbons is detected during drilling, drillstem tests can be performed along the interval where hydrocarbons were located. Such tests are performed using devices known as packers to isolate an interval, collect samples, and measure certain general parameters, including the type of hydrocarbons and the formation’s pressure and permeability, rendering it possible to make a summary assessment of the interval’s production capacity.

For drillstem testing, it is suggested that the AER’s practices be followed, particularly Directive 040: Pressure and Deliverability Testing Oil and Gas Wells and Directive 036: Drilling Blowout Prevention Requirements and Procedures, which are the most recent directives in this regard (GTEC03).

The “Good Practices” component of Study GTEC02 mentions that there may be traces of H<sub>2</sub>S in Québec. The authors believe that during drillstem testing, H<sub>2</sub>S should be included in the analysis of gas samples. In their opinion, this is not an atypical situation and in its present form, the RRPNGUR, combined with the opinion of Study GTEC03, are sufficient to cover this type of risk.

With regard to the objectives of drillstem tests, because they are used to acquire knowledge for the purposes of detecting the presence of a hydrocarbon reservoir and do not involve injecting fluids into geological formations, the authors of the “Good Practices” component of Study GTEC02 believe that this activity should be permitted during stratigraphic surveys.

### **Well deviation control**

Deviated or horizontal wells offer more production potential than vertical wells. The trajectory of a horizontally deviated well may be defined according to its inclination, depth, and azimuth. According to the convention of use, a 0° angle corresponds to a vertical well and a 90° angle corresponds to a horizontal well (IHS Engineering 360, 2005). Generally a well is said to be horizontal when the angle formed by the well and

the vertical exceeds 80°. After reaching a 90° angle, some wells may be drilled upwards. During horizontal drilling, measuring instruments record the borehole trajectory in real time. These instruments measure the borehole's inclination and azimuth. With a series of measurements at appropriate intervals (between 10 and 150 meters), the borehole's trajectory can thus be tracked.

We should point out that the trajectory of a well may be deviated because of a dip in geological layers and the orientation of structures. In such case, measuring the well trajectory at regular intervals during drilling helps anticipate this situation and gradually correct the well trajectory so that it follows the drilling program.

Due to the large number of horizontal wells drilled in Alberta and British Columbia, it is suggested that the regulations of these authorities regarding well deviation control be followed (Alberta's Regulation 151/71 and British Columbia's Regulation 282/2010) (GTEC03, Malo et al., 2015).

The "Good Practices" component of Study GTEC02 reports that in certain sectors studied in Québec, the change in well trajectory due to a dip in geological layers and the orientation of structures may be pronounced right from the surface. This so-called natural deviation may be anticipated up to a certain point by taking into account previous drilling data and seismic profiles, but this information still leaves room for uncertainties, particularly in highly tectonized regions like Gaspésie and Bas-Saint-Laurent.

Loss of control of the trajectory of exploratory drilling or drilling is not a risk per se because the consequences are essentially limited to potential cost overruns for the developer or the risk of missing its target.

However, more serious consequences could result in the long term in the event that several nearby wells are present in the same structure.

Even in highly tectonized environments, the trajectory may be easily controlled, provided that the problem has been anticipated and the necessary equipment is available. A deviation survey should always accompany the drilling completion report. With regard to deviation surveys, the authors feel that the current specifications under the RRPNGUR are sufficient.

### **Perforation prevention and control**

Following casing cementing, geophysical logging, and pressure, leak, and drillstem testing, perforations can be made through the casings and cement to establish a connection between a well and rocky formations at the intervals identified during drillstem testing. This activity may be a prerequisite for injectivity testing, fracking, or extraction or production testing. Depending on the characteristics of the environment, such perforations can be made using explosive charges.

For perforations, it is suggested that API RP 19B: Evaluation of Well Perforators be applied. It presents the methods for evaluating perforation systems based on various conditions of use (variable temperatures and pressures).

The authors also suggest using API RP 90-2: Annular Casing Pressure Management for Onshore Wells, which addresses the use of explosive charges during this type of activity. It presents recommended practices for the transport and onsite handling of explosives and the selection of perforator types (fire perforating guns or bullet

perforating guns). Types of equipment to be used at the surface and at the well bottom are also presented. The API recommends that staff who handle explosives on site have the necessary qualifications and are properly trained (GTEC03).

### **Injectivity testing**

Injectivity testing helps establish the flow rate and pressure at which fluids can be injected to determine a geological formation's capacity to absorb fluids or measure the pressures at which the geological formation fractures. The most widely used injectivity tests are the pressure fall-off test (PFO), diagnostic fracture injection test (DFIT), and fluid efficiency test (FET). These last two tests help establish the fracture parameters to be used to optimize hydrocarbon recovery in a reservoir with low permeability. It should be noted that the injection pressure used during injectivity testing differs significantly from the pressure at the well bottom due to the variation in fluid density and friction loss along the casing.

With regard to injectivity testing, Study GTEC03 recommends following Alberta's Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements, particularly Appendix 3, which provides step-by-step details on the injectivity test procedure and the maximum pressures that can be used for the wellhead (90% of the fracture pressure or the cement integrity pressure).

In Québec, injectivity testing does not require an environmental certificate of authorization if the volume of fluid used totals less than 50 m<sup>3</sup>. The Water Withdrawal and Protection Regulation (WWPR) establishes this threshold because activities requiring a total of less than 50 m<sup>3</sup> of fluid correspond to preliminary investigations that pose no environmental risks as the volumes injected are too small to have a real impact.

### **Fracturing stimulation**

In hydrocarbon exploration and extraction, "stimulation" is the general term for processes used to increase the permeability of the rocks surrounding wells and therefore the quantity of hydrocarbons recovered. Increased permeability improves fluid circulation. Stimulation of a hydrocarbon well through hydraulic fracturing is a physical process. It may be carried out with high or low fluid volumes. The difference between high volume hydraulic fracturing and low volume hydraulic fracturing is the amount of fluid used.

In Québec, high volume hydraulic fracturing is currently defined as an activity requiring more than 50 m<sup>3</sup> of fluids. Companies wishing to conduct hydraulic fracturing with more than 50 m<sup>3</sup> of fluids must obtain a certificate of authorization prior to conducting such work. In comparison, in New Brunswick high volume fracturing is defined as an activity that requires over 1,000 m<sup>3</sup> of fluids in any single stage.

A number of types of fluids can be used for fracturing, including water, liquefied (gelled) propane, or CO<sub>2</sub> combined with chemical additives. Injection of these fluids under pressure causes the formation of fractures in rock and increases its permeability. This increased permeability is preserved by also injecting a proppant consisting of sand or ceramic materials to keep fractures open when the pressure used for fracturing is released.

Water combined with chemical additives is the most commonly used fracking fluid for hydraulic fracturing. In the case of natural gas extraction in source rock deposits, horizontal drilling and the hydraulic fracturing techniques are used together to optimize hydrocarbon recovery.

The composition of fracturing fluids depends largely on the type of geology and the characteristics of the deposit. The chemical additives used vary from one well to the next. For exploration on Île d'Anticosti, it was necessary to identify the list of chemical additives that could be used as fracking inputs among those on the list established in 2013 during SEA work dealing with shale gas.

According to available information, the chemical additives used during hydraulic fracturing intended for liquid hydrocarbon extraction (oil) require the use of the same chemical additives as those used for gas hydrocarbons (natural gas). Study AENV12 (Centre d'expertise en analyse environnementale du Québec, 2015) helped identify 48 other compounds in addition to the 62 already identified during the SEA on shale gas.

The list of the 110 compounds likely to be used as chemical additives during fracturing activities and their Chemical Abstract Service (CAS) identifiers are presented in Table 36.

**Table 36 Chemical compounds likely to be used as chemical additives during fracturing activities**

Compound		CAS identifier	Use
English name	French name		
Acetaldehyde	Acétaldéhyde	75-07-0	Corrosion-inhibiting agent
Acetone	Acétone	67-64-1	Corrosion-inhibiting agent
Acetic acid	Acide acétique	64-19-7	Scale preventative
Fumaric acid	Acide fumarique	110-17-8	Gelling agent
Tall oil acid or fatty acids	Acide d'huile de tall	61790-12-3	Corrosion preventative
Formic acid	Acide formique	64-18-6	Acidifying agent
Sulfamic acid	Acide sulfamique	5329-14-6	Corrosion-inhibiting agent
Alcohol	Alcool	—	Oil well processing compound
n-butyl alcohol	Alcool n-butylique	71-36-3	Solvent
Ethoxylated alcohols, C14-15	Alcools éthoxylés, C14-C15	68951-67-7	Corrosion preventative
Ethoxylated alcohol, C12-15	Alcools éthoxylés, C12-C15	68131-39-5	Reflux stimulator
Ethoxylated alcohol, branched	Alcools éthoxylés, ramifiés	78330-19-5	Anti-emulsifier
Alkyl alkoxyate	Alkoxyates d'alkyle	—	Oil well processing compound
Alkenes, C>10 alpha-	Alpha-alcènes, C > 10	64743-02-8	Corrosion preventative
Nitrilotriacetic acid trisodium salt monohydrate	Amino triacétate de sodium	18662-53-8	Iron-sequestering agent
Acetic anhydride	Anhydre acétique	108-24-7	Fluxing agent
1,2-Benzisothiazol-3(2H)-one	1,2-Benzisothiazol-3(2H)-one	2634-33-5	Biocide

Compound		CAS identifier	Use
Cocamido propyl betaine	Bétaïne de cocamidopropyl e	61789-40-0	Clay and pH controlling agent, surfactant
1-Bromo-3-chloro-5,5-dimethylhydantoin	1-bromo-3-chloro-5,5-diméthylhydantoïne (BCDMH)	16079-88-2	Biocide
Butoxy ethanol	Butoxy éthanol, 2-	111-76-2	Acidifying agent
Carbonic acid, dipotassium salt	Carbonate de potassium	584-08-7	pH controlling agent
Carboxymethyl hydroxypropyl guar gum	Carboxyméthyl d'hydroxypropyl e gomme de guar	68130-15-4	Gelling agent
Carboxymethyl guar gum	Carboxyméthyl gomme de guar	39346-76-4	Interrupting agent
Hemicellulase enzyme	Cellulase	9012-54-8	Interrupting agent
Chlorine	Chlore	7782-50-5	Stimulation fluid
Carboxymethyl hydroxyethyl cellulose	Cellulose de Carboxyméthyl hydroxyéthyl éther	9004-30-2	Gelling agent
Hydroxylamine hydrochloride	Chlorhydrate d'hydroxylamine	5470-11-1	Corrosion-inhibiting agent
Octadecanamine, N,N-dimethyl-, hydrochloride, 1- (1:1)	Chlorhydrate de N,N-diméthyl octadécylamine	1613-17-8	Surfactant
Sodium Chloroacetate	Chloroacétate de sodium	3926-62-3	Biocide
1-(3-chloro-2-propenyl)-3,5,7-triaza-1-azoniatricyclo[3.3.1(3,7)] decane chloride	Chlorure de (chloro-3 propenyl-2(z))-1 triaza-3,5,7 azoniatricyclo-1 decane[3.3.1(3.7)]	51229-78-8	Biocide
Ammonium chloride	Chlorure d'ammonium	12125-02-9	Scale preventative
Trimethyloctadecyl ammonium chloride	Chlorure d'ammonium triméthyl d'octadécyle (ammonium quaternaire)	112-03-8	Surfactant
Choline chloride	Chlorure de choline	67-48-1	Clay controller
Hydrochloric acid	Chlorure d'hydrogène	7647-01-0	Acidifying agent
Complex alkylaryl polyo-ester	Composé d'acide gras et	68188-40-9	Corrosion preventative

Compound		CAS identifier	Use
	d'huile de tall		
Acrylamide copolymer	Copolymère d'acrylamide	38193-60-1	Friction reducer
Acrylamide copolymer	Copolymère d'acrylamide et d'acrylate	—	Oil well processing compound
Didecyl dimethyl ammonium chloride	Chlorure de didécyl diméthyl ammonium	7173-51-5	Biocide
Tetramethyl ammonium chloride	Chlorure de tétraméthyl ammonium	75-57-0	Clay controller
Tributyl tetradecyl phosphonium chloride	Chlorure de tributyl tétradécyl phosphonium	81741-28-8	Biocide
Zirconium hydroxy lactate sodium complex	Complexe de zirconium d'hydroxy lactate de sodium	113184-20-6	Crosslinking agent
Cumene	Cumène	98-82-8	Solvent
Benzene sulphonate derivative	Dérivé de sulfonate de benzène	147732-60-3	Additive for acid
Benzenesulphonic acid, C10-16 alkyl derivatives	Dérivés d'acide benzosulfonique, C10-16	68584-22-5	Additive for acid
Quaternary quinoline derivatives	Dérivés de quinoline	72480-70-7	Corrosion preventative
Dibromoacetonitrile	Dibromoacétonitrile	3252-43-5	Biocide
Dibromo-3-nitrilopropionamide, 2,2-	Dibromo-3-nitrilopropionamide, 2,2-	10222-01-2	Interrupting agent
Diethanolamine	Diéthanolamine	111-42-2	Interrupting agent
Ammonium difluoride	Difluorure d'ammonium	1341-49-7	Biocide
Naphthalene bis(1-methylethyl)	Di-iso-propylnaphthalène	38640-62-9	Solvent
N,N-dimethylformamide	N,N-diméthylformamide	68-12-2	Corrosion-inhibiting agent
Octadecanamine, N,N-dimethyl-, 1-	Diméthyl octadécylamine, N,N-	124-28-7	Surfactant
3,5-dimethyl-tetrahydro-1,3,5-thiadiazine-2-thione (Dazomet)	3,5-diméthyl-2h-tétrahydro-1,3,5-thiadiazine-2-thione	533-74-4	Biocide
1,4-Dioxane	1,4-Dioxane	123-91-1	Solvent
Propylene glycol	Dipropylène glycol	25265-71-8	Reflux stimulator
Distillates, petroleum, hydrotreated light	Distillats de pétrole	64742-47-8	Friction reducer, thickener

Compound		CAS identifier	Use
Sodium erythorbate	(C9-C16) (2x) Érythorbate de sodium	6381-77-7	Iron-sequestering agent
Fatty acid esters	Esters d'acides gras	91744-20-6	Friction reducer
Complex polyamine salts	Ethanediaminiu m,N1,N2-bis [2-[bis(2-hydrox yethyl)methylam monio]ethyl]-N1, N2-bis (2-hydroxyethyl) -N1,N2-dimethyl -,chloride (1:4), 1,2-	138879-94-4	Clay controller, pH reducer, buffer, surfactant
Ethanolamine	Éthanolamine	141-43-5	Scale preventative
Ethylamine	Éthylamine	75-04-7	Crosslinking agent
Ethyloctynol	Éthyl-1-octyn-3- ol, 4-	5877-42-9	Anticorrosion
Ethylene glycol	Éthylène glycol	107-21-1	Enzyme breaker
Formaldehyde	Formaldéhyde	50-00-0	Scale preventative, corrosion preventative, acidifying agent
Formamide	Formamide	75-12-07	Acidifying agent
Glutaraldehyde	Glutaraldéhyde	111-30-8	Biocide
Glycol	Glycol	—	Oil well processing compound
Glyoxal	Glyoxal	107-22-2	Crosslinking agent
Guar gum	Gomme de guar	9000-30-0	Gelling agent
Xanthan gum	Gomme de xanthane	11138-66-2	Gelling agent
Ethoxylated castor oil	Huile de ricin éthoxylée	61791-12-6	Reflux stimulator
	Huiles de base de faible toxicité	—	Anti-emulsifier, interrupting agent
Sodium hydroxide	Hydroxyde de sodium	1310-73-2	Stimulation fluid
2-hydroxyethyl cellulose	2-Hydroxyéthyle cellulose	9004-62-0	Gelling agent
Hydroxypropyl cellulose	Hydroxypropyl cellulose	9004-64-2	Gelling agent
Hydroxypropyl guar gum	2-Gomme du guar hydroxypropylée	39421-75-5	Gelling agent
Sodium hypochlorite	Hypochlorite de sodium	7681-52-9	Anti-emulsifier, stimulation fluid
Sodium lauryl sulfate	Laurylsulfate de sodium	151-21-3	Surfactant
Limonene, d-	Limonène, d-	5989-27-5	Reflux stimulator

Compound		CAS identifier	Use
Methanol	Méthanol	67-56-1	Corrosion preventative, acidifying agent
1-methoxy-2-hydroxypropane	1-Méthoxy-2-hydroxypropane	107-98-2	Solvent
Naphthalene	Naphtalène	91-20-3	Corrosion preventative
Polyethylene glycol-(phenol) ethers	Nonyl phénol éthoxylé	9016-45-9	Surfactant
Octamethylcyclotetrasiloxane	Octaméthylcyclotétrasiloxane	556-67-2	Anti-emulsifier
Ethylene oxide	Oxyde d'éthylène	75-21-8	Biocide
Ammonium persulfate	Persulfate d'ammonium	7727-54-0	Interrupting agent
Sodium persulphate	Persulfate de sodium	7775-27-1	Anti-emulsifier
Tributyl phosphate	Phosphate de tributyle	126-73-8	Anti-emulsifying agent
Polysaccharide blend	Polysaccharide (Mélange de)	—	Thickener
Propylene glycol	Propane-1,2-diol	57-55-6	Reflux stimulator
Propylic alcohol	Propane-1-ol	71-23-8	Corrosion preventative
Isopropanol	Propane-2-ol	67-63-0	Corrosion preventative, anti-emulsifier, reflux stimulator, acidifying agent, stimulation fluid
Propanediaminium-2-substitued, - hexaalkyl-, dihalide, 1,3-	Propanediamine -2-substitué,-1,3-di-chlorure d'hexaalkyle	—	Clay stabilizer
Propargyl alcohol	Prop-2-yne-1-ol	107-19-7	Corrosion preventative
Pyridinium	Pyridinium	16969-45-2	Corrosion-inhibiting agent
Oxyalkylated alkylphenol	Résines alkyphénoliques oxyalkylées	68891-11-2	Anti-corrosion acid
Boric acid sodium salt	Sel sodique de l'acide borique	1333-73-9	Crosslinking agent
Heavy aromatic Naphtha	Solvant Naphta aromatique lourd	64742-94-5	Corrosion preventative, acidifying agent
Tetrakis (hydroxymethyl) phosphonium sulfate	Sulfate de tétrakis (hydroxyméthyl) phosphonium	55566-30-8	Biocide
Zirconium sulfate	Sulfate de zirconium	14644-61-2	Crosslinking agent
Terpenes	Terpène	—	Oil well processing compound
Sodium tetraborate decahydrate	Tétraborate de sodium décahydraté	1303-96-4	Crosslinking agent
Zirconium tetranitrate	Tétranitrate de zirconium	13746-89-9	Crosslinking agent
Thiourea polymer	Thiourée	68527-49-1	Corrosion preventative

Compound		CAS identifier	Use
	(Polymère de)		
Triethanolamine	Triéthanolamine	102-71-6	Anti-emulsifier
Triethylene glycol	Triéthylène glycol	112-27-6	Reflux stimulator
Trimethylbenzene, 1,2,4-	Triméthylbenzène, 1,2,4-	95-63-6	Corrosion preventative
Sodium xylene sulphonate	Xylène sulfonate de sodium	1300-72-7	Surfactant
Triethanolamine zirconate	Zirconate de triéthanolamine	101033-44-7	Crosslinking agent
Zirconium complex	Zirconium, complexe de-	197980-53-3	Crosslinking agent
<b>Other compounds (U.S. EPA, 2015a)</b>			
Potassium hydroxide	Hydroxyde de potassium	1310-58-3	
Sodium chloride	Chlorure de sodium	7647-14-5	
Ethanol	Éthanol	64-17-5	
Citric acid	Acide citrique	77-92-9	
Phenolic resin	Résines phénoliques	9003-35-4	

Although this list presents all additives that have been identified in the United States for fracturing activities since 2005 (all types of hydrocarbons combined), it should be noted that recent lists provide roughly 40 of the most commonly used compounds. The United States Environmental Protection Agency (U.S. EPA) has also published its own index of compounds used in the United States based on 36,000 information disclosures (U.S. EPA, 2015a). By standardizing the nomenclature, the U.S. EPA has provided information on the number and quantity of individual compounds used by state and by well type.

### Fluids and chemical additives for Anticosti

Work under the AKAP “Environment” component (Study AENV12) helped identify the 20 most frequently reported additives in the information provided for oil wells in the United States (U.S. EPA, 2015a). The additives presented in Table 25 (Chapter 3) could therefore be used during hydraulic fracturing activities on Île d’Anticosti.

With regard to volumes injected during hydraulic fracturing stimulation, the authors of Study GTEC03 (Malo et al., 2015) suggest using the term “fluid volume” in the RRPNGUR to avoid being limited to water volume and thereby excluding hydraulic fracturing operations conducted with other fluids. This volume must also be defined for each well and not by fracturing stage in the same horizontal (or vertical) well.

Furthermore, the authors believe that the RRPNGUR should include a specific license for high volume hydraulic fracturing, in addition to the one for well completion. An application for such license should be accompanied by a fracturing operations plan including the following:

- Surface water and groundwater use and wastewater management plan (transport, handling, storage, and disposal)
- Disclosure of additives used
- Assessment of risks associated with handling additives in frac water and a management plan for such risks
- Creation of a reference database on the composition of surface water and groundwater before fracturing, i.e., a database establishing the “zero” or initial state
- Testing program to ensure well integrity
- Pressure monitoring program during fracturing operations
- Fluid volume measuring program during operations
- Geological analysis of existing data on the nature of faults and natural constraints (geological hazards)
- Digital model of the geomechanics of fracturing (fracture formation)
- Post-fracturing tracking and verification program
- Induced seismicity risk assessment, a monitoring program if there is a risk, and mitigation and response measures
- Post-fracturing report comparing the results obtained with the anticipated results

Notwithstanding the foregoing, the authors of the “Good Practices” component of Study GTEC02 mention that the Guidelines and the WWPR provide details on a series of guidelines and regulatory requirements that are based on the API Guidance Document HF1 for engineering aspects and govern most hydraulic fracturing operations in Québec. They suggest harmonizing the RRPNGUR with the Guidelines, WWPR, and opinions formulated in this section. Furthermore, the authors of the study believe that the risk associated with induced seismicity must also be taken into consideration in the case of faults and natural fractures (see GTEC02, “Risks” component).

It should be noted that the Guidelines recommend using surface water or water unfit for human consumption as sources of water for fracturing.

### **Stimulation techniques other than by fracturing**

Hydrocarbon well stimulation by acidization is a chemical process that uses injection pressures and volumes substantially lower than those of physical processes.

This method is the most widely used after physical processes (hydraulic fracturing). Stimulation using acid consists of injecting a reactive acid (hydrochloric or acetic) into a reservoir rock to increase its porosity and permeability, thus improving the hydrocarbon recovery ratio. For example, in sandstone formations, the acid reacts with carbonate to increase their porosity. In carbonate formations, the acid can completely dissolve areas in the formation by creating conductive channels that make it easier for hydrocarbons to flow up through the well.

For information on stimulation techniques other than by fracturing, the authors of Study GTEC03 suggest consulting the API Briefing Paper on acidization. This

document discusses the factors that need to be considered to protect the environment during this type of procedure. Most reference authorities trust this document for stimulation techniques other than by fracturing that employ chemical processes.

### **Extraction and production testing**

In Québec, the RPGNRS differentiates between extraction and production tests. The first are conducted during the exploratory phase on a well when drilling is carried out in accordance with a license. And production tests are mentioned when drilling is done for a well in development or production, that is to say when the well is drilled under an oil and natural gas production lease.

To conduct an extraction or production test, various pieces of equipment must be installed on the site, including a separator to process the hydrocarbons recovered, a tank to store the liquids recovered, and a gas flaring system. The tests consist of measuring, at specific intervals, the flow of hydrocarbons produced by the well and the corresponding pressure change in the producing area. The extraction and production tests can be completed through an open hole or perforations, injectivity tests, or physical or chemical stimulation. Flow and pressure change analysis is used to calculate the area's production potential. The data collected will be used as input for the deposit's economic assessment.

The authors of Study GTEC03 suggest using the Alberta Energy Regulator's Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting for extraction and production tests because this activity concerns hydrocarbon recovery and the proper environmental management of hydrocarbons, especially natural gas.

Just as for drillstem tests, the authors of the Study GTEC02 "Best Practices" component are of the opinion that even though Québec's geology is not conducive to the presence of H<sub>2</sub>S and the current data confirms that this gas is extremely rare, H<sub>2</sub>S should still be included in the analysis of gases sampled during extraction and production tests.

As in drillstem tests, the current RPGNRS provisions in effect, in combination with this advice, are sufficient to cover this type of risk.

### **Leak and migration monitoring**

Some steps require special monitoring to detect leaks or migration, such as during the well drilling phase, particularly once the casings are installed and are being cemented. As mentioned earlier, pressure and leak tests must then be done.

Leak and migration monitoring must also take place during the well completion phase, when hydraulic fracturing occurs. During this phase, the well and reservoir must be monitored continuously to adapt work to changes in conditions and prevent potential leaks and migration.

Generally, a monitoring system includes:

- A system of valves for isolating different areas based on the results of the production tests or the gas/oil ratios
- Sensors recording the pressure, fluid flow, and temperature in the well
- Control lines for all sensors for the transmission of data recorded downhole

- A control unit at the surface to process the information and control the system drilling fluid injection valves

Continuous monitoring is commonly used for drilling, fracturing, maintenance, or correction operations. It is an asset when managing well operations because it enables workers to carry out quick, targeted actions in the event of leaks or migration.

We suggest following the continuous monitoring practices associated with each activity that takes place during the life of a well (design, casing installation, cementing, production testing, closure, and so on) that were developed by Alberta and British Columbia. The following directives and guides set precise surveillance requirements:

Directive 017: Measurement Requirements for Oil and Gas Operations

Directive 040: Pressure and Deliverability Testing Oil and Gas Wells

- Directive 044: Requirements for Surveillance, Sampling, and Analysis of Water Production in Hydrocarbon Wells Completed Above the Base of Groundwater Protection
- Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements (Alberta)
- British Columbia Oil and Gas Commission (BCOGC): Measurement Guideline for Upstream Oil and Gas Operations, 2013
- COGC Well Testing Requirements, 2015

Regarding Québec, the Study GTEC02 “Best Practices” component states that hydrocarbons (more rarely H<sub>2</sub>S) can be present in their natural state near the surface in fresh water aquifers. These hydrocarbons can be confused with those from leaks or migration from drilled wells or mix with them. It is therefore important to fully understand the initial composition of the groundwater in hydrocarbons before drilling (zero state). The authors of the study are of the opinion that the prior definition of this zero state and the creation of a reference database would enable workers to document the presence of hydrocarbons in their natural state in fresh water aquifers and help them determine the exact cause, nature, and extent of potential contamination so the proper corrective measures could be applied.

The authors also suggest considering the presence of closed wells (temporarily or permanently) nearby when establishing zero state for a new drilling site. When these old wells have not been closed properly, the leaks or migration emanating from them should be taken into consideration when developing corrective measures.

Furthermore, the Guidelines and WWPR clarify the procedure for establishing a site’s zero state, as well as the surveillance and detection of potential leaks or migrations. These documents, combined with the advice stated in this section, should enable legislators to update the RPGNRS.

Based on the same study, the authors are of the opinion that the environmental monitoring imposed by the WWPR once work is completed, Minister’s Order AM-2014, and the RPGNRS should, at the very least, be made consistent. For instance, the WWPR stipulates that groundwater monitoring must be conducted during the temporary closure period of the well and the 10-year period following permanent closure. Minister’s Order AM-2014 states that monitoring must be done for five years after the sealing of a stratigraphic survey, and the RPGNRS provides for an annual inspection report when a well is closed temporarily.

Finally, the authors believe the supervision period after the permanent closure of a well should be adjusted based on the characteristics of the well, its history, and the local geology. Québec remains largely unexplored, and the exploratory drilling that will be done, outside of a few structures discussed here, will not result in discoveries every time. In cases where the drilling of a well does not lead to the discovery of hydrocarbons at depth, the well should not be monitored as long as a production well stimulated by hydraulic fracturing.

### **Corrective measures**

The chapter on hydrocarbon exploration and extraction states that gas leaks are the most likely event to require corrective measures. These leaks are categorized by the flow and composition of the gas detectable at the surface at the surface casing vent. For many reference authorities, a gas leak is considered serious if there is a risk of fire, danger to public safety, or ecological damage. In Alberta, when a leak exceeds 300 m<sup>3</sup> per day, it is considered serious and requires corrective measures by companies.

If leaks occur, certain servicing operations (i.e., well maintenance or repairs) can be carried out. Most of the time, they involve removing and replacing the production casing using a service platform, installing mechanical packers, or injecting cement to correct defective cementation of the annular space.

In terms of the corrective measure to be taken for leaks, Study GTEC03 (Malo et al., 2015) suggests following Enform's Primary and Remedial Cementing Guidelines. For gas leaks, we propose referring to the Canadian Association of Petroleum Producers (CAPP) practices, Management of Fugitive Emissions at Upstream Oil and Gas Facilities and Update of Fugitive Equipment Leak Emission Factor, which are the highest standards in the industry.

The "Best Practices" component of Study GTEC02 points out that Québec's guidelines are limited to establishing thresholds when corrective measures must be implemented. The technical aspects of such measures are left to companies' discretion. The corrective measures in the RPGNRS are incorporated in a well conversion license and handled the same way. There are no technical directives specifically about corrective measures in the Guidelines or the RPGNRS.

Yet this is not an obstacle to the application of corrective measures because their implementation is often tailored to each case and may take some time when the source of the leak cannot be determined with precision. The authors believe that the process may be facilitated when the isotopic signature of the leaking gas can be compared with the signature present at different intervals in the reservoir and its cap rock. Teams should be encouraged to conduct isotopic analyses at regular intervals during drilling for all new structures or explored regions.

Moreover, the authors are of the opinion that the previous definition of zero state and the creation of a reference database, as proposed in the previous section, would help determine the exact nature and extent of any contamination and choose the most appropriate corrective measures.

It must be mentioned that Section 230 of the Mining Act enables the Minister, when an emanation of natural gas threatens to cause personal injury or property damage, to order the person responsible for the emanation to do what is necessary to remedy the situation or, if there is no other solution, to seal off the source of the emanation. If the person responsible fails to comply with the Minister's order within the prescribed time,

the Minister may have the work done or the source of the emanation sealed off at the expense of the person responsible

### **Onsite hydrocarbon processing**

Hydrocarbon production often involves various gases and formation water that must be separated from the hydrocarbons. This step, which is necessary during drilling, extraction testing, production testing, or during production, is completed on site using a separator.

A separator is a vertical or horizontal vessel that separates oil, gases, and water. Separators can be classified as:

- Two-phase (for the separation of oil and gas)
- Three-phase (for the separation of oil, gas, and water)

They can also be classified based on their operating pressure:

- Low, between 10 and 180 psi
- Medium, between 230 and 700 psi
- High, between 975 and 1,500 psi

Inside the separator, gravity causes the fluids to separate since the heaviest liquid falls to the bottom of the vessel. The degree of separation between the gas and the liquids will depend on the supply pressure, the residence time of the mixture, and the type of flow. A turbulent flow makes separation into different phases more difficult than laminar flow.

For onsite hydrocarbon processing, we suggest Québec's regulation draw from the API's standards in Spec 12J: Specifications for Oil and Gas Separators. Onsite hydrocarbon processing using a separator is needed to properly classify the hydrocarbons recovered, ensure the safety of people and property, and protect the environment. API's Spec 12J is the standard most commonly used by reference authorities.

### **Surface equipment management**

One of the two objectives of Study GTEC04 (Malo et al., 2015) is to compile and establish best practices for surface equipment management for onshore work.

Surface equipment management refers to the handling of equipment used on the surface during drilling and completion, including fracturing, correction, surveillance, closure, equipment dismantling, rehabilitation, and site restoration, in order to protect people, property, and the environment. Surface management of products needed for subsurface operations—for instance, managing products on the surface that are used as inputs when creating fracturing fluids—is also part of surface equipment management.

Drilling site managers must take steps to prevent contaminants from migrating from the surface into the underlying soil and groundwater during hydrocarbon exploration and extraction. Many reference authorities require that companies submit the blueprint of the proposed drilling site (e.g., dimensions, type of backfill that they are considering using) to the regulatory body for consideration and approval before site construction begins.

The transportation, transfer, and storage of fluids and solids associated with hydrocarbon exploration and extraction involve spill risks. These may be limited by stringent practices, use of aboveground tanks for liquid storage, the installation of equipment that limits liquid migration in the event of a spill, such as tanks, as well as the installation of membranes under equipment and under onsite backfill.

Although the Alberta directives are, on the whole, very general in terms of surface equipment management, they are the most comprehensive guidelines on the topic. For this reason, the authors of Study GTEC04 submit them, including Directive 036 – Drilling Blowout Prevention Requirements and Procedures—which describes equipment and its minimum spacing, as well as the procedure to follow during hydrocarbon exploration and extraction—as reference material. It also covers management of onsite hydrocarbon-based fluids.

With regard to the transportation, transfer, and storage of fluids and solids associated with hydrocarbon exploration and extraction, the authors of Study GTEC04 are of the opinion that AER Directive 055: Storage Requirements for the Upstream Petroleum Industry is the most complete document on surface storage of products used during drilling and is the reference document for this topic. The authors also mention that, for multiwell pads with high volume hydraulic fracturing, the water destined for fracturing can be transported using dedicated aqueducts in order to reduce road traffic.

More specifically, the study on evaluating the environmental hazards of wastewater discharge (after treatment) in aquatic environments on Île Anticosti (AENV11 [Cloutier, 2015]) states that using an impermeable membrane on site minimizes the impact of leaks.

### **Drilling discharge and water management and disposal**

The second objective of Study GTEC04 is to compile and determine the best practices for managing and disposing of drilling discharge. The authors define drilling discharge as all residue from drilling activities, such as drill cuttings (solid residue) and liquid residue made up of saline formation water and wastewater from drilling fluids (drilling mud), excluding flowback water produced during hydraulic fracturing.

Drilling discharge consists mostly of drilling mud from drilling. Drilling fluids are thus a drilling input and drilling mud, an output. Consequently, the composition of drilling mud (output) is inextricably linked with the composition of drilling fluids (input).

As mentioned in a previous section, water-based drilling fluids are most commonly used because they have a minimal impact on the environment and, as a result, are easier to treat before they are disposed of or reused for other drilling. However, when drilling circumstances are more difficult (e.g., reactive shale intervals, deep wells, and horizontal wells), water-based drilling fluids do not always yield good drill performance. In these cases in particular, drill operators generally use more effective oil- or hydrocarbon-based fluids, which must be handled with extreme caution. This makes managing such fluids more demanding.

Drilling mud is made up of a number of substances. It usually contains water and the synthetic products shown in the section on drilling fluids. Their concentration in the mud varies considerably from one operator to another. During work, mud is often reconditioned and reused, and at the end of work, it is recovered for treatment.

Drilling mud is not usually considered “hazardous,” and in certain places, the solid portion (cuttings), which is high in calcium carbonate, is reused via landspreading.

On the subject of drilling mud management and disposal, the authors of Study GTEC04 suggest using the BCOGC’s Oil and Gas Handbook Drilling Waste Management Chapter and the AER’s Directive 050: Drilling Waste Management to protect people, property, and the environment.

More specifically, the study on the assessment of the environmental risks of wastewater disposal (after treatment) in aquatic environments on Île d’Anticosti (AENV11 [Cloutier, 2015]) reports that drilling discharge needs to be stored, handled, and transported in such a way that the natural environment will not be contaminated by runoff or infiltration. All tanks, leak containment systems, and basins must be impermeable and designed according to recognized practices. They must effectively meet storage needs while withstanding the stresses to which they will be subjected.

In Québec, MDDELCC defines drilling discharge as any solid or liquid substance, excluding final effluent, discharged by drilling activities, including wastewater and drill cuttings. The environmental requirements for drilling mud management appear in Section 2.4.7 of the guidelines:

- Drilling mud must be characterized to determine the proper management method. This characterization is used to verify whether the residue is incorporated in a hazardous material or has the properties of a hazardous material under the Regulation respecting hazardous materials. The document Normes pour classer les résidus de forage pétrolier ou gazier en vertu du Règlement sur les matières dangereuses clarifies the parameters that must be adhered to for such residue to be considered non-hazardous residual material.
- The developer must comply with the residual material management plan established according to the principles of reduction, reuse, recycling, reclamation, and disposal. Residues deemed non-hazardous that are intended for elimination must be handled in compliance with the Regulation respecting the landfilling and incineration of residual materials. If non-hazardous residues are reclaimed off-site, a specific certificate of authorization must be obtained from MDDELCC. While firms are waiting to reclaim or eliminate residues, it must be stored in impermeable basins. Residual hazardous materials must be managed, stored, treated, transported, and permanently disposed of in compliance with the Regulation respecting hazardous materials (CQLR, Q-2, r. 32). No site on Île d’Anticosti is authorized to receive residual hazardous materials.
- Information on the quantities of drilling residues generated and their final destination must be entered in the register. Before each shipment of residual material to an elimination or reclamation site, a characterization report must be sent to MDDELCC. This report must specify the selected management method and final destination. The data must be included in an annual report in compliance with the Regulation respecting hazardous materials.

Furthermore, Section 48.1 of the RPGNRS requires that drilling mud be deposited in an impermeable structure designed according to recognized practices during drilling. When drilling ends, the structure must be removed or dismantled and the drilling mud must be reclaimed or eliminated in accordance with the provisions of the Environment Quality Act and its regulations.

Lastly, Section 48 of the RPGNRS requires that the report submitted when drilling ends contain the types, quantities, and data sheets of products used in the creation of drilling mud.

### **Flowback water reuse, management, and disposal**

The third objective of Study GTEC04 is to compile and determine best practices for flowback water reuse, management at the surface, and elimination (disposal). The basic principle applied by all reference authorities studied consists of ensuring the safety of people and property and protecting the environment.

In this section, the term “flowback water” refers to the returning water containing the fracturing fluids and saline formation water that was already in the pores and fissures of the rock before fracturing. Flowback water is a product of hydraulic fracturing, and fracturing fluid is used during the process. The composition of flowback water (output) is therefore inextricably linked with the composition of the fracturing fluids (input), but unlike drilling fluids, these are transformed when used, particularly due to geology. Thus, by-products can form in the mixtures injected, and components can be released from the rock. Most reference authorities require flowback water to be collected, managed safely on the surface, and stored in closed tanks before being reused, if needed.

Like the reference authorities, the authors are of the opinion that reusing flowback water for subsequent fracturing is preferable in all cases, when possible. When flowback water is collected for reuse, it must be managed safely on the surface and stored in closed tanks as most reference authorities require.

Flowback water is known to have a high salt content and be slightly radioactive. Although the products used in hydraulic fracturing contain numerous substances deemed toxic and synthetic substances (see tables 25 [Chapter 3] and 36 [Chapter 4]), it is difficult to assess the actual effects of these substances, given their very low concentration (fracturing liquid is made up of more than 99% water and a proppant).

The following list contains the contaminants present in untreated flowback water and concentrations that exceed wastewater quality indicators:

- Total alkalinity
- Ammonia nitrogen
- Total Kjeldahl nitrogen
- Bromides
- Chlorides
- Conductivity
- Cyanides
- BOD5
- COD
- Fluorides
- SS
- Nitrates
- Nitrites
- pH
- Phosphorus
- Total dissolved solids
- Sulfates
- Sulfites
- Total sulfides
- Aluminum
- Silver
- Barium
- Beryllium
- Boron
- Cadmium
- Chromium
- Copper
- Iron
- Lithium
- Manganese
- Mercury
- Molybdenum
- Lead
- Selenium
- Strontium
- Thallium

- Zinc
- Benzene
- Benzo(a)pyrene
- Chloroethylene
- Dibromochloromethane
- Ethylbenzene
- Petroleum-derived hydrocarbons  
C10 - C50
- Naphthalene
- Anionic surfactants
- Tetrachloromethane
- Toluene
- 1,2,4-Trichlorobenzene
- 1,1,1-Trichloroethane
- 1,2,4-Trimethylbenzene
- Xylene
- Other VOCs and SVOCs
- Other HAPs
- Pentachlorophenol
- Total phenolic substances
- Radium 226
- Radioactivity (alpha and beta)  
(Bq/l)
- Naturally occurring radionuclides  
in the Th232 and U238 families
- Acute toxicity

Study GTEC04 gives two potential methods of flowback water disposal after the first use or subsequent reuse.

The first, and most common, practice is injecting this water into deep geological formations. This method is widespread in the United States and also used in Alberta and British Columbia. In Ontario, flowback water is considered industrial waste and thus cannot be injected into deep geological formations.

For surface management of flowback water before re-injection into deep geological formations, the authors of Study GTEC04 suggest applying the API's guidelines in Waste Management Associated with Hydraulic Fracturing and Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, which are the models that have inspired most North American authorities. Study GTEC04 suggests drawing on the EPA's Underground Injection Control (UIC) Program to regulate the disposal of flowback water in deep geological formations. This is based on the program's use in all American states that produce hydrocarbons and re-inject in deep geological formations, and the fact that the two Canadian reference authorities have drawn heavily from the EPA's UIC program for their respective regulations on this topic.

More specifically, the study on the assessment of the environmental risks of wastewater disposal (after treatment) in aquatic environments on Île d'Anticosti (AENV11 [Cloutier, 2015]) reports that wastewater, including flowback water and formation water that emanates from a well, need to be stored, handled, and transported in such a way that the natural environment will not be contaminated by runoff or infiltration. All tanks, leak containment systems, and basins must be leakproof and designed according to recognized practices. They must effectively meet storage needs while withstanding the stresses to which they will be subjected.

Moreover, the authors of Study GTEC04 take care to mention that, based on the information currently available in Québec, they cannot say that this method of eliminating flowback water can be used in Québec. Each site must be assessed based on its geology and production history.

The second practice cited in Study GTEC04 for flowback water disposal involves treating it in a facility.

As for surface management of flowback water before re-injection into deep geological formations, the authors of Study GTEC04 are of the opinion that the policies described

in the API's documents Waste Management Associated with Hydraulic Fracturing and Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing should be applied to surface management of flowback water before it is treated at a facility. Most authorities in North America have used these documents when creating their own policies.

Study GTEC04 proposes designing treatment facilities specifically for flowback water disposal.

As for surface management of flowback water before re-injection into deep geological formations, the author of Study AENV11 reports that wastewater, including flowback water and formation water that emanates from a well, must be stored, handled, and transported in such a way that the natural environment will not be contaminated by runoff or infiltration. All tanks, leak containment systems, and basins must be leakproof and designed according to recognized practices. They must meet storage needs effectively while withstanding the stresses to which they will be subjected.

Québec's environmental management rules for flowback water management are listed in Section 2.4.2 of the Guidelines and summarized below:

With the exception of the conditioning of wastewater for reuse by the developer, all wastewater pretreatment or treatment systems must be authorized in advance by MDDELCC. If wastewater and gas or oil runoff are treated on site, discharge into the aquatic environment must comply with certain requirements and be characterized in accordance with the monitoring program in Table 2 of the Guidelines. In addition, the developer must obtain environmental discharge objectives (EDOs) (MDDEP, 2008) specifically for its project. These EDOs, which are determined by MDDELCC, give a risk assessment for each discharge and serve to:

- Determine, when needed to protect the environment, final effluent discharge and monitoring requirements different from those stated in Table 1 of the Guidelines
- Promote the use of less toxic chemical products
- Determine the contaminants for which further treatment is needed
- Optimize the location of the final effluent spill point
- Promote more environmentally conscious practices

Acceptable treatment technology will have a discharge that complies with the discharge requirements in Table 1 of the Guidelines while coming as close as possible to the EDOs.

The Guidelines specify the monitoring parameters and frequency for final wastewater effluent in tables 1 and 2, and Appendix 14 describes the sampling method.

Specific information must be entered in the register for each drilling site. Thus, the date, origin, amount of water added, and amount and destination of the water removed must be recorded for each action that alters the liquid level in storage equipment. All gas and oil wastewater, as well as site runoff, if any, must be collected separately in leakproof equipment. The water should be transported through pipes as much as possible to reduce repercussions caused by trucking.

The volumes and characteristics of gas or oil wastewater treated and discharged on site or transported off site for treatment, as well as runoff discharged into the environment, must be compiled in a report sent to MDDELCC. Any exceedance of the requirements must be reported to MDDELCC immediately.

### **Temporary well closure**

A well is closed temporarily when drilling, completion, or alteration work is suspended with the intention of resuming at a later date. Closure consists of securing the site and well during the period of inactivity in order to protect property, people, ground- and surface water, air quality, and soil. The closure requirements may vary based on the type of well, geology, and the well's status before temporary closure.

For temporary well closure requirements, Study GTEC03 suggests following the AER's practices and those in Directive 013: Suspension Requirements for Wells or those in the British Columbia Well Completion, Maintenance and Abandonment, 2015 guide. These documents are proposed because of the quantity of wells drilled under the two reference authorities in question and their expertise in temporary well closure. The documents explain the equipment needed for well closure, monitoring and inspection requirements, inspection frequency, the necessary pressure tests, onsite fluid management, and the security measures that need to be taken around the site (e.g., visible and identified wellhead).

The authors of Study GTEC02's "Best Practices" component state that Québec's RPGNRS regulates the temporary well closure procedure in detail. Still, they are of the opinion that, during such closures, the preceding steps, notably those relating to casings, cementing, pressure and leak testing, and monitoring, should be taken into consideration in order to protect people, property, and the environment. In addition, temporarily closed wells should be monitored.

### **Permanent well closure**

The permanent closure of a well includes all the operations necessary for its permanent isolation. Whether it is because a well lacks production potential or because the reservoir is no longer producing, closure operations are a crucial step for the protection of property, people, groundwater, surface water, and air and soil quality. The proper procedure must be followed to effectively block hydrocarbons, formation water, and any other liquid from migrating into freshwater aquifers and to prevent hydrocarbons from flowing or migrating to the surface. Well closure generally consists of placing cement or mechanical plugs in the well at specific intervals in order to prevent fluid from migrating to the surface and maintain pressure inside the well.

Study GTEC03 suggests following the AER's practices and those in its Directive 020: Well Abandonment or the BCOGC's Well Completion, Maintenance and Abandonment Guideline, 2015. These best practices are recommended because of the quantity of wells drilled by these two reference authorities and their expertise in permanent well closure.

The authors of Study GTEC02 state in the "Best Practices" component that Québec's RPGNRS regulates the permanent well closure procedure in detail. Nevertheless,

without historical information, it is impossible to determine the potential risk caused by the degradation of a well's hydraulic isolation over many decades. To compensate for this lack, a cement curing test, conducted in a laboratory under the same conditions as those of the well (properties of the cement and the subsurface environment), could be used to determine the optimal monitoring period after permanent closure.

In addition, the authors of the study believe that, as for temporary well closure, the steps preceding permanent well closure (including those relating to casings, cementing, and leak and pressure testing) should be considered in order to protect people, property, and the environment.

### **Site restoration and rehabilitation**

Restoration encompasses all site rehabilitation activities completed to protect people, property, and the environment. These operations can begin before permanent well closure because part of the drilling site can be restored and rehabilitated after drilling and stimulation; however, site restoration and rehabilitation will end after the well is closed permanently. To manage this activity properly, a restoration plan is usually incorporated in work planning and must include activities like rehabilitation of contaminated soil, if any, and restoration of the land for another use. It must also include site monitoring to regularly check that the well is properly sealed and not emitting contaminants.

In Québec, site rehabilitation and well closure requirements are rather vague, and there is a real need for clear procedures and specific terms.

Given the quantity of wells drilled in Alberta and British Columbia and the expertise of the following reference authorities in site restoration and rehabilitation, the authors of Study GTEC03 are of the opinion that the AER's and BCOGC's rules are the best references on this topic. Furthermore, aspects that apply to site restoration and rehabilitation in the Québec mining industry could be adapted and used for hydrocarbons (e.g., requiring a company to submit a restoration plan and review it every five years, performance security).

### **Orphan wells**

An orphan well is a well with no legally or financially responsible party to manage well abandonment or site rehabilitation procedures. Study GTEC03 reveals that reference authorities have no specific technical requirements for orphan well management beyond financial considerations.

The authors' opinion on this subject is that the best practices for permanent well closure must be applied to these wells.

More than 950 oil or gas wells have been drilled in Québec since 1860. Of this number, some 700 are inactive, meaning they have been permanently closed and production is not possible. The "Best Practices" component of Study GTEC02 states that old wells, especially those located in Gaspésie, were closed according to improper practices that are no longer in use today and that some of these wells have caused oil to flow to the surface. Most of these wells have since been secured and closed properly through a permanent well closure program launched in the late 1990s. Additionally, the Québec government has inspected inactive wells since 2011. To improve this process and following on the May 30, 2014 release of the hydrocarbon action plan, the government

announced in October of the same year that it would implement a three-year plan to step up inactive well inspections. The particulars of this process are available on the MERN website.

#### **4.3.2 The marine environment**

From a geological point of view, Québec hydrocarbon research and development projects conducted offshore would all be located within one large geological region: the Gulf of St. Lawrence (see the index of geological regions). For the Technical Aspects theme, the marine environment concept consists of determining that these projects use the best practices for offshore hydrocarbon exploration and extraction outside Québec and for physical environments similar to Québec's.

The references retained to establish offshore best practices are Newfoundland and Labrador, the Canadian Arctic, and Norway. In addition to these regions, the best practices of two independent organizations—the Canadian Association of Petroleum Producers (CAPP) and the American Petroleum Institute (API)—were also studied.

From a technical point of view, it has already been determined as part of SEA2 that the Gulf of St. Lawrence is a special physical environment. As a result, it was deemed necessary to conduct studies to determine best practices for the region based on the unique geological risks of the Gulf of St. Lawrence and the Old Harry structure in particular.

#### **Physical considerations associated with the marine environment**

In Study GTEC07 (James et al., 2015), the authors are of the opinion that the ice and meteorological and oceanographic conditions in the Gulf of St. Lawrence pose an additional technical challenge for drilling work. Due to the environment in the Gulf, certain technical constraints must be met before drilling can be done because the work would be carried out in deep water and when ice could be present. This situation therefore affects the technologies, time of year, and options for potential development.

Nevertheless, the authors say that a number of companies specialized in drilling in conditions similar to the Gulf of St. Lawrence have developed technical expertise that takes into account the safety of people and property, environmental protection, and enhanced oil recovery. This expertise could be tapped to aid development in the Gulf. These companies are in Eastern Canada and other parts of the world where hydrocarbon exploration and extraction work occurs (e.g., Norway).

The authors of the study recommend continuing work (e.g., studies, analyses, compilations, assessments) to compensate for the lack of knowledge about the physical environment in the Gulf of St. Lawrence and to ensure that all suitable parameters are considered during potential hydrocarbon exploration and extraction in the region.

The additional work proposed to better protect people, property, and the environment and enhance oil recovery are as follows:

- A detailed study of what would be needed in the event of a spill, and suitable protocols and environmental measures
- A detailed study on the physical characteristics of the Old Harry sector
- A study on the impact of icebergs in the Old Harry sector

- A data analysis and compilation to assess the currents in the Old Harry sector
- A lifecycle analysis for all offshore hydrocarbon exploration and extraction activities
- An assessment of the constraints the presence of ice cover imposes in order to make the most of periods when drilling could occur
- An analysis and assessment of environmentally friendly fluids that could be used in drilling work
- Implementation of a long-term annual program for collecting data on the physical environment in the Gulf
- A detailed analysis of the freeze-up of the Confederation Bridge and the lighthouses around the Gulf of St. Lawrence in order to better predict how drilling platforms will respond to freezing spray
- An evacuation measures study
- A comprehensive study on icebergs (frequency and probability)

The authors of the study are of the opinion that, in order to optimize the protection of people, property, and the environment and enhance resource recovery:

- Those in charge of hydrocarbon exploration and extraction work must use Enhanced Oil Recovery (EOR) techniques
- Those in charge of hydrocarbon exploration and extraction work must make sure to apply the Improved Oil Recovery (IOR) process
- Best practices must be applied when designing wells and completing stimulation activities
- Additional space must be provided on drilling facilities
- Depths, ocean currents, and winds must be considered during initial planning for drilling facilities and work planning

The authors of the study conclude that it is possible to conduct hydrocarbon exploration and extraction in compliance with best practices, such as those currently used in the Grand Banks off Newfoundland, if the particular nature of the Gulf of St. Lawrence is taken into account. However, they remind readers that in-depth studies and other analyses on ice presence must be conducted first.

In Study GTEC09 (King, 2015), the results of the physical environment analysis for the Old Harry sector indicate that the prevailing winds are usually from the northwest. The strongest winds blow in December and January at an average 10.6 and 10.4 m/s, respectively. The maximum winds observed were 26.6 m/s.

We have noticed a similar trend for waves. Their maximum amplitude occurs in December and January, with an average height of 2.6 m at the most and maximum heights of 9.4 m. Generally, wave amplitude exceeds 4 m between October and April, except in winters with significant ice cover.

The results of the physical environment analysis for the Old Harry sector indicate that ocean currents flow mainly southeast. Deep down, the strongest currents are limited to the upper 50 m of the water column. On the surface, the average current speed is about 0.15 m/s, but at 50 m, it is no more than 0.05 m/s on average. The maximum current speed is 0.62 m/s on the surface and 0.45 m/s 50 m down.

The authors also assessed the risk of freezing spray formation. The season formation most likely begins in November and ends in April, peaking in January and February. At the height of the season, January has an estimated average of 13 days with a risk of light freezing spray, 6 days with a risk of moderate spray, and 1 day with a risk of harsher conditions. In February, an average 10 days were found to have a chance of light freezing spray, 5 days a chance of moderate spray, 2 days a chance of harsher conditions, and 1 day a chance of extreme conditions.

The information available on visibility conditions in the Old Harry sector indicates that, on a monthly basis, there are an average of roughly 20 hours of particularly reduced visibility (1 km or less). It is also highly likely that visibility will be less than 1 km between midnight and 1 p.m. in February and March.

Ice cover data (frequency, concentration, and type of ice) sheds light on existing conditions. Comparing the data over 10-year intervals tends to show that ice conditions are gradually becoming milder. For instance, in the past 10 years, there was no major ice cover for three winters, and cover over 90% of the study area was observed every other year. During this period, the average number of days with ice cover varied from 15 to 57.

Regarding icebergs in the Old Harry sector, the results indicate that the chances of seeing icebergs in this part of the Gulf are low. The author of the study states that icebergs have been seen in the Old Harry sector 24 times since the 17th century, with the last sighting in 1972. However, the author makes a point of clarifying that, unlike the Grand Banks sector, Old Harry is not monitored regularly for icebergs. Consequently, given the issues that even the occasional presence of icebergs creates for the protection of people, property, and the environment and enhanced oil recovery, this factor must be considered when planning and carrying out drilling in the Old Harry sector.

The results of the physical environment analysis for the Old Harry sector seafloor indicate that while the site is located in the Laurentian Channel, it is marked by a flat bottom with no pronounced relief. The channel's edges are located about 30 km from Old Harry. The substrate is made up of approximately 15 meters of unconsolidated sea mud (calcipelites) over a thin horizon of till.

The author of Study GTEC09 concludes it would be beneficial to carry out additional work (e.g., studies, analyses, compilations) to compensate for the lack of knowledge on certain aspects of the physical environment in the Old Harry sector. The additional work proposed to better protect people, property, and the environment and enhance oil recovery in the Old Harry sector is as follows:

- Analyze satellite data for a more complete picture of how often icebergs appear and the distribution, size, and thickness of pack ice
- Continuously measure the currents using a buoy recently placed in the sector (Buoy IML-10)
- Gather, compile, and update data on:

- Glaze and visibility
- Ice pack thickness and distribution
- The seafloor
- Loads that affect ice pack (using a platform)
- Carry out a preliminary analysis of the loads that affect ice pack, based on the information available

The Risks section of Study GTEC02 states that the information available on geological risks, particularly in the Old Harry site, is mainly geophysical or comes from the characterization of rock encountered during surveys of neighboring structures. The authors agree that the main geological risk is actually the lack of information because the Old Harry site has not been drilled. However, according to Study GTEC02, drilling completed in the St. Lawrence River Basin, near Anticosti, and in the Scotian Basin has not led to unforeseen geological risks. There is always some potential risk if there are natural fractures and faults, but it can be mitigated with an altered drilling program.

Although the depth of the water in the Old Harry sector (500 meters) is not a geological risk per se, the authors of Study GTEC07 stress that it should be taken into account in work planning. If drilling is authorized in the Old Harry site, best practices for deep water work should be applied. They also state that, depending on the literature consulted, deep water is defined as starting at 500 meters in some cases and at 600 meters in others.

### **Offshore seismic surveys**

The marine section of Study GTEC05 (Dupuis and Fillion, 2015) contains an overview of best practices for seismic data acquisition in the context of hydrocarbon exploration and extraction. The researchers considered Norway's and Canada's regulatory environments for the marine section.

The authors stress that, in Norway, the opening of a new offshore oil exploration sector is preceded by an assessment of the commercial, industrial, environmental, economic, and social impacts, as well as an evaluation of the pollution-related risks. This study is accompanied by a consultation whose administrative procedures are decided on separately. Operators are responsible for ensuring that surveys are carried out carefully and in a non-destructive manner. Receivers must be deployed in a way that will not interfere with fishing.

Three types of sources can be used: electric sources, pneumatic sources (compressed air gun), and explosive charges. Electric sources are most frequently used. The rules governing their use primarily concern worker safety and require properly grounded circuit breakers that are used only after being completely submerged.

The Statement of Canadian Practice with respect to the Mitigation of Seismic Sound in the Marine Environment describes procedures for minimizing the impact of pneumatic sources used during seismic surveys. This statement recommends, among other things, using the minimum amount of energy required and prescribes a series of measures to protect marine wildlife and endangered species. It also stipulates that a qualified observer and a security perimeter must be present. The user is also responsible for ensuring that equipment is in good working order. Use of explosive charges is subject to

the same rules as for onshore environments; there are no additional laws or regulations for offshore use.

## **Offshore drilling**

The purpose of Study GTEC06 (James et al., 2015) is to compile and establish best practices for offshore drilling. This work includes well drilling, completion with or without fracturing, different types of tests, corrective work, closure, facility dismantling, monitoring, and controls (during and after work) that must be completed by companies and lawmakers. Note that, for this study, legislative and regulatory frameworks and norms, directives, standards, and other documents that can be used to establish best practices were listed for each activity, while the authors give opinions by activity category. The opinions take into account Study GTEC02's "Risks" component and studies GTEC07 and GTEC09. Additionally, it is important to mention that unlike the onshore drilling section, this section does not put each activity into context because the objectives of each of these activities is the same for both offshore and onshore environments. However, offshore best practices must be determined because equipment, techniques, and technologies can differ from one environment to the next because of the unique physical characteristics of each one.

The various activities pertaining to offshore drilling are as follows:

### **Equipment selection**

- Equipment

### **Monitoring and control**

- Corrective measures
- Monitoring and control of leaks and migration
- Explosions
- Monitoring and control before, during, and after work

### **Fluids and solids management**

- Onsite hydrocarbon processing
- Drilling fluids
- Drilling waste management
- Water management
- Water reuse for subsequent fracturing
- Flowback water storage
- Flowback water disposal
- Produced water storage and disposal

### **Well development and completion**

- Well design and development
- Casing installation
- Casing cementation

- Wellhead
- Perforations

### **Well control**

- Location
- Blowout prevention system
- Fluid influx control

### **Tests**

- Pressure and leak tests
- Drillstem tests
- Injectivity tests
- Logging
- Directional surveys

### **Stimulations**

- Stimulation by fracturing
- Other stimulation methods

### **Closure**

- Temporary closure
- Permanent closure
- Facility dismantling

Generally, the authors of Study GTEC06 state that drilling regulations in effect in the Canadian Arctic, Newfoundland and Labrador, and Norway show numerous similarities. The regulatory environments of these three regions ensure the safety of people and property, environmental protection, and enhanced oil recovery. We also note that these regulatory regimes set safety objectives without specifying what methods must be used to achieve them. In order to understand the methods for achieving regulatory objectives, we must analyze the associated best practices

This governance mode reflects an objective-based approach. As a result, companies are responsible for ensuring the safety of people and property, environmental protection, and enhanced oil recovery. To attain these objectives, reference authorities use coercive measures in addition to ensuring best practices are implemented.

To introduce a new legislative and regulatory framework, the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB), Guidelines for Drilling and Production Activities, 2011, and the NORSOK standards used as a reference in the Norwegian guidelines are excellent models to follow. A study of these models shows that the NORSOK standards are generally much stricter than the C-NLOPB guidelines.

### **Equipment selection**

For equipment selection, the authors of Study GTEC06 consider the NORSOK standards to be an excellent reference. They govern most of the technical aspects of drilling equipment.

However, the authors are careful to mention that the NORSOK standards must be used with a degree of caution because they are not necessarily suitable for all scenarios for all physical environments or the latest technology.

According to the NORSOK D-010 standard, for example, deep waters start at 600 m irrespective of currents and potential forces acting on the marine riser system. The NORSOK D-001 standard states that the drilling equipment structure or fixed drilling unit must be designed to operate continually irrespective of the loads in an environment where winds can reach a speed of up to 30 m/s (108 km/hr.) for 10 minutes at 10 meters above the mean sea level. Table 2-1 of Study GTEC07 (2015) shows that extreme winds in the Old Harry area can reach 25 m/s and reached 25–30 m/s between 1954 and 2008 in the winter months (Stantec, 2013), whereas the wind speed to which the Grand Banks are exposed is higher.

Note that the API suggests adopting practices developed for ice and harsh environments. Even though exploratory drilling does not usually require the construction of mobile platforms, it may be helpful to be familiar with the criteria for selecting equipment suitable for the Gulf of St. Lawrence.

Thus, the authors are of the opinion that drilling equipment must be designed and selected for the physical environment where it will be used. In the Gulf of St. Lawrence, this includes rime, ice (if the drilling season coincides with the ice season), wind, currents, seafloor depth, and so on.

## Monitoring and control

The authors of the study are of the opinion that processes, activities, and equipment require continual monitoring to prevent, mitigate, correct, and be able to properly address any risks that might affect the safety of people and property and protection of the environment.

The authors believe that the HAZOP (hazard and operability study) method, one of the most commonly used methods for industrial risk analysis, is crucial. Furthermore, lessons learned from incidents that have taken place and those that could have been avoided must be taken into account and incorporated into the emergency plan.

The authors state that offshore drilling facilities should be designed to contain hydrocarbons, prevent their ignition, and allow for mitigation in the event of a fire. Potential dangers related to the safety of people and property and protection of the environment need to be addressed with preventative and corrective measures, if needed, and the emergency plan must also take these aspects into account.

The authors are also of the opinion that the systems required to ensure the safety of people and property and protection of the environment should have redundancy to still provide control and corrective measures if a failure occurs in a given system. Monitoring and control must be supported by independent, automated, and reliable (tested and maintained) systems.

Note that monitoring and control equipment includes physical components (parts) and procedures. There are numerous monitoring and control guidelines, standards, specifications, and best practices to draw from. Study GTEC06 lists these sources.

## Fluids and solids management

In order to explain fluids and solids management, some information from the SEAs' Environment theme has been included in this section. It puts the activities that generate fluids and solids into context to better understand the work and the opinions stated in Study GTEC06.

Oil and gas exploration produces residual materials in solid and fluid form (drilling mud). Drilling waste made up of cuttings and muds is the largest source of residual materials. During offshore drilling of the initial section of a well, waste is released directly onto the seafloor because the riser has not yet been installed at this stage.

Once the riser is in place, the waste is brought up to the drilling unit, and solid residues (cuttings) are separated from fluid residues (mud). While most of the mud is reused, mud-coated cuttings are discharged into the marine environment or disposed of on land.

The waste is made up of rocky debris extracted from the various geological strata encountered during drilling (cuttings) and fluids with a fresh or salt water, oil, or synthetic base, including certain additives. The additives in the fluid, their concentration in the waste, and the type of fluid used determine the potential environmental impact of this waste, as well as which management method should be used.

The volumes of drilling waste produced depend on the depth drilled. They vary from 1,100 to 2,000 m<sup>3</sup> for drilling with water-based fluids and 300 to 1,300 m<sup>3</sup> for synthetic-based fluids (Lee et al., 2011). In Canada and the United States, only waste consisting of water-based mud and synthetic-based mud can be disposed of in an offshore environment. Waste consisting of oil-based mud is generally injected into deep

geological formations or returned to shore, treated, and where appropriate, disposed of (Neff, 2005) given that it poses a risk for the environment.

Production water is generally separated on site during hydrocarbon extraction and processing on the platform. It is then discharged into the marine environment in accordance with certain limits. Treated water can also be reinjected into the deposit for secondary hydrocarbon recovery purposes or be disposed of in deep geological layers when regulations allow. Formation water can also be used for other purposes and reused onshore for industrial or agricultural purposes, for example. Onsite treatment is therefore contingent on its reuse.

Production water flow is very different depending on the type of hydrocarbon extracted (gas or oil). The volume of production water generated by natural gas extraction is, most of the time, much smaller than the volume generated by oil extraction. For an oil field with a number of active wells, the volume of production water generated can be thousands of cubic meters per day (Genivar, 2011).

Production water is composed primarily of contaminants originating from the geological formation, i.e., organic carbon, hydrocarbons, phenolic substances, salts, metals, and radioactive compounds (Lee et al., 2011), and frac water. The physical and chemical properties of production water vary according to the characteristics of the reservoir, the hydrocarbons extracted, and the additives added during hydrocarbon extraction and processing.

The composition of production water generated in gas fields is different from that generated in oil fields (Jacobs, Grant, Kwant, Marqueine, and Mentzer, 1992).

The BTEX content of production water in gas fields can be ten times higher than that in oil fields (Jacobs et al., 1992; Veil, Puder, Elcock, and Redweik, 2004). The pH of the water is also more acidic in gas fields (4.4 to 7 versus 4.3 to 10 for production water in oil fields). The amounts of chloride and ammonia nitrogen are generally much higher in the production water of gas fields.

Following onsite treatment and discharge into the marine environment, typical advection-dispersion, dilution, precipitation, adsorption, degradation, and volatilization processes take their course. These processes depend in large measure on the physical and chemical characteristics of the production water (flow, temperature, density, etc.) and the ambient conditions of the offshore environment. In general, dilution of a plume of contaminated production water offshore is quite quick a few hundred meters from the discharge point, with a dilution factor of 100 to 1,000 of the initial concentration (Bakke, Klungsoyr, and Sanni, 2013; Fraser et al., 2006).

Apart from production water, large quantities of ballast water and cooling water can be discharged into the marine environment by an offshore hydrocarbon exploration and extraction facility. Ballast water is used in particular for crude oil storage, the stability of the facility, or boat transportation. Ballast water used for crude oil storage consists of saltwater that may contain a certain amount of hydrocarbons when it is discharged into the marine environment. The volumes produced can be high and depend on the quantities of crude oil produced and transported.

Cooling water is used in the heat exchangers of offshore hydrocarbon exploration and extraction facilities, particularly to cool drilling mud or during natural gas compression for transport or injection. Seawater used as cooling water is generally treated with biocides to protect equipment from corrosion and the formation of biofilms, as part of it is discharged into the marine environment after use (purge). Cooling water discharges

contain various chemical products, including biocides (such as chlorine) with concentrations in mg/L, and their temperature is between 40°C and 45°C (Shah, 2013).

A certain amount of seawater and water from precipitation can seep or trickle into an offshore facility. Such runoff may be loaded with contaminants (hydrocarbons, glycol deicing agent, etc.) before it drains off into the marine environment. A distinction is made between bilge water, seawater that has seeped into an offshore facility, deck drainage, and seawater or water from precipitation that runs off the surface of a facility. The volume of surface runoff produced is generally smaller than the volume of cooling, ballast, or production water.

With regard to fluids and solids management during offshore drilling and completion, the authors of Study GTEC06 mention that for sound management of these activities, the overriding goal of the work performed during these two phases must be the safety of people and property and protection of the environment. The authors also specify that well integrity is the key determinant for limiting risks in fluids and solids management.

The authors believe that emission limits must be set and maintained at a minimum but achievable level based on work performance and that a results-based approach should be used.

The authors also believe that use of hydrocarbon-based drilling fluids must be limited and that sufficient quantities of products used to manufacture any type of drilling fluid must be available on the platform to limit the risks associated with their transport and handling. Special effort must be made to encourage use of fluids that have a minimal impact on the environment but do not compromise the quality of the structure (well integrity). Although drilling fluids may require reconditioning, the focus should be on reusing them. Disposal of drilling waste in the marine environment must be minimized. To this end, the company must be familiar with all other means of disposing of such waste and be subject to strict regulations that limit the volume that can be discharged into the environment.

Lastly, the authors believe that real-time monitoring of drilling fluids is essential so that those responsible for operations can be immediately informed of fluid losses in wells. Regulations should describe this process for risk prevention, detection, reporting, investigation, and rectification purposes.

In addition to the above, the authors of Study GTEC06 believe that a separate regulation for the processing of drilling and frac fluids is not necessary unless discharging them in deep geological layers is authorized.

### **Well design and completion**

In light of the elements identified in the comparative analysis on well design and completion, the authors of Study GTEC06 believe that obtaining a drilling or completion license should be subject to the presentation of independent studies on the seafloor characteristics and the geological risks that drilling entails.

### **Well control**

Study GTEC06 indicates that numerous guidelines, good practices, and standards have been formulated on well control since the Deepwater Horizon oil rig explosion that occurred in April 2010 in the Gulf of Mexico. Following the accident, much attention was paid to well control. Study GTEC06 shows that the requirements regarding this issue are similar with respect to API and ISO standards.

These requirements are as follows:

- A well must be controlled throughout its lifetime (i.e., during drilling, development, and production and after it is temporarily or permanently abandoned) by means of two separate mechanisms acting as a barrier.
- These mechanisms must be designed to withstand the maximum anticipated pressures.
- Relief wells are a priority and must be provided for in work planning.

The authors of Study GTEC06 believe that the mechanisms acting as a barrier are provided for in the initial work program. NORSOK standards should also be applied because they make it possible to obtain information in a standardized format that includes a technical drawing. The authors also specify that the mechanisms acting as a barrier must take safety into account in their design and operation. Among the mechanisms, use of obturators must be considered. Obturators must be operable in two different ways (e.g., remotely). Obturators used on the seafloor should be accessible to a remotely operated underwater vehicle. All pressurized equipment must be tested on an alternating, weekly basis. The authors point out that routine and maintenance tests on obturators are required to ensure work integrity and, by the same token, well integrity.

### **Testing**

The authors of Study GTEC06 feel it is important to perform leak tests to ensure the integrity of work, drillstem testing, and injectivity and extraction/production testing to accurately assess the potential and integrity of a geological formation.

The authors also feel that regulations on testing must be explicit, particularly with regard to the purpose of testing, and include a mechanism to transmit the information collected. It is equally important to know the real vertical depth of a well, measured from a known and clearly defined reference point.

Lastly the authors point out that the various types of tests are costly and unless they are regulated, companies may be less inclined to perform them properly and document them.

### **Stimulation**

The results of Study GTEC06 show that there are few regulations and guidelines on well stimulation using physical (fracking) or chemical (acidizing) methods during offshore hydrocarbon exploration and extraction. However, good practices regarding the basics to be observed are well documented, particularly compliance with the pressures used to maintain the integrity of a structure.

According to the authors, the NORSOK D-010 standard is appealing because it clearly introduces the notion of well stimulation.

Furthermore, the authors mention that in Newfoundland and Labrador and the Canadian Arctic, companies must hold a well conversion license to perform stimulation. To obtain such a license, they must show that the safety of people and property and protection of the environment are properly factored in.

The authors believe that this stimulation license is necessary because the pressures used are very different from the ones required for injectivity, extraction, and production testing, for example.

## Closures

Study GTEC03 describes three types of closures: emergency, temporary, and permanent closures. The first things to consider are well location, pressure control, and monitoring measures to ensure the safety of people and property and protection of the environment in the short, medium, and long term.

Regardless of the type of closure, the goal is to isolate geological formations containing hydrocarbons from water tables and the physical environment. To do this, a proper regulation must prescribe measures that can be adapted to the type of closure planned. The regulations in Norway and Newfoundland and Labrador on temporary and permanent well closures are similar. However, while Norway limits the duration of a temporary closure to two years, Newfoundland and Labrador imposes no limit but requires that well integrity be verified every three years. This approach is better adapted to sectors whose potential is still little known, because in such sectors more time may elapse between the exploration and extraction phases, unlike in Norway, where oil and gas fields are more mature and therefore better known.

With regard to permanent closures, all the authorities analyzed require the seafloor to be cleared. In the Canadian Arctic and in Newfoundland and Labrador, the purpose of this measure is to ensure the safety of any commercial activities, while in Norway it relates more specifically to fishing.

The regulations in Newfoundland and Labrador stipulate the depth at which casing must end below the seafloor surface so that a permanently closed well will not be subject to scraping by icebergs. With regard to well closures, the authors believe that although it is quite unlikely that such an event would occur in the Gulf of St. Lawrence, a clause requiring casings to end at a specific depth below the seafloor surface would be required, especially if wells are bored in shallow waters, to prevent risks associated with other human activities.

With regard to the procedures for permanent closure, the authors consider the API guidelines to be good references. However, if a regulation is desirable, the guidelines of the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) should be considered. Furthermore, the authors point out that monitoring of any abandoned well is important for ensuring well integrity in the short, medium, and long term and that monitoring data should be in the public domain.

## Inclusion of geological risks

Given the potential of the Old Harry geological structure, the “Risks” component of Study GTEC02 documented the potential geological risks associated with this structure. Because no drilling has taken place in this sector, the study indicates that the main risk factor is the lack of knowledge. However, the study shows that seismic surveys have been conducted in the Gulf of St. Lawrence, including the Old Harry sector, and that wells have been drilled in the St. Lawrence Basin and the Scotian Basin without any unexpected geological risk factors cropping up.

The authors of Study GTEC06 believe that to assess the geological hazards of this sector, in the event that a 3D seismic survey were conducted or an exploration well drilled in the Old Harry geological structure, it would be advisable to have the subsequent information analyzed.

Furthermore a number of geological and physical risks of potential hydrocarbon exploration and extraction (more specifically drilling and completion work) were studied by Corridor Resources. The environmental assessment report (Stantec, 2013) is an integral part of the drilling license application process for offshore license EL-55 issued by Newfoundland. The authors of Study GTEC06 believe that these reports, discussions, updates, etc. are a good reference for geological risk management.

Although the operational risks associated with seafloor depth are not a geological risk as such, the authors of Study GTEC06 believe that the depth of the seafloor, which is nearly 500 meters in the Old Harry sector, should be considered in work planning. Some studies define deep waters as waters where the seafloor is 500 meters below the surface, while other studies establish the threshold at 600 meters. Given that the Old Harry structure is located in the St. Lawrence Channel and that Study GTEC07 reports ocean currents in this sector, the authors think it would be necessary to study the combined effect of depth, ocean currents, and wind to adapt equipment and work methods to the specific conditions of Old Harry.

Furthermore, in the event that initial drilling and completion work were completed on the Newfoundland portion of the structure, the authors believe that it would be appropriate for Québec to access the information collected during this work so as to optimize the quality of work that could eventually be carried out on the Québec portion of the structure.

In conclusion, the authors mention that the comparative analysis made under Study GTEC06 helps identify major similarities between the various authorities analyzed. These authorities pursue a common goal, i.e., ensuring the safety of people and property, protection of the environment, and optimal resource recovery. The guidelines available from these authorities help determine how to meet this goal by referring to the industry standards and best practices adopted.

Because regulations provide for an objective-based approach for most of the authorities analyzed, companies are responsible for ensuring the safety of people and property, protection of the environment, and optimal resource recovery. However, specific standards and coercive measures have been established by the various authorities to meet these goals. With a view to implementing a new legal and regulatory framework, the authors feel the C-NLOPB guidelines are an excellent model to follow.

## 5. Economy

### 5.1 Scope

The Economy subcommittee's mandate is to assess how much we know about the costs and benefits of hydrocarbon development for Québec in general and for Île d'Anticosti in particular. Its purpose is also to study and estimate the economic impact that such development could have locally, regionally, and provincially.

The Economy subcommittee is also in charge of documenting the primary economic and financial aspects associated with hydrocarbon development so that the Québec government better understands the impacts and spinoffs that the industry (refineries, exploration, distribution, transport) is currently generating and that hydrocarbon extraction could generate.

Like with any industrial sector, there are numerous issues at play in hydrocarbon development, including royalties, economic spinoffs, social costs, jobs, and government income and spending, to name a few.

Most of these issues are general in nature, meaning they are virtually the same throughout Québec. Most of the economic studies were therefore conducted for the comprehensive SEA. Those for the Anticosti SEA were intended more to model plausible hydrocarbon development scenarios and assess their financial impacts and economic outcomes.

#### **Comprehensive SEA on hydrocarbons**

An initial knowledge acquisition phase took place in fall 2014 and winter 2015 as part of the comprehensive SEA on hydrocarbons. The SEA steering committee had the following economic objectives:

- Study the issues and impacts with regard to hydrocarbon development in Québec with a view to updating industry regulations, taxation, and governance for this industry
- Assess the economic costs and benefits of developing oil and natural gas sectors for Québec
- Document the spinoffs and what the oil and natural gas needs will be in future decades
- Document the known market potential of Québec's possible hydrocarbon resources and suggest what measures are needed to confirm this potential
- Compile best practices for sharing benefits with communities

Two knowledge surveys were established in Phase 1 of the SEAs:

- Gonzalez, P. et al., Bilan des connaissances de l'économie des hydrocarbures au Québec, Université Laval, 2015.
- Séjourné, S. and M. Malo, Géologie et potentiel en hydrocarbures des bassins sédimentaires du sud du Québec, Institut national de la recherche scientifique, Centre Eau Terre Environnement, 2015.

Issues associated with certain economic fields was found to be already well documented, including those concerning royalty systems and rent collection tools; local, regional, and global market knowledge; current knowledge of Québec projects and their potential; the level of industry development; the main principles of cost and benefit measurement; and ways to measure and value economic spinoffs.

Phase 2 of the SEAs produced specific knowledge about the hydrocarbon economy that did not emerge in the knowledge surveys. Seven studies were specified in the Additional Knowledge Acquisition Plan (AKAP) as necessary and are provided in Appendix 2.

Overall, economic issues were appropriately and fully addressed. Some aspects that the Economy subcommittee did not directly address were covered by others, like Society, or the transversal studies.

### **Anticosti SEA**

As part of the Île d'Anticosti SEA, the SEA steering committee had the following objectives for the Economy theme:

- Document the economic factors that typify the island; determine the primary issues and missing information
- Study the island's hydrocarbon potential, document its commercial viability based on current knowledge and its development conditions, including transport and the infrastructure needed for future operations
- Assess the resource's prospects given the remoteness, transport infrastructure, and lack of major users on the island
- Establish measures for maximizing local economic spinoffs
- Document the costs and benefits of hydrocarbon development

Two economic studies were conducted as part of the Economy20 theme and two others as part of the transversal theme for the Île d'Anticosti SEA (see Appendix 2).

This section covers development scenarios for hydrocarbon production and their financial and economic impacts, development of the economy and hydrocarbon expertise, economic issues, as well as needs to acquire additional knowledge about economic factors.

## **5.2 Hydrocarbon production development scenarios and their financial and economic impacts**

### **Anticosti**

Like any industry, hydrocarbon development creates labor needs as well as all kinds of infrastructure needs. It also has environmental, social, and economic impacts.

Development scenarios are a way to model and quantify with some degree of precision the repercussions and impacts that future hydrocarbon development could cause in terms of society, the environment, the economy, technology, and transport.

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<sup>20</sup> Studies AECN01 and AECN02 were combined in the same report.

To assess these impacts, hydrocarbon development scenarios were drawn up for Île Anticosti. They are based on plausible assumptions and show what deployment of platforms in the area could look like and how many wells could operate, as well as their locations.

These scenarios were also used to estimate what transport infrastructure would be needed. These needs are discussed in greater detail in Chapter 6 on transport. The scenarios also served to estimate hydrocarbon production levels and projected profitability (AECN01 and AECN02), which are provided later in this chapter and are based on additional cost and income assumptions.

Additionally, a cost-benefit analysis (Study ATVS02) encompasses both economic and financial aspects, but also takes social and environmental factors into account. This study's findings are given later in this chapter.

The scenarios developed for Île d'Anticosti are very detailed and have been developed and verified based on a number of sources. They take into account available assessments of potential hydrocarbon resources for Anticosti and known geological and geophysical characteristics.

In recent years, a variety of exploration and characterization work has taken place on the island. Based on available data, Sproule Associates estimated the potential hydrocarbon resources in the Macasty Formation at 43.6 billion barrels of oil equivalent<sup>21</sup> in 2011. However, this information alone was not enough for producing complete development scenarios.

To be able to develop such scenarios, a number of assumptions had to substitute for missing information, most based on geological equivalents and the opinions of experts. Much of the production information was derived from existing oil extraction operations in Ohio (Utica and Point Pleasant).

This process was feasible because of the relative geological simplicity of the Anticosti basin and because the data currently available is sufficiently detailed to complete such an exercise, notably because of the stratigraphic drilling program completed in 2015. The geology of extraction operations in Ohio is markedly more complex than that of Anticosti, particularly because of the networks of natural fractures and folding. The advancement of exploration and geoscientific knowledge acquisition may yield the data required to develop credible production scenarios for other basins in Québec.

A probabilistic financial model has been developed and tailored to assess the potential profitability of a hydrocarbon extraction project on Île d'Anticosti. It could be updated as new information becomes available.

However, it is important to note that even though the development scenarios and assumptions are considered plausible, they entail a degree of uncertainty. They must be interpreted as mere aids to estimating the potential impacts of future hydrocarbon development. The scenarios were also used as input in a number of companion studies conducted as part of the SEAs.

The scenarios were developed at a specific point in time based on the knowledge available at that time. They will change depending on the results of current and future exploration work (whether or not there are hydrocarbons), market conditions (resource price, equipment prices), technological advancements (extraction techniques,

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<sup>21</sup> For more information on hydrocarbon potential, see Séjourné, S. and M. Malo, M., *Géologie et potentiel en hydrocarbures des bassins sédimentaires du sud du Québec*, Institut national de la recherche scientifique, Centre Eau Terre Environnement, 2015. Note that potential resource assessments were also conducted by other firms.

machinery), resource prospects (domestic market, foreign market), legislation and environmental regulations (greenhouse gases, emission cap), promoters and their partners, and other factors.

The project promoters have not endorsed these scenarios. Rights and license holders are free to form their own development strategies, which could lead to a form of development different from that discussed in this section. The next step in development scenario fine-tuning consists of gradually replacing assumptions by real data as it becomes available.

### **Basic assumptions and platform deployment**

An initial scenario was developed at the beginning of SEA work in fall 2014. Called the “More” scenario, it was completed early in the winter of 2015 and served as the basis for launching all the companion studies for the SEAs in the AKAP.<sup>22</sup> A presentation on this scenario’s deployment in the field was given to Anticosti residents on May 7, 2015, and made public online on May 20, 2015.

- The “More” scenario concerns the largest area in terms of the zone that will be developed. Thus, using this scenario for companion studies leads us to anticipate the maximum conceivable impacts.

A second scenario was developed in winter 2015. Called the “Less” scenario, it is derived from the first scenario and based on the same deployment and development assumptions. The sole difference is that it covers a smaller area than the “More” scenario. This scenario was also presented to Anticosti residents on May 7, 2015, and made public on May 20, 2015. It is provided for information purposes and was not used for the companion studies.

A third scenario, the “Optimized” scenario, was developed in spring 2015. This scenario is a new version of the “Less” scenario developed in light of the new technical information obtained during SEA work on well productivity. The financial results in this section use this scenario.

The following are the basic assumptions for the scenarios:

- The development scenarios concern the operations stage, meaning they assume that commercially exploitable potential has been confirmed.
- The promoters have obtained all required government authorizations.
- Platforms for the oil and gas wells are introduced first in the northern part of the island (Jupiter sector). Since more is known about this area’s geology, it could be one of the best places to begin deployment. Furthermore, much exploration and geoscientific knowledge acquisition work has taken place in this area in recent years, and there are a number of access routes.
- The area showing extraction potential is free of regional and regulatory constraints, meaning regulatory restrictions (buffer zones), geological restrictions (Jupiter fault), and the areas residents use the most.<sup>23</sup>
- Development is progressive:
  - Platforms are built gradually over the first five years.

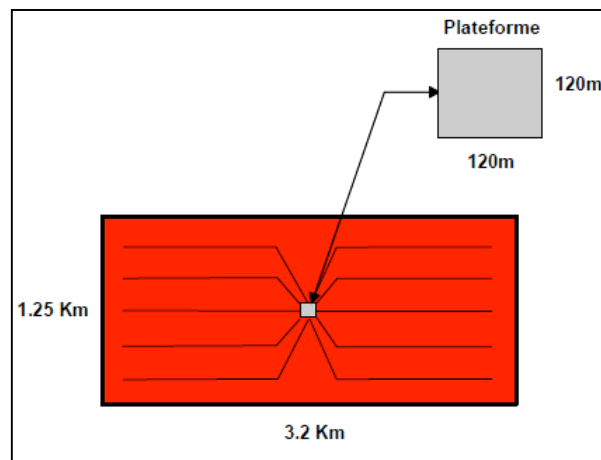
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<sup>22</sup> Excluding Study AECN02, which uses the “Optimized” scenario.

<sup>23</sup> Information on Île d’Anticosti’s land limitations is provided in Chapter 2 on the features of natural environments.

- The maximum number of new platforms built per year is reached by Year 6 of the project.
- Platform restoration begins in Year 26 of the project, when the reservoirs of the first wells are exhausted.
- The wells produce a mix of gaseous and liquid hydrocarbons (oil, natural gas, natural gas liquids).
- Production begins in 2020. This year is given for reference purposes only.
- All wells have a lifespan of 25 years.
- A platform has 5 or 10 wells.
- Platforms occupy a 120 meters x 120 meters area on the surface. The underground horizontal drains are 1,600 meters long, and the spacing between them is 250 meters. In total, a platform's underground coverage is 4 km<sup>2</sup>.
- When platforms stop producing, they are remediated. Equipment is dismantled, and the site is reforested and returned to its original state. Platform remediation requires less than a year of work.
- All extracted hydrocarbons are developed, meaning there is no burning.

**Figure 21 Dimensions of a platform with 10 wells and illustration of the underground impact of well drainage**



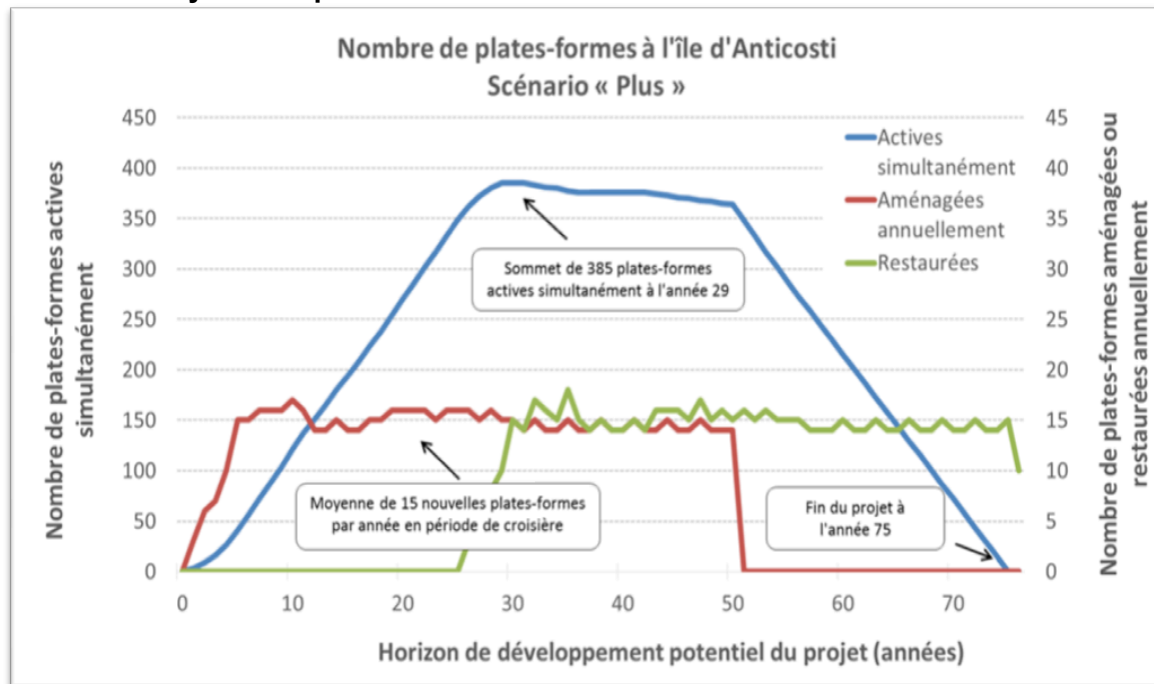
Note: The platform is the only portion visible from the surface.

## The “More” scenario

In this scenario, the zone with potential for hydrocarbon exploitation covers 47% of the island.<sup>24</sup> Once the current regulatory constraints (buffer zones, Jupiter fault, and the areas residents use the most) are taken into account, the zone occupies 34% of the area. This is the largest of the three scenarios.

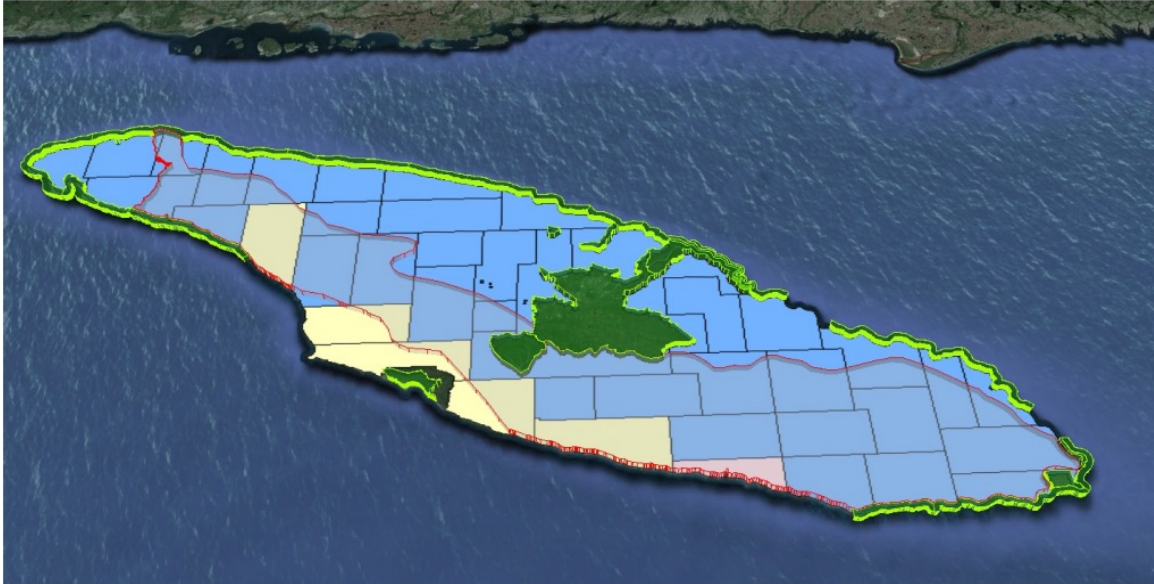
- Over 50 years, 712 platforms are built for a total of about 6,800 wells.
- In the maximum production period, an average 15 new platforms are built per year.
- There are never more than 385 platforms active at the same time for a total of 3,600 wells.
- The project lasts 75 years, since the wells are not all in production at the same time.

**Chart 1 Changes in platform construction and restoration on Île d'Anticosti over 75 years as part of the “More” scenario**



<sup>24</sup> As part of the financial evaluation, the development scenario area is expressed based on the area covered by the exploration licenses since the purpose of the financial evaluation is to calculate the profitability of hydrocarbon extraction in the area covered by the licenses and not on the entire island.

**Figure 22 Map of a potential development area that could be covered by the “More” scenario**



\* Green areas represent protected areas, which are excluded from the development zone.

\*\* Distribution of exploration license holders: blue = Anticosti Hydrocarbons L.P. licenses, yellow= Junex Inc., pink = TransAmerican Energy Inc.

### The “Less” scenario

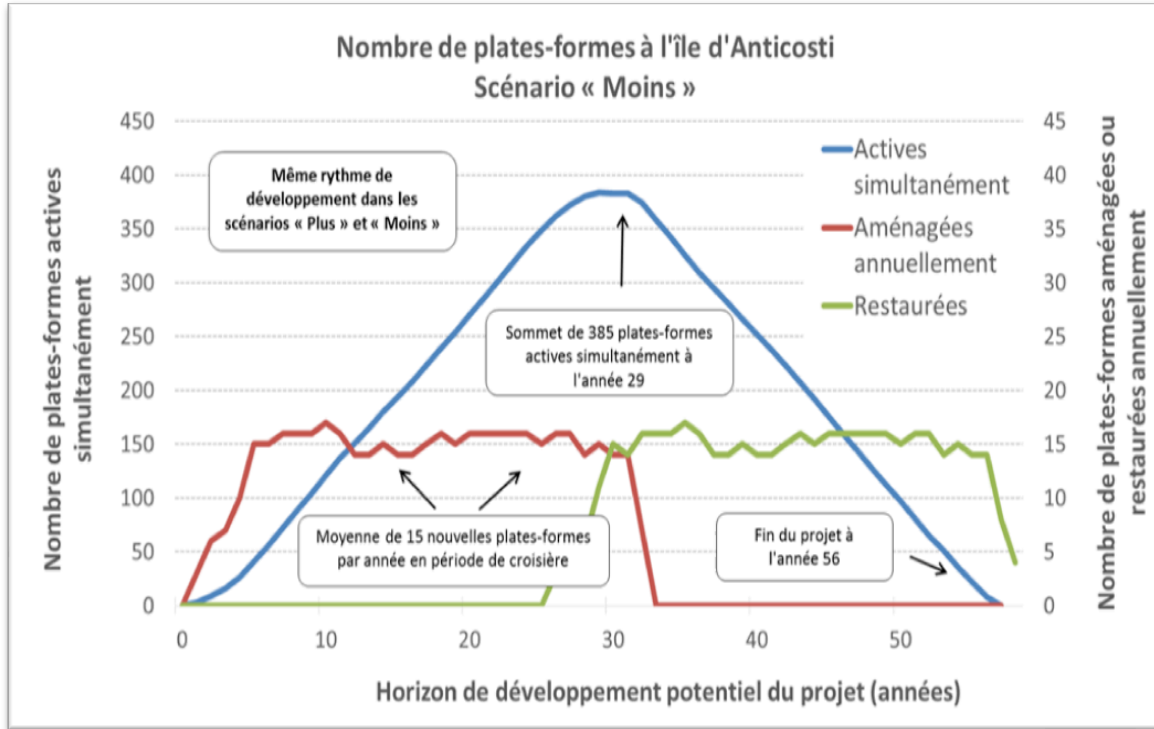
The “Less” scenario covers the same area with hydrocarbon potential as the “More” scenario except for a portion in the eastern part of the island that has been exempted because it may have less geological potential according to government data and present more environmental and technical complications, particularly because of the presence of wetlands.

This zone covers 30% of the island. Once the current regulatory restrictions (buffer zones, Jupiter fault, and the areas residents use the most) are taken into account, it occupies 21% of the total area.

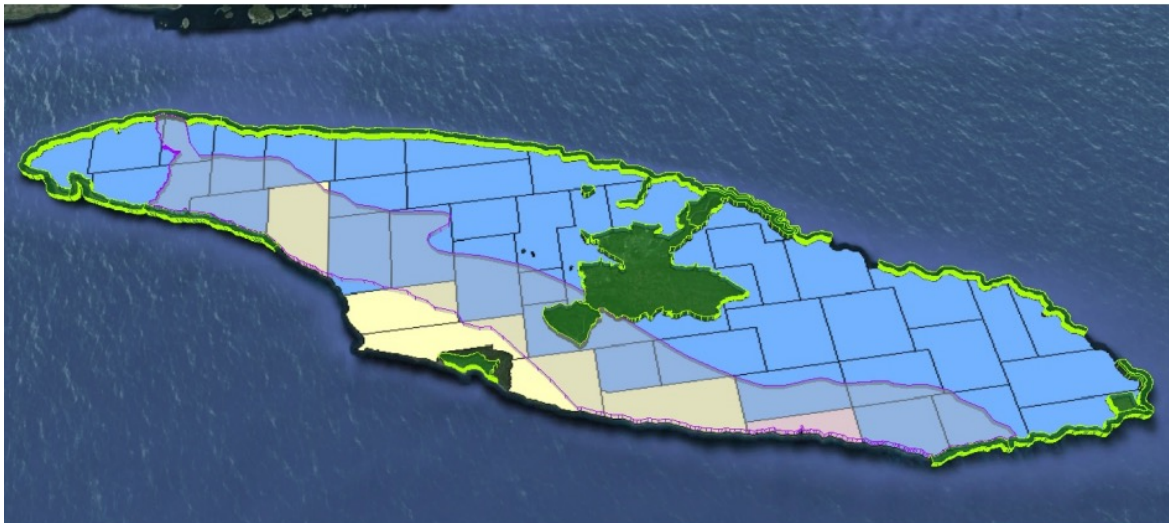
The speed of platform development and construction is the same as for the “More” scenario, but there are fewer platforms (and wells).

- Over 32 years, 445 platforms are installed for a total of about 4,155 wells.
- There are never more than 385 platforms active at the same time, for a total of 3,600 wells.
- The project lasts 57 years since the wells are not all in production at the same time.

**Chart 1: Changes in platform construction and restoration on Île d'Anticosti over 57 years as part of the "Less" scenario**



**Figure 23 Map of a potential development area that could be covered by the "Less" scenario**



\* Green areas represent protected areas, which are excluded from the development zone.

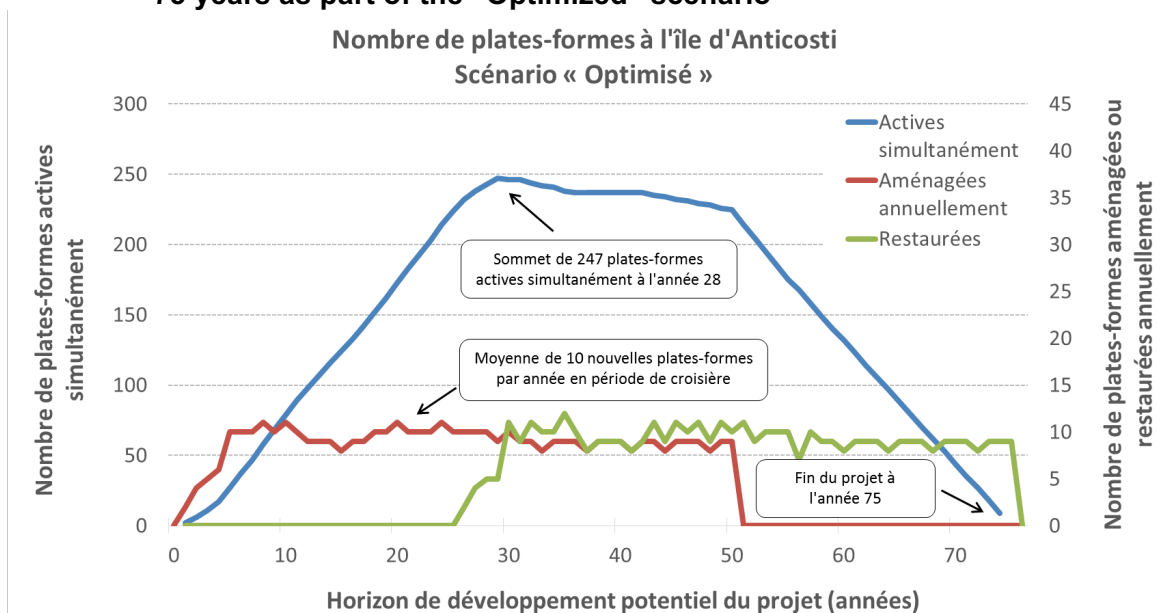
\*\* Distribution of the sectors occupied by exploration license holders: blue = Anticosti Hydrocarbons L.P. licenses, yellow= Junex Inc., pink = TransAmerican Energy Inc.

## The “Optimized” scenario

The “Optimized” scenario covers an area equal to that of the “Less” Scenario.

- The total number of platforms (and wells) is the same as for the “Less” scenario, except the speed of platform development is slower and thus extends over a longer period. At the height of development, an average of 10 new platforms are built per year.
- Over 50 years, 445 platforms are built for a total of 4,155 wells.
- There are never more than 245 platforms active at the same time for a total of 2,187 wells.
- The project lasts 75 years since the wells are not all in production at the same time.

**Chart 2: Changes in platform construction and restoration on Île Anticosti over 75 years as part of the “Optimized” scenario**



## **Production and financial assessment of the “Optimized” scenario**

### Production level

There is currently little information on the potential of the Macasty Formation. Exploration work completed to date on Anticosti has confirmed the presence of oil and natural gas and ascertained the hydrocarbon potential in the region. Anticosti Hydrocarbon’s more recent exploration work has been to identify areas that could have greater recovery potential.

Given that production has yet to take place on Île Anticosti, the oil and natural gas production data used in the scenarios have been based on data from extraction work in Ohio from the Utica and Point Pleasant geological formations, which are the best

geological equivalents of the Macasty structure on Île Anticosti.<sup>25</sup> For economic and financial projections, the “Optimized” scenario was used because it incorporates the most recent information, particularly on well productivity. This is because this scenario is limited to the area with greater geological potential, an area that is smaller than that of the “More” scenario and requires less transport and collection infrastructure. This is in line with industry practices for commercial production.

The financial assessment for a typical well takes the following factors into account:

- The total production during the well’s lifespan is estimated based on initial production and a decline curve. The data used to model these parameters comes from wells in operation at the comparable formations mentioned above.
- Initial production is estimated at about 82.5 million cubic feet/month (MMcf/month) for natural gas together with an average of 50 barrels of oil per MMcf produced, or about 4,125 barrels per month.
- A well’s level of oil and natural gas production declines quickly after it begins producing and follows a decline curve similar to that observed in the industry.
- After 25 years, a well will have produced about 2.8 billion cubic feet (Bcf) of natural gas and 140,500 barrels of oil, or 77.5% natural gas<sup>26</sup> and 22.5% oil. This proportion makes this a natural gas project.

For all wells built on Île Anticosti over the course of the project, production would total 11,683 Bcf and 584 million barrels (MMb).

At maximum production, 246 Bcf and 12.3 MMb would be extracted annually. Since Québec’s hydrocarbon consumption was estimated at about 217 Bcf of natural gas and the equivalent of 135 MMb of oil in 2012, the maximum annual production on Île Anticosti would make up 113% of Québec’s annual natural gas consumption and 9% of its oil consumption.

### Financial modeling

The project’s potential profitability is assessed using a probabilistic financial model. This model is based on the “Optimized” development scenarios developed as part of the SEAs, as well as various financial and cost assumptions.

The financial model developed can be used to:

- Assess the profitability of a project with set assumptions and to test the sensitivity of each variable taken individually
- Take uncertainty into consideration by modeling a multitude of possible combinations. During the Monte Carlo simulations, distributions are ascribed to more than 20 key variables, including initial hydrocarbon production, various cost variables (drilling, extraction costs), and the price of hydrocarbons. The results of the simulations shown in this study are based on 50,000 iterations.

The methodology for the financial model and information on the assumptions used are given in Study AECN01.

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<sup>25</sup> Geological equivalents were established as part of Phase 1 of the SEAs. See Malo, M. et al., *Synthèse des connaissances portant sur les pratiques actuelles et en développement dans l’industrie pétrolière et gazière*, Institut national de la recherche scientifique, Centre Eau Terre Environnement, 2015.

<sup>26</sup> Including natural gas liquids.

The project development stage (construction of facilities for commercial production) begins after the discovery of sufficient hydrocarbons so as to be commercially exploitable. The exploration costs are excluded from the financial model because the decision to proceed to the extraction phase is made after the exploration costs have been incurred.

Commercial development is impossible without confirmation that a hydrocarbon resource actually exist and in what quantities. Once this is known, feasibility and economic studies are required to determine what portion of the resource—the oil or natural gas reserves—is economically viable in the prevailing economic, technical, and regulatory environment. The Economy subcommittee’s work, based on the development scenarios, was therefore to assess the probable financial profitability, government revenue, and economic spinoffs of commercial hydrocarbon development on Île d’Anticosti in the event that sufficient reserves were confirmed.

To take into account the uncertainty of the assumptions, distribution values are allocated to more than 20 key variables, including initial production, costs, and hydrocarbon prices. The model can be used to estimate:

- The financial profitability of a project from a business perspective based on two indicators commonly used in the industry: the net present value (NPV) of benefits and the internal rate of return (IRR)
- The probability of a project’s profitability using Monte Carlo simulations
- The potential income and benefits for businesses and the government (royalties, tax revenue, and equity participation)

#### Investments and other costs

The project’s potential profitability was assessed by taking into account certain transport options mentioned by WSP as part of Study ATRA01, Conceptual Assessment of the Need for Transportation Infrastructures for Hydrocarbons Extracted on Île d’Anticosti.

Two methods of transporting hydrocarbons to markets were used for the financial analysis<sup>27</sup>:

- Processing by natural gas liquefaction on a factory ship anchored near the island, with an estimated cost of US\$7.1 billion, of which \$2.9 billion is directly related to the construction of the factory ship.
- Construction of an undersea gas pipeline to Gaspésie followed by a land-based pipeline to a point in the Trans-Québec & Maritime (TQM) Pipeline network (e.g., in Lévis), which would cover a total distance of about 900 km at an estimated cost of US\$9.6 billion, of which \$4.0 billion would go toward building the gas pipeline.

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<sup>27</sup> Other scenarios under consideration included a liquefaction plant either on the island, in the Côte-Nord region, or in Gaspésie. These scenarios are not included in this report since the costs and risks associated with a factory ship project are usually lower.

Other costs must also be considered to obtain the net benefits of the projects, including the cost of operation, well drilling, transport, and platform remediation, in addition to taxation and royalties. The main costs in the model are<sup>28</sup>:

- \$8.8 million on average to drill a well
- \$4.5 million to build a platform where wells will be located
- \$180,000 to close a well, or \$1,800,000 for a platform with 10 wells
- Taxation and royalties (depending on the current regime)
- Other project costs such as those for the cap-and-trade system (\$20 to \$25 per metric ton of CO<sub>2</sub> equivalent in 2020), extraction costs, fixed exploitation costs, and so on

In total, all of these investments and extraction costs are estimated to be, in 2020 constant dollars, \$133 billion for the factory ship option and \$89 billion for the gas pipeline option.

However, the portion of the costs attributable to taxation and royalties is not a cost but income for the government.

### Income

The price predictions used in the model are based on the fall 2015 scenarios from Québec's Ministère des Finances, which forecasts that prices (in constant dollars) will be:

- US\$3.81 per thousand cubic feet (Mcf) of natural gas at Henry Hub in 2020 and US\$5.19/Mcf in 2045
- US\$6.48/Mcf for natural gas in the factory ship option in 2020 and US\$8.83/Mcf in 2045
- US\$90.28/barrel of oil for Brent in 2020 and US\$122.17/barrel in 2045

Income will depend on production volumes, price trends, and conditions in the hydrocarbon industry. Since the potential markets for Anticosti's natural gas cannot be known with certainty at this time, the income attributed to it was calculated for natural gas in a gaseous state in continental markets and for liquefied natural gas in overseas markets.

On this basis, hydrocarbon development on Île d'Anticosti could generate income in 2020 constant dollars totaling \$203 billion with a factory ship and \$164 billion with a gas pipeline for the duration of the project (75 years).

### Financial results and benefits

If the estimated potential materializes, the financial model results show that hydrocarbon development on Île d'Anticosti could have commercial potential.

The average internal rate of return (IRR) is estimated at between 11.5% and 11.7% depending on the natural gas transport scenario chosen. This is higher than the typical 10% goal in the industry.

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<sup>28</sup> See Study AECN01 for all cost assumptions.

- A total of 50,000 simulations were conducted for each scenario in order to obtain a distribution of the net present value of the project's profits and estimate its average IRR.

**Table 37 Simulation results (based on the “Optimized” scenario)**

Transport scenario	Probability of profitability (%)	Average NPV of profits <sup>1</sup> (\$B)	Average IRR (%)
Factory ship <sup>2</sup>	80	2.15	11.7
Gas pipeline	86	2.14	11.5

(1) Calculated with a 10% nominal discount rate

Taking into account income and expenses, project profitability with a factory ship is estimated at about \$71 billion throughout extraction. In the case of a gas pipeline, net profits are estimated at \$75 billion.

With its stake in Anticosti Hydrocarbons and shares in Junex and Pétrolia share capital, the government could obtain a share of about 38% of the project's net profits shown in Table 38.

**Table 38 Estimates of hydrocarbon extraction profits (in billions of 2020 constant dollars, based on the “Optimized” scenario)**

	Factory ship	Gas pipeline
Income	203	164
Minus:		
- Investment	35	37
- Expenses (including taxes and royalties)	98	53
<b>Net profit</b>	<b>71</b>	<b>75</b>

Note: Amounts have been rounded and may not add up to the total shown.

\* The government holds a 35% stake in Anticosti Hydrocarbons L.P. and shares in Junex and Pétrolia share capital.

In addition to the profits from its stake in Anticosti Hydrocarbons and Junex's and Pétrolia's share capital, the government also profits from royalties and corporate income tax. Together, this totals between \$46 and \$48 billion (in 2020 dollars) for the government over the 75-year operating span. These sums represent more than 50% of the anticipated profit before taxes and royalties.

**Table 39 Total profit for the Québec government (in billions of constant dollars, based on the “Optimized” scenario)**

	Factory ship	Gas pipeline
Profit <sup>1</sup>		
- Stake in Anticosti Hydrocarbon	23	24
- Participation in Junex and Pétrolia share capital	4	4
Corporate income tax	7	7
Royalties <sup>2</sup>	13	13
<b>TOTAL</b>	<b>46</b>	<b>48</b>

Note: Amounts have been rounded and may not add up to the total shown.

1. To simplify, the profit from shares is based on the government's stake in Anticosti Hydrocarbon and in Pétrolia's and Junex's share capital on the assumption that the profits will be redistributed to shareholders.

2. Including royalties based on the current royalties regime provided in the *Regulation respecting petroleum, natural gas and underground reservoirs* (CQLR, chapter M-13, r.1), as well as priority royalties for Hydro-Québec, royalties for water, and rent from extraction leases.

### Economic spinoffs

Analysis of economic spinoffs from the “Optimized” scenario shows that development of the oil and gas industry on Île Anticosti could have a significant impact on jobs and economic growth in Québec.

The impact analysis was conducted for two separate transport options: a factory ship and a gas pipeline.

#### *Factory ship option*

For the factory ship option, it is assumed that the natural gas extracted on Île Anticosti will be transported off the island by ship after being liquefied on a floating liquefied natural gas unit. The oil and natural gas liquids extracted on the island would be transported by oil tanker.

The economic impact analysis for the factory ship option shows that the oil and gas industry on Anticosti could add a total of \$149.6 billion to Québec’s GDP over the 75-year span of hydrocarbon operations.

During this time, gas and oil industry development on Anticosti could contribute an average of \$2.0 billion to the GDP and create or maintain 2,177 jobs per year.

**Table 40 Economic spinoffs, factory ship option – 2020–2095  
(2020 constant dollars, unless otherwise indicated)**

	Jobs	GDP contribution	
	Annual average	Annual average (\$M)	Total (\$B)
<b>HYDROCARBON EXTRACTION AND PROCESSING</b>			
<b>Infrastructure costs</b>	<b>342</b>	<b>39.0</b>	<b>2.9</b>
Direct	179	23	1.7
Indirect	163	16	1.2
<b>Running costs</b>	<b>1,575</b>	<b>1,926</b>	<b>144.95</b>
Direct	915	1,849	138.7
Indirect	660	77	5.7
<b>Subtotal</b>	<b>1,917</b>	<b>1,965</b>	<b>147.4</b>
<b>NATURAL GAS LIQUEFACTION AND HYDROCARBON DELIVERY BY SHIP</b>			
<b>Infrastructure costs</b>	<b>0</b>	<b>0.0</b>	<b>0.0</b>
Direct	0	0.0	0.0
Indirect	0	0.0	0.0
<b>Running costs</b>	<b>260</b>	<b>29</b>	<b>2.2</b>
Direct	141	16	1.2
Indirect	119	13	1.0
<b>Subtotal</b>	<b>260</b>	<b>29</b>	<b>2.2</b>
<b>TOTAL</b>	<b>2,177</b>	<b>1,994</b>	<b>149.6</b>

Note: Indirect activities are those by suppliers of goods and services to businesses connected with the project on Île d'Anticosti. Amounts have been rounded and may not add up to the total shown.

1. The number of jobs is calculated in full-time equivalents.

Source: Ministère des Finances du Québec

### Gas pipeline option:

For the gas pipeline option, it is assumed that the natural gas extracted on Île d'Anticosti will be sent off the island by gas pipeline. Like the factory ship option, the oil and natural gas liquids extracted on the island would be transported by oil tanker.

The economic impact analysis for the gas pipeline option shows that the gas and oil industry on Île d'Anticosti could add a total of \$160.0 billion to GDP over the 75-year hydrocarbon extraction period.

During this time, gas and oil industry development on Anticosti could contribute an average of \$2.1 billion to the GDP and create or maintain 2,601 jobs per year.

**Table 41 Economic spinoffs, gas pipeline option – 2020–2095  
(2020 constant dollars, unless otherwise indicated)**

	Jobs	GDP contribution	
	Annual average	Annual average (\$M)	Total (\$B)
<b>HYDROCARBON EXTRACTION AND PROCESSING</b>			
<b>Infrastructure costs</b>	<b>436</b>	<b>49</b>	<b>3.7</b>
Direct	230	29	2.2
Indirect	206	20	1.5
<b>Running costs</b>	<b>1,609</b>	<b>2,021</b>	<b>151.5</b>
Direct	933	1,942.4	145.7
Indirect	676	78.2	5.9
<b>Subtotal</b>	<b>2,045</b>	<b>2,070</b>	<b>155.2</b>
<b>TRANSPORTATION OF NATURAL GAS BY PIPELINE AND OIL BY SHIP</b>			
<b>Infrastructure costs</b>	<b>292</b>	<b>36</b>	<b>2.7</b>
Direct	159	23	1.7
Indirect	132	13	1.0
<b>Running costs</b>	<b>265</b>	<b>27</b>	<b>2.1</b>
Direct	81	9	0.7
Indirect	184	18	1.4
<b>Subtotal</b>	<b>556</b>	<b>64</b>	<b>4.8</b>
<b>TOTAL</b>	<b>2,601</b>	<b>2,134</b>	<b>160.9</b>

Note: Indirect activities are those by suppliers of good and services to companies connected with the project on Île d'Anticosti. Amounts have been rounded and may not add up to the total shown.

1. The number of jobs is calculated in full-time equivalents.

Source: Ministère des Finances du Québec

## Development scenarios – Other geological basins

### Geological potential by basin

In addition to Anticosti, other geological basins are known for their hydrocarbon potential, such as Gaspésie, the St. Lawrence Lowlands, Bas-Saint-Laurent, and the Gulf of St. Lawrence. Exploration and geoscientific knowledge acquisition work has taken place on some of these basins in the past. In spite of everything, even though these basins have considerable theoretical potential, information on them is still incomplete, and no large-scale commercial development is planned in the short term.

Gaspésie is the region with the most advanced resource potential assessment. The Gulf region appears to contain geological structures conducive to hydrocarbons, although exploration there is still in the very early stages. This includes the Old Harry site, located on the border between Québec and Newfoundland and Labrador. Other targets and environments of potential interest for hydrocarbon extraction were studied in further depth as part of the GTEC08 study.

There is currently not enough data on the St. Lawrence Estuary and Bas-Saint-Laurent to express an opinion as to whether there are potentially recoverable hydrocarbon resources or whether development is economically viable.

The following table summarizes what is known about potential hydrocarbon resources in Québec's main geological regions.

**Table 42 Current knowledge on Québec's hydrocarbon potential**

Region	Type of hydrocarbon	Assumed extraction technique	Comments
St. Lawrence Lowlands	Shale gas, possibility of unconventional oil	Horizontal drilling and hydraulic fracturing	Current knowledge indicates the Utica shale porosity is too low for conventional commercial development. According to the analyses, the hydrocarbons are mostly made up of natural gas, although small quantities of condensate were detected during drilling.
	Conventional natural gas	Conventional natural gas extraction	Natural gas accumulations have been discovered and developed in the St. Lawrence Lowlands in the past.
Île d'Anticosti	Possibility of shale oil, unconventional gas, and oil in conventional reservoirs	Horizontal drilling, hydraulic fracturing, and conventional oil extraction	Unlike the St. Lawrence Lowlands, the oil and gas resources on Île Anticosti remain theoretical. For the moment, Anticosti Hydrocarbons' oil and gas exploration is focusing on the Macasty Formation, which is thought to contain shale gas and oil. However, Junex is also interested in conventional oil in geological units older and deeper than the Macasty Formation.
	Possibility of oil and natural gas in conventional reservoirs	Natural gas extraction	Exploration work has revealed source rock with oil and gas potential in the southwest of the island where thermal maturity is greater.
Gaspésie	Oil and natural gas in conventional reservoirs	Natural gas and oil extraction	This region is historically known to contain conventional reservoirs of oil and natural gas. For the moment, the Galt reservoir—the first in Gaspésie to be drilled horizontally by Junex and to deliver a potentially commercially viable production rate—is being considered for hydrocarbon development. Meanwhile Pétrolia is continuing its exploration work on the Haldimand and Bourque properties as well.
	Possibility of unconventional gas and oil	Horizontal drilling and hydraulic fracturing	
Bas-Saint-Laurent	Possibility of oil and natural gas in conventional reservoirs	Natural gas and oil extraction	Total organic carbon (TOC) analyses show signs of hydrocarbons in the region. Although preliminary, work on the Massé property located nearly 50 km from the Rimouski region, as well as an independent assessment, has confirmed the presence of hydrocarbons without specifying recoverable volumes.
	Possibility of unconventional gas and oil	Horizontal drilling and hydraulic fracturing	

Region	Type of hydrocarbon	Assumed extraction technique	Comments
St. Lawrence Estuary	Oil and natural gas in conventional reservoirs	Gas and oil extraction in a marine environment	This area's potential cannot be properly assessed on the basis of the seismic data currently available. However, natural gas has been observed escaping numerous times.
Gulf of St. Lawrence (Old Harry), including Îles-de-la-Madeleine	Oil and natural gas in conventional reservoirs	Gas and oil extraction in a marine environment	The Gulf of St. Lawrence section (including Old Harry) is conducive to the presence of oil and natural gas. Certain sections could contain both oil and natural gas.

Source: CIRAIG and Ministère de l'Énergie et des Ressources naturelles, 2015

### Development scenarios

The SEA on shale gas report released in 2013 already contained development scenarios for the St. Lawrence Lowlands, so current SEAs will not look further into the matter. It should be noted, however, that there is no commercial hydrocarbon production in Québec at present, although there are a number of exploration projects at varying stages of advancement.

A number of exploration projects are concentrated in the Appalachian geological province, mainly in Gaspésie and Bas-Saint-Laurent, but also in the Gulf of St. Lawrence. Study GTEC01 determined and described comparables for the most advanced oil and gas projects in Québec, including the Massé, Bourque, Haldimand, Galt, and Old Harry projects.

One of the findings of this study, which was discussed in greater detail in Chapter 4, is that data from comparable projects cannot simply be transposed onto Québec's reservoirs to determine production potential. This is partly because of our still incomplete understanding of the properties of Québec reservoirs, as well as the unique character of each oil basin, but also because of human factors, such as how extraction methods change over time, local economic parameters, and regulatory differences.

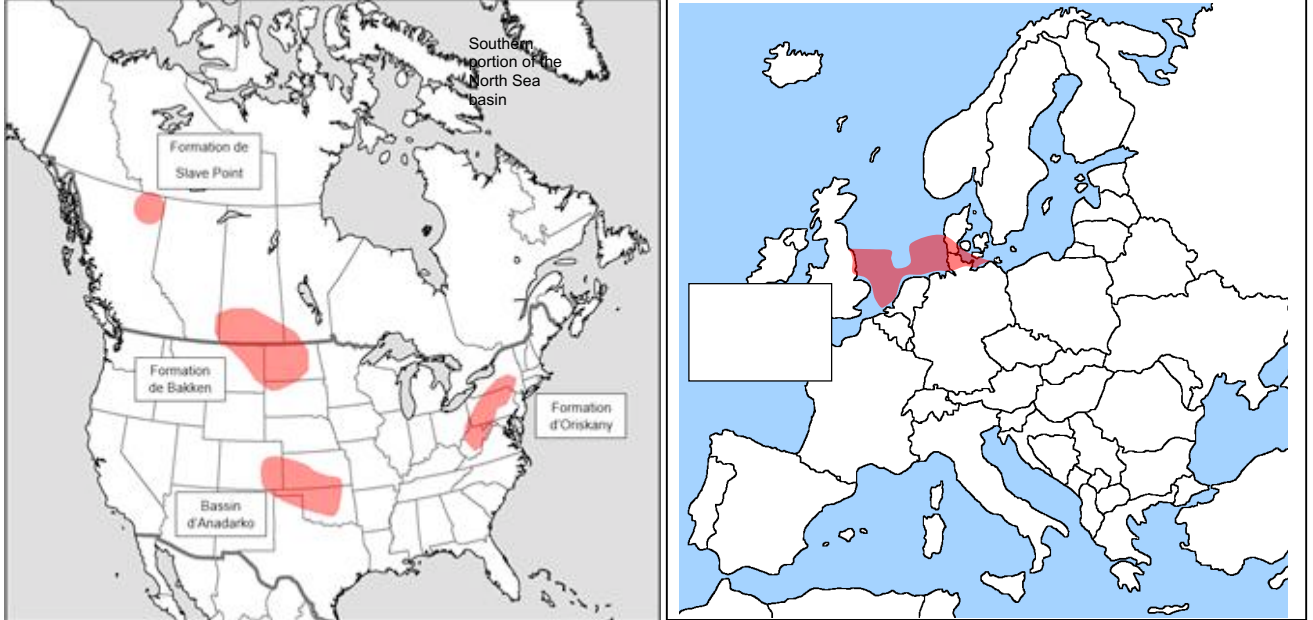
Furthermore, the geological equivalents underwent development in a legislative and regulatory context different from that of Québec, which complicates comparisons with Gaspésie and Bas-Saint-Laurent even more. So, even though the equivalents are comparable to the Québec basins from a strictly geological point of view, there are still too many unknowns, such as the geometry, density, and permeability of fracture networks and the scope and interconnectedness of dolomitized zones, which limits the use of these equivalents, to make economic or technical predictions or comparisons. We must thus wait until data on Québec's basins becomes available before developing production scenarios for them.

Scientific knowledge of the hydrocarbon potential of the Gulf of St. Lawrence is still very preliminary. Most of the exploration work performed to date in this sector was carried out in the 1960s and 1970s. It mainly consisted of geophysical surveys that led to some wells being drilled, primarily in Îles-de-la-Madeleine. More recent work concentrated on the Old Harry geological structure sector. This area is mainly known based on geophysical surveys and its surface properties, and it has never undergone drilling. In

the case of Old Harry, the lack of project advancement and in situ drilling data suggest that that the project has not advanced enough for a production scenario to be considered. Nevertheless the Study GTEC08 work included modelling the geophysical properties of the Gulf of St. Lawrence. It also noted various types of geological environments that may contain hydrocarbons, including numerous salt domes and various structural traps.

The equivalents are the result of geological contextualization to identify geological basins comparable to those observed in Gaspésie, Bas-Saint-Laurent, and the Gulf of St. Lawrence. The description of Québec's basins and the equivalents proposed in this document is a summary; readers who wish to explore their properties in greater depth can refer to the Study GTEC01 report Identification of Geological Basins Matching the Geological Structures in the Gaspésie and Bas-Saint-Laurent regions, and in the Gulf of St. Lawrence.

**Figure 24 Location of geological equivalents  
For Gaspésie, Bas-Saint-Laurent, and the Gulf of St. Lawrence**



Source: Ministère de l'Énergie et des Ressources naturelles, September 2015

### Next steps

While development scenarios have not been created for basins other than Anticosti, producing them is a good idea.

The government can complete production scenarios as information is obtained.

Scenario development is an approach often used by governments to better plan, estimate, and regulate potential oil and gas industry development.

In using this approach, the government has gained more expertise and better knowledge of the oil and gas industry and its development. These scenarios should enable the government and the public to better anticipate what the development of an oil and gas industry could look like in the region.

Through the scenarios from the current SEA, the government was able to predict that commercial production of oil and gas on Île d'Anticosti could be economically profitable. Development of the industry would generate considerable revenue for promoters and the government over 75 years. Since there is very little data available at present, actual income could be higher or lower than stated, depending on new information and market fluctuations, if commercial development occurs.

Besides a considerable amount of tax income, potential hydrocarbon extraction on Île d'Anticosti would lead to considerable economic spinoffs in Québec in terms of jobs, increased GDP, and positive effects on the balance of trade. Potential commercial hydrocarbon production on the island could lead to the creation or maintenance of well-paid direct and indirect jobs, as well as profits for the promoters and their suppliers of goods and services.

The scenarios developed by the government must be seen as tools for better understanding the potential impacts of hydrocarbon development in certain Québec geological basins.

The next step—development scenario fine-tuning—could consist of gradually replacing assumptions with real data obtained during additional exploration and geoscientific knowledge acquisition work.

Besides Île d'Anticosti, for which development scenarios have been produced and presented in this document, other Québec geological basins have known hydrocarbon potential. Scenarios have not been produced for these basins, located in such regions as Bas-Saint-Laurent, Gaspésie, and the Gulf of St. Lawrence since information and production methods are not yet advanced enough to lead to plausible assumptions. The government could continue work on such scenarios as new knowledge comes to light.

## 5.3 Development of the economy and hydrocarbon expertise

### Potential market

Quebecers consume hydrocarbons every day. They are primarily used as fuel in various forms of transportation, while a portion is also used to produce goods of all kinds.

All hydrocarbons consumed are imported as Québec does not produce any oil or gas commercially.

Hydrocarbon production in Québec could replace oil and gas imports. In a context where it is preferable to minimize the distances hydrocarbons are transported, such production would allow local markets to consume the resource, and only the surplus would be exported, if any.

This section presents the current situation and potential markets for resources that Québec may choose to produce.

### Current and future consumption in Québec

#### Natural gas

Demand for natural gas in Québec was 5.98 billion cubic meters in 2014 with an estimated peak of about 36 million cubic meters per day in winter (Statistics Canada). Two distribution companies—Gaz Métro and Gazifère—are the main suppliers.

Gazifère serves 40,000 clients and operates 886 km of pipeline in the Outaouais region, while Gaz Métro supplies more than 195,000 clients with a network of more than 10,000 km of pipeline<sup>29</sup>.

According to Régie de l'énergie (R-3900-2014), Québec's demand for natural gas should increase an average of 2% per year until 2030. It is expected to come from outside Québec and be imported by TransCanada PipeLines' (TCPL) main system.

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<sup>29</sup> Gaz Métro, *Gaz Métro en bref* (2015).

## Natural gas liquids (NGL)

In 2013 Québec demand for natural gas liquids (NGL) was 707 million liters, with more than 90% of it propane (Statistics Canada). With a sample retail price of about \$0.80/liter in 2013, NGL is an approximately \$560-million market in Québec.

Propane is primarily used as an industrial fuel source (36%), in businesses and institutions (32%), and in agriculture (21%). A small portion is also used in the residential sector (7%) and in transportation (3%).

Québec produces propane at two refineries, in Montréal and Lévis, and it is distributed to the province's consumers primarily through some 20 distributors. They purchase propane from the two refineries or import it. A portion of the propane produced and imported is then exported outside the province.

Supplementing these distributors are a number of companies that offer services related to the propane industry: cylinder exchange, appliance installation and maintenance, propane delivery, cylinder filling, appliance sales and so on. Association québécoise du propane has 109 member businesses serving all of Québec (AQP, 2015).

## Oil

Until 2013 nearly half of Québec's crude oil was imported from Africa (Algeria, Angola, and Nigeria), while the rest came primarily from producers in the North Sea, United States, and Mexico. It was supplemented by smaller suppliers, notably from western and eastern Canada, which provided about 5% of Québec's refined oil.

Since 2013 importers have tried to profit from the persistent difference between the price of a barrel of oil from Alberta, indexed to the West Texas Intermediate (WTI), and that of Brent from the North Sea—the benchmark for crude oil abroad. With the growing availability of oil from North Dakota, Texas, New Mexico, and Colorado, the United States dislodged Algeria in 2014 as the primary source of crude oil in Québec. U.S. imports have spiked over the past two years and now account for more than half of all crude oil imported into Canada.

The refined petroleum products (RPPs) sold in Québec range from gasoline to petroleum coke, petrochemical inputs, jet fuel, and asphalt. Many of the sales occur in the approximately 3,000 service stations in the province (Régie de l'énergie, 2015). These sales are mainly for gasoline and diesel, for a total of 8.55 billion liters of fuel retailed in 2013. These two products account for about 60% of the total volume of RPPs sold in Québec (Statistics Canada). In 2014 a total volume of 20.79 billion liters of RPPs was sold in Québec, the equivalent of 130 million barrels of oil or 358,000 barrels per day.

The two major players in RPP refining and distribution are Valero and Suncor, whose refining facilities are in Lévis and in Montréal, respectively. There are also RPP brokers meeting certain industrial clients' needs, as well as distributors who possess service station networks, or supply these networks.

Québec produces certain oil-based processed products in greater quantities than it consumes, while it must import certain processed products that it does not produce enough of in order to meet its needs.

**Table 43 Québec refineries**

	Valero	Suncor
<b>Location</b>	Lévis	Montréal
<b>Capacity (barrels per day)</b>	265,000	137,000
<b>Acceptable crude oil density</b>	23–46° API	21–40° API

Source: HEC Montréal, 2015

## **Resource potential: domestic Québec market**

### Natural gas

There are two major types of natural gas transport and supply contracts: firm agreements, which are often negotiated for longer terms, and “supply tools to satisfy the winter spike,” which are adjusted annually.

Since December 2014 Gaz Métro has agreed through firm contracts to acquire 90% of its needed supply from TransCanada Pipelines (TCPL) until 2030.<sup>30</sup>

Québec’s natural gas comes primarily from the Dawn Hub in southern Ontario. Deliveries from this hub have increased in recent years.

The advantage of the Dawn Hub is that it is likely to attract producers, brokers, and merchants of natural gas from the U.S. West, Midwest, and South, as well as the Utica Shale and Marcellus formations. This variety puts it in a pricing range very close to continental prices, which are currently very low.

As a result, the short-term prospects for local natural gas distribution from Québec are limited because of Gaz Métro’s multiyear agreement with TCPL and competition from the Dawn Hub as a supply source. However, the current supply agreements will gradually expire over time, and market dynamics could shift to account for Québec production.

### Natural gas liquids

Since propane is mainly recovered in the oil refining process, its market (price and supply agreements) is tied to the oil market. Supply agreements are at the prevailing market price and can fluctuate from week to week.

### Oil

The production capacities of Québec’s two refineries equal about the quantity of oil Quebecers consume daily. Generally, refineries purchase the cheapest crude oils that their facilities can handle. For example, the Valero refinery in Lévis cannot refine heavier oils (less than 23° API<sup>31</sup>). The Suncor refinery is configured for heavier oil refining, which means it can produce asphalt. However, it cannot refine bitumen from Alberta’s oils sands, which has an API gravity of 10 or less.

<sup>30</sup> According to the last agreement negotiated and approved by the National Energy Board (NEB) in December 2014 (NEB, 2014, Reasons for Decision RH-001-2014).

<sup>31</sup> API gravity expresses the density of crude oil. The lighter it is, the lower the density and higher the API gravity.

Refinery supply contracts are usually short, and supply sources can change very quickly. This explains why Québec's oil imports have changed so fast in recent years, as explained above.

Québec refineries could easily decide to draw on oil produced locally. Since refineries' supply agreements are guided mainly by the price of crude oil, locally sourced oil is plausible as long as the price is the same as on international markets and transport costs are competitive. Locally produced oil could even enjoy a competitive advantage because it doesn't need to be shipped as far.

It is worth mentioning that most hydrocarbon projects in Québec are relatively modest in size in comparison with demand in the province. In fact, their potential production would only amount to a fraction of the refining capacity of the province's two refineries.

Hydrocarbon consumption would need to drop considerably to achieve Québec's emission reduction objectives for greenhouse gases by 2050. Yet based on Québec's trajectory for greenhouse gas reduction, we estimate that residual consumption will hold steady at 140,000 to 250,000 barrels per day in 2030. Besides the consumption of hydrocarbons as fuel, other oil and natural gas uses (such as in agriculture and waste) need to be targeted for greenhouse gas emissions to drop.

### **Resource potential: Export market outside Québec**

#### Natural gas (in a gaseous state)

Export potential for natural gas in a gaseous state (not liquefied) is limited to the continent.

Despite recent growth in natural gas consumption in North America caused primarily by the closure of coal-fired power stations and the construction of natural gas-fired power stations, the increase in North American supply has exceeded the increase in demand in recent years.

The continued development of new shale gas sites in the United States ensures that competition in foreign continental markets will remain strong in the coming years. However, depending on technical variables, quantities, prices, and costs, new supply sources can still gain access to the continental market.

Potential export of any natural gas produced in Québec will be affected by still unknown or unpredictable factors, such as transport and storage capacities, market entry costs, transaction type, and time of year.

The balance between supply and demand in the continental natural gas market changes constantly, mainly because of the revolution caused by shale gas extraction in the United States.

Essentially, the potential for continental natural gas export depends on cost. The infrastructure needed to transport gas on a large scale—usually gas pipelines—is expensive to build, and access to existing infrastructure is limited. Opportunities remain realistic in the long term, but the industry faces major hurdles.

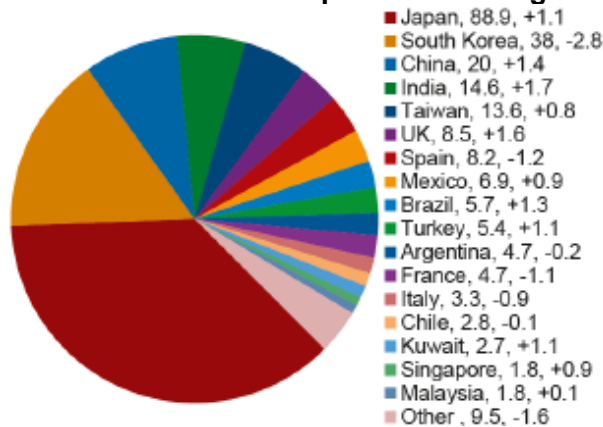
#### Liquefied natural gas

Unlike natural gas in a gaseous state, liquefied natural gas (LNG) has potential for international export.

The dynamics are, however, similar to those of natural gas in a gaseous state: the current North American glut makes it difficult to seize international opportunities. Numerous liquefaction projects on North America’s east and west coasts are currently in development, including some that are very advanced. Consequently current and future markets are extremely competitive, and it would appear difficult for Québec projects to count on these export markets.

Global demand for LNG is historically dominated by Japan and South Korea, which make up more than 50% of the market. Demand in China, India, and Taiwan, however, is strong and growing.

**Chart 4: Demand for liquefied natural gas in 2014 in MTPA and growth versus 2013**



MTPA: Million tons per annum  
Source: IGU World LNG Report, June 2015

## Oil

There is an oil glut today in international markets. Price will be a key factor in whether Québec is attractive to global markets, as will API gravity, which determines which refineries are able to process the oil. Since the numerous refineries in the Gulf of Mexico are configured to process heavy oil, Québec could not in all likelihood sell the light oil it would export in this market. In addition to crude oil exports, oil could also be processed in Québec, and the products could be exported. These products would have different market opportunities than those of crude oil.

If Québec became an oil producer and its production were sold on global markets, the province’s production would account for a tiny fraction of global production. Since oil is traded in global markets at comparable prices around the world, oil produced in Québec and sold at world prices would certainly find takers.

### **Resource potential: Unique features of the Anticosti project**

At present, only the Valero refinery in Lévis would be able to refine the type of light oil that would in all likelihood be extracted on Anticosti (API of 45).

According to an HEC Montréal analysis, there are four potential markets for natural gas produced on Anticosti. More will be known about each option as the project advances, notably in terms of cost, distribution agreements, and infrastructure requirements, and access.

For economic and market reasons, the closer the sales point, the greater the likelihood of the transport method being a pipeline. Conversely, the further away the sales point,

the greater the likelihood of the gas being shipped by boat, train, or truck once it has been liquefied.

#### Option 1: Côte-Nord

- Demand in the Côte-Nord administrative region could potentially amount to 25 to 50 Bcf of natural gas per year if Plan Nord projects are taken into account. This option is attractive because Côte-Nord is relatively close to Anticosti and is home to a number of current or prospective industrial projects, which could benefit from direct access to a natural gas source. However, for this option to pan out, several major mining projects will have to go ahead.

#### Option 2: The Québec distribution network

The second option is connecting to Gaz Métro's or TQM Pipeline's natural gas distribution networks in the province.

In the former case, the objective would be to connect with the Gaz Métro network in Saguenay. This would make it possible to supply GNL Québec Inc.'s project, Énergie Saguenay. Other projects in the region, such as Sysgaz, are also being studied, and the companies that develop them could become potential customers.

In the latter case, the objective would be to access a point on TQM Pipeline's network. For example, the distance from Île d'Anticosti to Lévis would be about 900 km, which would require the resource be transported in a liquefied rather than a gaseous state. This option has the advantage of adding the resource to the distribution network that supplies Québec, but is also part of the North American network.

#### Option 3: Maritime provinces

The Maritime provinces have the advantage of proximity and present a potential opportunity, particularly New Brunswick's Moncton area, about 400 km from Anticosti.

While the entire potential market is rather limited, one of the major draws of the Maritime market would be taking advantage of Canaport's facilities in Saint John, New Brunswick, where the company is contemplating converting its current regasification facility into a liquefaction facility for exporting.

#### Option 4: International market

The last option is the international market. To do this, Anticosti natural gas would need to be liquefied. This could take place on the island or nearby in facilities that would have to be built.

The largest target markets are in Asia. Instability in Europe—with the troubles involving Russian gas—has also created business opportunities. Yet, as previously discussed, competition could increase in these markets in the coming years.

Québec currently imports all of the hydrocarbons it consumes. Local hydrocarbon production could replace the province's imports. However, the market is complicated. The natural gas market is currently continental in nature, while the oil market is global. In addition, Québec processes certain oil-based products in greater quantities than it consumes, while it must import certain products that it does not produce in sufficient

quantities to meet its needs.

This means that, even if Québec becomes an oil producer, it will probably continue to import and export hydrocarbons and processed products.

According to main hydrocarbon demand projections, attractive market opportunities exist at the local, continental, and international levels. However, in all cases, Québec hydrocarbons will face competition from existing players. The answer may be for Québec companies to gain a foothold by taking advantage of their geographic proximity to local markets and lower transport costs to offer more attractive pricing to consumers. There is a market for local oil and gas, but the big challenge is to keep costs down, including development, production, and transport costs.

Given the international community's plans to restrict greenhouse gas (GHG) emissions worldwide to limit global warming to a further 2°C by 2100, the global oil market is expected to contract, and demand for natural gas, while it may continue to rise internationally, should decrease in North America. This decline in the global hydrocarbon market could pose profitability challenges for oil and gas produced in Québec, which would face numerous better-established players with possibly lower production costs.

The SEAs were unable to document to any great extent the most attractive opportunities for Québec.

With an eye to continuing to improve our understanding, it would be worthwhile to document what concrete actions could be taken to take advantage of hydrocarbon distribution or processing opportunities in Québec and serve the interests of consumers and suppliers.

### **Development potential**

The hydrocarbon industry encompasses exploration, extraction, processing, and transport. Other businesses provide peripheral support to the industry, including its various suppliers of goods and services.

### **Suppliers' expertise**

Overall, Canada is a leading hydrocarbon producer. Extraction is concentrated in certain Western Provinces, which also possess about 80% of the industry's jobs. The remaining operations are located in the Atlantic Provinces.

To date there are few Québec companies active in Canadian gas and oil development. This appears to be directly linked to the lack of such operations in the province.

Literature shows that the spinoffs are greatest (jobs/suppliers) chiefly in the provinces where gas and oil production is actually taking place, and this is true in both Western (Alberta, British Columbia) and Eastern Canada (Newfoundland and Labrador).

According to a 2012 study by KPMG-SECOR,<sup>32</sup> Québec received approximately 2.1% of the direct and indirect economic impacts of oil production in Western Canada. Furthermore, almost all of the jobs associated with this were connected with the relative size of existing sectors in Québec's economy. Other studies show similar results for Western and Eastern Canada.

<sup>32</sup> KPMG SECOR for Fédération des Chambres de Commerce du Québec (FCCQ), November 2013, *Economic Impacts of Western Canada's Oil Industry*

There are, however, a certain number of Québec companies located mainly outside the province that have developed hydrocarbon-specific expertise. These often offer niche products and services in such fields as instrumentation, tools, and specialized services like consulting engineering.

In addition, while numerous Québec companies are not ready to meet the needs of a local hydrocarbon industry, a great many show potential and are interested in participating. These companies need to be able to anticipate business opportunities to take full advantage of them.

### **Workforce potential**

In general, Québec has workers it needs to adequately support the emergence of a new industry. However, the fact that local workers are available is not enough for them to successfully meet the needs of the hydrocarbon industry. These workers will need to possess the skills and abilities required by the industry. The emergence of such an industry in Québec could put strain on the province's supply of skilled workers.

The main challenge in meeting the industry's potential workforce needs is training.

The jobs the gas and oil industry needs require extremely varied levels of expertise, ranging from minimal for manual workers to advanced for science specialists and technology experts. Depending on the level of complexity, training can be obtained at universities, colleges, and vocational schools, or even in companies, which often have their own training programs.

Québec does not have a university program whose main goal is to train specialists to work in the hydrocarbon industry.

But Québec universities do offer a number of programs in geology, geological engineering, and earth sciences, and certain fundamental lessons also apply to mineral exploration and hydrocarbon production and exploration.

At present, graduates from these programs must continue their training at other Canadian universities to specialize in the gas and oil field. Thus, if the need for expertise were to quickly develop in Québec, it would be possible for a small group of specialists to emerge quickly enough to meet the industry's needs.

Given the historical importance of Québec's mining sector, there are a number of college-level programs with a strong focus on the mining industry's needs. A large part of the basic skills and knowledge taught in such programs applies to the hydrocarbon sector.

If the need were to arise, specific subjects could be added to these programs to meet the needs of the hydrocarbon industry. The instructors in charge of these programs already possess a background in geology and geotechnics and could also acquire supplementary knowledge more directly related to hydrocarbons.

In terms of vocational training, a number of institutions already offer programs that can guide students to the basic trades in the gas and oil industry. These programs can be supplemented by more specialized training within companies.

Québec has a complex industrial structure, a skilled workforce, a creative entrepreneurial network, and leading-edge training centers. Building on expertise acquired in the mining and other sectors, a hydrocarbon production could conceivably give rise in short order to a comprehensive industrial structure of suppliers of goods and services. Furthermore, the labor pool would be sufficient to meet the demand.

A number of training programs could immediately meet the industry's "basic" needs, while others, particularly those at the university level, would need updates to adequately address the industry's needs.

To date, Québec companies are relatively absent from Canadian oil and gas development. This appears directly linked to the lack of such development in the province. Analyses show that the economic impact of hydrocarbon extraction occurs largely in the province where the resources are extracted.

It therefore seems reasonable to believe that hydrocarbon development in Québec could benefit suppliers of good and services in the province, in addition to local workers who would fill industry jobs.

By calling on existing training institutions and updating their academic programs to better match the hydrocarbon industry's needs, it would be possible to quickly train the necessary workforce. Similarly, Québec suppliers would be able to adapt to meet industry needs.

The industry could thus rely on a local workforce already in possession of the necessary skills or quickly able to acquire training. Local workers and businesses should therefore prepare for a new industry's arrival, in order to properly satisfy its requirements. The province must also ensure that the entrepreneurial resources currently available are adequately prepared to quickly seize potential business opportunities.

All of the preceding suggests that industry suppliers and a workforce are likely to develop in Québec and quickly get involved in the hydrocarbon industry should it develop.

In order to maximize job creation in Québec, the government should better document the actions needed to properly address training needs. It must also ensure that the entrepreneurial resources currently available are adequate prepared to quickly seize future business opportunities.

## **Potential workforce needs**

### **Background**

To assess the workforce needs associated with possible future hydrocarbon development, KPMG was tasked with developing an approach and an economic model as part of the SEAs.

A number of sources and references from similar projects were used to extrapolate the workforce needed for drilling (e.g., site preparation, drilling, waste management), well operation (e.g., maintenance, tests), and well restoration (e.g., cementing, site restoration).

However, the study does not consider jobs associated with processing natural gas and transporting gas and oil from the drilling platforms to processing or liquefaction plants or factory ships. Moreover, the study does not include the labor required to put road infrastructure in place, renovate airports, and build housing modules.

- While these needs are not counted, they represent numerous additional jobs, created mainly during the infrastructure construction phase.

- In the case of Île d'Anticosti (the details of which are provided in this section), many hundreds of direct and indirect jobs would be created.

**Activities associated with a hydrocarbon industry’s workforce needs**

- Drilling and well stimulation encompasses the phases between site preparation and the beginning of operations, including on-site equipment mobilization, drilling, and well cementation. This step is the most labor-intensive, but also one of the most temporary because, once wells have been completed, needs diminish.
- Production involves roles related to the maintenance and repair of a well throughout its active life.
- These jobs persist year after year as long as the well is active.
- Like drilling, the restoration phase requires temporary workers, who will be on site only for the duration of the work, which involves plugging the well and site restoration activities.
- It has been noted that the average salaries in the industry are generally higher than those of other industries, with the salaries of the main trades often exceeding \$100,000.

**Drilling costs**

The labor estimates are based primarily on the drilling costs. They were modeled mainly using the Institut de la statistique du Québec intersectoral model.<sup>33</sup> In the calculations, the same base cost was altered to account for the specific features of each of Québec’s geological basins (e.g., Gaspésie or Anticosti). Since the projects in the Gulf of St. Lawrence are in the very early stages, it did not seem appropriate to show cost structures here.

**Table 44 Anticipated development costs for a well in Gaspésie and Anticosti (in 2015 dollars)**

Development phase	Gaspésie	Anticosti	% from Québec suppliers*
<b>Well drilling</b>	\$4,870,000	\$5,189,000	54%
<b>Hydraulic fracturing</b>	Not applicable	\$3,471,000	35%
<b>Combined total</b>	\$4,870,000	\$8,659,000	47%

\* Represents the portion of the expenses attributed to Québec suppliers. The rest of the expenses are attributed to imports. This data is based on the input-output matrix from the Québec intersectoral model with certain adaptations made for the hydrocarbon sector

Sources: Literature review, business data, and expert interviews; KPMG analysis

In total, we estimate that Québec suppliers could obtain 54% of drilling costs and 35% of costs related with the hydraulic fracturing step. If the fracturing and drilling costs are combined, 47% of costs would come back to Québec.

This figure is comparable to Québec’s average imports for the machine manufacturing industry, whose foreign purchases total about 56% of its goods and services expenses, or for the chemical manufacturing industry (53% of imports).

<sup>33</sup> See Study GECN02 for methodology details.

Québec suppliers are the most prominent in services related to site preparation and construction, equipment transport, site supervision, and waste management.

KPMG used the average repair and maintenance costs over a well’s lifespan and estimated average production costs to be \$100,000 per year, which recur annually once well construction is complete. Restoration costs, including well closure (cementation) and site restoration, are estimated to be \$180,000 per well and stop after the well is closed.

**Estimated workforce needs on Île d’Anticosti**

Based on the “More” development scenario from Study AECN01 presented earlier, a maximum 6,800 wells could be drilled on Anticosti over 75 years. This works out to 143 wells per year once the project hits its cruising speed, for a maximum of about 3,600 wells active at the same time in Year 29. Note that the jobs associated with the “Less” and “Optimized” scenarios are not shown here, but there would be fewer jobs, proportionate to the number of wells.

We estimated that drilling, exploitation, and restoration of a single well on Anticosti would translate into some 23 direct and indirect jobs (in person-years).

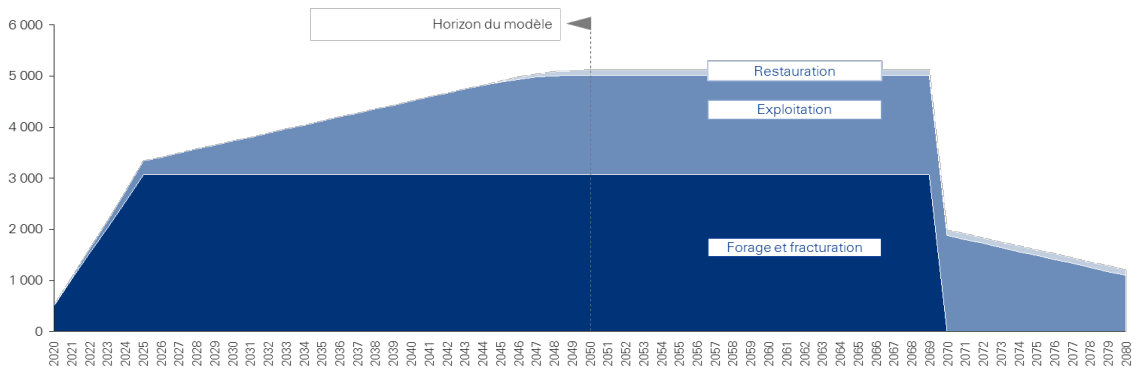
**Table 45 Anticipated jobs per well on Anticosti (for a typical well, in person-years)**

Phase	Direct jobs	Indirect jobs	Total
<b>Drilling and fracturing</b>	14.28	7.12	21.40
<b>Extraction</b>	0.25	0.30	0.55
<b>Restoration</b>	0.46	0.31	0.77

Source: ISQ simulation results; KPMG analysis

At their peak (years 29 to 49 of the project), operations on Île Anticosti would provide employment to a total of about 5,130 workers (2,985 direct and 2,145 indirect jobs) annually, including 3,060 working in drilling, 1,960 in extraction, and 110 in well restoration. It should be noted that some of these jobs may not be located in the production area.

**Figure 25 Changes in jobs associated with deployment on Île d’Anticosti (“More” scenario) 2020–2080, in person-years**



Note: The profession estimate model covers 2020 to 2050 only.  
 Source: KPMG, results of simulations done using the *Institut de la statistique du Québec* intersectoral model based on the “More” deployment scenario released by the government on May 20, 2015. The year 2020 is used for reference purposes only.

These jobs are spread over various categories:

- More than a quarter (26%) are in the trades, transportation, machinery, and related fields.
- Business, finance, administration, and management positions make up about 27% of the direct and indirect jobs sustained by the industry.
- Positions in the natural and applied sciences account for 16% of jobs, which are held by professionals working in the physical sciences, such as civil, mechanical, electrical, and chemical engineering; IT; and technical engineering; among others
- There are also occupations in sales and service (12%), natural resources (9%), manufacturing and utilities (5%), and other trades (5%).

**Estimated workforce needs in Gaspésie**

Based on the same model, jobs were modeled for potential commercial production in Gaspésie.

We estimated that drilling, extraction, and restoration of a single well in Gaspésie would translate into about 15 direct and indirect jobs (in person-years). This is less than for Anticosti, mainly because hydraulic fracturing would not take place.

**Table 46 Jobs per well in Gaspésie (for a typical well, in person-years)**

Phase	Direct jobs	Indirect jobs	Total
<b>Drilling</b>	9.33	4.31	13.64
<b>Extraction</b>	0.25	0.30	0.55
<b>Restoration</b>	0.46	0.31	0.77

Source: ISQ simulation results; KPMG analysis

Hydrocarbon development generates many jobs that usually pay above-average wages, often exceeding \$100,000 per year. Like the mining sector, a large portion of jobs are created during infrastructure construction, and the number of jobs created is usually linked directly to the size of the investment made.

Over the lifespan of a well, drilling, extraction, and restoration would translate into about 23 jobs each year for Anticosti and 15 for Gaspésie.<sup>34</sup> As a result, this number increases linearly depending on the number of wells built. Infrastructure construction also creates other jobs. However, how many is determined by related expenses, which may vary considerably depending on how much infrastructure is needed, which in turn differs from one project to another.

For the Anticosti project, the number of jobs created would be substantial—up to 5,100 direct and indirect jobs at the height of production. Direct jobs would be located on the island with fly-in fly-out services, and indirect jobs would mainly be made up of suppliers of goods and services. Note also that development of the hydrocarbon industry in Québec could cause native Quebecers currently working in the industry in Western Canada to return to the province.

We estimate that Québec will have a sufficient labor pool to satisfy the demand after a few years of adjustment. The challenge of training workers called to develop supplementary skills tied to the hydrocarbon industry and of creating new programs for more specialized jobs is considerable.

## 5.4 Economic issues

### Royalty and community benefit-sharing regime

#### Royalty regime

At present, hydrocarbon royalty regimes are included in the Regulation respecting petroleum, natural gas and underground reservoirs.

- Oil royalties vary between 5.0% and 12.5% of the value of wells for any given month, depending on their average daily production. Gas royalties range from 10.0% to 12.5% of the value of wells, depending on whether or not daily production exceeds established thresholds.

In the 2011–2012 budget, the Québec government announced its intention to modify the shale gas royalty regime to increase the capture of rents, maintaining a good balance in extraction-related benefit-sharing.

- As in other Canadian provinces, like Alberta and British Columbia, the proposed royalty rate would vary from 5% to 35% of the value of wells based on their productivity. A higher rate would therefore apply to more productive wells.
- Unlike the current regime, this approach has the advantage of automatically adapting to the performance of shale gas wells, whose productivity decreases rapidly.

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<sup>34</sup>The job calculations are based on the cost structure, which estimates the cost of drilling one well to be \$4.9 million in Gaspésie and \$5.2 million on Anticosti. Additional costs of \$3.5 million are added per well on Anticosti because of fracturing. Consult Study GECN02 for further information.

Under the 2012–2013 budget, the government announced a new oil royalty regime for oil produced in an onshore environment.

- Following the example of Alberta and Saskatchewan, the new regime proposed introducing a royalty rate varying between 5% and 40% based on well production.

The same budget also set out the principles for a royalty regime for hydrocarbons produced in an offshore environment, but did not provide details of its provisions.

- Regimes for offshore environments often provide for lower royalty rates at the start and higher ones when eligible investment costs have been recovered. This is the case for Newfoundland and Labrador.

However, the two royalty regimes proposed for Québec have not been adopted by the National Assembly.

Under the hydrocarbon SEAs, the knowledge summary confirmed that no further studies on royalty regimes were needed for Québec.

- In recent years the government has acquired experience and knowledge with regard to oil and natural gas taxation and royalty regimes in both onshore and offshore environments.
- This has led to the release of two draft royalty regimes: one for shale gas under the 2011–2012 budget and one for oil under the 2012–2013 budget.

Despite their release, these two proposed regimes have not been adopted by the National Assembly. The SEA, especially in terms of the development scenarios, is therefore based on the current royalty regime.

Royalty regimes for commercial hydrocarbon production will need to be considered.

The SEAs concentrated more on the issue of sharing benefits gained from oil and gas resource development rather than on the terms and conditions of royalty regimes.

### **Oil and gas resource development revenue and benefit sharing**

Any new industrial project in a community is sure to have both positive and negative impacts. Various mitigation measures must therefore be implemented. Such measures must involve the community and ensure its approval. The government wishes to strike a fair balance in sharing revenues and benefits between what is collected by the government (royalties), companies (profits), and workers (salaries) so as to foster social well-being.

It is important to keep in mind that this chapter on the Economy theme deals with economic aspects, while the chapter on Society deals with social acceptability as a whole. The reader can therefore refer to Chapter 8 for more information on social issues.

One of the mitigation measures sometimes adopted by governments consists of sharing royalties and revenues from natural resource development. Phase I of the SEAs thus concluded that more needed to be learned during Phase II, particularly with regard to experiences elsewhere in the world and other non-renewable natural resources.

In 2014, the government committed to sharing revenues from mining, oil, and gas extraction with aboriginal communities and municipalities.<sup>35</sup>

The government looked into natural resource development benefit sharing in parallel to the SEA work.

#### Renewal of the fiscal pact with municipalities

An interministerial committee on sharing royalties with municipalities was set up and is overseen by Ministère des Affaires municipales et Occupation du territoire (MAMOT). The committee concluded that the “Grants in Lieu of Access to Natural Resource Royalties” program will be enhanced under the renewal of the fiscal pact with municipalities.

The fiscal pact was renewed on September 29, 2015. The royalty component of the pact grants municipalities a total of \$100 million over four years, at a rate of \$25 million per year.

The approach is twofold:

- A first component ensures that municipalities hosting new projects benefit more from positive spinoffs from a social acceptability perspective. The fiscal pact will help communities face the challenges of economic and demographic growth associated with new natural resource extraction projects so that they are better prepared to meet the needs generated by such projects. Up to \$10 million a year will be earmarked for this.
- A second component is an enhanced version of the existing measure. Funds are allocated based on intensity of natural resource extraction (including activities that, like exploration, do not result in royalties) and include an equalization component so that all regions benefit from the redistributed amounts. The measure is for RCMs and for municipalities not belonging to an RCM that exercise the powers of an RCM, excluding cities and agglomerations with a population of 100,000 or more. The annual budget will correspond to the difference between the total \$25 million budget and the amounts allocated under the first component.

#### Aboriginal communities

Preliminary work under the responsibility of Secrétariat aux affaires autochtones (SAA) has been undertaken and guidelines will be identified following discussions with aboriginal representatives. This work involves developing a new sharing model as this initiative is new for Québec. It still requires a certain amount of time to be completed. Section 8.4 of this documents deals specifically with aboriginal communities.

#### Unique features of the hydrocarbon sector

The government’s work on the issue of royalty sharing has highlighted the fact that a formula applicable to one industrial sector cannot necessarily be applied to all sectors in the same way.

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<sup>35</sup> Announcement made by the premier at the 2014 Fédération québécoise des municipalités conference: <http://www.lapresse.ca/actualites/politique/politique-quebecoise/201409/25/01-4803592-couillard-sengage-a-partager-les-redevances-avec-les-municipalites.php>

This is the case for the hydrocarbon sector, which has certain unique features unlike other natural resource sectors such as mining (extraction of metallic and non-metallic minerals) or forestry.

To better document this issue and identify these features of the hydrocarbon sector, a study was carried out under the SEAs on the issue of hydrocarbon royalty sharing (**Erreur ! Nous n'avons pas trouvé la source du renvoi.**).

Operating modes in six reference regions were documented: Alberta, British Columbia, Newfoundland and Labrador (NL), Pennsylvania, Brazil, and Norway.

In most regions, the majority of royalties from hydrocarbon extraction goes directly into the budget of the province, state, or country. Nevertheless, many also use oil and gas royalty-sharing mechanisms in one form or another. Such redistribution helps compensate for the inconvenience caused by resource extraction, which affects primarily local and regional communities. However, methods vary greatly from one region to the next. Most create an intergenerational redistribution tool, a sovereign wealth fund, (such as the Alberta Heritage Savings Trust Fund, the Pennsylvania Oil and Gas Lease Fund, or the Norway Government Pension Fund) where part of the government's hydrocarbon revenues are deposited, although such funds are not specifically for local or regional redistribution.

Some regions, like Pennsylvania, have introduced laws allowing counties to collect royalties on wells and allowing municipalities to tax compensation schemes, particularly for local road use.

Other regions, like NL, require promoters to submit a benefits plan that can, for example, provide that the local workforce has hiring priority, that research and development expenditures are made, or that goods and services are purchased locally.

The government took the first steps toward royalty sharing with the renewal of the fiscal pact with municipalities. The hydrocarbon sector, although comparable to the mining sector, has some unique characteristics. A royalty-sharing formula adapted for hydrocarbons and inspired by best practices observed in elsewhere in the world will eventually need to be implemented in Québec.

Another form of benefit sharing could be in the form of equity investments by the government in exploration or development projects or directly in companies. In Québec the government is a minority shareholder in Junex and Pétrolia, where it owns about 16.5% and 16.2%<sup>36</sup>, respectively, of the shares, and holds a 35% stake in Anticosti Hydrocarbons.

In recent years, the Québec government has worked on establishing oil and natural gas royalty regimes.<sup>37</sup> It will need to update its work and continue discussions to add a potential benefit-sharing component. These discussions must also take into account the possibility of including issues specific to hydrocarbons under the fiscal pact with municipalities.

The SEA work determined that each region has its own unique characteristics with

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<sup>36</sup> On September 1, 2015, the government announced through Ressources Québec a \$3.8 million investment for the first phase of Pétrolia's exploration work on the Bourque property. The transaction had not been completed when this document was written, but the government's share is expected to be about 16.2%.

<sup>37</sup> See 2011–2012 and 2012–2013 budgets.

regard to hydrocarbon development benefit sharing.

It is therefore important for Québec to find a solution adapted to its realities that takes into account the legislative framework, the tax system, land use, and the powers granted to municipalities.

### Québec's competitiveness and competitive positioning

The hydrocarbon industry, including extraction and all peripheral operations, is a globalized economic sector whose major players are also among the biggest companies in the world, all economic sectors combined (Table 47).

**Table 47 Top ten companies in the world in terms of revenue, 2014**

Name	Oil company	Revenue (US\$ million)	Headquarters
<b>Wal-Mart</b>	No	\$476,294	United States
<b>Royal Dutch Shell</b>	Yes	\$459,599	Netherlands
<b>Sinopec Group</b>	Yes	\$457,201	China
<b>China National Petroleum</b>	Yes	\$432,007	China
<b>Exxon Mobil</b>	Yes	\$407,666	United States
<b>BP</b>	Yes	\$396,217	United Kingdom
<b>State Grid</b>	No	\$333,386	China
<b>Volkswagen</b>	No	\$261,539	Germany
<b>Toyota Motor</b>	No	\$256,454	Japan
<b>Glencore</b>	No	\$232,694	Switzerland

Source: *Fortune*, 2015

Yet there are local junior players that are small private or publicly listed companies, most often in hydrocarbon research and exploration.

In hydrocarbon extraction, especially for oil, projects generally compete with each other globally. The market is international, investors are located around the world, and production companies are multinationals.

It is therefore important to position Québec in the global supply and demand dynamic. Furthermore, apart from economic variables, other factors affect perceptions of the appeal and profitability of hydrocarbon development in Québec.

**Table 48 Examples of variables that affect the perception of a region’s appeal for oil and gas extraction projects**

Quantifiable variables	Qualitative variables
Production cost structure	Environmental constraints
Government inputs and levies	Acceptance by communities
Geological knowledge	Political will to protect the environment
Network of available suppliers	Investment climate
Workforce availability	Regulation scope
Emissions trading scheme	Bureaucracy
Proximity to markets	Interest of consumers
Infrastructure availability	Trends in global supply and demand
Tax systems	

Source: Ministère de l'Énergie et des Ressources naturelles

It is therefore important to examine the issue in its entirety to determine whether hydrocarbon extraction can take place in Québec from a win-win perspective for the government, all Quebecers, and project promoters with respect to government objectives, particularly with regard to the environment.

It should be noted that it is possible for the international community to make commitments and take measures to reduce GHG emissions so that the two-degree global warming target is met. This could have repercussions on world oil consumption and could limit the size of the market for petroleum products, an outcome that would change the dynamic of the global market.

Since 2007, Vancouver’s Fraser Institute has been publishing the results of a global survey on the perceptions of the appeal of various regions for hydrocarbon exploration and production. The ranking includes 16 variables that determine the competitive attractiveness of these regions (see Table 49 below). A global index is calculated for each region (Policy Perception Index) based on the average of the 16 variables.

The 2014 results rank 156 regions based on responses from 158 oil and gas companies from around the world. A breakdown by state or province is also presented for Canada, Australia, the United States, and Argentina. The survey was conducted between June 3 and August 23, 2014, and the results were made public in November 2014.

- In 2014, Québec ranked 133rd in the world among locations to invest in hydrocarbon exploration.
- This position is due primarily to recent instability associated with current and future hydrocarbon development regulation in Québec. In recent years, Québec announced its intention to review its royalty regime and adopt a regulation dealing with hydrocarbon development. Despite the announcement, these intentions have not translated into new legislation, and as a result hydrocarbon industry companies and investors are still waiting.

**Table 49 Québec's Rank - Global Petroleum Survey 2014, Fraser Institute**

Policy perception index variables	Québec's rank
Fiscal terms	147
Taxation in general	155
Environmental regulations	153
Enforcement of environmental regulations	131
Cost of regulation	151
Protected areas	149
Trade barriers	136
Labor regulations	41
Quality of infrastructure	112
Quality of geological database	101
Labor availability and skills	129
Disputed land claims	112
Political stability	87
Security (physical)	64
Efficiency of regulatory administration	151
Legal system	62
<b>Québec's rank based on total score of 16 variables</b>	<b>133</b>
<b>Total no. of regions</b>	<b>156</b>

Source: Global Petroleum Survey, Fraser Institute

The government has undertaken to introduce a specific hydrocarbon legislative and regulatory framework in the months following release of the final SEA reports.

If the government chooses to go ahead with its hydrocarbon development activities, this new legislative and regulatory framework must include the following:

- Best technical and transport practices
- The highest standards of environmental protection and personal safety
- The fairest royalty and benefit-sharing regime for residents

These objectives must, however, be achieved while ensuring regulatory consistency with what is done elsewhere so that Québec can remain competitive and attract the key industry players and investors ready to do things in the best way possible.

### **Municipal assessment: How the current system works**

Under the Act respecting municipal taxation, all property, with some exceptions, is entered on the property assessment roll and generates municipal and school revenues.

This rule also applies to pipelines, although they are subject to certain conditions. The value of a pipeline entered on the property assessment roll is fully taxable for municipal and school taxation purposes.

Hydrocarbon pipelines generate revenue for municipalities that varies based on the value entered on the roll for such pipelines and the tax rate used. According to MAMOT data, the value entered on the property assessment roll for all such pipelines in Québec was at least \$740 million for 2015. These pipelines run through various municipalities, whose applicable tax rates vary from \$0.20 to \$4.1161 per \$100 of assessed value. The municipal taxes thus generated are estimated to be \$10.9 million.

As the average school tax rate is \$0.25 per \$100 of assessed value, the associated revenue for school boards is estimated to be around \$1.8 million.

#### Impacts associated with hydrocarbon transport

As indicated in the hydrocarbon knowledge summary published under the SEAs in April 2015, we do not yet have information on the potential effect of the presence of pipelines or railways via which hydrocarbons are transported on a municipality's assessment roll.

For this reason, Phase 2 of the SEA has better documented this issue by means of a literature review on the subject (**Erreur ! Nous n'avons pas trouvé la source du renvoi.**). A total of six scientific studies conducted in North America in recent years were recorded. These studies use statistical models to assess the impact of the development of oil and gas pipelines, as well as the impact of associated accidents, on municipal property values.

The studies show that, in general, oil and natural gas pipelines do not have a statistically significant impact on the value of nearby properties. The impacts documented appear to be short term. Accidents and spills are what temporarily reduces the value of properties near pipelines, even if they are far away from the sites.

It is much more difficult to document the impact on property values of railways built to transport hydrocarbons especially since no studies have been recorded. It may be of benefit to Québec to further document this issue while also taking into account impacts of railway accidents.

Oil and natural gas transport raises all kinds of economic, social, and environmental issues as well as a variety of risks. From an economic perspective, the perception of risk can have a positive or negative impact on property values and the property tax revenues of municipalities. The SEAs have revealed that building pipelines to transport hydrocarbons does not generally have a significant long-term impact on a municipality's real estate wealth. Only small-scale, short-term impacts have been recorded in various studies.

It should be kept in mind that real estate wealth is something that directly affects citizens and municipalities. Transparency and best practices in project development may help minimize potential negative impacts on real estate wealth.

Little is known about the impacts on real estate wealth of rail transport of hydrocarbons. It may be of benefit to Québec to further document this issue while also taking into account the impacts of railway accidents.

## Externalities and mitigation and compensation measures

In the preceding sections we have seen that oil and gas exploration and extraction generate economic activity, promoting job creation, better salaries for workers, revenues for the government and municipalities, and profits for companies. However other, often negative, effects occur without being taken into account on the markets or reflected in prices.

A thorough understanding of these externalities is key to implementing effective and efficient policies and regulations. Before intervening to reduce or offset externalities, it is important to be familiar with their nature and anticipated financial impact.

To this end, a study on the anticipated externalities for Île d'Anticosti<sup>38</sup> was provided for under the SEAs.

**Table 50 Reference framework for externalities related to future hydrocarbon exploration and extraction on Île d'Anticosti**

Water	Samples Process water Treatment and disposal
Air	Atmospheric contaminants (COV, NOx, ozone, etc.) GHG emissions
Land	Land use conflicts Natural ecosystems (fragmentation and biodiversity) Radioactivity Seismicity Rehabilitation and closure of wells
Transport	Water Land Air
Social externalities	Noise Health and safety Well-being of communities

Source: Study **Erreur ! Nous n'avons pas trouvé la source du renvoi.**, MDDELCC, 2015

Analysis of the various externalities has helped identify important issues that Québec (and particularly Anticosti) should expect to face.

For example, the risk of drinking water and groundwater contamination is a prime concern for the public and for government authorities.

GHG emissions from future hydrocarbon exploration and extraction could significantly boost Québec's annual output, which could have an impact on its emission reduction targets.

Furthermore, hydrocarbon exploration and extraction could affect tourism, hunting, and fishing on Île d'Anticosti. Communication between the various parties and the adoption

<sup>38</sup> Study ATSV-01: Determining the possible negative effects of hydrocarbon development on Île d'Anticosti.

of avoidance and mitigation measures would help take into account certain negative impacts.

The study on externalities revealed that future hydrocarbon development on Île d'Anticosti could cause conflicts between competing types of resource use. Even though these competing interests do not have a high social cost across Québec, they nevertheless raise concerns among some users (e.g., vacationers, hunters, anglers).

Île d'Anticosti is home to 24 Atlantic salmon rivers, including five used for recreational fishing, which generates \$1.7 million in economic benefits. The outfitting industry generates \$12 million in annual benefits.

Consideration could be given to planning a consultation/participation mechanism to help avoid, mitigate, or offset these future externalities to the satisfaction of all parties.

### **Cost-benefit analysis of future hydrocarbon development on Anticosti**

A cost-benefit analysis (CBA) is a decision-making tool for evaluating and comparing the positive impacts (benefits or advantages) and negative impacts (costs or disadvantages) for society of a draft policy, a plan or program (PPP), or a major project. CBAs are particularly commonplace in transportation, agriculture, public health, and the environment.

By assessing the costs and benefits of a PPP on the same basis and timescale, a CBA can guide public officials in determining how socially acceptable a project is. It is a way to evaluate various options and test different assumptions by analyzing key variables.

Few CBAs have looked at the issue of hydrocarbon extraction. It is not easy to gauge all economic, social, and environmental costs and benefits based on a single unit of measurement (in this case, the dollar).

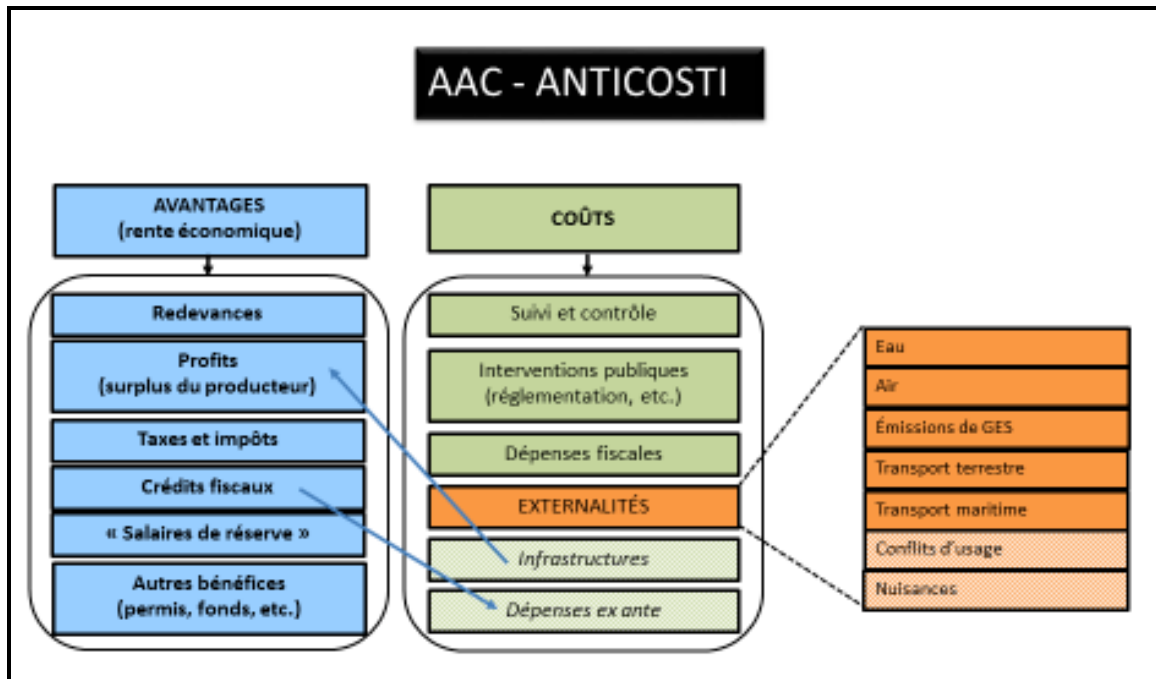
The main objective of Study **Erreur ! Nous n'avons pas trouvé la source du renvoi.** under the SEAs is to determine the most significant costs and benefits and to identify the best ways to maximize benefits while reducing costs for Anticosti residents and all Quebecers.

In short, this analysis seeks to simultaneously achieve three objectives:

- Help authorities with decision making by providing the most comprehensive picture possible of the costs and benefits of hydrocarbon development on Île d'Anticosti
- Examine the best ways to maximize the benefits and minimize the costs for Québec society as a whole and for Anticosti residents
- Inform the Québec public and especially Anticosti residents about the main anticipated environmental, economic, and social issues, be they positive or negative

The main expected costs and benefits of hydrocarbon extraction as identified by the CBA are summarized in the following figure.

**Figure 26 Main variables in the cost-benefit analysis for Anticosti**



Source: Study ATVS01, MDDELCC, 2015

The Anticosti CBA does not put precise dollar figures on all costs and benefits of hydrocarbon development on Île d'Anticosti for Québec as a whole. At this early stage, there is too much uncertainty surrounding many of the assumptions to take such a detailed approach. The study instead determines and presents the order of magnitude of the main impacts, both positive and negative, to inform and guide public officials with regard to the real implications of such development.

- The preliminary Anticosti CBA findings are as follows:
- Price and volume projections, which are highly speculative, will be key in determining the expected benefits.
- The GHG emission assessment revealed a considerable gap between the “social cost of carbon”<sup>39</sup> and the price paid by operators under the cap-and-trade system for greenhouse gas emissions (SPEDE). The emissions could also delay Québec's attainment of its GHG reduction goals.
- Royalties are a major factor for both social return (as profits) and profitability of operators (as costs).
- The expected cost of infrastructure could be enormous and substantially reduce both the social and private returns (benefits).
- The issue of the risk of spills associated with land and water transportation of hydrocarbons is crucial, particularly in the case of oil, even though many market instruments are available that can internalize part of the risk.

<sup>39</sup> Social cost of carbon: The net present value of the impact of climate change over the next 100 years of one additional ton of carbon emitted into the atmosphere today (Watkiss, 2006).

- Although local impacts (disturbances and conflicts of use) are not considerable on a provincial level, they may affect the local population. Compensatory measures may have to be considered.
- It is difficult to assess the potential impacts on the island's fauna, flora, and ecosystems in monetary terms. Additional work may have to be undertaken to fill this gap, particularly with regard to white-tailed deer and Atlantic salmon.
- Lastly the choice of discount rate(s) is crucial because it will determine the value given to time and future generations.

The Anticosti CBA study published under the SEAs must be periodically updated and enhanced as new information becomes available or certain assumptions are clarified.

## 6. Transport

### 6.1 Scope

The Transport steering committee received a mandate to study all technical, environmental, economic, and social issues affecting hydrocarbon transport. The following themes were addressed:

- Safety in hydrocarbon transport
- Environmental impacts of hydrocarbon transport methods (in conjunction with the Environment theme)
- Best risk mitigation technologies for various transport methods
- Transport infrastructures required for potential hydrocarbon extraction on Île d'Anticosti

#### **Comprehensive SEA on hydrocarbons**

Under the comprehensive SEA, the SEA steering committee set the following objectives for Transport:

- Analyze the risks to the safety of any person, any property, or the environment for the various hydrocarbon transport methods (train, truck, ship, and pipeline)
- Propose the best prevention measures for hydrocarbon transport
- Assess the best practices for mitigating the negative externalities of hydrocarbon transport for the receiving environment, to ensure transport is compatible with existing land use and to promote social acceptability of projects
- Compare the GHG emissions of the various hydrocarbon transport methods

An initial knowledge acquisition phase took place in fall 2014 under the comprehensive SEA on hydrocarbons. The following two studies were conducted during this phase:

- Innovation Maritime, *Knowledge Report – Marine Transport of Hydrocarbons*, Institut maritime du Québec, 2014.
- Trépanier M. et al., *Knowledge Report – Ground Transport of Hydrocarbons in Québec*, CIRANO and Centre risqué et performance, École Polytechnique de Montréal, 2015.

The knowledge summary published in March 2015 outlines these two studies. The main findings were as follows:

- There is little data on hydrocarbon road transport in Québec. Available data focuses mainly on hazardous materials in general. There is also very little data on hydrocarbon rail transport, particularly for Québec companies.
- Given that a significant portion of accidents associated with the transport of hazardous materials occurs during transshipment, an in-depth study on the issue is required.
- To be effective, the regulatory framework must foresee suitable monitoring and control measures on the part of regulatory authorities. A situation report on such measures is required.

- With regard to pipelines, the Energy East project pointed to the need for a detailed review of risks associated with watercourse crossings (including the St. Lawrence River) and the best applicable techniques and practices in the presence of such risks.

Further to these findings, five studies were proposed under the Additional Knowledge Acquisition Plan (AKAP) to continue the knowledge acquisition phase for Transport.

Two Transversal studies also examine some aspects of the issue of hydrocarbon transport. The regulatory component of these studies will be addressed in this chapter.

It should be noted that the content of the Transport study concerning the control and monitoring measures of Québec ministries and agencies for road, rail, and pipeline transport methods was addressed in two other studies to avoid overlap. All the studies are presented in Appendix 2.

### **Anticosti SEA**

Under the Anticosti SEA, the SEA steering committee gave the Transport steering committee a mandate to assess the following elements:

- The infrastructure required to transport hydrocarbons depending on the type of hydrocarbons present (natural gas or oil). This assessment includes the infrastructure required to collect, treat, fractionate, store, transport, and ship the resource to consumer markets
- The cost of such infrastructure if Québec were to proceed with the commercial development phase
- The nature and cost of the road infrastructure required for future hydrocarbon development on Île d'Anticosti

The two Transport studies conducted for the Anticosti SEA are presented in Appendix 2.

## **6.2 Hydrocarbon development on Île d'Anticosti**

### **Background**

The transport infrastructure scenarios for extraction of hydrocarbons on Île d'Anticosti are based on a number of assumptions. Because the project is currently in the preliminary exploration stage, these assumptions, described in previous chapters of this report, have a high degree of uncertainty. They concern:

- The number of wells drilled, their location, their operating spans, the amounts of oil or natural gas that can be extracted, the type of hydrocarbons, etc. (Chapter 5 – Economy)
- Drilling technologies and related equipment (Chapter 4 – Technical Aspects)
- Environmental constraints specific to Île d'Anticosti and the Gulf of St. Lawrence (Chapter 3 – Environment)
- Potential markets (Chapter 5 – Economy)

The infrastructure scenarios will become clearer when data collected on site becomes available, in the event that exploration continues and leads to resource extraction.

WSP Canada Inc. (WSP) conducted Study ATRA01 – Conceptual assessment of the need for transportation infrastructures for hydrocarbons extracted on Île d’Anticosti in order to export products to consumer markets. The study addresses the following points:

- Inventory of similar projects around the world
- Brief description of the environmental components (land, marine, and human) and environmental constraints
- Context for potential markets
- Presentation of a development scenario
- Composition of oil and gas as well as the definition of products and by-products to consider
- Presentation of infrastructure scenarios and a cost assessment

A summary of the content of this study is presented on the following pages.

**Similar projects**

To visualize the transport infrastructure scenarios, WSP looked at projects that had already been or were in the process of being completed. The hydrocarbon development conditions of these projects, located in island or northern environments, might be comparable to those of Île d’Anticosti. Such an exercise helps:

- Illustrate environmental issues encountered in the development of certain projects
- Document the issues, solutions, and technical feasibility of the transport infrastructure scenarios

Table 51 presents projects that have been or are in the process of being completed and bear similarities to the situation on Anticosti.

**Table 51 Hydrocarbon projects around the world**

Project	Country	Type of hydrocarbons	Description	Similarities
Hibernia, Terra Nova, and White Rose	Canada (Newfoundland)	Conventional oil	The Hibernia platform was designed to withstand the numerous icebergs in the waters of the region. It produced its first barrels of oil in November 1997. Hibernia’s current production is estimated at 220,000 barrels per day. Terra Nova and White Rose were producing an average of 86.7 million barrels per year from 1997 to 2007. Oil is shipped by tanker to various Canadian refineries or the Whiffen Head transshipment terminal in Newfoundland.	Offshore environment Northern environment Canadian project
Sable Island	Canada (Nova Scotia)	Conventional natural gas	Offshore gas extraction started in 1999. This project, whose lifespan was projected to be 25 years, was initially producing 11 million cubic meters per day until 2010, when its production decreased by nearly half, dropping to 5.5 million cubic meters per day. The project consists of a network of platforms, with operations primarily on the Thebaud platform. This infrastructure is connected to the coast by a submarine gas pipeline	Offshore environment Northern environment Canadian project

			nearly 225 km long. Conventional natural gas is liquefied at the Goldboro plant and shipped by tanker across the Maritimes and to the eastern United States.	
Barrow Island	Australia	Conventional oil and natural gas	Barrow Island is located 50 km northwest of Australia. Its deposits have been commercially extracted since 1967. The hydrocarbons from this source are transported to oil tankers via submarine pipelines 10 km long.  In 2009, expansion of the site (the Gorgon project) was approved by Australian authorities and begun. The project consists of building offshore gas platforms, a submarine pipeline for transporting hydrocarbons to Barrow Island, a liquefaction plant, and an LNG export terminal.	Island environment
Arun LNG	Indonesia (Sumatra)	Liquefied natural gas (LNG)	This project consists of liquefaction facilities with a total capacity of 12.5 million tons per year and five 127,000-cubic-meter storage tanks located in an island environment. The site is in the process of being converted into an LNG receiving terminal (the local gas reserves having been depleted).	
PT Donggi-Senoro LNG	Indonesia	LNG	This project is currently in the startup phase and consists of a liquefaction plant, a storage tank, and a jetty for rail transportation. The site's capacity is 2 million tons per year.	Coastal environment
Yamal LNG	Russia	LNG	This megaproject in the far north is in the construction phase. It involves the drilling of more than 200 wells, the construction of a vast gas terminal and a liquefaction plant with a capacity of 17 million tons per year, and the commissioning of 16 icebreaker tankers with a capacity of 170,000 cubic meters each.	Northern environment

There are a number of oil and gas projects in island or northern environments around the world. Although we must be careful when making comparisons, we can nevertheless observe that from a technical feasibility standpoint, a number of these projects have been conducted in conditions similar to those on Anticosti and have used technology and infrastructure adapted to local conditions.

### Environmental constraints

However, WSP's report mentions certain environmental constraints that will need to be taken into account with regard to hydrocarbon transport on Île d'Anticosti and in the Gulf of St. Lawrence.

- The possibility of burying pipelines on Île d'Anticosti is limited because from a geomorphological standpoint, the surface deposits across the island are thin.
- Bogs cover vast areas on the eastern part of the island, so hydrocarbon extraction in this sector would be subject to environmental and technical constraints.
- The presence of cliffs, coupled with ice, wind, and currents, constitute major constraints for creating port sites, especially on the north shore of the island. The south shore would be more appropriate for a port site.

Despite the constraints observed on Île d'Anticosti, WSP believes that they would not prevent the anticipated infrastructure projects from being carried out. If they materialize, such infrastructure projects (pipelines, plants, etc.) will, however, need to comply with

the various MDDELCC approval processes, particularly the environmental assessment and permitting processes.

### **Potential markets and associated infrastructure**

There is much uncertainty about the oil, natural gas, liquefied natural gas (LNG), and natural gas liquid markets. The following assumptions concerning the markets for which Anticosti's production would be intended were used for the transport infrastructure scenarios studied by WSP:

- Liquid petroleum would be transported by tanker to continental refineries located on the Atlantic Basin. The maximum production capacity would be about 45,000 barrels/day (development scenario, Chapter 5 of this report).
- The various gas components would be marketed individually (a gas fractionation plant would be required).
- Natural gas could be shipped to the North American continental market via pipeline or to the international market by tanker in the form of LNG. The maximum production capacity would be about 280 Bcf/year (development scenario, Chapter 5 of this report).
- For natural gas liquids:
  - Propane and butane would be grouped together to be marketed in the form of liquefied petroleum gas (LPG) and shipped by tanker to the international market.
  - Since there is no market for this product and because of the major constraints associated with transporting it (liquefaction is required), ethane would be developed locally. It would be isolated in part and sent to a turbine to produce electricity to operate industrial facilities. A certain amount could also remain in the natural gas.

However, because there is much uncertainty about the development of markets, WSP believes that it is difficult to anticipate the destination of the hydrocarbons that would be produced on Île d'Anticosti. A prospective promoter could just as well turn to the international market as the continental one (Québec, Maritimes, U.S., etc.). The destination of products and by-products would have a definite impact on the choice of transport infrastructure.

### **Transport infrastructure scenarios**

For each scenario, an upstream pipeline network is present on Île d'Anticosti to transport hydrocarbons to the infrastructures.

In all scenarios, liquid petroleum and natural gas liquids are extracted at the fractionation plant and shipped by tanker.

The transport infrastructure scenarios developed by WSP differ primarily in terms of the natural gas management approach and are as follows:

SCENARIO 1: Building of a gas fractionation plant and a liquefaction plant on Île d'Anticosti

SCENARIO 2:	Use of a floating liquefied natural gas (FLNG) vessel equipped with a gas fractionation plant and a liquefaction plant
SCENARIO 3:	Building of a gas fractionation plant and a liquefaction plant on the mainland (Côte-Nord or Gaspésie) with a submarine pipeline connection
SCENARIO 4:	Building of a gas fractionation plant on Île d'Anticosti with a pipeline connection to the continental transportation network

## Summary of required processing infrastructures

### Platform infrastructures (in all scenarios)

As the development scenario in Chapter 5 indicates, each platform would accommodate five to ten wells. Platform infrastructures would include:

- Triphase separators
- Liquid transfer pumps
- Gas compressors
- Water and ethylene glycol storage tanks
- Various infrastructures (shelters, tanks for liquids, etc.)

### Collection, storage, and delivery system (in all scenarios)

To transfer oil and gas extracted from each well, WSP determined that a collection network would have to be installed to ensure collection from 6,800 wells distributed among 712 platforms. The network would include about 1,700 kilometers of pipeline of various sizes, which would transport oil and gas together to a central processing point (see Figure 27).

Following the initial development of this collection network, WSP points out that a number of other studies will be required to develop an optimized collection network based on field constraints. The network presented in Figure 27 was developed to briefly assess what would be required on Île d'Anticosti.

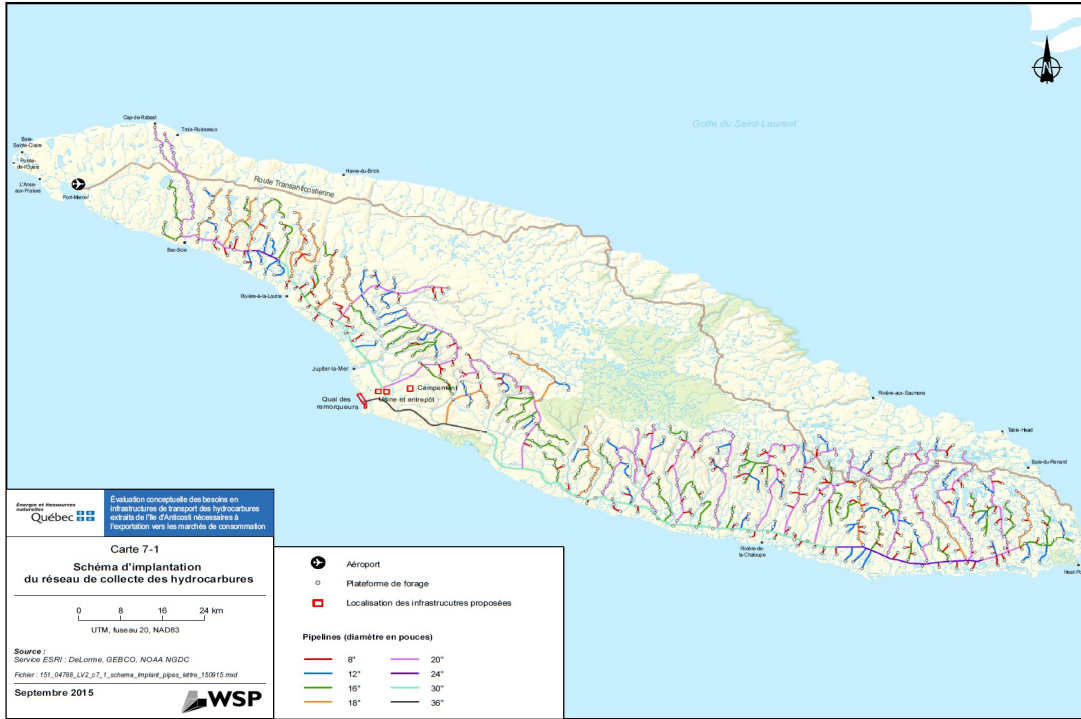
### Fractionation plant (in all scenarios)

A fractionation plant would be required to extract various products present in the gas phase. The processing plant would enable the following products to be isolated:

- Methane (natural gas)
- Ethane
- Propane and butane (in the form of LPG)
- Pentane, hexane (natural gas condensates)
- Heptane and octane (light oil)
- Carbon dioxide (CO<sub>2</sub>)

The plant would be equipped with fractionating towers, cooling towers, pumps, compressors, etc.

**Figure 27 Collection network and location of proposed plants on Île**



**d'Anticosti**

Liquefaction plant (in scenarios 1 and 3)

This plant would enable natural gas to be liquefied using a refrigeration process. Liquefaction makes it possible to store and handle larger volumes of gas, as liquid natural gas takes up about 600 times less space than natural gas. This unit would be downstream of the gas fractionating plant. The technology to be prioritized should be the subject of a feasibility study.

Furthermore, the liquefaction plant should be equipped to extract carbon dioxide from natural gas.

Floating liquefied natural gas (FLNG) vessel (in Scenario 2)

In Scenario 2, an FLNG vessel would be used to fractionate hydrocarbons and liquefy and store all elements obtained. This approach has many benefits compared to building and operating a plant on the island. The development of FLNG vessels began in the 1970s with drilling platforms for extracting hydrocarbons in deep waters.

A report from the firm KPMG40, quoted in WSP's report, presents the benefits of this technology, which could be particularly appealing for Île d'Anticosti. It would help:

- Reduce the environmental footprint and impacts on communities
- Significantly lower costs because FLNG vessels are usually built in Asia, which would mean savings on salaries and materials. Furthermore, eliminating the costs associated with the ground preparation and foundation of a plant helps reduce costs
- Mitigate the risks of cost overruns and quality failures. It is generally easier to control construction costs and quality in a shipyard
- Increase operational flexibility because an FLNG vessel can serve a number of markets and be relocated
- Promote greater flexibility in terms of financial options. Various business models are possible with respect to capital and operating costs to finance the infrastructure

Despite the benefits of having an FLNG vessel in the Gulf of St. Lawrence, WSP recommends:

- Studying the legal and regulatory context (federal and provincial) for operating this type of vessel
- Carefully examining the various financial models possible for purchasing and operating an FLNG vessel
- Documenting the constraints in the Gulf of St. Lawrence (ice, wind, tides, etc.)

#### Continental pipeline (in Scenario 4)

Scenario 4 would consist of collecting and transporting hydrocarbons to a fractionating plant on Île d'Anticosti. Natural gas would be transported via a submarine pipeline to the south shore of the St. Lawrence River, then via an onshore pipeline to Lévis.

This scenario could be an attractive option because regions along the pipeline like Gaspésie and Bas-Saint-Laurent could be connected to the natural gas network, and this would have a lasting impact on their economic development.

To confirm the technical and economic feasibility of such a pipeline, WSP recommends conducting a study. The firm points out that there are generally huge cost differences in pipeline projects despite equivalent distances. It is also important to consider both technical and economic factors such as the availability of labor, the price of materials, and the cost of easements.

#### **Summary of required ancillary infrastructure**

##### Marine facilities for receiving materials and transporting hydrocarbons (in all scenarios)

Marine facilities should be adapted to the construction, operation, and maintenance needs of equipment and infrastructure present on the island. Except for labor, all equipment for hydrocarbon development and transport should be transported by barge. Marine facilities would have to be built for this.

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<sup>40</sup> <http://www.kpmg.com/Global/en/IssuesAndInsights/ArticlesPublications/floatingLng/Documents/floating-LNG-evolution-and-revolution-for-the-globas-industry.pdf>

Marine facilities would also be required to transport hydrocarbons, based on the infrastructure scenarios described earlier in this chapter.

The current Port-Menier port facilities cannot meet these needs. The location itself of the port (near the town center) is a major constraint. Its shallow waters and relative distance from possible development sites are other major constraints.

According to WSP, a potential site for marine facilities is located on the south shore of the island (see Figure 27). The site was chosen based on its distance to the area of operation and the apparent absence of rocky formations on the shoreline.

WSP recommends further study on the technical feasibility of building a second port on Île d'Anticosti. The presence of cliffs, coupled with ice, wind, and currents, constitute major constraints for creating port sites.

To transport equipment and materials on Île d'Anticosti, the following marine infrastructures would be required:

- An LCT (landing craft tank), Fleximat, or other barge ramp (see Figure 28)
- A permanent caisson wharf might be required (to be evaluated during a feasibility study on the issue)
- A dolphin: Mooring structure extending above the water for mooring barges
- A breakwater: Floating jetty used to reduce the intensity of wave action (Figure 29)
- Bollards: Steel posts used to secure the mooring lines of ships

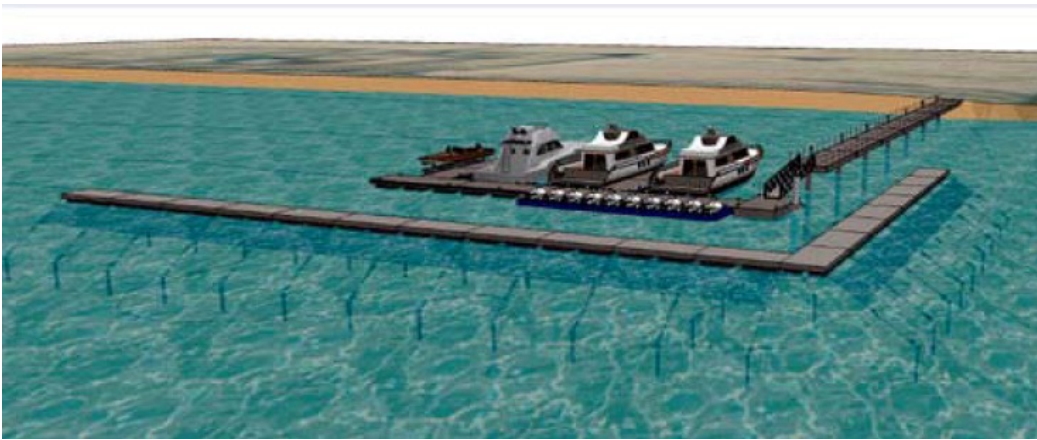
To ship hydrocarbons, the following marine infrastructures would be required:

- Submarine pipeline (1 to 3 km)
- Turret loading: Offshore mooring system used to moor ships for the purpose of loading them with hydrocarbons (Figure 30)

**Figure 28 LCT barge**



**Figure 29 Floating breakwater**



**Figure 30 Turret loading**



Airport (in all scenarios)

Air transportation would be a major component of hydrocarbon exploration and development on Anticosti. A number of similar projects observed around the world indicate that in the absence of a sufficient supply of local labor with the required skills, fly-in fly-out (FIFO) transportation is used in combination with accommodation in housing modules. This scenario does not, however, exclude the possibility of part of the workforce living on Île d'Anticosti. Using a combination of these two methods should be studied.

Air transportation of workers would require an airport that could accommodate Boeing 737 aircraft. According to WSP, the airport in Port Menier could be used provided that the airport's existing 1,372-meter-long asphalt runway is extended to 2,027 meters.

Worker housing (in all scenarios)

Worker housing on Île d'Anticosti would require the construction of major infrastructure. Housing modules would be built.

### Operation and maintenance (in all scenarios)

An operations center, maintenance workshops, warehouses, and garages would be required to support operations. Production process control and maintenance planning for transport infrastructure would be carried out at a 24-hour operations center.

### Energy and services (in all scenarios)

Facilities would also be required for:

- Water treatment (drinking water, process water, wastewater)
- Electricity production (thermal power plant)
- Other services such as procurement, fire protection, communications, and safety

### **Potential locations**

Processing and liquefaction facilities would be located inland in the southern part of the island. The housing complex would also be located near the plants to facilitate worker travel between the housing modules and worksites. The operations and maintenance center and the energy and services complex would also be located there (see Figure 27).

As previously mentioned, port facilities would be located on the south shore of the island (see Figure 27).

### **Infrastructure scenario costs**

In this study, WSP completed a preliminary cost estimate for the required infrastructure. A detailed estimate using a traditional engineering cost estimation approach would have been much too costly. Such an estimate far exceeds the scope of this study.

Furthermore, the very wide variation in cost of the required materials and equipment, the use of patented technology for various components, and the lack of past experience to draw on from similar projects in Québec are all factors that make the cost estimation process complex.

The approach proposed by WSP consists of determining an overall order of magnitude for scenario costs based on comparable costs observed in similar LNG projects around the world. The overall project cost per capacity unit was therefore determined to be C\$3,665 (US\$2,000) per ton of LNG produced annually.

To break the overall cost down for each project infrastructure subgroup, WSP consulted four studies (see the firm's report for bibliographic references). These studies break down the costs of dozens of projects completed elsewhere in the world. The projects include both a hydrocarbon processing plant and an LNG plant.

**Table 52 Cost breakdown per infrastructure subgroup**

Infrastructure subgroup	Collection, storage, and delivery	Processing	Liquefaction	Energy and services	Other infrastructure	Total
	26%	9%	40%	17%	8%	100%

Cost detail by component

Based on this analysis, WSP assessed the cost of the four scenarios to be between \$12 billion and \$17 billion, including the drilling platforms, for the entire operating period considered.

By applying the above methodology, the costs of each scenario can be broken down by infrastructure subgroup. These costs are presented in Table 53.

**Table 53 Costs for each scenario considered (\$billion) (CAD)**

		1 Fractionation and liquefaction on the island	2 Fractionation and liquefaction on a ship	3A Fractionation on the island and liquefaction in Côte-Nord	3B Fractionation on the island and liquefaction in Gaspésie	4 Pipeline connection on the south shore
1	Platform infrastructure	3.204	3.204	3.204	3.204	3.204
2	Collection, storage, and delivery	3.109	2.332	3.109	3.109	3.103
3	Gas fractionation	1.119	0.839	1.119	1.119	1.348
4	Liquefaction	5.099	3.824	5.099	5.099	0
5	Energy and services	2.114	1.586	2.114	2.114	2.540
6	Other infrastructure	995	746	995	995	1.191
7	Submarine and onshore pipeline	N/A	N/A	124	249	5.278
	<b>TOTAL (\$billion) (CAD)</b>	<b>15.640</b>	<b>12.531</b>	<b>15.765</b>	<b>15.889</b>	<b>16.664</b>

In its study, WSP believes that a number of infrastructure scenarios are possible for hydrocarbon extraction on Île d'Anticosti. The costs of the various scenarios vary between \$12 billion and \$17 billion. Except for Scenario 4, all the scenarios provide that gas will be liquefied before being shipped to markets.

**Assessment of additional needs of required road infrastructures**

The new port and industrial facilities built in the southern part of the island would have to be connected to the drilling platform network and Port-Menier. Various routes are currently being studied by MTQ (ATRA02 – Assessment of supplementary needs for road infrastructures on Île d'Anticosti in order to extract hydrocarbons). A new road would likely have to be built to connect the southern part of the island to Route Transanticoستنienne and therefore to Port-Menier. The section of Route Transanticoستنienne that would be used by the heavy trucks required for hydrocarbon development would need to be upgraded. The financing method for these road infrastructures has not yet been determined, but a portion could be assumed by private promoters.

As the analysis was still in progress at the time of writing of this report, the conclusions on the best route and its costs will be included in the final report of the Anticosti SEA.

A network of logging-type access roads would also need to be built to reach all the drilling platforms. The positioning of each road section has not been specifically determined, but the map of the collection network provides a good idea of the extent of the access roads (see Figure 27). The costs of this road network should normally be borne by the promoter in charge of drilling.

## 6.3 Legal framework and management of hydrocarbon transport by type of transport and for multimodal platforms

### Ground transport legal framework and management

The knowledge summary published in April 2015 mentions notable weaknesses in Québec in the preparedness of workers in the event of a major accident or spill and in their response and coordination capabilities. These weaknesses were also identified at the damage restoration and financial compensation stage. Studies address some specific aspects of the situation, but none provide a complete picture of the situation in Québec for the hydrocarbon sector.

All these elements are governed by a legal and regulatory framework. To be effective, the framework must foresee suitable monitoring and control measures on the part of regulatory authorities. With regard to hydrocarbon ground transport, Study GTRA02 – Control and monitoring measures by Québec government departments and agencies for road, rail, and pipeline operations was included in the AKAP to provide an overview of the situation.

To avoid overlap, the content of Study GTRA02 was handled in Study GTVS01 – Examination of emergency prevention, preparedness, and intervention measures in the event of a major on-shore incident under the Transversal theme and in Study GTRA01 – Issues concerning intermodal transportation and hydrocarbon transshipment operations.

Study GTVS01 was in progress at the time of writing of this report. The findings and recommendations concerning the status of oversight and monitoring for ground transport will therefore be included in the final report of the comprehensive SEA.

Study GTRA01, conducted by Centre interuniversitaire de recherche en analyse des organisations (CIRANO), was also in progress at the time of writing of this report. However, CIRANO made certain findings that could put it on different tracks when its final report is published. These findings are therefore provided below as a guideline only.

### Pipeline transport

Study GTVS01 indicates that Régie du bâtiment (RBQ) regulates the construction, monitoring, and maintenance of provincial pipelines transporting refined petroleum products, but not crude oil. Because they are not governed by RBQ, crude oil pipelines and their storage tanks are not subject to any inspections.

It is recommended that the legal and regulatory framework be amended to ensure that the transport of crude oil via provincial pipelines is covered by strict technical standards

with respect to preventive, preparatory, and response measures in the event of a major accident.

Because Study GTVS01 was not completed at the time of writing of this report, other findings and recommendations will be included in the final report of the comprehensive SEA.

### **Ground transport (rail and road)**

Study GTVS01 examines these two methods of ground transport. Its findings and recommendations will be included in the final report of the comprehensive SEA.

#### **Watercourse crossing by pipelines**

With regard to pipelines, the Energy East project pointed to the need for a detailed review of risks associated with watercourse crossings (including the St. Lawrence River) and the best applicable techniques and practices in the presence of such risks. The associated study (GTRA03) is in progress; the final results will be available in the final report of the comprehensive SEA.

### **Marine transport legal framework and management**

The study on preventive, preparatory, and response measures in the event of a major accident – offshore (GTVS0241) by Institut maritime du Québec (IMQ) determined the following facts:

The Canadian regulatory system is strict. It conforms to international agreements and compares with systems in effect in many other countries.

Canada has additional provisions regarding compensation.

Canada and the entire international community set limits on the types of eligible ecosystem-restoration expenses that can be compensated.

The Canadian Compensation Regime upgraded international provisions for compensation by establishing the Ship-source Oil Pollution Fund.

Canada has additional provisions regarding winter navigation.

Canadian legislation has a reinforced structure requirement for ships for winter navigation.

In a technical publication (TP14335F – Winter Navigation on the River and the Gulf of St. Lawrence: Practical Notebook for Marine Engineers and Deck Workers), Canada proposes a series of measures and recommendations intended for ship captains transiting in the St. Lawrence in winter. The document includes regulatory requirements, voluntary requirements, and recommended means of reducing the risks of the presence of ice, slush, and low temperatures.

There are also special provisions for tankers (publications TP14335F and TP15163B).

#### **IMQ recommends:**

- Better defining the role of municipalities and better informing them of the Marine Oil Spill Preparedness and Response Regime

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<sup>41</sup> The consultation document takes into account the findings and preliminary improvements, given that the final version was recently received.

- Making improvements regarding eligible expenses for compensation
- Including the complete restoration of affected ecosystems following examination (as in the U.S. regime)
- Enhancing research programs on the impact of spills, the development of recovery techniques, and ecosystem restoration
- That the Québec government get involved in developing the federal government's Area Response Plans (ARP), which will enable response standards to be adapted according to site-specific factors (quantity, climate, responders)

## Multimodal platform legal framework and management – preliminary findings<sup>42</sup>

### Background

As noted in the hydrocarbon knowledge summary, accidents involving hazardous materials (including oil), regardless of the type of transport used (apart from pipeline transport), occur twice as often at fixed facilities than during transport.

These operations often fall under the jurisdiction of more than one level of government, which may complicate regulation and the sharing of responsibilities. Most of the time safety management systems are integrated into fixed facilities more easily than on modes of transport (namely moving vehicles and transportation infrastructure).

On this basis, the CIRANO team was mandated to conduct a study on hydrocarbon loading and unloading on multimodal platforms in Québec, under the SEAs (Study GTRA01).

### Hydrocarbon loading and unloading on multimodal platforms in Québec

#### Definition of a multimodal platform

A multimodal platform is defined as a facility that can accommodate several modes of transport. In Québec, road transport is still used in addition to rail, marine, and pipeline transport, either alone or in combination. Gas stations<sup>43</sup> are excluded from this definition. They will, however, be considered in the overall analysis given their large number and the risks they may pose. They generally use truck transportation only.

Loading and unloading are the most problematic activities even if only one mode of transport is considered. CIRANO's study therefore concentrated on these activities.

#### Number and location of multimodal platforms

Data from the Régie du bâtiment du Québec (RBQ) register of high-risk petroleum equipment was used primarily to inventory multimodal platforms in Québec. The statistics that follow should be interpreted with caution, given the fact that crude oil is not governed by RBQ (regulations concern only petroleum products, including gasoline, diesel fuel, fuel ethanol, aviation fuel, and fuel oil). Furthermore, even though RBQ regulations apply to all petroleum equipment facilities in Québec, some facilities may not

<sup>42</sup> The information in this chapter may be revised in the final report of the comprehensive SEA following publication of CIRANO's final report.

<sup>43</sup> Gas stations include all fuel-dispensing stations with or without service engaged in the retail sale of fuel for automobiles.

be subject to RBQ because they are under federal jurisdiction. Taking into account these two limitations, the key points are as follows:

- According to RBQ data, CIRANO lists around 4,200 sites (including around 3,300 gas stations) where petroleum products are loaded and unloaded. The ten largest facilities in the RBQ register represent 59% of the total petroleum product storage capacity in Québec.
- Among the 900 sites where products are loaded and unloaded (excluding gas stations), CIRANO identified a hundred or so multimodal platforms to consider for this study. They include mainly commercial oil storage depot operators and industrial or mine sites (e.g., the oil storage depots at the Valero refinery in Lévis and the Suncor refinery in Montréal-Est).
- These multimodal platforms account for 70% of the total storage capacity of all sites where petroleum products are loaded and unloaded in Québec.
- About 70 facilities are associated with rail transport, 40 with marine transport, and five with pipelines.
- The multimodal platforms were geotagged. Nineteen percent are in the Montréal region, 14% in the Montérégie region, 9% in the Québec/Chaudière-Appalaches region, and 58% in other Québec regions.
- In terms of storage capacity, the multimodal platforms in the Montréal area account for 49% of the total capacity of all sites, Montérégie 20%, and Chaudière-Appalaches 14%.

#### **Multimodal platform accident statistics**

There is no database that accurately lists and analyzes accidents involving hydrocarbon spills on multimodal platforms. It is therefore difficult to quantify this phenomenon in Québec and changes over time.

The best source of information to attempt to quantify accidents on multimodal platforms is Transport Canada's (TC's) Dangerous Goods Accident Information System (DGAIS) database. However, the following factors must be taken into account:

- The accidents analyzed occurred at facilities during handling<sup>44</sup> (versus during transit). They include but are not limited to loading and unloading accidents.
- Accidents must be declared when a release exceeds a certain threshold. Under Section 8.3 of the Transportation of Dangerous Goods Regulations, this threshold is set at 200 liters for flammable liquids or a release of 10 minutes or more for Class 2 gases.
- Some accidents that are not subject to the required declaration threshold are in the database. TC encourages reports of such accidents to be filed for analysis purposes. The data is useful for developing new standards. "Near misses"<sup>45</sup> are thereby archived in the database.

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<sup>44</sup> Transport Canada defines the term "handling" as meaning the loading, unloading, packing, or unpacking of dangerous goods in a means of containment or transport for the purposes of, in the course of, or following transportation and includes storing them in the course of transportation..

<sup>45</sup> "Close call" and "dangerous occurrence" are also terms for an event that could have caused harm but did not.

Given that not all accidents and releases are reported to TC, the DGAIS database may underestimate their number. It is therefore important to interpret the following data with caution.

Because there was a change in methodology between 2000 and 2001, accident statistics were recorded over the 2001–2014 period. A total of 59 accidents (spills of at least 200 liters or releases of gas of more than 10 minutes) occurred at fixed facilities during this period.

Accidents were analyzed by year, administrative region, cause, and product type. Although trends are not easy to identify, this data is not fully representative of multimodal platforms, and the sample size is small, the following conclusions can be drawn:

- The number of accidents is fairly constant from year to year.
- The number of accidents and the volumes spilled are greater in Montréal and the Capitale-Nationale and Montérégie regions.
- The carrier was responsible for accidents in 76% of cases (in only 19% of accidents, the fixed facilities were responsible and in 5%, the shippers).
- Forty-nine percent of handling accidents at fixed facilities occurred at rail terminals, 36% at road terminals, 5% at marine terminals, and 10% at other facilities (processing plants, gas stations, and air terminals).
- Forty-seven percent of accidents were due to human error while 36% were caused by equipment failure.

### **CIRANO's preliminary findings concerning the multimodal platform legal framework and management**

Following a number of consultations with government experts and interviews with private companies operating multimodal sites, CIRANO made some preliminary findings that helped identify good practices in Québec and potential improvements, which are presented in tables 54 and 55.

Seven main issues and two transversal issues were identified to perform the analysis. They represent measures that may be taken to prevent or reduce the likelihood of an accident with hydrocarbons and to reduce the consequences of such an accident, with respect to prevention and protection barriers.

**Table 54 Good multimodal platform management practices observed in Québec**

Issue	Good practices observed in Québec
Design and construction of fixed facilities (loading and unloading bays)	Control room computerization to automatically alert key people in emergency situations Loading bays designed to take external risks into account and enhance site safety
Activity reporting	None
Shipping documents and signage	Checklists of loading and unloading safety measures in the driver's handbook (in the form of step-by-step instructions and photos)
Employee training	Development of a course outline, including safety measures to use during hydrocarbon loading and unloading Introduction of a system consisting of several types of assessment (theory and ground simulations) and an objective grading system
Safety measures	Use of bottom loading with an overfill detection system during loading
Emergency plans and measures	Sharing of equipment and staff between facilities in the same geographic region to cope more efficiently with emergencies
Accident reporting	None

**Table 55 Possible improvements to multimodal platform management**

Issue	Possible improvement
Design and construction of fixed facilities	Production of guides that summarize design requirements and standards for loading bays
Activity reporting	Standardization of reporting criteria between the provincial and federal governments Improvement in the quality of data collected
Shipping documents and signage	Tightening of the compliance monitoring process and application of regulatory requirements
Employee training	Joint development of training templates by the various ministries involved Introduction of a provincial TDG minimum knowledge exam (e.g., online exam with a minimum pass grade)
Safety measures	Tightening of the compliance monitoring process and application of regulatory requirements Consultation of companies in advance of

Issue	Possible improvement
	regulations to develop good practices guides that would be disseminated in addition to more general regulations, setting objectives rather than means
Emergency plans and measures	Harmonization of all the various ministries' requirements Tightening of the compliance monitoring process and monitoring of emergency plans through validation by designated inspectors
Accident reporting	Harmonization of the various ministries' databases Revision of the accident report to enhance and improve information collected in databases with fields that make it easier to assess the causes of accidents and that provide a clearer picture of the response measures taken and the outcome
Communication	Improved understanding of legislation: Development of practical guides that compile the requirements of the various ministries in a single document Improvement in and promotion of communication and the sharing of information among all industry players, all levels of government (including the municipal level), and the general public Use of existing organizations such as joint municipal industrial committees (CMMIs) and industrial associations to relay information from ministries as well as good practices
Inspections	Tightening of compliance and monitoring processes and stricter monitoring of regulatory compliance on platforms where hydrocarbons transit
Across the board for all issues	Review of the legal and regulatory framework for crude oil (transport, storage, and handling)

CIRANO's preliminary analysis identifies three key priority areas for improvement to make the loading and unloading phases safer: training, accident reporting, and safety measures. We note that improvements can involve both prevention and protection.

# 7. Spill Management

## 7.1 Scope

Concerning the contingency measures to be taken in the event of a spill, which were studied as a means to address environmental and cross-cutting issues, the SEA steering committee set as its primary objective to fully review onshore and offshore accident prevention, preparedness, and response measures for both hydrocarbon transport and oil and gas development activities. More specifically, the committee had to:

- Determine whether current oil and gas shipping regulations ensure the safety of the public (workers included), the environment, and goods
- Assess the response capacity of the various organizations concerned based on their respective roles and responsibilities
- Propose legislative and regulatory amendments for major spills
- Determine what can be done to ensure the funding of restoration and compensation measures in the event of major spills

Marine oil spills can have major consequences on ecosystems because spilled oil spreads quickly in water and can be difficult to clean up. This section also takes stock of applicable knowledge with respect to weather in the St. Lawrence River and Gulf.

## 7.2 Onshore

### Impact of onshore oil spills

Québec has had very few major land spills. Most onshore oil spills lead to soil and groundwater contamination, bad odors, and explosions or fires whereas marine spills are usually problematic due to how quickly oil spreads through the water column.

Land spills are generally subject to regulations on contaminated areas.

### Contaminated soil management

Applicants must comply with sections 8 and 9 of the Regulation respecting hazardous materials (RRHM) (CQLR, Q-2, r. 32) if the soil is contaminated by hazardous materials as defined in the regulation. In the event of a spill, all contaminants must immediately be removed and the soil affected cleaned or treated on site without delay.

Whether soil contaminants are hazardous or not, soil can be treated on site or offsite in an authorized receiving area in compliance with the Regulation respecting the burial of contaminated soil (RRBCS) (CQLR, Q-2, r.18) and the Regulation respecting contaminated soil storage and contaminated soil storing stations (RRCSSCSSS) (RLRQ, Q-2, r.46).

No site is currently authorized to receive contaminated soil on Île d'Anticosti. It is therefore important to consider the logistics of moving soil to an off-island location or look into establishing a new contaminated soil storing station to reduce transport distances. In some cases, the second option would be subject to the RRBCS and the Regulation respecting environmental impact assessment and review.

## **Land rehabilitation**

A soil characterization study certified by an expert is required within six months of ceasing hydrocarbon exploration and extraction in accordance with Section 31.51 of the Environment Quality Act (EQA) (CQLR, Chapter Q-2).

If the characterization's results indicate that contaminant concentrations exceed the limits set out in Appendix 1 of the Land Protection and Rehabilitation Regulation (LPRR) (CQLR, Q-2, r. 37), a notice of contamination must be entered in the land register (EQA, Sec. 31.58). A rehabilitation plan must also be submitted to MDDELCC for approval if soil contaminant concentrations exceed the regulatory limits under Section 31.51 of the EQA as set out in Section 1 of the LPRR. For contaminants not listed in the LPRR, the Soil Protection and Contaminated Sites Rehabilitation Policy (MEF, 1998a) stipulates that rehabilitation must aim to restore soil and groundwater quality to what it had been before activities began.

## **Onshore prevention measures**

Study GTVS01 on the examination of emergency prevention, preparedness, and intervention measures in the event of a major onshore incident is intended to assess the preparedness of various public and private responders—including municipal bodies—their technical and financial capacities, and the mechanisms in place to coordinate their efforts. It also addresses the ability of companies to cover the costs of essential restoration and compensation measures.

This study was not yet complete at the time of writing this document. The findings and areas for improvement will be included in the final report of the comprehensive SEA.

## **Spill response**

According to Study AENV15 (MDDELCC, 2015c), no regulations on hydrocarbon exploration and development activities introduced by Ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques (MDDELCC) and Ministère de l'Énergie et des Ressources naturelles (MERN) currently call for risk or contingency plan assessments. An MDDELCC order indicates that no such assessment is required for approval requests under Section 22 of the EQA.

However, in its Lignes directrices provisoires sur l'exploration gazière et pétrolière (MDDELCC, 2014b), MDDELCC stipulates that all authorization holders must apply the contingency plan developed jointly with local authorities as soon as any incident that could pose a threat to the environment or human health or safety takes place.

Meanwhile, in an order dated June 30, 2014, MERN specifies the conditions and obligations applying to all oil, natural gas, and underground reservoir exploration on Anticosti land reserved for the State. One of these obligations is that exploration permit holders are to submit contingency plans before conducting any work.

Given that no Québec regulation establishes explicit objectives and standards for risk analysis and contingency planning, the information requested in the MDDELCC guidelines and MERN order on contingency planning indicates that improvements should be made to regulations in this regard.

Under Section 9 of the Regulation respecting hazardous materials, any company responsible for or affected by a spill involving hazardous material, whether it has a contingency plan or not, must stop the spill, inform the MDDELCC minister, recover the

hazardous material, and remove any contaminated material not cleaned or treated on site.

In addition to the company, various departments and agencies may also be called upon to respond to environmental emergencies based on their roles and responsibilities. Municipalities are the first and main responders for any (onshore) emergencies in their territories. However, MDDELCC can also take action to minimize environmental impacts during such emergencies, supporting municipalities through its Urgence-Environnement service.

## 7.3 Offshore

### Impact of offshore oil spills

St. Lawrence oil spills could come from a number of sources. Tankers present the greatest threat due to the amount of oil they carry, although compartmented tanks and mandatory double hulling reduce the risk of major spills.

The Gulf of St. Lawrence is a fragile, rich, and diverse ecosystem providing many major ecosystem services to society. Its various resources are vital to many human activities and, as such, any damage to the Gulf poses a risk to many of these activities. A number of areas of ecological or biological interest have been identified by various governmental and non-governmental organizations.

Studies on oil spills in cold environments (e.g., the *Arrow* [Nova Scotia, 1970], *Amoco Cadiz* [France, 1978], *Exxon Valdez* [Alaska, 1989], *Sea Empress* [United Kingdom, 1996], and Chalk Point/Swanson Creek [Maryland, 2000] spills) conducted several years after the fact have revealed the following:

- Animals and plants still experience the adverse effects of major oil spills after many years have passed
- It can take years for animals and plants to recover from oil spills
- It is crucial that any species affected by an oil spill be monitored long-term to assess the impact of the spill and the environment's recovery potential

As part of this SEA, Study GENV32 (Chalut and Brêthes, 2015) provided an overview of potentially vulnerable areas in the Estuary and Gulf of St. Lawrence with a view to the responsible development of Québec's maritime oil resources.

The risks involved in transporting hydrocarbons by sea are many and vary based on means of transport (pipeline, tanker, rail), facilities used (pumping stations, marine terminals, etc.), and transport intensity. The incidence of spills and cumulative damage therefore varies tremendously and is hard to quantify, although navigation measures have historically limited spills in the Gulf of St. Lawrence to a few incidences, despite heavy maritime traffic. Oil spills are some of the main risks associated with oil shipping and development.

Spill management will depend on the size and the behavior of oil slicks. Study GENV22 (CEAEQ, 2015a) determined how oil behaves and weathers in aquatic environments and Study GENV23 established environmental forensics tools for the oil and gas industry aimed at identifying those responsible for oil slicks of unknown origin. Study

GENV28 (CEAEQ, 2015b) developed supplementary methods of analysis involving marker tracking for characterizing oil in water

The impact of an oil spill on the Gulf of St. Lawrence ecosystem could be dire, as many elements of marine environments can complicate cleanup activities, such as deep seabeds, ice floes, and high winds. Strong ocean currents, seasonal ice cover, low water temperatures, nearby shorelines, and a unique and fragile ecosystem all amplify the potential impact of oil spills on the environment.

When it comes to birds and mammals, few studies have been conducted on the effects of oil spills (except oiling) and response methods used to clean contaminated areas, and the long-term effects of response methods are largely unknown. Since these animals have long life cycles, it is likely that such disruptions will bring about long-term reproductive and development issues and endanger their survival.

### **Impact of oil spills in cold environments**

Study GENV24 (Allaire-Verville, 2015) assessed the impact of oil and response methods on cold coastal ecosystems several years after spills had occurred. Many cases were examined, namely that of the Arrow (Nova Scotia, 1970), Amoco Cadiz (France, 1978), Exxon Valdez (Alaska, 1989), Sea Empress (United Kingdom, 1996), and Chalk Point/Swanson Creek (Maryland, 2000). The main reasons for selecting these five cases were that, on the one hand, scientific data on them is plentiful and readily available, and on the other, they involve diverse spill sites and ecosystems.

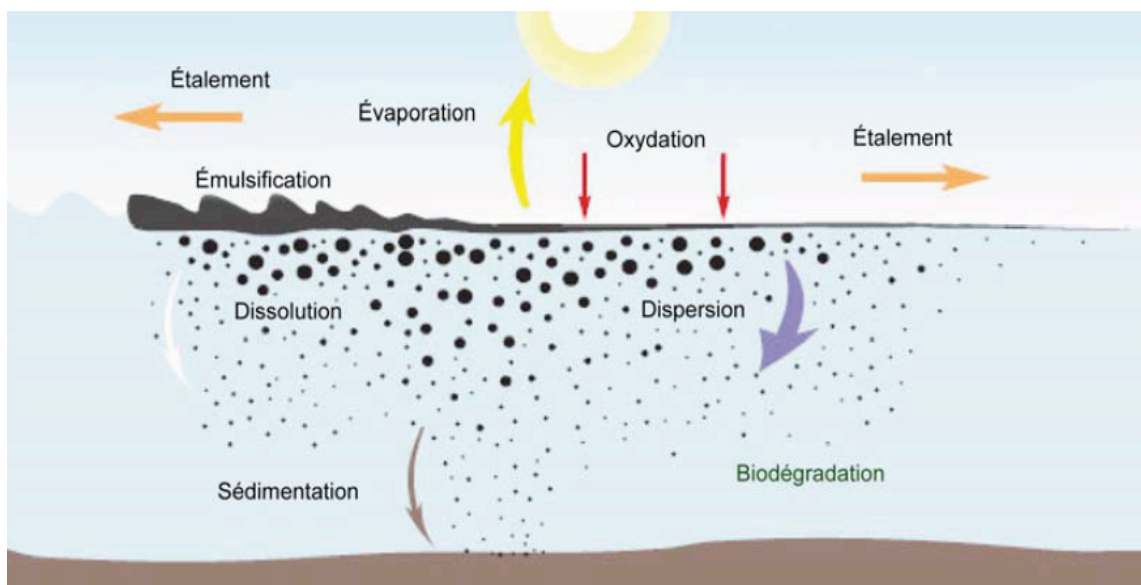
The results revealed the following:

- 1) Animals and plants still experience the adverse effects of oil spills after many years have passed.  
Long-term effects can be observed in algae (bleaching and reduced coverage), plants (reduced coverage and growth), invertebrates (disruption of community structure among benthic invertebrates, changes in abundance of taxa, reduced growth, and signs of cellular stress in bivalves), fish (histological and genetic abnormalities), birds (death by oiling), and mammals (death).
- 2) It can take years for animals and plants to recover from oil spills.  
Algae, plant, invertebrate, and fish communities have at times taken more than ten years to recover. Given that the long-term effects on mammals have not been systematically studied, their recovery time could not be determined. However, it would seem that animals with longer life cycles tend to have longer recovery times.
- 3) Analyzing net environmental benefits after oil spills in coastal environments can minimize the impacts of response methods.  
Studies conducted after the *Exxon Valdez* and *Amoco Cadiz* spills seem to show that high-pressure hot-water washing negatively affected ecosystems and their recovery times. These cases demonstrated that response methods influence ecosystem recovery. Net environmental benefits analyses (NEBA) would make it easier to plan oil spill response operations and use methods that are less likely to affect the environment and help communities recover in the short or medium term.
- 4) It is crucial that any species affected by an oil spill be monitored long-term to assess the impact of the spill and the environment's recovery.  
The fact that spill-related effects have been observed in organisms many years down the line shows how crucial it is that animals and plants be monitored long-term. Such monitoring provides invaluable data for assessing the state of affected environments, their recovery, and any need for further cleanup.

## Hydrocarbon decomposition by bacterial communities native to the Gulf of St. Lawrence after an oil spill

Study GENV32 (Lemarchand and Desbiens, 2015) reviewed the state of knowledge on hydrocarbon biodegradation in the Gulf of St. Lawrence. Once oil has been introduced in an aquatic environment, it triggers various natural decontamination mechanisms. These include abiotic mechanisms (evaporation, dissolution, dispersion, photo-oxidation) and biotic mechanisms (microbial degradation) (Margesin and Schinner, 1999). Together, these mechanisms determine the effectiveness of decontamination and the environment's ability to recover. Recovery capacity also depends on the characteristics of the oil in question and the physicochemical and biological conditions of the receiving environment.

**Figure 31 Processes influencing the fate of oil in marine environments**



Source: Genivar (2011)

Many microorganisms can metabolize organic pollutants (hydrocarbons, pesticides, solvents, plastics) and convert them into cellular components. However, bacteria and fungi—the primary agents of environmental degradation—are the only microorganisms capable of metabolizing oil. No single microorganism can break down all components of crude or refined oil. Some bacteria can break down multiple hydrocarbons or even an entire class of hydrocarbons, but the tens of thousands of compounds contained in oil can be broken down naturally only through the joint efforts of all members of a complex microbial community (Head, Jones, and Roling, 2006).

Oil in cold saltwater spills tends to spread and form a thin film on the surface. Water and oil emulsions can then be formed by wind and waves. The dispersion of hydrocarbons into the water column as emulsions expands the contact surface with the environment, thereby increasing access for the microbes capable of breaking hydrocarbons down (Leahy, 1990). At this stage, the oil's chemical composition is key. Simple molecules like saturates are degraded first, followed by light aromatics, heavy aromatics, and finally polar compounds (Leahy, 1990).

A major feature of the Gulf of St. Lawrence ecosystem that has a strong influence on indigenous microbial communities' ability to biodegrade hydrocarbons is its winter ice cover, which varies in size from year to year. The Gulf of St. Lawrence usually freezes over in mid-December along Québec's continental shores and a bit later along the insular shores of Anticosti and Îles-de-la-Madeleine. Ice formation progresses all the way to the west coast of Newfoundland by mid-February. Breakup begins around mid-March and continues into the second week of April offshore (Genivar, 2011). This ice cover can significantly alter the fate of hydrocarbons in winter by altering their bioavailability for microbial biodegradation.

Lemarchand and Desbiens (2015) analyzed over twenty studies conducted in the last 40 years on the effects of oil contamination in the St. Lawrence River system. While the data from these studies is crucial to understanding the potential risks of oil spills in the Gulf of St. Lawrence, it is insufficient to ascertain the ecosystem's capacity for oil biodegradation.

Hydrocarbon biodegradation in the Gulf of St. Lawrence is influenced by a number of factors including abiotic and biotic processes. While physicochemical and weather conditions in the Gulf are relatively well known, the same cannot be said of the ecosystem's microbiological diversity. There is currently very little data on the abundance, diversity, and seasonal fluctuations of bacterial communities native to the Gulf. Even less data is available on the presence of hydrocarbonoclastic microorganisms<sup>46</sup> in these communities. This lack of microbiological data is a major obstacle to estimating the Gulf's inherent recovery potential and its resilience with respect to oil spills.

## **Impact of mitigation and restoration measures**

### **Chemical dispersants**

Chemical dispersants, much like hydrocarbons, are very diverse in terms of chemical composition and, by extension, can contain a variety of toxins. As with other contaminants, reactions to chemical dispersants vary by species. Embryonic and larval stages seem to be more sensitive than adult stages. Significant differences in toxicity levels have also been observed between various hydrocarbon/dispersant blends. Such blends are far more toxic to aquatic organisms—regardless of their trophic level—than dispersants and hydrocarbons alone. Most studies attribute this to increased PAH levels and greater exposure to oil droplets for organisms in the water column, resulting in a larger contact area between organisms and oil.

According to Study GENV31 (Pelletier, 2015), there is no consensus in the scientific community as to whether chemical dispersion should be used because some believe it does more harm than good and that natural attenuation is more effective and less toxic to the environment. Most scientific reports conclude that dispersants themselves are of low toxicity to marine animals. Nevertheless, acute and sub-lethal toxicity levels have repeatedly been observed in many aquatic species when dispersants are used on oil. There are many well-documented cases of long-term oil toxicity in fish and some marine mammals, but it is hard to attribute these toxic effects to dispersion itself so many years after the fact.

American authorities have developed a decision tree (see figure below) that presents the simple steps decision-makers and their scientific advisors have to take before

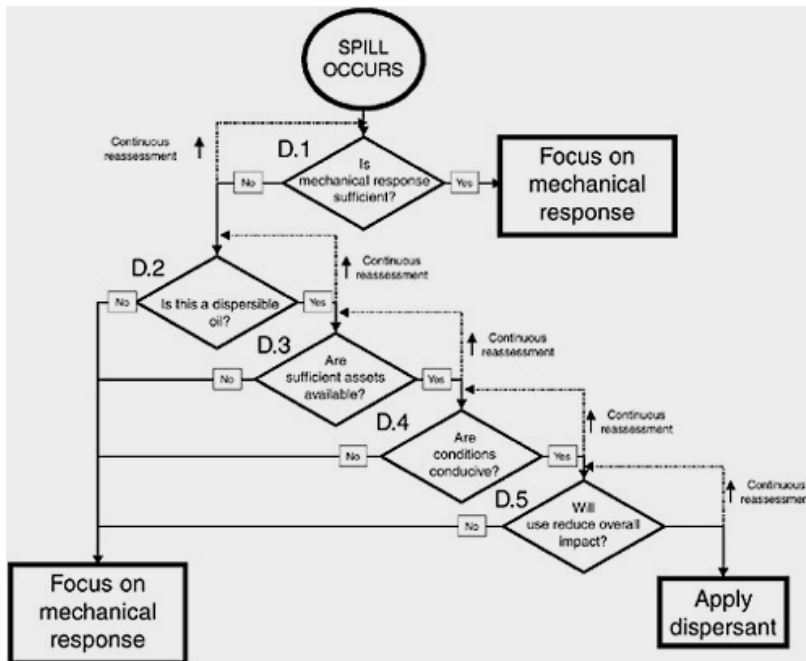
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<sup>46</sup> Bacteria that break down hydrocarbon chains.

authorizing the use of dispersants for a given oil spill in a well-defined area. Here are some of the key questions to ask:

- 1) Would mechanical treatment be enough given the size of the spill?
- 2) Are the means and logistics for applying dispersants readily available?
- 3) Are conditions favorable to dispersant use?
- 4) Will using dispersants significantly reduce the impact of the spill in question?

**Figure 32 Simplified decision tree for determining whether dispersants should be used after oil spills. Diagram adapted from NRC (2005), page 28, figures 2 and 4.**



The last question is by far the hardest to answer and can easily spark heated debates between proponents and opponents. Usually, to facilitate the process, some sites known to be at risk are preauthorized for dispersant use. This way all discussions relating to dispersant use can be had beforehand, whether concerning the environmental risks associated with dispersant use in certain marine areas or the particularities of certain ecosystems or animal communities that would, for instance, have to be protected at all costs from an oil spill.

Study GENV31 recommends that a decision be made on dispersant use in the Estuary and Gulf of St. Lawrence.

Should dispersant use be accepted, it recommends that a preapproval mechanism be put in place for certain marine areas for which dispersal use would be authorized by following the steps in the above decision tree.

Lastly, it is suggested that special attention be given to diluted bitumen, which presents unique risks that are poorly understood by scientists, and that a program be established to determine its “dispersability” and the best methods for cleaning it.

A good example of a research program worth continuing is the documentation and active research program on the behavior and effects of crude oil and diluted bitumen on lacustrine and marine ecosystems, as well as the tools available or to be developed to combat spills in northern conditions.

### **Potential danger of diluted bitumen in marine environments**

More knowledge would be required in this regard to better understand:

- The role of asphaltenes and their precipitation in corrosion mechanisms
- The influence of chemical composition, the role of bacteria, the behavior of solid particles, and stability of water-oil emulsions in corrosion mechanisms
- The effects of aging processes, on their own and combined, on the physicochemical properties of diluted bitumen in order to predict its floatability in fresh and salt water
- The effects of weathering processes on the behavior of bitumen in order to predict its floatability in marine environments

### **Chemical beach cleaners**

As with other contaminants, reactions to beach cleaners vary from one aquatic organism to another. Among species studied in labs or in situ, benthic organisms like chironomids and amphipods in freshwater and mussels and sea urchins in saltwater seem to be the most sensitive to beach cleaners in the long term. Furthermore, based on the data collected, the toxicity of oil/beach cleaner blends seems to be lower than that of beach cleaners alone. Based on available data, the lethal toxicity of Corexit 9580 appears to be the lowest of all commercially available beach cleaners. Its toxicity is generally low although some species—shellfish in particular—are more sensitive to it.

That said, few studies have been conducted on beach cleaners and the data available is not enough to accurately estimate the danger these products pose to Québec’s aquatic environments. Moreover, few studies have been conducted on the chemical fate of beach cleaners and leachates containing a mixture of beach cleaner and oil in environmental conditions akin to those found in Québec’s aquatic environments. Such information would be crucial to assessing organism exposure risks.

### **Solidifiers, elasticizers, demulsifiers, and surfactants (used to make oil slicks more compact)**

Based on the few available studies, when solidifiers are mixed with oil their toxicity for aquatic organisms is low. This could be due to the fact that once combined, solidifiers and oil are no longer soluble in water. However, this is only based on two studies. The literature review also points to a lack of information on elasticizers, demulsifiers, and surfactants used to herd or contract oil slicks and how experimental studies are needed to address these gaps in knowledge.

### **Clay-oil aggregates (COAs)**

Based on the data on hand, dispersing oil slicks with COAs may encourage the natural biodegradation of hydrocarbons. However, COAs tend to migrate toward sediments, which is particularly hazardous to benthic organisms. Not enough information is available to determine the fate of COAs in sediments, specifically the resuspension of oil and potential effects on benthic organisms.

### **Sediment remobilization, oil slick spreading, and oil/water separation**

Oil/water separation can be a dangerous response method due to the presence of oil in the final effluent. There is little data on the toxicity and persistence of these compounds in aquatic environments.

### **Waste oil burning**

Burning waste oil can be dangerous due to air emissions, especially if smoke particles settle in the water or on the ground. In such cases, plants and animals are likely to be affected.

### **Burning in open water and ice-affected waters**

Burning at sea is a response method that quickly removes a large amount of spilled oil. Eliminating light compounds is more important than eliminating heavy ones, as the latter tend to concentrate in burn residue. This method can be toxic to ecosystems because, while burn residues tend to float at first, after a few days—depending on the initial density and chemical composition of the oil spilled—they tend to settle. Although there is not much data on the ecotoxicological effects of burn residue, the data on hand indicates the presence of many pyrogenic PAHs and metals that are known to adversely affect organisms. Aquatic ecosystems receiving such burn residues are therefore thought to be at risk. Air emissions from burning oil are also a threat to the environment, especially if smoke particles settle in the water or on the ground. The contaminants in these particles could harm plants and animals exposed to them. Lastly, some products used to make this technique more effective or lessen pollution can also pose a threat to aquatic organisms.

### **Bioremediation**

A number of approaches have been developed to facilitate the biodegradation of hydrocarbons by microorganisms. Among them, it seems that an enriched culture of selected, indigenous microorganisms may be more suitable to local conditions than commercial bioaugmentation agents. However, biostimulation agents appear to be more effective than bioaugmentation agents in terms of promoting hydrocarbon biodegradation, especially those containing nutrients or biosurfactants. According to Tyagi, da Fonseca, and Carla (2011), mixing bioaugmentation, biostimulation, and biosurfactant agents based on the characteristics of the contaminated site could be a promising strategy for accelerating bioremediation. Yet very little information is available for most of these approaches, and further experiments would be required, in particular for DNA-altering bioaugmentation agents and biosurfactants.

## Natural attenuation

The EPA<sup>47</sup> recognizes natural attenuation as a method for restoring contaminated soil and sites, but only if certain conditions are met. The first condition is that the source of contamination must be shown to have been removed. The second condition is that the physical, biological, and chemical characteristics of the environment must be shown to allow for the contaminant to be completely broken down and not just diluted. Once demonstrated, these conditions must be monitored to show that they have been maintained long enough for the contaminant in question to have been broken down.

Note that should this method be used somewhere, the area's environmental quality would have to be monitored over several years to determine how successful natural attenuation was and whether the mass of hydrocarbons was reduced. Monitoring would be supplemented by identifying 1) geochemical and biological indicators showing that natural attenuation has reduced hydrocarbon concentrations and 2) natural processes involved in natural attenuation as well as their effectiveness so as to predict environmental contamination patterns over time until objectives have been achieved.

Most of the above methods require a certificate of authorization under current regulations in Québec as they either introduce new contaminants into the environment or do not recover the spilled oil. That said, oil/water separation and waste oil burning may be considered, subject to sections 32 and 70.9 of the *Environment Quality Act* (Chapter Q-2, 2015). A system for issuing certificates of authorization in these special situations would make for quicker response times and reduce the impact of spills on the environment.

Given the particularities of Québec aquatic environments (cold water, ice cover, species), additional knowledge is required on the physical and chemical evolution of contaminants and response-related products (dispersants, emulsifiers, etc.) to better understand their ecotoxicological effects. Specifically, the following should be determined:

- The physical and chemical fates and biodegradability of the following in Québec's aquatic environments, especially when ice is present: a) dispersants and dispersant/hydrocarbon blends, b) beach cleaners, c) solidifiers, d) elasticizers, e) demulsifiers, f) surfactants used to make oil slicks more compact, g) hydrocarbons in the form of COAs settling on sediments, h) oil soot and burn residue.
- The ecotoxicological effects of all agents mentioned above on cold-water species commonly seen in Québec's aquatic environments.

## Offshore prevention measures

After analyzing the preliminary SEA1 findings (AECOM Tecscult Inc., 2010), the government decided, in fall 2010, that no oil or gas exploration or extraction activities would be allowed in the St. Lawrence Estuary or northwestern Gulf basins. This decision led to the adoption of the Act to limit oil and gas activities in June 2011. This act prohibits

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<sup>47</sup> [http://www3.epa.gov/epawaste/hazard/correctiveaction/resources/guidance/rem\\_eval/protocol.pdf](http://www3.epa.gov/epawaste/hazard/correctiveaction/resources/guidance/rem_eval/protocol.pdf)

any oil or gas activity in the St. Lawrence west of Île d'Anticosti and on any island in the area (MDDELCC, 2015b).

### **Review of prevention, preparedness, and response measures for major oil spills**

Two observations were made with respect to offshore environmental contingency measures following the SEA2 analyses (Genivar, 2011), namely that emergency response capacities are deficient (Observation 5) and that knowledge is lacking (Observation 8). Since then, given the significance of these issues, the federal and provincial governments have taken steps to alleviate them, whether directly or indirectly, but have not actually fixed them.

With regard to Observation 5, the following issues have not been addressed:

- There is still no clear system in place for coordinating federal and provincial response operations in the Gulf.
- The capacity and response standards required by the Marine Oil Spill Preparedness and Response Regime may be inadequate if a spill were to take place, especially in remote areas (Gulf of St. Lawrence and Nord-du-Québec) or under extreme winter conditions.
- Government and private resources are not sufficient to carry out quick and effective response operations in Nunavik or anywhere north of the 60th parallel should an oil spill take place at sea.
- Provisions should be made to help municipalities prepare for the risks associated with offshore oil development and shipping, especially with regard to drinking water intakes in the St. Lawrence River.
- The Marine Oil Preparedness and Response Regime should provide a training plan and joint exercises for the entire response community.

More knowledge was acquired to address Observation 8, but not enough. The following areas require further development: oil recovery methods when ice is present, mechanical recovery methods for surface oil, and oil dispersion models for spills in fresh and salt water, especially cold water.

### **Response capacity**

ECRC and CCG only use mechanical recovery methods to respond to marine oil spills. While aware of other techniques, like dispersion and burning, ECRC and CCG have no direct experience with them in the St. Lawrence River. The consequences of using such techniques in the St. Lawrence are therefore unknown.

The responders consulted have no special plans for response operations conducted in winter, in particular those involving ice. Ice seems to be treated like any other operational issue including special weather conditions such as strong winds, waves, and rain.

In their past experiences with winter oil spills, ECRC and CCG have noticed that ice tends to contain oil, facilitating mechanical recovery before the oil can reach sensitive areas. That said, winter response operations are still hampered by ice and monitoring oil slicks can be an issue given the current state of knowledge in that regard.

The standards specify the operational recovery criteria for response organizations as illustrated in **Erreur ! Nous n'avons pas trouvé la source du renvoi.** below.

**Table 56 Recovery standards for certified organizations**

Niveau	Déversements	Délais d'intervention*	Traitement du rivage	Durée de récupération sur l'eau	Équipement
1	150 tonnes	6 heures	500 m/jr	10 jours	Stockage suffisant pour assurer les opérations 24/24 et pour contenir le double de la quantité récupéré en 24 heures.
2	1 000 tonnes	12 heures	500 m/jr	10 jours	
3	2 500 tonnes	18 heures*	500 m/jr	10 jours	
4	10 000 tonnes	72 heures*	500 m/jr	10 jours	

\*Sous certaines conditions, le temps de transport peut s'ajouter à ces délais

Sources : Gouvernement du Canada, Innovation maritime

The maximum response time for oil spill operations involving 10,000 tons of oil has been set at 72 hours—the most stringent such standard. These requirements were established with oil tankers typically seen in Canadian waters in mind. The biggest such tankers have a capacity of about 150,000 tons of deadweight.<sup>48</sup> The ship's hold is subdivided into separate tanks with double-hull protection and capacities of about 10,000 tons each.

Responders such as Transport Canada and the Canadian Coast Guard have determined that no spill should exceed 10,000 tons of oil and have set equipment and staffing requirements for response operations accordingly.

When considering all its equipment and resources, ECRC's response capacity greatly exceeds the requirement for 10,000-ton oil spills.

Without performance criteria such as the total amount of oil to recover, response time, and speed of daily oil recovery and coastal decontamination, it is hard to estimate the maximum response capacity of ECRC and its partners.

### Roles and regulations in marine environments

Most countries, including Canada, have signed the international oil spill response conventions. The provisions of these conventions are integrated in Canada in a similar way as in other states covered by the study. Canada and these countries have some of the strictest compliance monitoring and enforcement systems.

All studied states and Canada have established Port State Control<sup>49</sup> ship inspection programs, sometimes jointly, in particular to guard against flag states<sup>50</sup> with laxer regulatory enforcement.

Oil companies also have their own international control system for tankers. The St. Lawrence-based oil companies consulted require that ships comply with these additional checks as well.

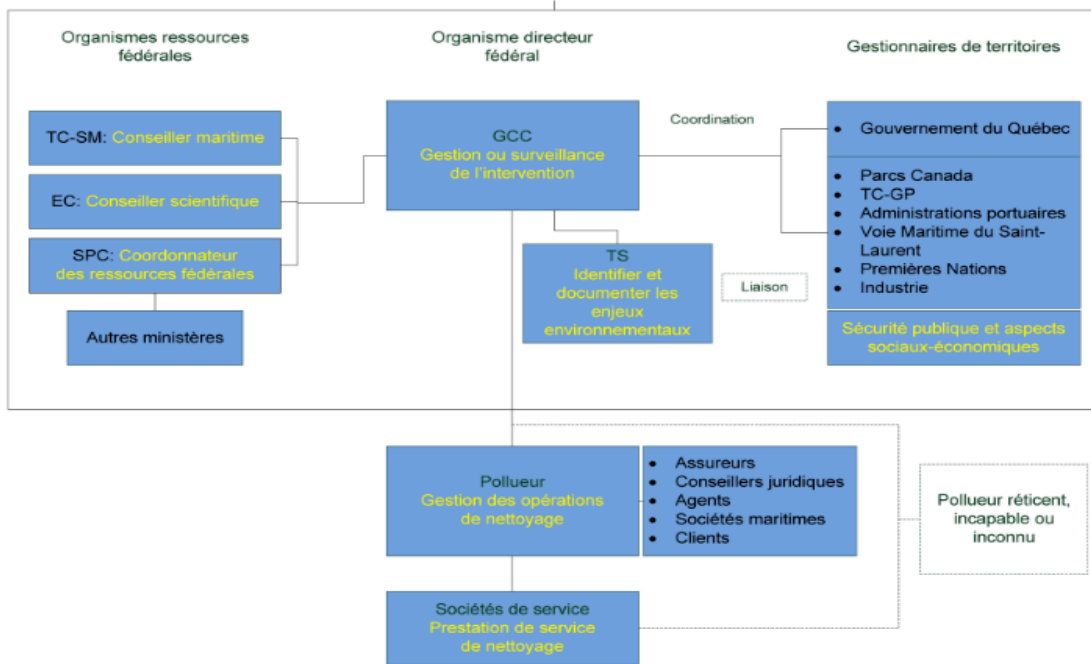
<sup>48</sup> The **deadweight** of a ship is its maximum carrying capacity; it is calculated by subtracting the ship's light displacement (total ship weight without cargo or supplies) from its loaded displacement (total ship weight when fully loaded—midship drafts at waterline).

<sup>49</sup> Port State Control (PSC) is a ship inspection program whereby foreign vessels entering a sovereign state's ports are checked to ensure that their condition and that of their weapons material are in compliance with the requirements of international rules and that they are adequately manned and operated under these rules.

<sup>50</sup> Flag states are states under whose laws vessels are registered and are responsible for ship control. Inspections take place before registration and every year thereafter. They are comprehensive and include reviewing and verifying documents and procedures, assessing overall ship structure, machines, and equipment, as well as conducting evacuation drills and testing fire extinguishers.

The Marine Oil Spill Preparedness and Response Regime is the main legislative tool in Canada. The regime is based on the polluter pays principle and defines the roles and responsibilities of organizations involved in handling oil spills (Figure 33).

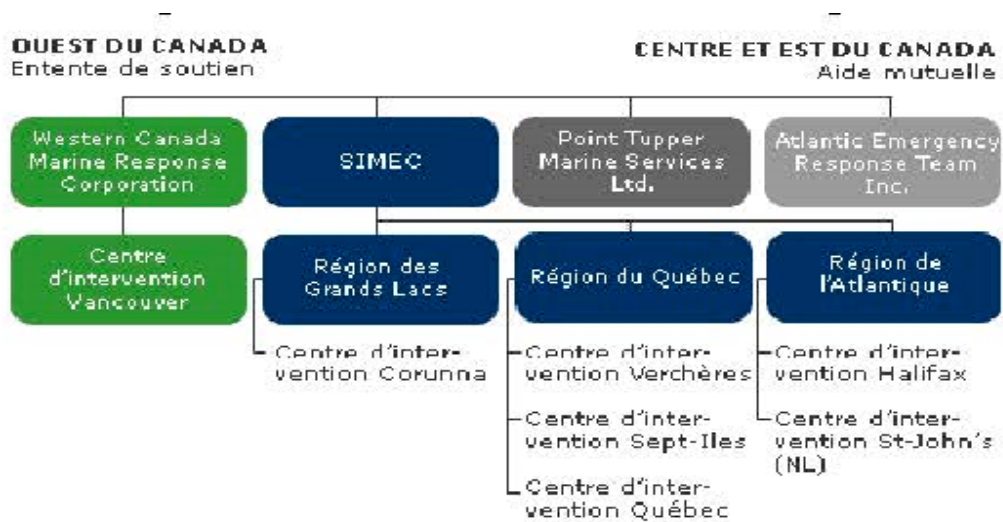
**Figure 33 Organizations responsible for responding to marine oil spills**



Source : Garde côtière canadienne

As shown in this figure, the Canadian Coast Guard serves as the governing body for the various responders. Shipowners, for their part, play a central role in managing cleaning operations. They have to comply with various regulatory requirements and have oil spill contingency plans, oil recovery equipment, and properly trained crews. For each of their vessels, shipowners must enter agreements with response organizations with the expertise to handle marine oil spills of any size (Figure 34), like the Eastern Canada Response Corporation (ECRC). Such organizations are regulated by the Response Organizations and Oil Handling Facilities Regulations.

**Figure 34 Certified response organizations**



Source : SIMEC, 2015

With three response centers in Québec, ECRC has a long list of members including organizations like Hydro-Québec and CN, both of which required some degree of response capacity.

Modern oil tankers have 10,000-ton sealed tank compartments, which explains SIMEC's response capacity. While ships can carry up to 100,000 or even 200,000 tons of oil, it is unlikely, based on the history of such spills, that more than one compartment will be punctured (see Mechanical methods section).

A number of Canadian and Québec government ministries and agencies have significant roles to play—depending on their areas of expertise—during ship-related oil spills, including Environment Canada, Fisheries and Oceans Canada, Transport Canada, Ministère du Développement durable, de l'Environnement et de la lutte contre les changements climatiques (MDDELCC), and Ministère de la Sécurité publique (MSP) (see GTVS02).

While provincial and municipal involvement is not clearly defined in the CCG Marine Spills Contingency Plan – National Chapter, framework agreements have been established in Québec.

Provincial and municipal participation should be better defined in marine spill contingency plans.

Under special circumstances, the roles and responsibilities of the Canadian Coast Guard may be delegated to municipalities without it being possible to compensate them in full.

A survey was conducted to determine how well municipalities understand their roles and responsibilities as primary responders in the event of oil spills in the St. Lawrence River. The results made it clear that major cities have much more knowledge in this regard. Big cities are far better prepared and have greater response and training capacities than smaller ones do.

Industrial municipalities have a distinct advantage: local companies generally act as good corporate citizens and do much to support public safety measures (e.g., Valéro, Port of Montréal, Kildair, Rio-Tinto, CEZinc, Valport).

These valuable partnerships with the private sector provide municipalities with benefits through the sharing of expertise, resources, and material, as well as numerous training and exercise opportunities. Most of these municipalities have a good understanding of their responsibilities, in particular in terms of marine oil spills. They have established permanent emergency preparedness units and have developed and validated contingency and civil protection plans through multidisciplinary exercises and real-life experience.

Many of the municipalities surveyed have no specific response or risk assessment plans for marine oil spills, despite having economic activities or sensitive natural environments tied to the maritime sector.

Study GTVS02 suggests doing the following:

- Raise awareness of the Marine Oil Spill Preparedness and Response Regime so the public and municipalities can better understand how it works
- Raise awareness of the national contingency plan among municipal civil protection authorities
- Establish a formal discussion process with municipalities for marine oil spills
- Give municipalities better access to in-depth analyses of marine oil spill risks and impacts
- Support municipalities that could potentially be affected by marine oil spills and get them to take these risks into account in their contingency plans

### **Improvements to the current Regime**

The federal departments consulted have started working to improve the Marine Oil Spill Preparedness and Response Regime by incorporating a number of recommendations made by a review committee (see Appendix A of Study GTVS02). These recommendations include the following:

- Develop localized response plans—especially for the St. Lawrence between Montréal and Île d’Anticosti—that take into account the particularities and potential risks of the regions they cover. These plans should reflect local conditions such as environmental hazards, maritime activity, the presence of ice, and other special weather conditions.
- Reinforce the polluter pays principle by abolishing the maximum liability of the Ship-source Oil Pollution Fund and replacing it with a fee on oil transport and by allowing the Fund to establish an emergency account to support Canadian Coast Guard response operations
- Enhance leadership and management by establishing an interministerial committee tasked with ensuring consistency among the national plans of the various responders involved
- Raise public awareness of the Regime

- Regularly collect information on oil spills to find new ways to improve the Regime and set up an R&D program aimed at understanding the effects of oil spills and developing oil recovery and site restoration techniques

Study GTVS02 suggests doing the following:

- Join Transport Canada in developing a localized response plan for the St. Lawrence between Montréal and Île d'Anticosti, adapting it for geographic and environmental conditions as well as socio-environmental realities
- Consider whether it would be reasonable to have the plan cover a larger area

### **Compensation for damage**

According to Study GTVS02, the compensation funds of the states examined are financed by the hydrocarbon industry. The United States is an exception as it has its own compensation system. That said, the American system is still based on the same principles used internationally.

Canada and the entire international community set limits as to what types of ecosystem restoration expenses are eligible for compensation. However, the United States considers all ecosystems as national assets warranting comprehensive restoration programs financed by polluters or compensation funds. Americans consider any expense relating to the complete rehabilitation of affected ecosystems as subject to compensation.

All states analyzed have undertaken to set up studies aimed at understanding the effects of oil spills and developing oil recovery and site restoration techniques. Some states have the oil industry finance these research programs through their compensation funds or pollution control programs.

The Ship-source Oil Pollution Fund was established on April 24, 1989, to serve claimants.

It reviews and assesses all claims presented to it. Claims are subject to appeal to the Federal Court of Canada.

The Fund settles claims for oil pollution damage or anticipated damage caused by the discharge of oil from all classes of ships on inland or coastal waters, including the exclusive economic zone of Canada.

Once claimants have received compensation, administrators are obligated to take all reasonable measures to recover the payments from shipowners or any other responsible party.

### **Research and development**

During Study GTVS02, all analyzed states set up studies aimed at understanding the effects of oil spills and developing recovery and site restoration techniques. Some states have the oil industry finance these research programs through their compensation funds or pollution control programs.

Canada and Québec are conducting research in this regard but funding and research priorities have not been addressed in a national plan and do not always take the particularities of the St. Lawrence into account.

In order to properly prepare compensation files, it is crucial that the initial state of affected areas be thoroughly documented. SEAs on the gulf and estuary have revealed knowledge gaps in this regard that will have to be bridged.

MDDELCC initiated studies on marine environments with a knowledge acquisition program in 2012–2013. St. Lawrence Action Plan studies can also help improve knowledge in this regard.

Stakeholders consulted recognize how vital research, innovation, and training are to reducing the impact of oil spills. However, the fact that studies in this field are poorly coordinated means that research efficiency suffers and available funding is not used optimally.

SEAs on the St. Lawrence Gulf and Estuary have provided preliminary descriptions of initial conditions in these environments. They have also pointed to a lack of knowledge, which would have to be addressed before any large-scale development of the hydrocarbon industry could take place.

## 8. Societe

### 8.1 Scope

The Society steering committee's mandate is to describe anticipated social issues and impacts of Québec oil and gas development, with particular focus on:

- Aboriginal issues
- Social and economic impact
- Public health and safety
- Social acceptability

#### Comprehensive SEA on hydrocarbons

In fall 2014 and winter 2015, the comprehensive SEA on hydrocarbons began Phase I of its mandate to acquire knowledge of the entire oil and gas sector. For Society issues, the SEA steering committee set out to:

- determine the anticipated impact of oil and gas development on aboriginal, local, and regional populations, especially regarding living conditions, quality of life, health and safety, and the ability of communities to accommodate these activities in affected regions;
- determine what actions and approaches might make communities more receptive to these projects, notably by taking the concerns of affected populations into account; and
- determine what actions can prevent adverse social effects (or keep them at an acceptable level for affected populations) and promote the benefits of oil and gas exploration and development.

In Phase I of the SEA, separate knowledge reviews for the four Society components (aboriginal issues, social and economic impacts, public health and safety, social acceptability) shed light on the state of current knowledge—and areas in need of improvement—to help inform decisionmakers of the benefits, drawbacks, and risks of oil and gas development for affected populations.

The Additional Knowledge Acquisition Plan (AKAP) was then submitted for feedback to stakeholders from civil society, the research and business communities, environmental groups, and, in particular, the Anticosti community. To supplement this knowledge, three topics were selected:

- Inventory of potentially sensitive areas, characteristics, and land uses in regions selected for SEAs (**Erreur ! Nous n'avons pas trouvé la source du renvoi.**)
- Experience with participation by indigenous communities in natural resource development outside Québec (**Erreur ! Nous n'avons pas trouvé la source du renvoi.**)
- Analysis of factors that affect the social acceptability of oil and gas development, and suggestions about regional modes of governance (**Erreur ! Nous n'avons pas trouvé la source du renvoi.**)

## Anticosti SEA

The Anticosti SEA Society component was addressed in a single comprehensive study: a social and economic profile of Île d'Anticosti, what impact residents anticipate oil and gas development will have, and an assessment of the community's ability to adapt as well as possible solutions (**Erreur ! Nous n'avons pas trouvé la source du renvoi.**).

### Regions examined from a Society perspective

The regions examined from a Society perspective in Phase I of the SEAs included (on land) the St. Lawrence Lowlands, Anticosti, Gaspésie, and Bas-Saint-Laurent and (on water) the Estuary and Gulf of St. Lawrence including Îles-de-la-Madeleine.

For Phase II of the SEAs, regional studies focused on areas likely to undergo oil and gas development or that were close to such areas, and for which no prior SEAs had been done and updated or additional information was required. These include the land portions of Bas-Saint-Laurent and Gaspésie, the Gulf of St. Lawrence (including Îles-de-la-Madeleine), Île d'Anticosti, Minganie RCM (to which the Municipality of Anticosti belongs), and the two neighboring RCMs for comparison purposes (Sept-Rivières and Le-Golfe-du-Saint-Laurent). Maritime, rail, and pipeline oil and gas transport are discussed in Chapter 6.

## 8.2 Comprehensive SEA: General Description and Sensitive Areas

The regions included the comprehensive SEA on hydrocarbons (for the inventory of uses and determination of sensitive areas) are the land portions of Bas-Saint-Laurent and Gaspésie, the Québec portion of the Gulf of St. Lawrence (including Îles-de-la-Madeleine), and the three easternmost RCMs in Côte-Nord.

Apart from the St. Lawrence Lowlands, for which a strategic environmental assessment (2011-2014) is already available, the areas selected for the **Erreur ! Nous n'avons pas trouvé la source du renvoi.** study (conducted by *Université du Québec à Chicoutimi's Laboratoire d'expertise et de recherche en géographie appliquée/LERGA* [Applied Geography Research Laboratory])<sup>51</sup> were those considered most likely to bear the impact of oil and gas research and development.

In conducting their study, the researchers expanded its scope to include the estuary portion of shoreline RCMs in Bas-Saint-Laurent.

We should also note that in 2011 and 2014, the Québec government adopted the *Act to limit oil and gas activities* and the *Act to amend the Act to limit oil and gas activities and other legislative provisions*, which prohibit hydrocarbon research and development in the Estuary and Gulf of St. Lawrence (including the islands located there).

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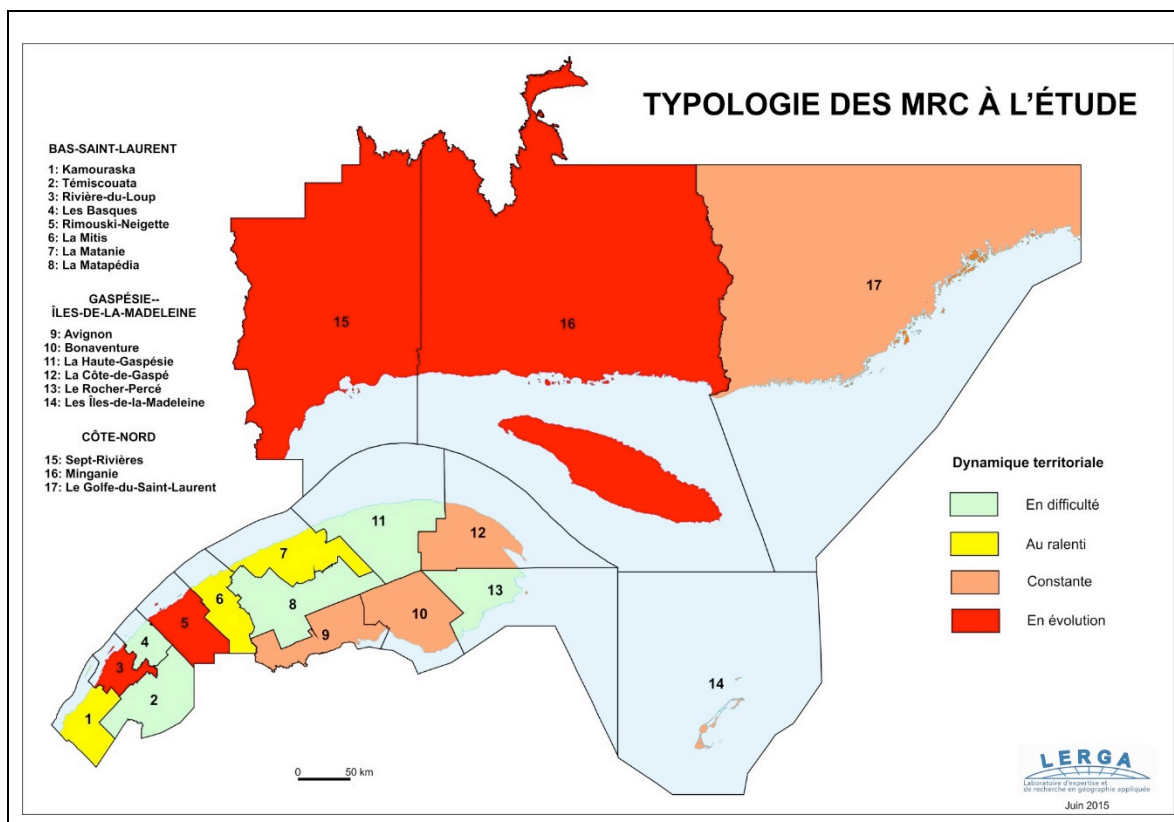
<sup>51</sup> Gauthier, M. et al. 2015. *Inventaire territorial et analyse cartographique de 17 MRC localisées au Bas-Saint-Laurent, en Gaspésie-Îles-de-la-Madeleine et sur la Côte-Nord incluant le Golfe du Saint-Laurent*, Applied Geography Research Laboratory (LERGA), UQAC. 346 pp.

## Study area: overview

Based on data from the study by Gauthier et al. (2015) and information compiled by *Ministère de l'Énergie et des Ressources naturelles*, an overview of the study area was drawn up.

The study area, which measures 316,223 sq. km, has 173 municipalities, 17 RMCs (including Îles-de-la-Madeleine) and a total population of 336,548 (see 35).

**Figure 35 Study Area**



Source: RCM classification and indigenous community locations (GSOC01 Map 65)

The region is home to three aboriginal nations. First is the Maliseet Nation in Bas-Saint-Laurent (roughly 1,100 non-resident members). Then there are three Mi'kmaq communities in Gaspésie: Gesgapegiag (1,400 members, roughly half of whom are residents), Listuguj (nearly 3,700 members, roughly 2,100 of whom are residents), and Gespeg (roughly 650 members). Lastly, five of Québec's nine Innu communities live in the study area. These are, from west to east, Uashat-Maliotenam (roughly 4,200 members, more than three-quarters of whom are residents) and four other communities of which nearly all members are residents: Mingan (roughly 580 members), Natashquan (just over 1,000 members), La Romaine (roughly 1,100 members), and Pakuashipi (roughly 350 members).

In addition to a regional inventory and map analysis, Gauthier et al. (2015) discuss social and economic conditions throughout the region and describe some 15 demographic, social, economic, and change indicators for each of the 17 RMCs (Table 57). The study

was thus able to categorize RCMs based on territorial vitality (struggling, slow, steady, or evolving).

**Table 57 Study Area Aggregate Statistics**

Item	Qty	Km <sup>2</sup>	%
Total area		316,223	100.00
Land area		180,233	56.99
Marine area		135,990	43.00
Urban areas		223	0.07
Recreational areas		1,030	0.33
Agricultural areas		3,900	1.23
Agricultural enterprises	2,320		
Wetlands		2,008	0.63
Protected areas		15,757	4.98
Forest areas (km <sup>2</sup> )		158,753	50.20
Fishing ports	67		
Fish processing enterprises	43		
Fishery zones (sea)		39,643	29.15
Ecologically and biologically significant areas (sea)		30,592	9.67
Oil and gas wells and test wells	285		

More specifically, the Gulf of St. Lawrence covers 43% of the study area, which contains vast, ecologically important areas for marine mammals, fish, invertebrates, and plankton. Some 43 fish and shellfish processors operate in its fishery zones, along with 25 marine aquaculture sites. It is also home to much bird life, with seabird habitats scattered along thousands of kilometers of shoreline. In addition, it contains study areas for two proposed marine protected areas: the American Bank (992 km<sup>2</sup>) opposite Gaspé and Îles-de-la-Madeleine (16,568 km<sup>2</sup>).

Commercial fisheries represent the Gulf's biggest economic activity by far. An inventory of uses and constraints in a marine environment (Gauthier et al., 2015) was used to create the following table:

- The fishery employs more than 4,500 people in fish plants supplied by some 1,060 active vessels in Québec.
- The most fished species are northern shrimp, snow crab, Atlantic herring, American lobster, and black turbot.
- In 2012 some 56,523 tonnes of fish and shellfish worth an estimated \$160 million were unloaded in Québec ports.

On land, forest areas account for some 48% of the total study area and supply a total of 48 sawmills and 3 pulp and paper mills located mainly in Bas-Saint-Laurent and Gaspésie. Some 1.2% of the region is used for agriculture, mostly in Bas-Saint-Laurent and, to a lesser extent, Gaspésie and Îles-de-la-Madeleine.

In the RCMs of Témiscouata, La Mitis, Avignon, Côte-de-Gaspé, Bonaventure, Îles-de-la-Madeleine, and Sept-Rivières, some 1,030 sq. km of land are used for recreational purposes.

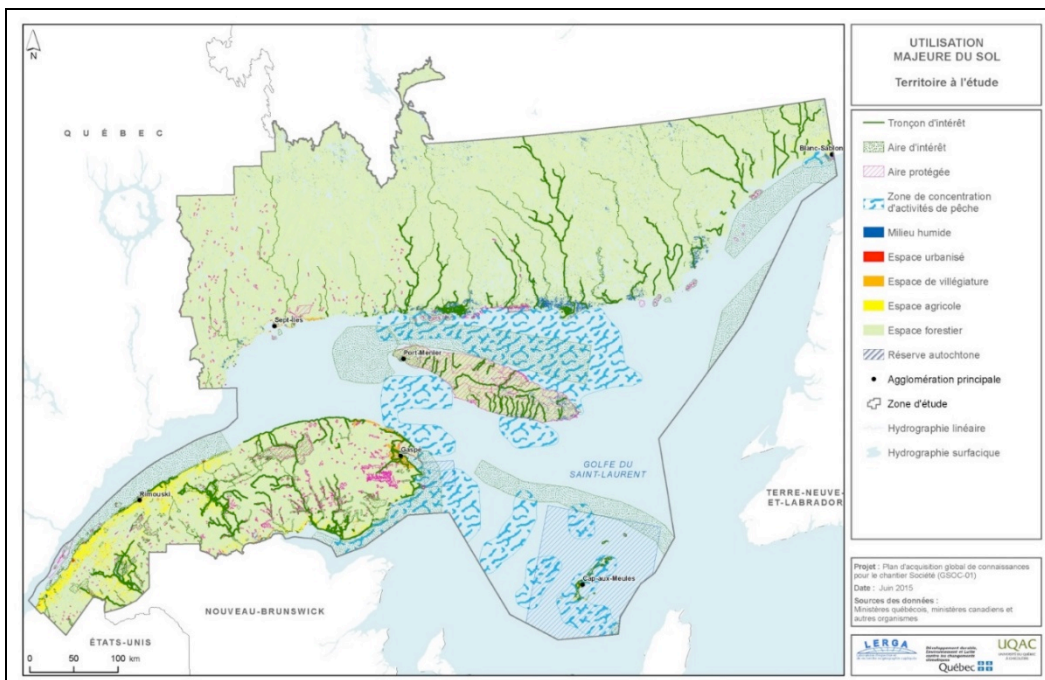
The areas of interest identified by all RCMs cover 7,128 sq. km, most of it of ecological significance (5,944 km<sup>2</sup>). Wetlands account for 0.6% of the total study area, while protected areas represent 11.6%.

With regard to wildlife activities, the region has 93 salmon rivers, 11 wildlife reserves, 22 controlled harvesting zones, and 33 outfitters with exclusive rights. These structured wildlife areas cover some 25,994 sq. km, while the three Côte-Nord RCMs have 85,749 sq. km of beaver reserves.

At present, oil and gas exploration is concentrated in eastern Québec. Though wells have been drilled in Gaspésie since 1860, it was not until 2005 that this intensified (especially for Côte-de-Gaspé RCM and the municipality of Île d'Anticosti). A total of 285 test wells have been drilled, 62 of which are active.

Figure 36 provides a summary of inventoried uses for the whole study area. **Erreur ! Nous n'avons pas trouvé la source du renvoi.**

**Figure 36 Study Area Major Uses**



GSOC01 Map 66

Source:

Based on inventoried uses and summary descriptions of each RCM, the following sections will present sensitive areas identified in Gaspésie-Îles-de-la-Madeleine, Bas-Saint-Laurent, and part of Côte-Nord<sup>52</sup>. For details on the methodology used, refer to the GSOC01 study.

<sup>52</sup> For details of the methodology, see Gauthier et al.

## **Gaspésie-Îles-de-la-Madeleine**

This administrative region, which includes the Gaspé Peninsula and Îles-de-la-Madeleine, spans an area of 20,155 sq. km and has 92,684 inhabitants.

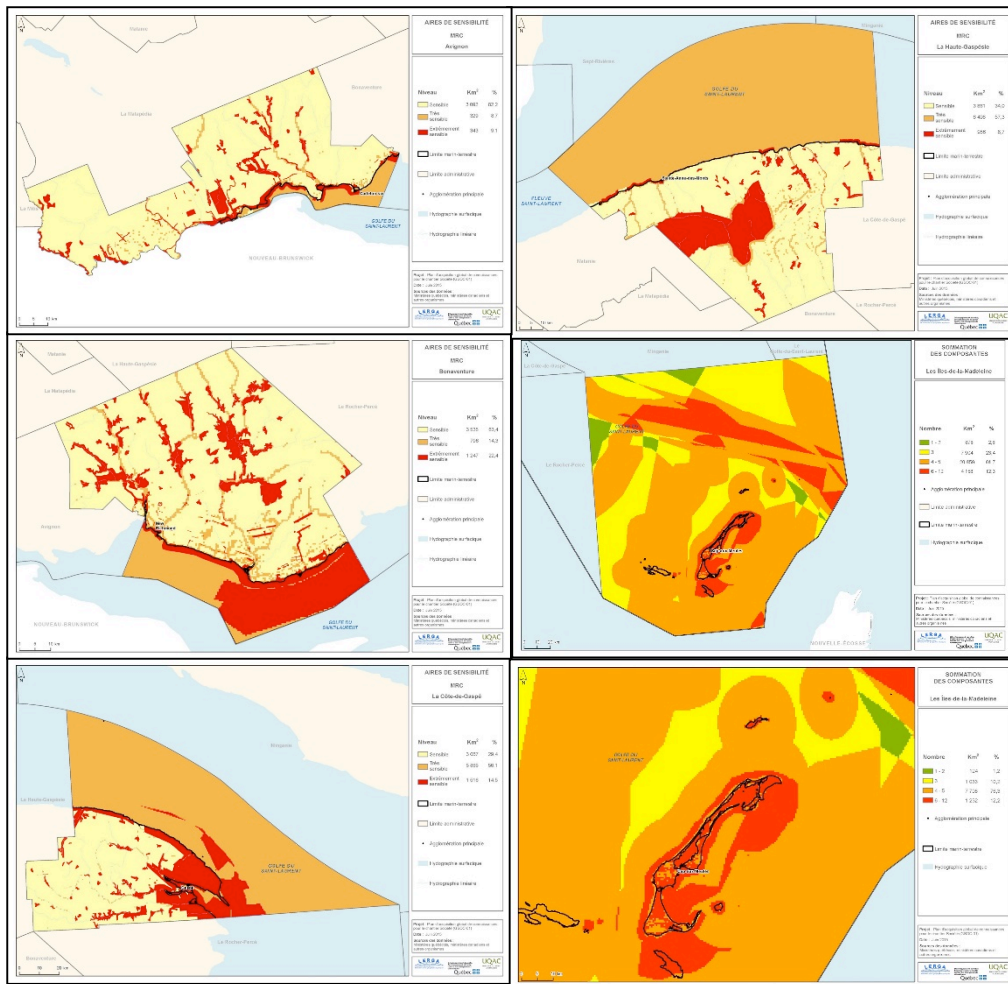
It includes the Avignon, Bonaventure, Haute-Gaspésie, Côte-de-Gaspé, and Rocher-Percé RCMs and the urban agglomeration of *Îles-de-la-Madeleine* (which comprises two municipalities, *Les Îles-de-la-Madeleine* and *Grosse-Île*). The region's biggest town is Gaspé, with 15,171 inhabitants in 2015. Altogether the region has just over 40 municipalities and three native reserves—Listuguj, Gesgapegiag and Gespeg—that have pending land claims that extend beyond their current limits.

In Gaspésie-Iles-de-la-Madeleine, fishing remains an economic force even if the trend today is toward diversification. The peninsula and the islands attract large numbers of tourists, whether to visit Percé Rock, Forillon National Park, Mont-Saint-Pierre, or the famous red cliffs of Belle-Anse (Îles-de-la-Madeleine). According to *Institut de la statistique du Québec*, the GDP of Gaspésie-Iles-de-la-Madeleine has the highest proportion of tourism revenues of all regions in the province (9.46%, or twice that of the Capitale-Nationale region).

Farming and produce, wind energy, logging (Gaspésie), and salt mining (Îles-de-la-Madeleine) also serve to diversify the region's economy.

Based on the aforementioned uses, sensitive areas were identified in the five RCMs (including the urban agglomeration of *Îles-de-la-Madeleine*) (Figure 37).

**Figure 37 Sensitive Areas in the Avignon, Bonaventure, Haute-Gaspésie, Côte-de-Gaspé, and Rocher-Percé RCMs and the urban agglomeration of Îles-de-la-Madeleine**



Source: GSOC01 maps 33, 36, 39, 42, 45, and 46

## Bas-Saint-Laurent

The Bas-Saint-Laurent region runs 320 kilometers along the St. Lawrence River's south shore and extends down to the U.S. border.

The area is home to 201,035 inhabitants, just over half the study area's population. It is bordered to the north by the river and numerous islands, to the south by Maine and New Brunswick, to the east by Gaspésie and to the west by Chaudière-Appalaches.

Bas-Saint-Laurent has eight RCMs (Kamouraska, Témiscouata, Rivière-du-Loup, Les Basques, Rimouski-Neigette, La Mitis, La Matapédia, and La Matanie), as well as more than 100 municipalities and the Cacouna and Withworth Indian reserves.

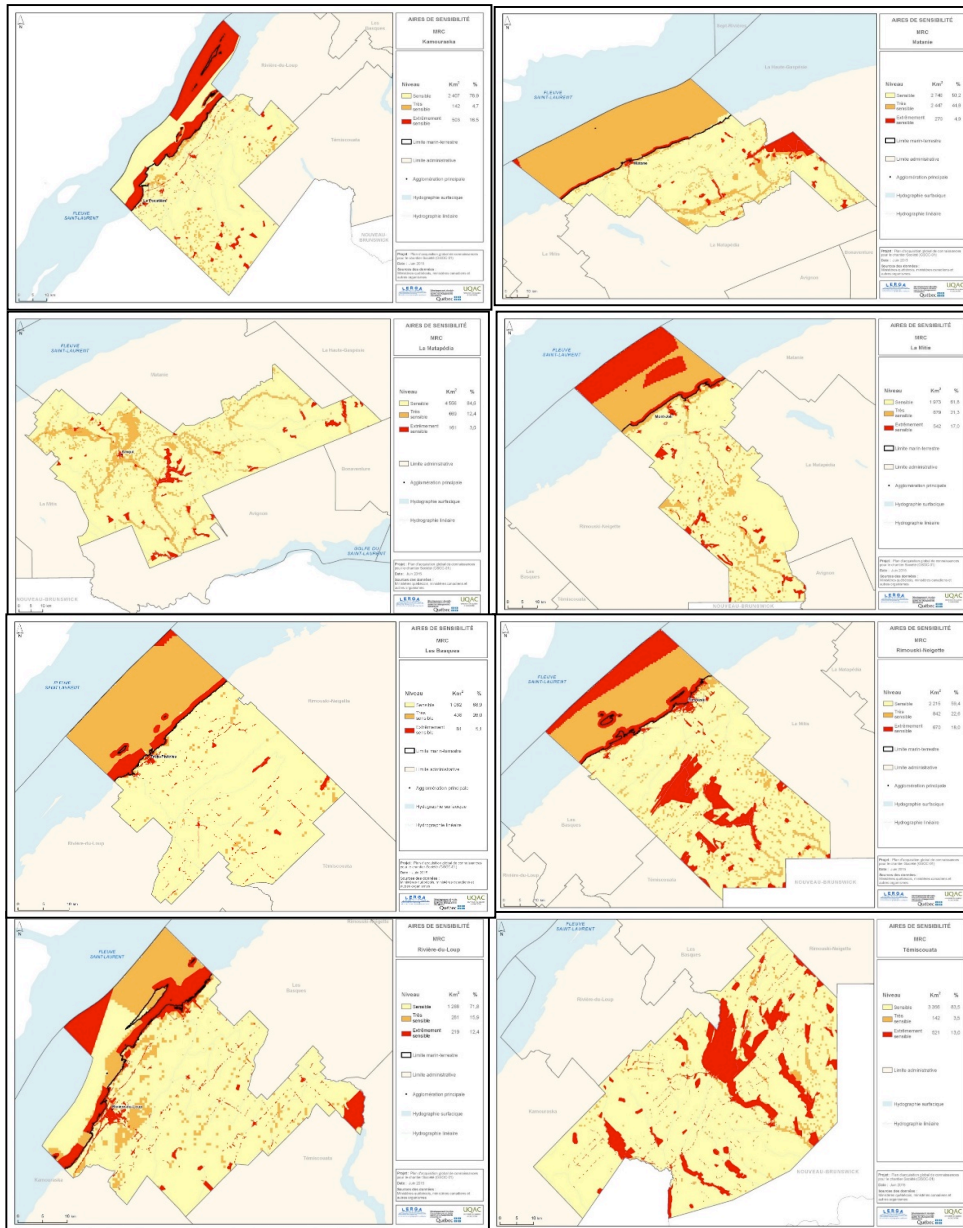
Logging is a mainstay of the Bas-Saint-Laurent economy, with agriculture and tourism also playing major roles. The agrifood sector makes an important contribution, as does the presence of higher learning institutions and five technology transfer centers.

Fast growing areas in Bas-Saint-Laurent include wind energy; specialized marine resources, science and technology; peat moss and agro-environmental technology development; and budding expertise in green construction.

The region's GDP also has a high proportion of tourism revenues (2.77% in 2011, or \$175 million), slightly higher than the provincial average of 2.05%.

Based on the aforementioned uses, sensitive areas were identified in Bas-Saint-Laurent's eight RCMs (Figure 38).

**Figure 38 Sensitive Areas in the Kamouraska, Témiscouata, Rivière-du-Loup, Les Basques, Rimouski-Neigette, La Mitis, La Matapédia and La**



**Matanie RCMs**

## **Côte-Nord**

The Côte-Nord region runs along the St. Lawrence from Tadoussac to the border of Newfoundland and Labrador, and then goes deep inland until it reaches Saguenay–Lac-Saint-Jean to the west and Nord-du-Québec to the north.

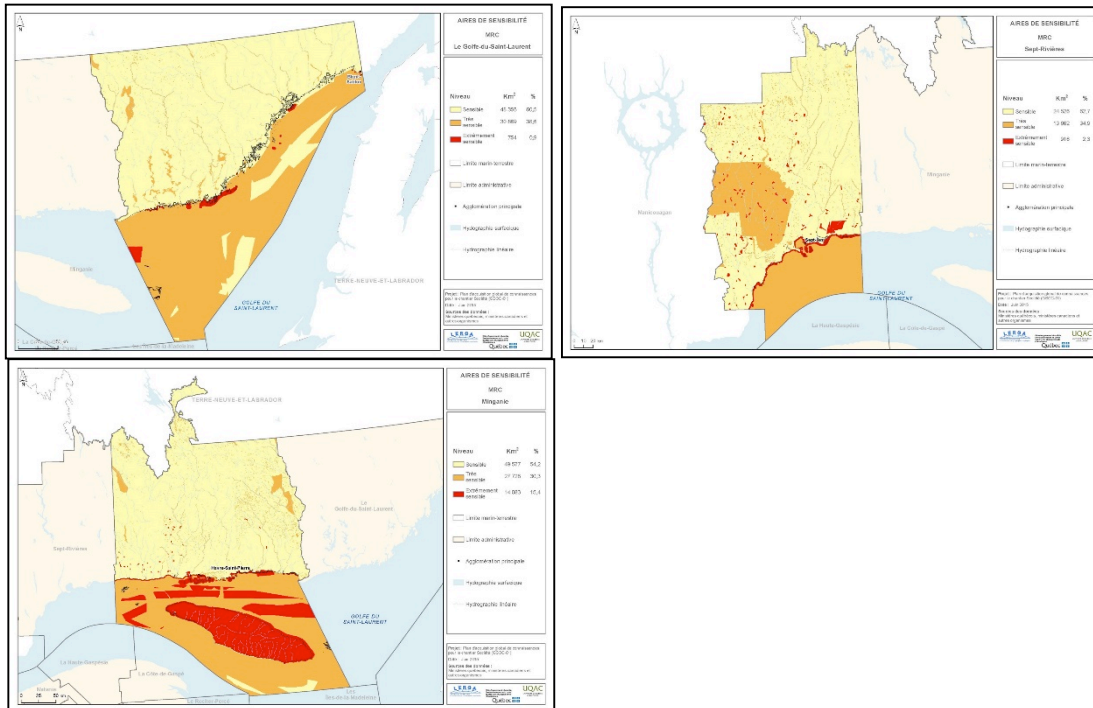
While the region has six RCMs, the comprehensive SEA has focused on just three: La Minganie RCM (which includes the municipality of Anticosti), and the two neighboring RCMs of Sept-Rivières to the west and Golfe-du-Saint-Laurent to the east. These three RCMs contain 46 municipalities (including the city of Sept-Îles, which had a population of 25,844 in 2015) as well as the Innu communities of Uashat-Maliotenam, Mingan, Natashquan, La Romaine, and Pukuashipi.

The three RCMs have an average land base of 34,000 sq. km, far exceeding that of other study regions.

Among other things, Côte-Nord is characterized by large hydroelectric developments dating back to the 1950s as well as iron and titanium mines. It has also diversified its economy through ecotourism (whale-watching cruises from Manicouagan and Duplessis, excursions to Île d'Anticosti and the Mingan Archipelago, etc.). Its tourism revenues are lower than the provincial average (1.69% vs. 2.05%).

Based on the aforementioned uses, sensitive areas were identified in Côte-Nord's three study RCMs (Figure 39).

**Figure 39 Sensitive Areas in the La Minganie, Sept-Rivières and Le Golfe-du-Saint-Laurent RCMs**

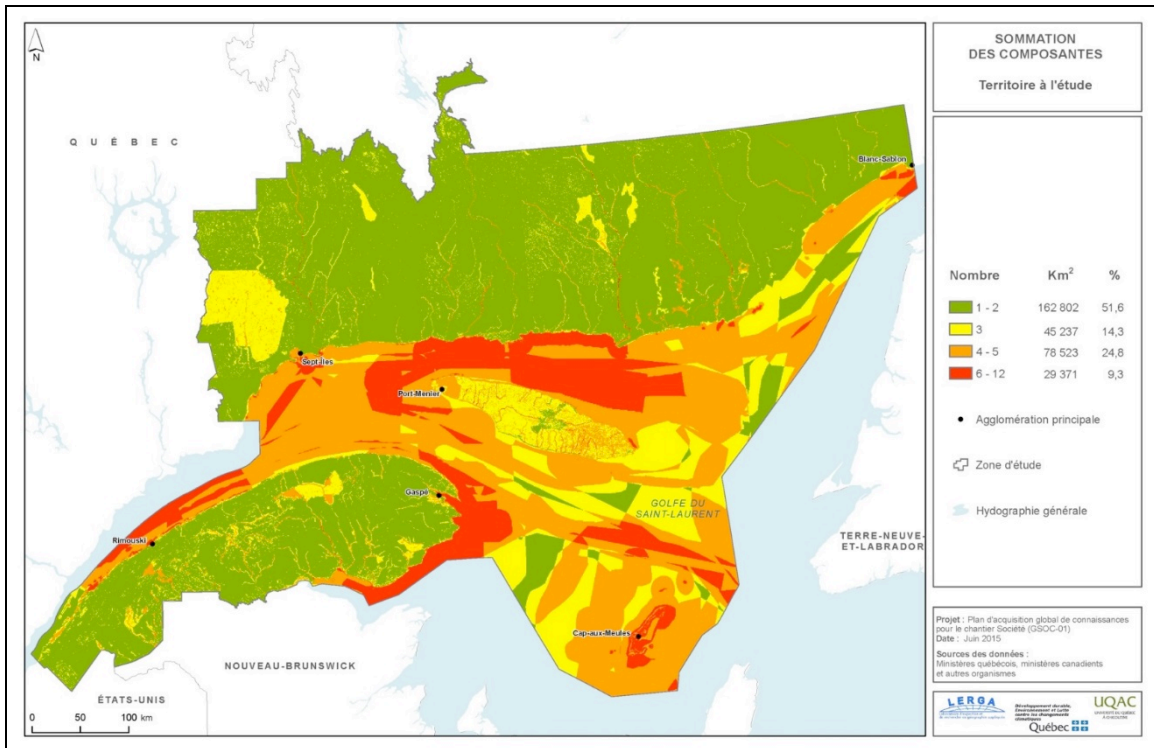


Source: GSOC01 maps 54, 57, and 60

**Summary: sensitive areas within the study area**

Before determining sensitive areas, an analysis of land features shows that the region is more homogeneous, with most of the area covered by one or two components (primarily forest). The marine environment is quite different, with overlapping components that can reach up to 12 layers of information (georeferenced by site) on the parameters for protecting, presenting, or developing biological resources (**Erreur ! Nous n'avons pas trouvé la source du renvoi.7**).

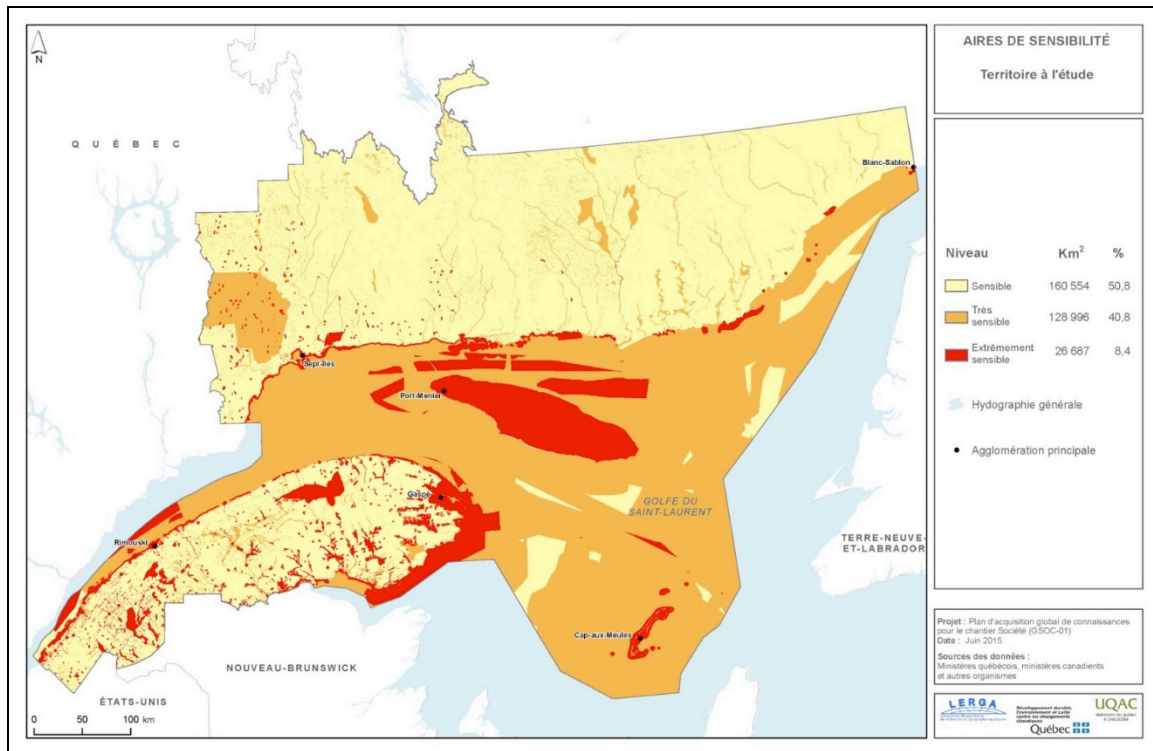
**Figure 40 Summary Description of Study Area Components (GSOC01 map 67)**



Source: GSOC01 map 67

An analysis of study area components was used to create a summary map of its sensitive areas: extremely sensitive areas comprise 8.4% of the region (26,687 km<sup>2</sup>), very sensitive areas account for 40.8% (128,996 km<sup>2</sup>), and sensitive areas represent 50.8% (160,554 km<sup>2</sup>) (Figure 41).

**Figure 41 Summary of Sensitive Areas in Study Area**



Source: GSOC01 map 68

Each of a region's components was given a value of 1 when sensitive areas were identified. To reflect the actual value the community places on each inventoried use, the results of the inventory of uses and mapping of sensitive areas must be validated by the community.

## 8.3 Anticosti

### Profile of the Anticosti community

#### Anticosti's recent history<sup>53</sup>

A brief review of the island's recent history reveals just how unique the region is, marked not just by remoteness and historical dependence on big landowners, but by the resilience of its people, who have retained strong bonds with this remarkable community.

The era of Henri Menier left an indelible mark on Anticosti residents that endures to this day. In the late 19<sup>th</sup> century Henri Menier, the island's then-owner, imported (among other things) 75 pairs of white-tailed deer to try to keep mosquitoes away from his loggers. This single action created the vast deer herd that is now one of the island's biggest resources. The herd caused an ecological upheaval by leading to the near-disappearance of certain plant life, giving rise in turn to the decline of species like the black bear. This is the origin of today's "resource," the massive herd of white-tailed deer available to hunters. In the Henri Menier era, community members were invited to sell their property in exchange for work and a yearly salary. It was also a time of social and class division, where only the wealthy had a right to hunt or to fish for salmon.

Acquired by Wayagamak Pulp & Paper in 1926, the island began a period of intensive logging. Its natural resources continued to be managed by a sole operator, perpetuating the feeling among local residents that they were not masters in their own home. Logging operations were temporarily halted in 1930.

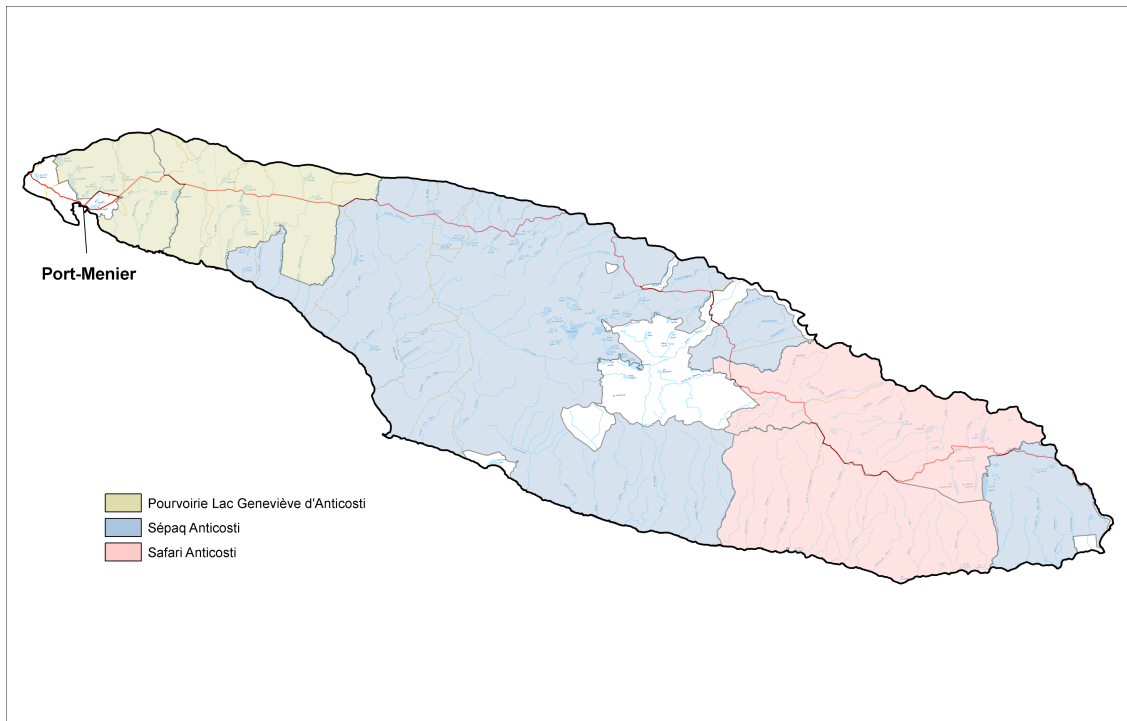
By the 1960s logging had started again, and the first work was begun on exploring for oil and gas. But in the face of access and transport problems, profitability issues, isolation and a harsh climate, Consolidated-Bathurst sold the island to the Government of Québec in 1974.

From 1974 to 1984 (the year it became a municipality), Anticosti underwent a major shift toward an economy based on hunting, fishing, and tourism. During these 10 years, outfitting fell under government authority. In 1984, local residents acquired a new degree of autonomy, earning the right to buy property as well as exclusive hunting rights to an area known as *Territoire des résidents* (Residents' Land). In the early 2000s, *Société d'établissements de plein air du Québec* (SÉPAQ) gradually took over management of the region. Today *Pourvoirie du Lac Geneviève* is the only hunting area managed by Anticosti residents. A network of outfitters with exclusive rights covers most of the island (Figure 42), with white-tailed deer hunting as the main activity. The last aerial inventory, conducted in 2006 (Rochette & Gingras, 2007), counted 166,000 deer on the island.

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<sup>53</sup> All information in this subsection is adapted from the master's thesis of Anne-Isabelle Cuvillier, UQAM, 2015.

**Figure 42 Outfitters with Exclusive Rights on Anticosti Island**



Source: AENV04 and AENV05 studies

Logging resumed in 1995, this time under a Forest Management Agreement (FMA) with *Produits forestiers Anticosti* (Anticosti Forest Products). Logging activities ceased from 2013 to the summer of 2014.

### **Contemporary profile<sup>54</sup>**

A review of recent demographic data offers a glimpse of Anticosti's social structure.

The resident population, concentrated in Port-Menier in the west end of the island, was 240 at the time of the 2011 Census and estimated at 205 in 2014. However, some of these people leave the island to study on the mainland or get away for the winter. The estimated year-round resident population is about 175. A key feature of the island is its busy tourist season, which brings its share of seasonal workers (100 to 200) along with thousands of hunters, anglers and vacationers.

Some 15 students attend École Saint-Joseph, from kindergarten to Secondary II. The island's average age is 47, with people over 15 comprising 87% of the population in 2011.

In terms of infrastructure, the community has a gymnasium, arena, fitness center, library, school, church, municipal office, dispensary, tourism office, campground, IT community access center, ecomuseum, mechanical rake, water treatment plant, and two sewage pumping stations. It also has a thermal power plant, a wharf, and an airport.

There are a number of businesses and services: a post office, a Caisse Desjardins, a consumer coop with a food store and a gas station, an outfitter, and various associations

<sup>54</sup> All data in this subsection is taken from Boisjoly-Lavoie, A. et al., 2015. *Anticosti, une communauté riche de son patrimoine, complexe et à la recherche de son développement*. CCC-CURA, 64 p.

including the Knights of Columbus and the *Table de concertation sur la foresterie* (Roundtable on Forestry), to name but two.

The island's remoteness and isolation have their drawbacks, such as transportation costs to and from the mainland. For example, a return plane ticket costs \$450 to Sept-Îles and \$1,500 to Québec City. A return ticket by boat (April to January only) costs \$110 for residents and \$164 for non-residents.

All residents are connected to the municipal water supply, which draws on groundwater. In 2012 and 2013, drinking water samples exceeded certain microbial standards (atypical and fecal coliform), prompting authorities to issue boil water advisories that lasted throughout 2013. For wastewater discharge, part of the community is on the municipal sewer network while newer buildings have septic systems.

The 270-kilometer Trans-Anticosti Highway, which runs west to east across the island, has no winter snow removal. In the cold season, most people get around by snowmobile.

Here are some economic data and employment figures:

- Average income of Anticosti residents aged 15 and older: \$26,853 (2005)
- Labor force participation rate, La Minganie RCM: 72.3% (2005)
- Employment rate, La Minganie RCM: 44.7% (2005)
- Unemployment rate, La Minganie RCM: 38.2% (2005)
- Year-round jobs: roughly 64
- Seasonal jobs: between 114 and 211 (2015<sup>55</sup>)
- Economic spinoffs from tourism sector: \$13 million (based on 2012 data)

Anticosti residents are proud of their region, resources, and cultural heritage. Islanders have a strong sense of belonging to the community, and some still fear having economic decisions made by others on their behalf as was done in the Menier, Wayagamak, and pre-municipal periods.

Of the many benefits of island life, residents cite the peace and quiet of Port-Menier, a sense of kinship and solidarity, and a feeling of safety throughout the community. Remoteness and isolation have led to unique practices that reflect the resourcefulness of islanders, who depend on outside suppliers for food and provisions, energy, and medical services.

In describing their community, Anticosti residents use 11 phrases to define its identity and character<sup>56</sup>.

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<sup>55</sup> Based on interviews conducted in the community (2015).

<sup>56</sup> For a detailed presentation on each description, see Boisjoly-Lavoie et al.

Key Descriptions:

*their region*

*munity*

*entrepreneurs*

*a means of survival*

*is unsuited to local context*

*but declining*

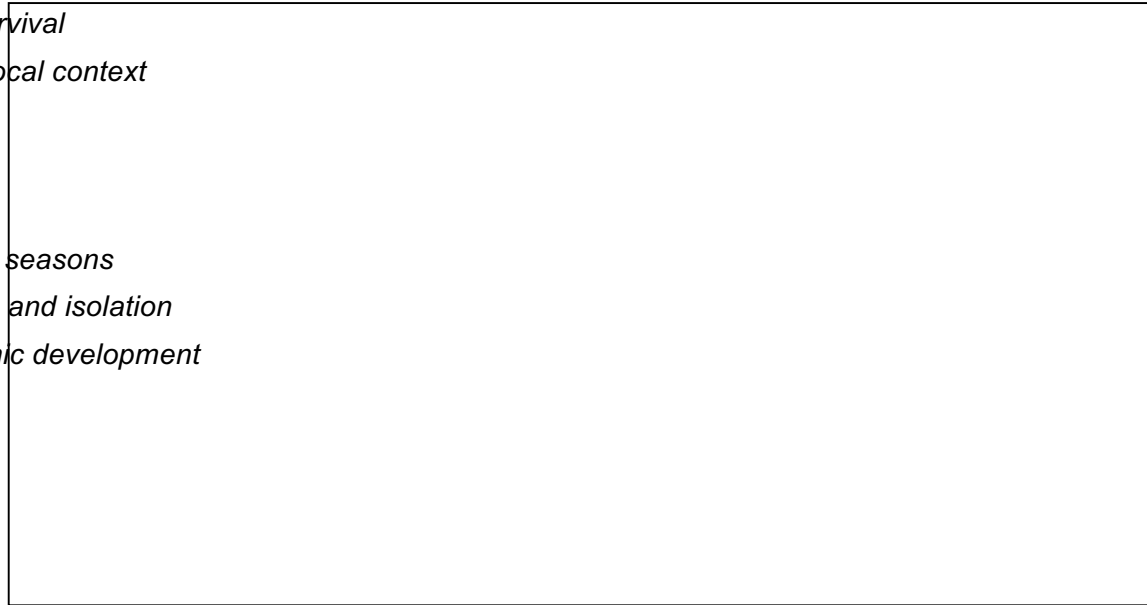
*g social fabric*

*ues*

*by climate and seasons*

*by remoteness and isolation*

*ial and economic development*



However, the community feels its regulatory framework prevents the optimal use of island resources. For example, Anticosti residents would like to market venison, get their seafood directly from fishing vessels at Port-Menier's wharf, and obtain their dairy products from island farms—none of which is possible under current regulations.

The island's remoteness and small population also pose problems for some sectors and residents:

- Only once-a-month access to a doctor, roughly every two months to a dentist (for anything more, they must travel to Côte-Nord)
- Reduced post office and caisse populaire hours
- Requirement for young people to leave the community to continue school after Secondary II
- No care facilities for the frail elderly
- Drug delivery system in need of improvement
- No daycare services

Since peaking in the 1920s, Anticosti's population has steadily declined. Among the reasons for this are that families leave the island when their children continue school past Secondary II, and many seniors move to the mainland for services that meet their needs. The declining population is also an aging one, as new arrivals tend to include more pensioners than young families.

The island's other social aspects include high-priced consumer goods, average incomes higher than those of the Minganie-Basse-Côte-Nord census area, seasonal employment, high air travel costs, below-market housing costs, and a sluggish economy, especially in the tourism sector.

## **Territorial inventory of land uses and sensitive areas**

Île d'Anticosti is located in the Gulf of St. Lawrence, separated from Côte-Nord by the Jacques-Cartier Strait and from Gaspésie by the Honguedo Strait. With 7,943 square kilometers, it is Québec's largest island. It is part of Minganie RCM.

The island is almost entirely covered by forest (7,259 km<sup>2</sup>). It also has many wetlands (364 km<sup>2</sup>), as well as lakes, rivers, and shoreline (233 km<sup>2</sup>). The settled area, located at the western tip, consists of roughly 1 square kilometer.

Île d'Anticosti has 61 sites of interest, mostly ecological (1,207 km<sup>2</sup>), with 691 kilometers of ecological interest areas along the island's 24 salmon rivers, among other things. Virginia white-tailed deer are everywhere (with 20 deer per square kilometer in some areas), and white-tailed deer yards cover some 99% of the island.

White-tailed deer hunting is Anticosti's biggest economic activity, bringing close to 5,000 hunters a year to the island. Structured wildlife areas (SEPAQ Anticosti, Safari Anticosti, and Pourvoirie Lac Geneviève) also offer a wide range of recreational and tourism activities including fishing, quadding, snowmobiling, moose hunting, wildlife observation, and hiking.

Data collected in early 2015 from SEPAQ Anticosti (*Société des établissements de plein air du Québec*) show that SEPAQ alone brings in:

- 2,800 hunters a year
- 1,200 vacationers (and anglers) a year
- Revenues of \$1.7 million (2013) for vacationers and \$6.8 million for hunters

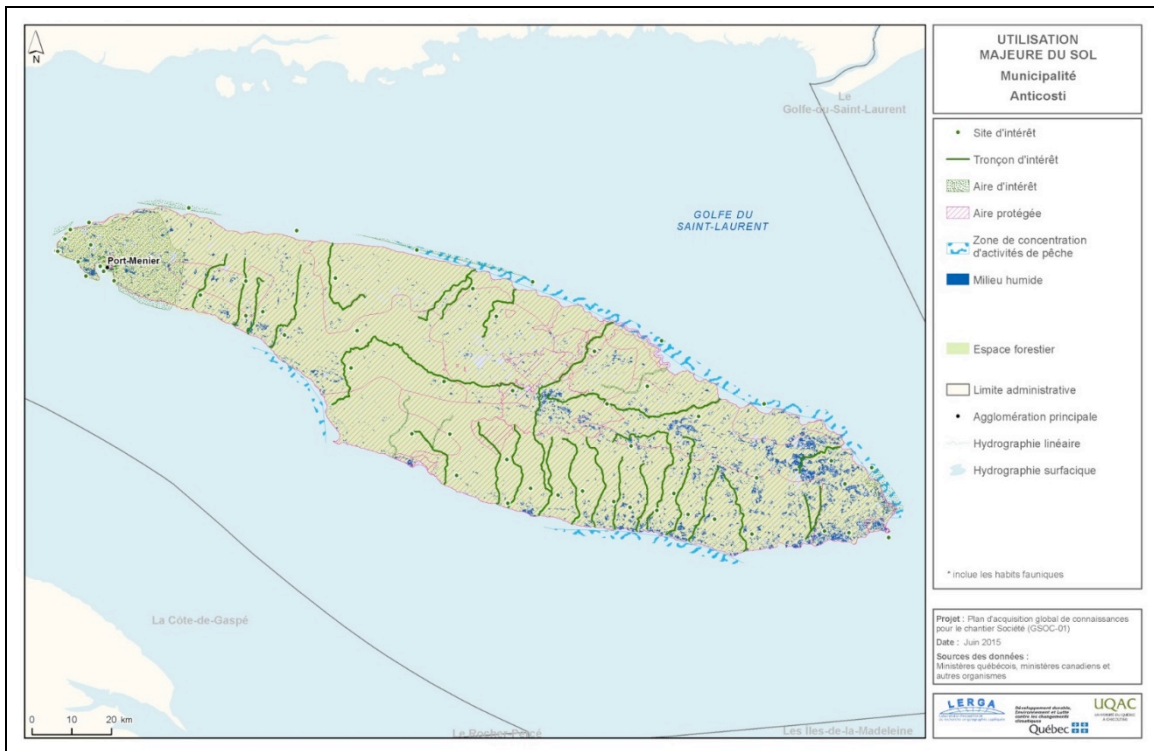
With three campgrounds, three B&Bs, and a youth hostel also available as accommodation. *Parc national Anticosti* is one of the island's major attractions, along with Baie-Sainte-Claire (site of Château Menier, which burned down in 1953) and the Anticosti ecomuseum.

Another major land use is oil and gas exploration, with 15 wells drilled between 1963 and 1999. Some 22 wells and stratigraphic test holes have been drilled since 2005, with 2 wells still active.

### Land uses

Aside from the national park in the middle, Anticosti has at least three other land use components: forest, structured wildlife areas, and conservation areas (see Figure 43).

**Figure 43 Major Land Uses on Île d'Anticosti**

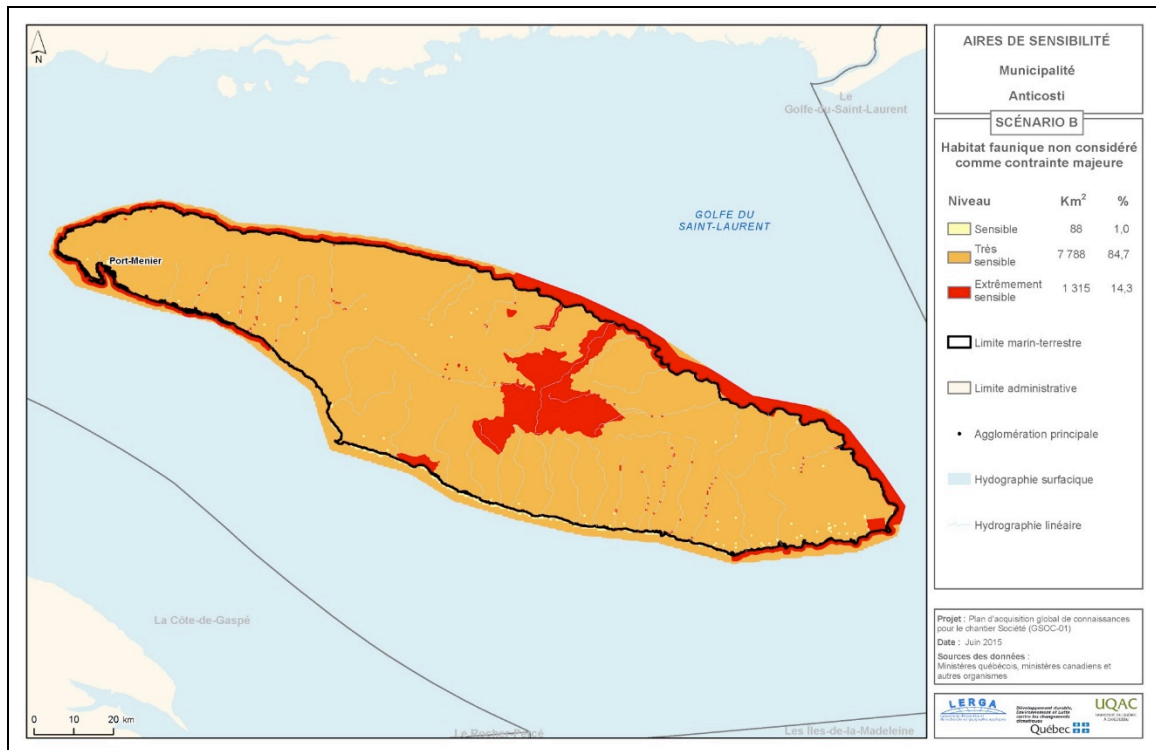


Source: GSOC01 map 61

Extent and levels of sensitivity vary greatly depending on whether white-tailed deer yards are considered a major constraint (at present, only yards protected by the national park and the two nature reserves are deemed protected areas). That is why the UQAC team prepared two scenarios for sensitive areas.

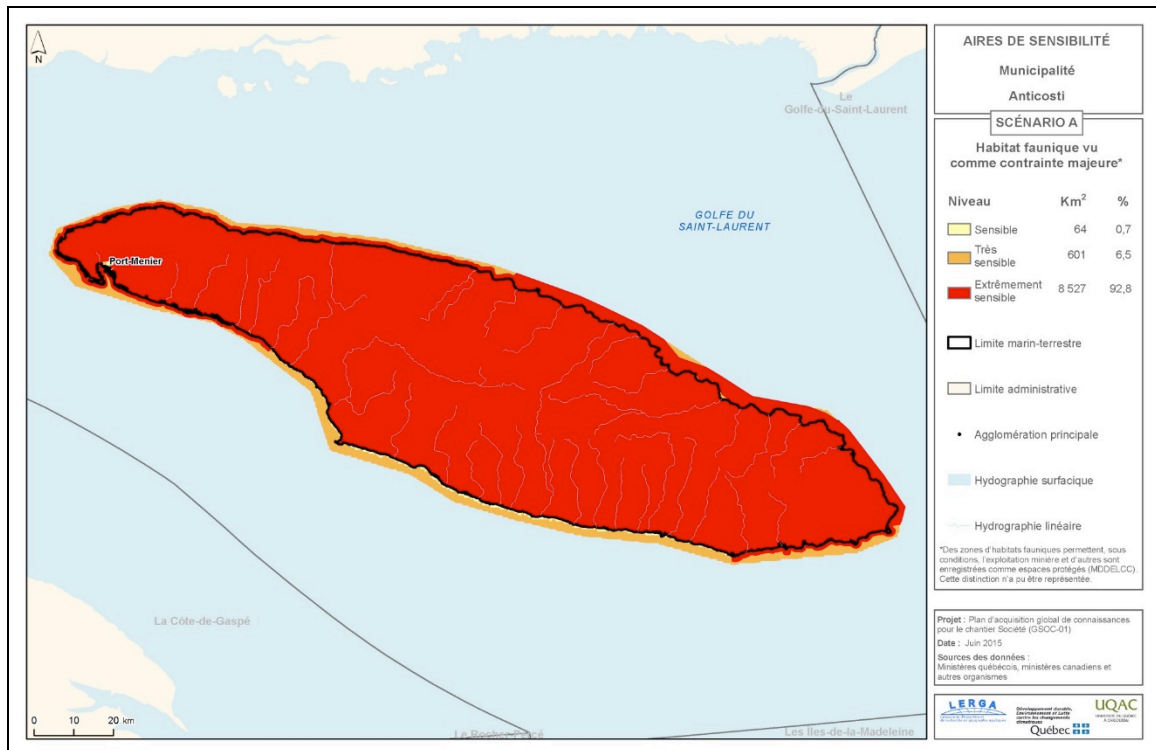
If white-tailed deer yards are not seen as a major constraint, the sensitive areas will match the Figure 44 illustration. Conversely, if the areas are seen as a major constraint (like those listed in Québec's register of protected areas), the extent and level of sensitivity in these areas will match the **Erreur ! Nous n'avons pas trouvé la source du renvoi.**<sup>45</sup> illustration. Based on the scenario used, extremely sensitive areas will vary from 14.3 to 92.8 percent while very sensitive areas vary from 84.7 to 6.5 percent—greatly affecting the assessment of sensitivity levels.

**Figure 44 Sensitive Areas for Île d'Anticosti – Scenario Where White-Tailed Deer Yards Are Not Considered a Major Constraint**



Source: GSOC01 map 64

**Figure 45 Sensitive Areas for Île d'Anticosti – Scenario Where White-Tailed Deer Yards Are Considered a Major Constraint**



Source: GSOC01 map 63

**Oil and gas industry: anticipated effects**

The ASOC01 study by UQAR researchers describes anticipated impacts on the Anticosti community of oil and gas development on the island. Using the well platform deployment scenarios from May 2015, the results of studies AENV17 and GECN02, and feedback from ground work in May and September 2015, it makes various preliminary observations, of which the main ones are presented in the table below.

**Table 58 Preliminary Observations of Main Anticipated Impacts on the Anticosti Community of Oil and Gas Development on the Island**

Positive Impacts	Negative Impacts
<b>Health and welfare</b>	
Possible improvement in healthcare services	Reduced sense of personal safety
Possible increased vitality of village	Impact on physical and mental health
	Possible drug or alcohol related problems if fly in fly out
<b>Environmental quality</b>	
New vitality in Port-Ménier	New environmental nuisances and potential contaminations
	Lack of time to prepare for a spike in the local population
<b>Economic resources and material well-being</b>	
Possible increase in the local population	Negative impact on hunting and fishing

Positive Impacts	Negative Impacts
Economic prosperity	Loss of forestry lands
Community able to attract new residents	Inability of local businesses to offer competitive wages
<b>Culture</b>	
Possible new opportunities for social interaction	Loss of way of life, less peace and tranquility
	Loss of ecological heritage
	Transition from a service-based economy to a primary sector-based economy
<b>Family and community</b>	
School can be saved and kindergarten added	Departure of certain residents
Dilution of social tensions	Polarized points of view and reduced community spirit
	Deep divisions already present in the community
<b>Institutions, laws, politics, and equity</b>	
No positive impact identified	Municipal officials unprepared to oversee development
	Services and infrastructure unable to support any further pressure
	Increased conflict between port users
<b>Relations between the sexes</b>	
No positive impact identified	Possible imbalance between higher wages paid to blue collar workers (men) than service workers (women)

These preliminary observations will serve as a guide in documenting the adaptability and resilience of the Anticosti community should oil and gas development come to the island. They make up the third theme of the ASOC01 study, whose conclusions will be taken into account in the final SEA on Anticosti.

## 8.4 Aboriginal Participation

Québec is home to 11 aboriginal nations: the Inuit nation (14 villages with some 10,500 residents in 2012) and 10 Amerindian nations (Abenaki, Algonquin, Atikamekw, Cree, Huron-Wendat, Innu, Maliseet, Mi'kmaq, Mohawk, Naskapi) comprising 41 communities. As of 2012, Québec had an aboriginal population of 87,091 (59,471 residents and 25,932 non-residents).

Many native communities are located in areas where natural resources already play a big part in the local economy. And many individuals also have a mode of life that is still very much in tune with the land. Although it has not always been the case, native communities are increasingly key players in natural resource development. They have higher expectations. Projects must be developed with a greater eye to ethical behavior and social acceptability, which are often the keys to success. Native communities also seek to participate in more ways (partnerships, employment, etc.) and benefit more directly from resource extraction spinoffs. New jurisprudence on the recognition of native rights, including the Crown's obligation to consult, has helped forge a new context and made respect for native interests and concerns an essential part of the process.

Some of these communities are already actively involved in natural resource development. Occasionally this is through private agreements, such as the close partnership between Raglan Mine and the Nunavik communities of Salluit and Kangiqsujuaq. Other times the community's involvement is completely different—the

Mi'kmaq Nation is helping develop a Gaspésie wind farm by partnering with a developer to provide a block of energy through an agreement with the Québec government. More often than not, the goal is to acquire viable economic resources to address the continuing disparity in wealth and development compared to other communities—natural resource development offers good opportunities for employment and economic progress.

Various models of native participation in natural resource development are found elsewhere in Canada. Analysis of these may prove useful in the context of new energy source development in Québec. For instance, a review of native participation in the resource extraction industry in British Columbia and Alberta could prove illuminating, as this sector's development success has been driven in large part by new ways of involving native communities.

The **Erreur ! Nous n'avons pas trouvé la source du renvoi.** study (M. Papillon, Udm, 2015)<sup>57</sup> set out to review and report on native participation in resource development outside Québec, especially Western Canada. The information in the following subsections is taken from this study.

### Participation mechanisms

Many aboriginal communities wish to play a more active and direct role in development projects. Of course, one desire is to minimize the adverse effects these projects can have on native lands or land claims and to maximize project benefits. But there are also incentives to address economic and social issues, the lack of employment opportunities for young people, and dependence on government subsidies and “development more direct strategies for participating in local development.” (Papillon, *Université de Montréal*, 2015).

Aboriginal participation in resource development projects can also yield benefits for sponsors and governments. It minimizes the risk of opposition from affected communities, helps foster a climate conducive to investment and development, and reduces uncertainty.

Based on examples from Alberta and British Columbia, the GSOC03 study reviewed four participation mechanisms: consultation, Impact and Benefit Agreements (IBAs), royalty sharing, and support for native entrepreneurship.

### Consultation

Like the federal government and all provincial jurisdictions in Canada, the Québec government is required to consult—and, where applicable, make accommodations—when a decision or action it is considering is likely to affect the claimed or established rights of aboriginal peoples.

*“... the Crown must act honorably in its relations with aboriginal peoples. When making decisions about a project, the authorities must weigh, through a consultation process, not just the established rights of aboriginal groups but those to which they have a reasonable claim.”<sup>58</sup> The Court has also established a duty to accommodate affected communities*

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<sup>57</sup> Papillon, M. 2015. *Toward a New Partnership? Report on the Participation of Aboriginal Communities in Natural Resource Development Outside Québec*. 52 pp.

<sup>58</sup> Among the Supreme Court's important decisions concerning the duty to consult, of particular interest are *Nation Haida v. British Columbia* (2004), *Taku River v. British Columbia* (2004), *Mikisew Cree v. Canada* (2005), *Rio Tinto Alcan v. Carrier Sekani* (2010),

*when these rights are significantly affected, through changes to the project or compensatory measures.”*

Source: Papillon M., 2015, p. 6.

To help government departments and agencies fulfill this duty, in 2006 Québec's *Secrétariat aux affaires autochtones* published the Interim Guide for Consulting Aboriginal Communities (updated in 2008). Of the four participation mechanisms studied, consultation is the most institutionalized to date and the only for which there is jurisprudence.

Aside from identifying a community's social and environmental concerns, consultation can help determine a project's social acceptability.

A review of aboriginal consultation practices in Alberta and British Columbia shows significant differences in the mechanisms used, the role of developers, the legitimacy of the process, and the limitations of this approach.

### **Mechanisms used**

Aside from the legal duty to consult, some provinces consult aboriginals for the sake of good neighborly relations. And approaches vary. For example, Alberta has a central decision-making process while British Columbia has an internal coordination office to share information on aboriginal communities and avoid duplicated efforts.

Aboriginal consultation is often an integral part of established mechanisms, and the courts feel that such processes meet consultation requirements. But many native organizations are critical of the practice, both in Québec and elsewhere.

“Lack of attention to unique aboriginal concerns is a major issue in the literature on recent strategic environmental assessment consultations, especially for oil and gas transport in Western Canada. It is important to distinguish aboriginal consultations from public ones—a distinction greatly facilitated if the process has clear rules or a clear regulatory framework.”

(Papillon, M., 2015.)

Consultation is a part of decision-making and, according to Martin Papillon, is the most limited direct participation mechanism in the resource development process (Papillon, M., 2015). To improve the social acceptability of oil and gas projects, we must ensure greater community involvement in their planning and development. Mechanisms established to this effect must be based more on ethical norms than constitutional requirements.

Encouraging aboriginal peoples to play an active part in developing consultation policies or guidelines that concern them, particularly to ensure that they agree on end goals, is a winning strategy.

### **The role of developers in the consultation process**

Whether under treaties or court rulings, the Crown is viewed as the one responsible for consulting with aboriginal communities and involving them in decision-making processes, not project developers. But the jurisprudence also teaches that the Crown

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*Beckman v. Little Salmon/Carmacks* (2010), *Behn v. Moulton* (2013), *Nation Tsilhqot'in v. British Columbia* (2014), and *Grassy Narrows v. Ontario* (2014).

can delegate certain of the procedural aspects of consultation to developers, such as supplying technical information to aboriginal communities. Project developers can also be brought into the process when the Crown needs to work out certain accommodation measures.

The role of developers in consultation processes varies from one jurisdiction to the next. For example:

- Until recently, in Alberta consultations were almost the sole responsibility of developers (this has since changed).
- In Yukon, the Northwest Territories, and Nunavut, developers must negotiate Impact and Benefit Agreements (IBAs) with affected aboriginal communities (a precondition for project authorization).
- In Alberta and Saskatchewan, developers must adhere to precise timeframes and conditions for providing information to communities.
- British Columbia encourages developers to fund community consultations, while Alberta collects a tax and diverts part of the revenues to communities.

Support measures also exist, such as in BC, which provides promoters with guidebooks to facilitate their contact with native communities.<sup>59</sup>

### **Legitimacy of consultation processes**

Aboriginal communities and government do not always interpret the jurisprudence on consultation the same way. Consequently the consultation processes that governments adopt are not always greeted as legitimate, although they do appear to be a precondition to successful relations. But a review of approaches in Alberta and BC highlights two issues. First, governments tend to determine consultation mechanisms unilaterally. Second, there are deep disagreements between communities and those leading the consultations, especially regarding end goals.

The cases of New Brunswick and Nova Scotia need further review, as these provinces have received support (albeit partial) from provincial native organizations for the governments' consultation policies.

### **The limits of consultation**

Procedural issues and technical language inherent in the process are among the noted shortcomings of Crown consultations. While aboriginal peoples see project consultations as a chance to assert their right of approval, they are often consulted only at advanced stages of planning or investment. Papillon (2015) notes that clear aboriginal consultation mechanisms could help build trust between these communities and project sponsors.

More inclusive mechanisms (Impact and Benefit Agreements [IBAs], royalty sharing, support for native entrepreneurship, etc.) could encourage native communities to play a full and active part in resource development projects.

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<sup>59</sup> A number of documents are available on the BC government website (<http://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/consulting-with-first-nations>), including [Building Relationships with First Nations: Respecting Rights and Doing Good Business](#), published in English, Mandarin, Japanese and Korean.

## **Impact and benefit agreements (IBAs)**

Impact and Benefit Agreements are private, generally confidential agreements between developers and aboriginal groups, negotiated outside the regulatory framework of the project approval process.”

(Papillon, 2015)

There have been negotiated IBAs in Quebec for some 30 years, notably between Hydro-Québec and communities affected by natural resource development projects. But the practice is growing more common, due in part to new jurisprudence in native rights, the use of social acceptability as an approval criterion, and the increasing ability of communities to oppose projects.

There are roughly 200 IBAs in Canada in resource extraction and energy transport industries. Though IBAs are normally confidential, research has found them to contain a number of features:

- Environmental impact mitigation measures
- Site rehabilitation
- Natural habitat preservation
- A financial component
- Lump sum payments
- A percentage of project revenues
- Job measures
- Workforce training measures
- Local infrastructure investment
- Promotion or education programs for a native group’s language and culture

“IBAs have become a must in wind energy, hydroelectric, mining, and oil and gas projects that affect native communities. The practice developed in a parallel and complementary manner with the environmental assessment process and the notion of the duty to consult, due largely to the constraints and limits of the consultation process (Fidler and Hitch, 2009). IBAs let native people play a more active role in defining projects, to help minimize their harm and share their benefits.” (GSOC02, p. 18)

Nearly all IBAs contain clauses stating that the aboriginal group consents to the project and that the agreement is confidential. But negotiating and implementing an IBA raises issues, in particular regarding its confidential nature, the superimposing of a new layer of negotiation mechanisms, and the consultations held as part of the environmental assessment.

These issues are as follows:

- Due to the confidential nature of IBAs, community members do not know exactly what has been negotiated on their behalf.
- IBAs are sometimes concluded before or during consultation periods. They often indicate that native communities have consented to the project, even though IBAs are mostly economic agreements while consultations cover all manner of social, economic, and environmental issues.

- Given the confidential nature of IBAs, there are risks of abuse and misuse of funds.
- There is a chance the government will see the conclusion of an IBA between a developer and a native community as a form of consultation that exempts it from the duty to consult.
- Concluding an IBA may aggravate conflicts with groups that are excluded, whether aboriginal or not.

Full transparency also has its share of issues, both for developers and communities.

The study suggests the government frame IBAs to ensure they take better account of consultation processes and are more transparent.

### Royalty sharing

Royalties are sums of money paid to the government by businesses in exchange for development rights.

The **Erreur ! Nous n'avons pas trouvé la source du renvoi.** study notes that royalty sharing with native communities is based on the principle that as distinct peoples who occupied Canadian lands before the Crown acquired them, indigenous people have a right to benefit from income generated by economic activity. The study also notes that Perry Bellegarde, Grand Chief of the Assembly of First Nations, has made royalty sharing one of his priorities.

Though royalty sharing encourages affected communities to accept resource development projects, it is applied unevenly across Canada. Alberta and Saskatchewan do not use it, arguing it has no legal basis since prairie First Nations surrendered their rights by signing historical treaties. Manitoba and Ontario proceed on a case by case basis, while New Brunswick, Quebec, and Newfoundland and Labrador have signed royalty-sharing agreements in some cases. British Columbia routinely uses royalty sharing under the reconciliation policy it adopted in 2004.

**Table 59 Examples of Royalty Sharing under Modern Treaties**

Agreement	Royalty sharing
Yukon First Nation final agreement	50% of the first \$2 million, 10% after that
Gwich'in and Sahtu final agreements (NWT)	7.5% of the first \$2 million, 1.5% after that
Tlicho final agreement (NWT)	10.4% of the first \$2 million, 2% after that
Nunavut final agreement	10.4% of the first \$2 million, 5% after that
Nunatsiavut final agreement (NL&L)	50% of the first \$2 million, 5% after that (the province also shares 5% of the royalties from Voisey's Bay nickel mine)

Source: Papillon, 2015.

Depending on the jurisdiction, royalties are paid on the basis of bilateral agreements (British Columbia), to the entire aboriginal nation (or nations) living in the province or territory (Northwest Territories), or based on a mixed formula with part of the royalties

paid to the affected community and the rest put in a consolidated fund for the social and economic development of all First Nations in the province or territory. These bilateral agreements are occasionally the result of a general negotiation process or are signed on very specific issues. “This is the approach in British Columbia, which negotiates bilateral agreements according to a predetermined model in certain sectors (forestry, mineral resources, oil and gas, renewable resources, tourist infrastructure)” (Papillon, M., 2015). This practice of British Columbia’s opens the door to royalty sharing outside the confines of modern treaties, but is part of a negotiating philosophy that mutually recognizes the existence of land claims.

Royalty sharing reduces uncertainty about resource development, since the public nature of its mechanisms makes both government and aboriginal authorities more accountable. Compared to IBAs, royalty sharing allows more flexibility in the use of funds.

Research has revealed issues that may arise in such mechanisms, the most important being that it may, depending on the formula, create winners and losers in the “geography and history lottery”—whether between native communities themselves, or between native communities and nearby non-native ones.

Other issues include the ability of small communities to manage large funds, internal tensions relating to their use, the limited ability of governments to impose precise accountability models once the funds are paid, and, lastly, relations with non-native communities. Experience has also pointed to issues in defining the limits of a community’s area of interest, what is meant by “royalties,” and the fact that the government can decide to take these amounts into account when calculating transfer payments.

### **Support for native entrepreneurship**

In addition to direct grants for communities, cooperative agreements between native groups and non-native private firms are best for establishing long-term business relationships. Such agreements have a more lasting impact and are not necessarily associated with a specific project, making them different from similar measures that may be contained in an IBA.

However, access to capital is an issue, as is the ability of communities to manage the risks associated with a project. The study suggests governments act as guarantors by providing interest-free loans or funding the creation of economic development officer positions in communities. But it advises caution and a thorough knowledge of each community’s internal dynamics.

### **Conclusion on mechanisms**

Consultation is a compulsory mechanism that is part of jurisprudence, IBAs and royalty sharing are matters for negotiation, whereas support for entrepreneurship requires more direct participation in resource development projects. Ensuring these mechanisms fit seamlessly together is no small challenge—the most striking example being the link between public consultations and the negotiation of IBAs under an environmental assessment process.

The **Erreur ! Nous n’avons pas trouvé la source du renvoi.** study notes that “ideally, a project’s consultation process and technical impact assessment should set clear parameters to negotiate agreements that follow a compensatory logic.” **Erreur ! Nous n’avons pas trouvé la source du renvoi.**, p. 27

## Participation mechanisms in British Columbia and Alberta

### British Columbia

Of all the provinces, British Columbia has the most ambitious approach to aboriginal relations—one linked to the development of amicable ties with aboriginal peoples.

In the last 15 years, 500 agreements have been negotiated in land resource management alone. British Columbia was also the first province to adopt a guide on how to consult with aboriginal peoples. While the guide is not recognized by the main native organizations (due to persistent disagreements over the scope of the duty to consult), various ministries use it as a basis for developing policies and guidelines.

The government negotiates consultation protocols with native communities to, among other things:

- inform communities whenever a decision or project requires public consultation,
- establish funding mechanisms, and
- establish terms and conditions (deadlines, access to information, etc.).

This alternative course builds consensus and does away with government-imposed guidelines. It has the advantage of securing aboriginal buy-in and guaranteeing the credibility of the consultation process, which cannot be disputed if it is applied as agreed.

The BC government negotiates royalty-sharing agreements on an almost routine basis. For example, in the forestry sector it has signed some 150 royalty-sharing agreements since 2003. In the mining sector it has signed some 15 agreements since 2008. It also has a system to share revenues from hydroelectric and wind energy development.

Aside from formalizing aboriginal consultation mechanisms, encouraging the negotiation of IBAs and concluding royalty-sharing agreements, the BC government has set up the following native entrepreneurship support measures:

- Funding
- Workforce training
- Access to venture capital
- Skills development

It has also made strides in promoting employment opportunities, especially in the natural resource sector.

To promote oil and gas transport projects, the government created a special type of agreement: Natural Gas Pipeline Benefits Agreements. To date, it has signed 54 agreements with 27 First Nations. For example, the Gitxaala Nation and the government signed an agreement for a one-time payment of \$1,540,000. Annual payments from a \$10 million joint fund are divided between signatories of similar agreements for the TransCanada Pipelines Prince Rupert Gas Transmission Project. But royalty-sharing agreements are not always enough.

To illustrate the importance of having various ways to engage with aboriginal peoples—from initial consultations to negotiated agreements or support for partnerships—the GSOC02 study looked at the proposed Lelu Island natural gas terminal.

For this project to export natural gas to Asian markets, a private consortium and the government signed a series of agreements with Lax Kw'alaams (compensation

measures and royalty sharing) for a total of \$1.149 billion over 40 years. The experience was not a success, as the community wanted a part in evaluating the project and defining its acceptability criteria. When it was not granted this, it lost faith in the consultation process.

“Though important, economic partnership agreements are not enough. For native people to play a meaningful role in these matters (rather than just share in the profits of resource development), these agreements must be negotiated in a way that complements the environmental assessment and consultation processes.”  
(Papillon, 2015)

## Alberta

Alberta’s model is very different from that of BC.

“Alberta leaves it to project developers to promote more substantive direct relations with native communities, including financial relations. The province concedes it has a duty to consult, but delegates most of this responsibility to developers. It also rejects any form of financial compensation or public revenue sharing for resource extraction, but encourages developers to negotiate economic partnership agreements with native communities, including IBAs.” **Erreur ! Nous n’avons pas trouvé la source du renvoi.**, pp. 35–36.

This approach has certain advantages, such as lowering expectations about the role of the state, reducing costs to the public purse, and forcing developers to develop stable relations with affected communities.

But there are just as many disadvantages. It increases the risk of legal and political disputes with First Nations and can cause greater disparity between communities. For instance, if a community has signed no IBA with the promoter, the project may adversely affect its living standards while providing no actual benefits. According to the **Erreur ! Nous n’avons pas trouvé la source du renvoi.** study, Northern Alberta is the region of Canada with the largest income differential between natives and non-natives.

Alberta’s model can be explained by the fact that the region with the largest oil sands deposit is subject to the terms of an historical treaty. While the government says the treaty settles all subsurface resource issues, this view is not shared by native organizations.

Alberta’s Policy on Consultation with First Nations, adopted in 2005, clearly outlines the government’s role both in projects and in planning. In the former case, its role is simply to ensure the developer’s consultation process does not conflict with Crown obligations. In the latter, the government consults communities itself.

Issues discussed at these consultations include regulations, policies, strategic land use planning, and decisions concerning Crown management of lands, natural resources, forests, the air, flora, and fauna.

In 2013 the government changed its consultation policy by, among other things, adding a central Aboriginal Consultation Office. The Office is responsible for holding consultations on strategic issues and determining the conformity of developers’ consultation processes. The policy also establishes timeframes as well as a fund to support native participation. The fund is paid for by new permit fees for developers.

Centralizing consultations with aboriginals also has the indirect effect of limiting input from them and consideration of their concerns during pre-decision project reviews and environmental assessments.

To support native communities in the resource development process, the Alberta government relies mostly on large-scale employment programs and the promotion of partnerships between developers and native communities or businesses. The **Erreur ! Nous n'avons pas trouvé la source du renvoi.** study notes the following programs:

- First Nations Development Fund: supports community job creation and infrastructure development initiatives (value: \$128 million)
- First Nations Economic Partnerships Initiative: promotes partnerships between native and non-native businesses (value: \$20 million per year)

First Nations Training to Employment Program: supports training and employment partnerships between private sector, government and aboriginal organizations (results: 40 community training centers, 89% job search success rate, and creation of a provincial association for aboriginal professionals and entrepreneurs (Aksis)

Since 2011, the Alberta government has been developing a provincial employment strategy specifically for aboriginal peoples.

In Alberta, aboriginal participation occurs at two different times: at initial stages (strategic planning, especially land use planning) and implementation stages (when it's time to consider actual development issues). To illustrate these modes of participation, the GSOC02 study explored two case studies: the development and adoption of the Lower Athabasca Regional Plan, with its high concentration of oil sands mining projects; and the case of the Fort McKay community, also located in an oil sands mining zone.

In 2008 the Alberta government issued a Land-Use Framework identifying the Lower Athabasca region as a priority. It then began an elaborate process to develop a land use plan and hold public consultations, but seems to have established the process unilaterally. So, despite 107 meetings with First Nations Métis organizations, the plan was opposed. The main objections were a lack of transparency in the consultation process and the scant influence the consultations seem to have had. The aboriginal chiefs also felt the consultation process was imposed on them.

Following the case study, Papillon (2015) felt it would have been useful to address aboriginal concerns by noting the importance of treaty rights and Crown obligations in the consultation process or creating a joint body to monitor the plan.

The case of Fort McKay is an illustration of access to employment in an industry whose presence had met with opposition in the community for several decades. In 1986 the Alberta government set up the Fort McKay Industry Relations Corporation to promote job creation in the aboriginal community. By developing businesses that have partnership agreements with industry, the corporation has helped the community generate some \$150 million in yearly revenues. But this economic development model is not welcomed by all in the community, or by nearby native communities that lack the same benefits. Despite the prosperity it has created, rates of substance abuse and domestic violence remain high. Some residents feel oil and gas activities are directly responsible for the deterioration in the environment and the community's way of life.

The GSOC02 study concludes with some ideas worth noting:

1. The four mechanisms in the study are complementary. Ideally, they should be part of an overall strategy to encourage aboriginal partnerships in natural resource development. British Columbia has the most ambitious approach in this area and could serve as a model for Québec.
2. To ensure legitimacy, this type of strategy should be developed in collaboration

with the province's main native organizations. It may be good to start with a joint statement recalling the relationship's key principles and establishing clear mechanisms for determining areas of common interest.

3. The Alberta and British Columbia experiences can offer lessons to help minimize conflict, especially with regard to consultation. For example:
  - a. Lack of attention to unique aboriginal concerns is a major issue in the literature on recent strategic environmental assessment consultations, especially for oil and gas transport in Western Canada (see the Lax Kw'alaams example). It is important to adapt these processes to the native cultural, legal, social, and political context. The creation of separate structures and processes is an avenue worth exploring.
  - b. It is also important to approach consultations in a relational and dialogue-based manner rather than a strictly legal one. An overly procedural approach could make participants lose sight of the end goals (i.e., to reconcile differing interests and ensure projects are socially acceptable).
4. IBAs let native people play a more substantive role in development than consultation alone. They also let developers and communities work together in a spirit of collaboration rather than confrontation. But IBAs have limitations (their essentially economic nature, lack of transparency, lack of government control over their content, etc.). While encouraging affected parties to negotiate IBAs, governments should consider regulating them to ensure they are more transparent and better reflect consultation processes.
5. Royalty sharing has played an increasing role in negotiations when governments want to minimize legal uncertainty and gain the support of native communities affected by a major project. British Columbia is a pioneer in this regard as the only province to develop a systematic policy of negotiating bilateral royalty-sharing agreements with First Nations. Despite some difficulties, this approach seems to be bearing fruit.

Measures encouraging native people and communities to take part in the resource economy should not be underestimated. If flexible enough, they can help build bridges between native communities and project developers (as in Fort McKay, for example). But such measures are not enough on their own, and must be used in conjunction with other mechanisms.

## 8.5 Social Acceptability and Territorial Governance

Social acceptability is key to the success of resource development projects, whether conducted by private sector firms, communities, or public-private partnerships.

To gain a better understanding of factors that affect the social acceptability of energy resource development projects, *Centre de recherche sur la gouvernance des ressources naturelles et des territoires* (CRGRNT) of *Université du Québec en Outaouais* was commissioned to review a number of energy projects from a territorial governance perspective. To draw useful lessons that might be applied to Québec, the study included

a review of current practices in five other jurisdictions<sup>60</sup> (see GSOC03 study). This section (8.5) presents the preliminary results of this study.

While opponents of fossil fuel development cite environmental, public health, or safety concerns (or personal values and ideology), resistance is often based on territorial issues. This SEA therefore also reviews the issue of social acceptability from a territorial governance perspective.

The first component of the Gauthier et al. study (2015) concerned the notion of social acceptability and the factors that influence it.

### **Social acceptability**

A great deal of research has focused on the concept of social acceptability. Gauthier et al. (2015) have conducted a number of studies, including several recent ones in Québec. While the issue is often raised at public consultations, it is interesting that it appears in no current laws or regulations.

While a large part of BAPE reviews concerns the qualitative assessment of a project's social acceptability, a lack of assessment criteria, indicators, conditions, and knowledge of the concept's limitations means there are still a wide range of approaches for defining it. In fall 2016, *Centre de recherche en éducation et formation relatives à l'environnement et à l'écocitoyenneté* of *Université du Québec à Montréal* will publish a doctoral thesis research paper<sup>61</sup> (Batellier, 2015) listing the four approaches developed by Saucier et al. (2009) to define the concept of social acceptability:

- Social acceptability as a means to ensure projects obtain some form of acceptance from the community
- Social acceptability as a path, process, or outcome
- Social acceptability as the extent of public agreement or disagreement
- Social acceptability as the outcome of an interactive process between stakeholders

To add to the difficulty, some associate social acceptability with related concepts like social license to operate or free, prior, and informed consent.

At the start of the GSOC03 study, in preparing energy project analysis frameworks and case studies outside Québec, researchers were asked to use at least six factors that affect social acceptability:

- Values, beliefs and expectations
- Perceived risks
- Community and environmental impacts, including reconciling land uses with a project's impact on a community's way of life
- Level of trust in developers and institutions

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<sup>60</sup> Gauthier, M. et al. 2015. Évaluations environnementales stratégiques sur les hydrocarbures. Analyse des facteurs d'influence de l'acceptabilité sociale des activités de mise en valeur des hydrocarbures et propositions relatives au mode de gouvernance territoriale. Centre de recherche sur la gouvernance des ressources naturelles et des territoires, Université du Québec en Outaouais. Volumes I and II. 320 pages.

<sup>61</sup> Batellier, P., 2015. Acceptabilité sociale. Cartographie d'une notion et de ses usages. Cahier de recherche UQAM: Les publications du Centr'ERE. 143 pages.

- Benefits and impact on affected populations
- Participation processes

These factors were then incorporated into an analysis framework with three variables: project (nature and objectives as perceived by the community), host community, and ways to ensure a project is compatible with the host community (planning and design approaches, level of public participation in the planning process, developer's corporate culture, use of procedural rules, etc.).

A project's nature refers to its *who*, *what*, *how*, and *why*. Aspects of the host community can also affect a project's social acceptability (the project's compatibility with the chosen location, its integration into the region based on the community's vision and economic vitality, etc.).

Lastly, "a planning and consultation process that ensures a project is compatible with the host community is seen as a key factor for social acceptability" (Gauthier et al., 2015). Complete, unbiased information and a clear institutional framework are winning strategies for getting the public to participate in the process.

On a more practical matter (energy resource governance), a study on major energy projects in Québec and elsewhere (Gauthier et al., 2015) identified the anticipated roles of the various parties involved (government, communities, and the general public) and explained key factors in determining a project's social acceptability.

The study reviewed the following projects:

- Suroît combined cycle plant in Beauharnois
- LNG terminal in Cacouna, Bas-Saint-Laurent
- St. Lawrence Pipeline between Lévis and Montréal-Est
- Rivière Romaine hydroelectric complex
- Changing modes of governance in the wind energy sector (1998–2015)

In addition to these projects, the authors also sought to draw lessons from experiences with the SEA on shale gas and the study by *Commission sur les enjeux énergétiques du Québec*. They also studied cases in Alberta, Newfoundland and Labrador, Norway, Australia, and several U.S. states.

### **Roles and responsibility of government authorities**

What roles and responsibilities could government authorities play in the planning, development, implementation, and completion of energy development projects?

#### **Role of the government**

Based on the GSOC03 study, the key roles and responsibilities of government authorities are to manage the resource in a responsible manner that benefits everyone; regulate and monitor the industry; safeguard life, property and the environment; plan the project; and aid with industry integration in the region.

Government authorities would also be expected to acquire knowledge; support research, development and innovation; provide information that is clear, unbiased, and as

complete as possible; prepare guides for negotiating compensation and economic benefits; and set project implementation conditions, including a financial framework.

Government authorities must ensure legal and regulatory frameworks on hydrocarbons have provisions on the framing of agreements between developers and communities (municipalities, RCMs, native communities, etc.).

### **Role of municipalities and RCMs**

At the local and regional level, lessons from the GSOC03 study suggest the main role of local communities is to ensure integrated land use planning, in part by identifying areas that are compatible with oil and gas development. It is also to structure demand to help projects integrate into the community, to negotiate and sign agreements with developers to optimize spinoffs and benefits, and to ensure sound management of the royalties paid to them by developers. On the operational level, their role is to adapt emergency measures to project requirements (fire department, drinking water monitoring and testing, road infrastructure maintenance, etc.) and involve the promoter financially in this regard. They also need to stay informed of project developments, help evaluate and monitor them, consult the community and take positions based on the public's concerns and expectations, identify conditions needed to successfully complete the project, and take part in project assessments and BAPE hearings. The study also says it would be helpful for communities to identify sensitive areas.

### **Role of the public**

Public participation in a project's early planning and development stages helps boost its social acceptability. Both individual and corporate citizens are expected to be well informed about the project and its industrial sector; clearly express their concerns, expectations and needs; and share local and traditional knowledge of the community's development history and strategy. Citizens are also expected to take part in public consultations and, whenever possible, help define projects, take part in the developer's impact study if applicable, and serve on oversight committees.

### **Social acceptability factors for energy projects**

A study of five major energy projects has identified a number of factors that play a role in determining a project's social acceptability.

At the forefront are environmental issues and a project's social and economic impact on the community. Governance is also a factor: a project's rationale and nature, host community makeup, project planning, and citizen participation all influence whether a project is accepted by a community.

### **Social concerns**

Key social concerns include the environment, public safety, adequate emergency preparedness, road maintenance, drinking water monitoring and testing, and a project's inherent costs for the municipality.

### **Governance**

From the results of the GSOC03 study, it is clear that a shared vision for energy development in Québec and a comprehensive plan to develop the sector over time are factors in the social acceptability of oil and gas projects. Projects for which all the

alternatives are carefully weighed—including the status quo—are also more apt to be positively received.

The sector's implementation model is also a factor in determining a project's social acceptability. The acceptance of hydroelectricity in the 1960s, and of the more recent spate of wind farms, is partly explained by their collective and community-based character.

Public control and supervision of the oil and gas industry together with well-established impact assessment and monitoring mechanisms are also key factors in determining a project's social acceptability.

Land development and planning tools, not just for the zone directly affected but for neighboring ones as well (municipal land use plans, RCM development plans, public land use plans adopted by the government, etc.) are key to a project's successful implementation in a community.

Conversely, when ministry authorizations override land use planning tools, communities feel excluded from the decision-making process. Blocking citizen participation at a project's early decision-making stages will increase community resistance.

The history and quality of relations between the developer and the community are key determinants. Communities with a degree of cohesion are also more open to codesigning projects with a developer than divided communities with highly polarized views.

Developers who are willing to address community concerns, espouse a shared vision, and meet needs are better received. Concerns take different forms: maximizing local economic spinoffs, hiring local workers and businesses, recovering certain types of byproducts to reuse them in other local industrial processes, providing more benefits to the local community with regard to the products produced (such as natural gas or electricity), etc.

Agreements between developers and local communities (municipalities, RCMs), as well as regional development funds to meet certain local needs such as paying off municipal debt, upgrading municipal facilities, and redistributing resources to devitalized municipalities, are thought to play a positive role in successful project integration. However, when agreements are reached privately between elected officials and developers before the public is briefed and consulted as part of an environmental assessment process, this can skew the optics and cause many to view it as antidemocratic and a biased approach to environmental examination and analysis.

*"The planning stage is the first step in the project process and occurs on two main levels: the national public policy level (to establish a vision, framework, and procedures for development) and the local level (to ensure the project is compatible with the host community). Halfway between the two is the regional level, which can be a worthwhile addition, especially in the case of wind energy.*

*Lack of planning and inadequate oversight have been big issues in the shale gas sector, resulting in strong opposition. They also plagued the first years of wind energy development, generating a sense of worry in communities."*

(GSCO03, p. 46)

We can also draw lessons from the wind energy experience. The adoption of national objectives; the production of guides for local communities; the creation of regional development plans identifying areas that are favorable, favorable under certain

conditions, or unfavorable; and even the adoption of zoning plans by municipal authorities can be winning strategies for territorial governance.

Integrated planning of a region's resources also helps make projects socially acceptable. For example, some have suggested identifying the best rivers for hydroelectric projects and those it would be best to preserve and develop for recreational uses.

An integrated multidisciplinary study of a project's impact is also worth considering, with special attention to social and cumulative impacts. Results can be presented in a manner adapted to the target audience, focusing on issues of concern to citizens while letting them help define the scope of the study.

Public participation in early decision making is also key in shaping a community's position on an energy project. "Public participation mechanisms are important at all stages of a project, from the sector's rationale to the various development phases." (**Erreur ! Nous n'avons pas trouvé la source du renvoi.**, p. 48) Conversely, the lack of early participation processes creates a climate of mistrust. In such cases, further effort is needed to develop a new basis for discussion with the community and build a climate of trust conducive to project acceptance.

Keeping citizens informed through various means, presenting information as clearly and completely as possible, and explaining issues of concern are essential to promote transparency and encourage public participation in consultations at the various project stages.

Similarly, monitoring mechanisms that make allowance for community participation contribute greatly to a project's social acceptability. Residents, tourism stakeholders, users, or members of neighboring native communities can play a very significant role in monitoring projects through their knowledge of the community and the people who live there. Monitoring activities should focus not just on environmental parameters but on social concerns such as public health and economic issues (the hiring of local residents after proper training, etc.).

For oil and gas projects with potentially major economic, environmental, and social impacts, developing aboriginal and community partnerships in the early stages of the process has become a key factor in constructive, effective, and long-term government strategies.

### **Lessons to draw from the energy projects studied and from governance practices outside Québec**

A thorough review of energy projects and a comparative study of cases in Alberta, Newfoundland and Labrador, Norway, and significant U.S. states have imparted a wealth of lessons on practices in oil and gas development that either promote social acceptability or make it hard or impossible to introduce the industry into a community.

In particular, a review of governance concerns (the project's rationale and nature, respect for the various components of the host community, the planning process, public participation mechanisms, etc.) offers lessons on successful practices for ensuring social acceptability.

Should the government choose to develop the oil and gas sector in Québec, there are ways to ensure that projects achieve a greater level of social acceptability. These are listed below according to stakeholder group.

## **Government authorities**

- Oversee oil and gas transport and development on the basis of the principles of sustainable development and with the strictest possible regulatory mechanisms and environmental measures
- Plan oil and gas development in conjunction with local and regional communities, letting local communities in particular have a say over project sites and deployment conditions
- Oversee negotiations with regard to site access
- Prepare social acceptability best practice guides for developers and local communities
- Oversee the development of appropriate safety measures and rules and coordinate them between developers and municipalities
- For impact assessments, take an approach more in tune with regional issues (conduct a regional strategic environmental assessment before reviewing a certain project, etc.)
- Adopt public consultation mechanisms that reflect the needs of local communities, and specific mechanisms for the needs of native communities
- For project monitoring mechanisms, ensure host community participation by providing adequate financial support and unbiased, fair, and accessible information
- Provide support for a neutral, arm's length organization to conduct economic studies on projects

## **Developer**

- Be attentive to and address the host community's vision and needs to facilitate project integration
- Directly address the interests of local communities
- Ensure there are long-term benefits, i.e., beyond the construction period
- Adopt measures to promote workforce training and to find and recruit local suppliers and workers, e.g., through regional subcontracting clauses, calls for tender solely for the region, etc.
- Ensure affected local and native communities are involved in the project's planning from the earliest stages, and that they also take part in the impact assessment
- Take into account local and traditional knowledge in addition to scientific and technical knowledge
- Adopt public consultation mechanisms that reflect the needs of local communities, and specific mechanisms for the needs of native communities

## **Municipalities, RCMs**

- Limit potential usage conflicts
- Mitigate the cumulative impact of various industrial projects through the integrated planning of area resources at the local and regional levels
- Identify areas that are compatible with oil and gas operations and note them in the region's planning and development tools
- For project monitoring mechanisms:
  - Play an active part in developing and implementing monitoring programs
  - Promote access to unbiased, fair, and straightforward information
  - Promote the development of community expertise and know-how in monitoring a project's environmental, social, and economic aspects

It takes time to develop new industries and projects. Trust between communities on the one hand and governments, developers and the industry they wish to introduce on the other is not always easily achieved within the brief timelines allowed for planning a project. It takes time for people to learn the facts of a project and accept it into their community. And we would do well to note that social acceptability evolves over time and can never be taken for granted.

Developing oil and gas projects in a gradual manner would let us learn from experience and adapt practices to issues as they arise, helping ensure harmonious coexistence between the industry and the host community.

To ensure the social acceptability of new industries and projects, it is important to respect the pace of local communities and Quebecers and allow them the time they need to learn and adjust.

# Appendix 1 – Steering Committee Members

## Government representatives

### Co-chairs

Gilbert Charland, Deputy Minister, Ministère de l'Énergie et des Ressources naturelles

Christyne Tremblay, Deputy Minister, Ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques

### Other government representatives

Luce Asselin, Associate Deputy Minister of Energy, Ministère de l'Énergie et des Ressources naturelles

Simon Bergeron, Assistant Deputy Minister of Budgetary Policy, Ministère des Finances

Jacques Dupont, Assistant Deputy Minister of Water, Expertise, and Environmental Assessment, Ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques

Louis Morneau, Associate Deputy Minister, Direction générale de la sécurité civile et de la sécurité incendie, Ministère de la Sécurité publique

Martin Arsenault, Assistant Deputy Minister of Territories, Ministère des Affaires municipales et de l'Occupation du territoire

Anne-Marie Leclerc, Assistant Deputy Minister, Ministère des Transports

### Independent members

Michel A. Bouchard, Full Professor, Université de Montréal, and Senior Research Associate, McGill-UNEP Collaborating Centre on Environmental Assessment

Nathalie de Marcellis-Warin, Associate Professor, École polytechnique de Montréal, and Vice President, CIRANO

Maurice Dusseault, Professor, University of Waterloo

Christiane Gagnon, Full Professor, Université du Québec à Chicoutimi

Pierre-Olivier Pineau, Full Professor, HEC Montréal

Ariane Plourde, Director, Institut des sciences de la mer de Rimouski

### Coordination

Lynda Roy, Coordinator, Ministère de l'Énergie et des Ressources naturelles

## Appendix 2: Additional Knowledge Acquisition Plan

ID	Study title	Agent(s)	Description	Status
AENV01	Preliminary assessment of greenhouse gas (GHG) emissions generated by hydrocarbon extraction on Anticosti	Government of Québec (MDDELCC)	GHG emissions will be assessed, in particular, using an approach based on comparisons with current extraction from comparable deposits.	COMPLETED
AENV02	Assessment of water needs for the hydrocarbon industry on Anticosti	Government of Québec (MDDELCC)	The water needs of the hydrocarbon industry will be estimated based on a review of the literature covering current shale deposit exploration and extraction methods.	COMPLETED
AENV03	Determination of watercourses that cannot meet the water needs of the hydrocarbon industry on Anticosti	Government of Québec (MDDELCC)	The ability of a river and its watershed to supply the volume of water needed by the hydrocarbon industry depends first on the characteristics (hydrological, ecological, etc.) of the watercourse concerned and second on the spatial and temporal distribution of the water withdrawals required by the hydrocarbon industry. This project will establish these elements and map the sections of watercourses that cannot provide the necessary volume of water.	COMPLETED
AENV04	Biophysical and biological characterization of Île d'Anticosti	Government of Québec (MDDELCC)	Biophysical characteristics of Île d'Anticosti, including vegetation, and determination of the main ecological contexts. The data will be presented by ecological unit or by watershed.	UNDERWAY
AENV05	Establishment of zones where legislative and regulatory constraints apply, and other zones where constraints exist on Île d'Anticosti	Government of Québec (MDDELCC)	Mapping of zones affected by legislative constraints relating to conservation (protected areas, areas covered by conservation measures); mapping of zones of interest for conservation purposes (presence of elements identified as sensitive or of interest—threatened or vulnerable species, wetlands, etc.); mapping of constraints under the MDDELCC legislative and regulatory framework.	UNDERWAY
AENV06	Hydrology and hydrometry of watersheds on Île d'Anticosti	Government of Québec (MDDELCC)	Description of the initial known state of surface hydrology in watersheds on Île d'Anticosti, and mapping of usable surface water.	COMPLETED
AENV07	Assessment of the noise impacts associated with petroleum exploration and extraction activities on Île d'Anticosti	External	Assessment of the noise impacts that planned activities, equipment and processes may have on the surrounding environment and determination of suitable mitigation measures.	UNDERWAY

ID	Study title	Agent(s)	Description	Status
AENV08	Modeling of the atmospheric dispersion of potential contaminants, to assess the impact on air quality of hydrocarbon exploration and extraction activities on Anticosti	External	Modeling of the atmospheric dispersion of potential contaminants, to assess the impact on air quality of hydrocarbon exploration and extraction activities on Anticosti.	UNDERWAY
AENV09	Establishment of the baseline of surface water quality and determination of sensitive aquatic environments	Government of Québec (MDDELCC)	Current state of knowledge concerning water quality in water bodies on Anticosti; characterization of water quality on the eleven watercourses on the island, dealing first with watersheds on the southern slope, more suitable for hydrocarbon exploration and extraction activities.	UNDERWAY
AENV10	Establishment of the baseline state of communities of benthic macroinvertebrates in the rivers on Anticosti	Government of Québec (MDDELCC)	Current state of knowledge concerning the biological integrity of benthic communities in watercourses on Anticosti; characterization of benthic communities in the eleven watercourses on the island, dealing first with watersheds on the southern slope, more suitable for hydrocarbon exploration and extraction activities.	UNDERWAY
AENV11	Assessment of the environmental risks of wastewater disposal (after treatment) in aquatic environments on Île d'Anticosti	Government of Québec (MDDELCC)	Assessment of the potential risks of wastewater disposal in aquatic environments on the island and determination, if applicable, of sectors or water bodies where the environmental constraints are particularly limiting for the industry.	UNDERWAY
AENV12	Review of the contaminants liable to be found in wastewater from sampling, drilling, and fracturing work by the shale oil and gas industry and updating of knowledge about the dangers of contaminants for the environment	Government of Québec (MDDELCC)	The objective of the project is to update knowledge about the substances likely to be used by the industry and information on the contaminants liable to be discharged into aquatic environments following sampling, drilling and hydraulic fracturing work on Île d'Anticosti. This will make it possible to determine if the new knowledge available can be used to fill the gaps identified by the shale gas strategic environmental assessment (SEA) with respect to the potential impact of such activities on the environment.	COMPLETED

ID	Study title	Agent(s)	Description	Status
AENV13	Current state of knowledge concerning the toxicity associated with non-manual intervention methods for spills of petroleum-derived hydrocarbons	Government of Québec (MDDELCC)	When petroleum-derived hydrocarbon products are spilled, several intervention methods may be used: manual and mechanical (excavation, dredging, etc.), chemical (dispersants, etc.), or physical (aggregation, etc.). Each method has advantages and disadvantages. Chemical methods have drawbacks intrinsic to their toxic potential. Physical methods such as aggregation are less well known. Several non-manual intervention methods have been selected: three chemical and two physical. The goal of the project is to update knowledge about the toxicity associated with each intervention method to deal with spills of petroleum-derived hydrocarbons.	COMPLETED
AENV14	Development of criteria concerning surface water quality for petroleum-derived hydrocarbons, taking the specific features of Anticosti into account	Government of Québec (MDDELCC)	The goal of the project is to adapt the criteria for water quality for petroleum-derived hydrocarbons, for both fresh and salt water, to the specific features of Anticosti.	UNDERWAY
AENV15	Current situation of environmental emergency measures in Québec: onshore emergencies	Government of Québec (MDDELCC)	Current situation of environmental emergency measures in Québec for onshore emergencies. This study will provide input for Study GTVS01.	COMPLETED
AENV16	Review of the literature concerning the potential impacts of hydrocarbon (oil and gas) development on aquatic biological communities and their habitat, and concerning related monitoring programs. Characteristics of the liquid waste generated by the petroleum industry	Government of Québec (MDDELCC)	Review of the literature concerning the actual and potential impacts of hydrocarbon (oil and gas) exploration and extraction activities on aquatic biological communities (fish, benthic macroinvertebrates, diatoms, etc.).  Completion of an inventory of programs to monitor the physiochemical, toxic, and biological components of aquatic environments in other countries and territories (United States, Canada, etc.) in connection with hydrocarbon exploration and extraction. Nature of funding programs and mechanisms.  Updating and compilation of information on the characteristics of liquid waste (wastewater from drilling, wastewater from processes and production, etc.) generated by the hydrocarbon (oil and gas) industry.	UNDERWAY

ID	Study title	Agent(s)	Description	Status
AENV17	Creation of a typical oil and gas project outline for Anticosti	WSP	The goal of the study is to describe a “typical” project as realistically as possible, in other words to obtain a detailed and realistic outline of the operations and activities connected with hydrocarbon exploration and extraction on Anticosti. The “typical” project outline will then be used to assess the impacts of hydrocarbon exploration and extraction on the environment, society, and the economy.	UNDERWAY
AENV18	Characterization of Atlantic salmon habitat on Île d’Anticosti and review of the literature concerning the impact of accidental hydrocarbon spills on salmon in rivers at various stages in their lifecycle	Université du Québec à Chicoutimi	Description of the specific features of salmon spawning grounds on Île d’Anticosti and determination of specific measures to be put in place in the event of accidental spills of contaminants.	COMPLETED
AENV19	Characterization of the white-tailed deer population and identification of the possible impacts of oil and gas activities, in particular taking the development scenario into consideration	Université Laval	Characterization of the white-tailed deer population and identification of the possible impacts of oil and gas activities, in particular taking the development scenario used in the SEA into consideration.	COMPLETED
AENV20	Wildlife overview of Île d’Anticosti	Government of Québec (MFFQ)	Wildlife overview of Île d’Anticosti, potential impacts, and appropriate recommendations.	COMPLETED
AENV21	Preliminary assessment of the risk of soil and rock movements as a result of petroleum exploration and extraction on Île d’Anticosti	Government of Québec (MTQ)	Preliminary assessment of the impact of petroleum exploration and extraction on potential risks for large-scale soil and rock movement on Île d’Anticosti, based on available information.	UNDERWAY
GENV22	Current state of knowledge concerning the behaviour and weathering of petroleum-derived hydrocarbons in aquatic environments (fresh and salt water), especially when ice is present	Government of Québec (MDDELCC)	Review of the literature concerning the characteristics of petroleum-derived hydrocarbons shipped through Québec, and the behavior and weathering of petroleum-derived hydrocarbons in aquatic environments (fresh and salt water), when ice is absent and present.	COMPLETED
GENV23	Establishment of environmental forensic tools applicable to the oil and gas industry	Government of Québec (MDDELCC)	Identification of environmental forensic tools applicable to the oil and gas industry and assessment of their potential usefulness in MDDELCC actions to determine the origin of spills.	COMPLETED

ID	Study title	Agent(s)	Description	Status
GENV24	State of knowledge concerning the impact of petroleum-related accidents and intervention methods used for northern coastline systems	Government of Québec (MDDELCC)	The objective of this study is to list in situ studies conducted to assess the long-term recovery of coastline environments affected by an oil spill and, as a result, to present the residual impacts observed on flora and fauna, including migratory birds, in such environments.	COMPLETED
GENV25	Determination of the consequences of the chronic effects of oil platform presence on aquatic and pelagic ecosystems in the Gulf of St. Lawrence	ISMER, Université du Québec à Rimouski	Activities on oil platforms generate many different forms of liquid, solid, and gaseous waste. Because of the treatment technologies currently used, the discharge standards and the dilution rates, the waste remains low-level. However, the waste is chronic, and its impact on the environment is not well known, because it is hard to study. The goal of this study is to determine the current state of knowledge concerning the chronic impacts of oil platform operations (excluding accidents) on aquatic, pelagic, and benthic ecosystems in the marine environment.	COMPLETED
GENV26	Radioelements used to measure radioactivity for the purposes of the Regulation respecting hazardous materials	Government of Québec (MDDELCC)	Radioelements are found in certain forms of waste, such as drilling mud. The goal of this study is to review and, if necessary, amend the lists of radioelements to be measured depending on the waste being characterized, as set out in the provisional guidelines for oil and gas exploration.	COMPLETED
GENV27	Revision of the parameters analyzed and measurements taken with respect to soil radioactivity	Government of Québec (MDDELCC)	The soil characterizations that must be conducted at various stages in petroleum exploration and extraction are described in the preliminary guidelines on oil and gas exploration. This project involves updating, if necessary, the characterization protocol by revising the list of parameters analyzed and measurements taken.	COMPLETED
GENV28	Development of analysis methods in addition to conventional methods to characterize petroleum-derived hydrocarbons and monitor changes in the impact of a spill using specific biomarkers in surface water, ground water and waste water	Government of Québec (MDDELCC)	The presence of hydrocarbons in environmental matrices is conventionally determined using a method that detects a concentration of 0.1 mg/L in water. This method is often used as an indication of contamination, but does not allow monitoring using smaller traces or a fine-trained characterization of petroleum products. The development of additional analysis methods to allow a more effective characterization of petroleum products is essential to provide stronger support for environmental monitoring.	COMPLETED

ID	Study title	Agent(s)	Description	Status
GENV29	Current situation of emergency environmental measures in Québec: The off-shore environment	Government of Québec (MDDELCC)	<p>Current situation of emergency environmental measures for the offshore environment in Québec.</p> <p>This study will provide input for Study GTVS02.</p>	COMPLETED
GENV30	Estimate of GHG emissions by geological basin, using a range of extraction scenarios, and impacts on Québec's GHG record and its GHG reduction objectives	Government of Québec (MDDELCC)	Estimate of the GHG emissions likely to be generated by hydrocarbon exploration and extraction activities, by geological basin.	UNDERWAY
GENV31	Chemical fate of the hydrocarbon/chemical mix for chemicals used to treat oil spills	ISMER, Université du Québec à Rimouski	<p>Effective response following a spill depends on a proper understanding of the chemical fate of the hydrocarbons and chemical treatment agents involved. In incidents involving marine pollution, the use of certain response methods could be suggested as a complement to or substitute for mechanical response methods. The treatment agents used are chemical dispersants, beach cleaners, solidifiers, elasticizers, emulsion breakers, and herders. When a hydrocarbon is spilled in the environment, several physicochemical transformations take place. These changes occur more or less quickly, beginning immediately after the spill of hydrocarbons in the environment, and often depend on the environmental conditions and the type of hydrocarbon spilled. The goal of the project is to study the physicochemical fate of the treatment agents that may be used in response methods following a spill of petroleum-derived hydrocarbons in the environment, especially if the spill involves a mixture of chemical treatment agents and hydrocarbons.</p>	COMPLETED

ID	Study title	Agent(s)	Description	Status
GENV32	Review of existing knowledge concerning the potential ability of indigenous bacterial communities to degrade hydrocarbons in the St. Lawrence estuary and gulf	ISMER, Université du Québec à Rimouski	Review of existing knowledge on microbial communities in the waters of the St. Lawrence Estuary and Gulf. Review of existing knowledge concerning the capacity for the microbial degradation of petroleum-derived hydrocarbons in the subpolar (cold) environment; (a) factors limiting the degradation of HCPs; (b) response efficiency of indigenous microbial communities; (c) effect of temperature and seasons.	COMPLETED
GENV33	In-depth analysis of the results of the program to acquire data on groundwater (Programme d'acquisition de connaissances sur les eaux souterraines, or PACES)	Government of Québec (MDDELCC)	In-depth analysis of the results of the program to acquire data on groundwater in order to improve knowledge about the possible impacts on groundwater and municipal supply wells in previously studied regions.	COMPLETED
GENV34	Summary of studies and analyses of marine zones of interest conducted by various organizations	ISMER, Université du Québec à Rimouski	Summary of existing studies to characterize areas of ecological interest and sensitive or vulnerable zones in Québec's marine territory (St. Lawrence Estuary and Gulf). Where the information is available, this summary will be supported by summary maps.	COMPLETED
GENV35 <sup>62</sup>	Potential dangers of diluted bitumen	ISMER, Université du Québec à Rimouski	If the new petroleum-derived hydrocarbon supply and transport and oil exploration projects come to fruition, the risks of an oil spill in Québec will increase for the St. Lawrence and the aquatic environments crossed by the future pipelines. To protect and conserve ecosystems and the ecological services they provide (biogeochemical cycle of nutrients, primary production, drinking water and food supply), it is essential to better understand the fate of the petroleum-derived hydrocarbons that could be passing through Québec, including diluted bitumen or dilbit. Indeed, the behavior and persistence of diluted bitumen in ecosystems are still not fully understood. Neither are the impacts of a spill of this type of oil. The goal of the project is to have information to better target decision making actions during oil spills in aquatic environments.	COMPLETED

<sup>62</sup> Study GENV35 was added to the list of additional studies to be conducted at the request of the hydrocarbon SEA steering committee.

ID	Study title	Agent(s)	Description	Status
ASOC01 <sup>63</sup>	Social and economic overview of the population of Anticosti and assessment of expected changes and possible solutions	Université du Québec à Rimouski	<p>This will be an empirical study using a documentary, evaluative, and participative approach depending on the stage concerned. Centre de vigilance et d'intervention sur les enjeux pétroliers à Anticosti and the municipality of Île-d'Anticosti will participate in all stages of the research.</p> <p>The first stage will be to draw up a social and economic overview of the Anticosti community. Demographics, services, municipal infrastructure, tourism activities, culture and values, and development positioning, in particular, will be documented.</p> <p>The second stage, using the development scenario selected for the SEA, the typical project outline, the overview of the community, and the literature reviews and data inventories completed during the first phase of the SEA, will determine the expected socioeconomic changes.</p> <p>The third stage will establish the ability to adapt and the resilience of the Anticosti population and define possible solutions or mitigation measures to deal with the expected changes.</p>	UNDERWAY
GSOC01	Inventory of land uses and characteristics and potentially sensitive zones in the target areas	Université du Québec à Chicoutimi	<p>Completion of a systematic assessment of the zones sensitive to the potential impacts of the hydrocarbon industry in the following areas:</p> <ul style="list-style-type: none"> <li>- De la Minganie, De Sept-Rivières, and Du Golfe-du-Saint-Laurent regional county municipalities</li> <li>- The onshore portion of Bas-Saint-Laurent</li> <li>- The onshore portion of Gaspésie-Îles-de-la-Madeleine</li> <li>- The Gulf of St. Lawrence</li> </ul> <p>For each area, the sensitive zones will be listed and described in terms of their surface and content; thematic maps will be produced and mitigation measures will be proposed.</p>	COMPLETED

<sup>63</sup> Study ASOC01 includes three components: an overview of the Anticosti community, an analysis of the expected social impacts, and an analysis of the ability to adapt.

ID	Study title	Agent(s)	Description	Status
GSOC02	Experiences from the participation of aboriginal communities in natural resource development activities outside Québec	Université du Québec à Montréal	<p>The project is to examine and report on relevant experiences from outside Québec, in particular Western Canada, with respect to the participation of aboriginal communities in natural resource development activities and benefits, including the sharing of royalties.</p> <p>The mandatary for the study will document the mechanisms for aboriginal participation; the impacts of natural resource development on practices, activities, the environment, and the social development of the aboriginal communities concerned; methods for sharing royalties or other profit-sharing approaches; and the mechanisms contained in agreements signed as part of natural resource development projects, especially involving hydrocarbons.</p>	COMPLETED
GSOC03	Analysis of the factors influencing the social acceptability of hydrocarbon development activities and proposals for an approach to territorial governance	Université du Québec en Outaouais	<p>Analysis of the factors influencing the social acceptability of recent large-scale projects (analysis of briefs, social networks, media, etc.).</p> <p>Overview of the way in which social acceptability factors are taken into account in places where hydrocarbon development activities are favorably received by communities and assessment of the transposable nature of the success factors identified, with respect to:</p> <ul style="list-style-type: none"> <li>- Current approaches and processes in Québec in terms of access to information, consultation, public participation, and followup with the communities affected</li> <li>- Practices and approaches for joint action and partnership-based governance, in connection with land planning and integrated resource management, such as those implemented in Québec</li> </ul>	UNDERWAY
GTEC01	Identification of geological basins matching the geological structures in the Gaspésie and Bas-Saint-Laurent regions and in the Gulf of St. Lawrence	INRS	<p>The objective of this study is to identify geological basins that have characteristics comparable to the geological structures in the Gaspésie and Bas-Saint-Laurent regions of Québec and in the Gulf of St. Lawrence. This will help improve knowledge of the potential of the structures and of related technical issues.</p>	COMPLETED

ID	Study title	Agent(s)	Description	Status
GTEC02	Assessment of the geological risks associated with certain geological structures	INRS and Stéphan Séjourné	<p>The objective of this study is to identify and list the aboveground and belowground geological risks connected with certain geological structures to determine, where applicable, the sectors that require particular attention during hydrocarbon exploration or extraction work. A specific section will focus on the situation on Anticosti.</p> <p>In parallel, the Geological Survey of Canada will conduct studies on certain geological parameters on Anticosti, such as its natural seismicity and the geomechanics of the Macasty Formation and its cap rock.</p>	COMPLETED
GTEC03	Best practices – Hydrocarbon exploration and extraction work – On-shore drilling	INRS	<p>The objective of this study is to identify and list best practices in order to review the legislative and regulatory framework for onshore drilling. A list of the laws, regulations, standards, and directives in force in other countries and territories and of the best practices recommended by recognized organizations will be completed for this purpose.</p>	COMPLETED
GTEC04	Best practices – Management of surface equipment, management of drilling waste, re-use and waste water management	INRS	<p>The objective of this study is to identify and list best practices in order to review the legislative and regulatory framework for the management of surface equipment, the management of drilling waste, and the reuse and disposal of water onshore. A list of the laws, regulations, standards, and directives in force in other countries and territories and of the best practices recommended by recognized organizations will be completed for this purpose.</p>	COMPLETED
GTEC05	Best practices – Hydrocarbon exploration work – Seismic surveys	Université Laval	<p>The objective of this study is to identify and list best practices for seismic surveys connected with hydrocarbon exploration activities onshore and offshore. A list of the laws, regulations, standards, and directives in force in other countries and territories and of the best practices recommended by recognized organizations will be completed for this purpose.</p>	COMPLETED

ID	Study title	Agent(s)	Description	Status
GTEC06	Best practices – Hydrocarbon exploration and extraction work – Offshore drilling	Recovery Factor	The objective of this study is to identify and list best practices in order to establish, in conjunction with the federal government, a safe legislative and regulatory framework for offshore drilling. A list of the laws, regulations, standards, and directives in force in other countries and territories and of the best practices recommended by recognized organizations will be completed for this purpose.	COMPLETED
GTEC07	Technical aspects of infrastructures and work associated with off-shore activities, in particular taking ocean current and ice movements into account	Recovery Factor	The objective of this study is to determine the technical considerations and recommended measures for the establishment of offshore drilling infrastructures and associated activities, including supplies and transshipment, in the specific context of the Gulf of St. Lawrence, in particular with respect to ocean currents, seabed topography, ice movements, and ocean storms.	COMPLETED
GTEC08	Detailed analysis of the data from magnetic and gravimetric airborne survey done in the Gulf of St. Lawrence	Géophysique Camille St-Hilaire Inc.	The objective of this study is to better characterize geological anomalies and locate them more precisely, via the detailed interpretation of available geophysical data. This interpretation will also highlight the presence of geological structures, such as faults and hydrocarbons traps, and the type of rock. This data should help improve knowledge of hydrocarbon potential in the Gulf of St. Lawrence.	COMPLETED
GTEC09 <sup>64</sup>	Technical considerations and characterization of the physical marine environment in the Old Harry sector	C-Core	The objective of this study is to identify and characterize the technical considerations that could potentially impact offshore drilling infrastructures, drilling activities, including supplies and transshipment, and measures specific to the prevailing conditions in the Old Harry sector, specifically with respect to winds, waves, ocean currents, sea spray icing, visibility, ice floes, icebergs, and the seabed.	COMPLETED

<sup>64</sup> Study GTEC09 was added to the AKAP in order to examine the physical environment of the Old Harry structure since this geological structure currently has the highest off-shore oil exploration and hydrocarbon extraction potential.

ID	Study title	Agent(s)	Description	Status
AECN01	Creation of detailed development scenarios for Anticosti	Government of Québec	As part of this work, a number of scenarios for the commercial extraction of hydrocarbons on Anticosti will be drawn up, taking into account the preliminary potential assessments and the geological characteristics of the Macasty Formation. These scenarios will, in particular, characterize the possible quantity produced by hydrocarbon type and the pace of the drilling program. In conjunction with the typical project outline created under Study AENV17, the scenarios will be used to assess the potential effects (social, environmental and economic) of commercial extraction, if the government decides to allow the development of hydrocarbons on the island.	COMPLETED
AECN02	Commercial profitability, government revenue and economic benefits of commercial hydrocarbon extraction on Anticosti	Government of Québec	The objective of this study is to assess, based on the development scenarios selected for the SEA (Study AECN01), the financial profitability of commercial hydrocarbon extraction on Anticosti, the net revenue that could accrue to the government, and the economic benefits for Québec as a whole and for the local and regional economy.  This study will provide key input for the transversal Study ATVS02.	COMPLETED
GECN01	Basic scenarios for hydrocarbon production by geological basin	Government of Québec	The goal of this study is to assess plausible production levels for possible commercial extraction from the hydrocarbon basins in Gaspésie and Bas-Saint-Laurent and the Gulf of St. Lawrence. The scenarios will be used to assess potential revenue for the government if a decision is made to develop the geological basins.	CANCELLED <sup>65</sup>
GECN02	Labour force needs associated with the development of a hydrocarbon industry in Québec	KPMG	The objective of this study is to analyze the jobs generated in oil and gas extraction by a typical production project. Labor needs will be defined in terms of numbers of jobs and required qualifications. This analysis will identify the job opportunities generated by the development of the oil and gas industry in Québec.	COMPLETED
GECN03	Sharing of revenues and benefits from natural resource extraction	Université Laval	The study will analyze experience in other jurisdictions concerning the sharing of revenues and benefits from natural resource extraction with local communities (municipalities) and regional communities, for example by sharing royalties.	COMPLETED

<sup>65</sup> Study GECN01 was cancelled due to a lack of useful information about analogous geological formations for the production of development scenarios for geological basins in Québec other than Anticosti.

ID	Study title	Agent(s)	Description	Status
GECN04	Potential domestic and international markets for resources produced in Québec	HEC Montréal	The work completed as part of this study will determine potential consumer markets for the oil, natural gas, and condensates produced through possible hydrocarbon development in Québec. The study will establish the domestic, continental, and/or worldwide markets for each type of hydrocarbon produced, taking possible substitutions into account (for example, replacing fuel oil for industrial uses or replacing coal in power generation) and the cost of the required infrastructures.	COMPLETED
GECN05	Competitive advantages and disadvantages of hydrocarbon extraction in Québec	Canadian Energy Research Institute (CERI)	Description of the current situation for the main economic, environmental, and social variables influencing oil and gas activities in Québec, and comparison with other countries and territories, in order to analyze Québec's potential competitiveness in the sector quantitatively and qualitatively.	UNDERWAY
GECN06	Review of the expertise required for hydrocarbon extraction and potential for the development of a Québec service industry in the sector	Communications Jean-Marc Carpentier	This study will seek to determine how the development of certain hydrocarbon resources in Québec could promote the growth or emergence of specialized service industries. First, it will establish the major fields of expertise in the industry, and then it will see whether the expertise is currently available in certain Québec enterprises or in its teaching, research, and innovation institutions. It will also establish the actions that could support the emergence of new enterprises able to grow in Québec and eventually extend their activities outside Québec.	COMPLETED
GECN07	Effect on municipal taxation values	Government of Québec (MERN)	The positive or negative impacts on municipal taxation values resulting from the construction of a pipeline.	COMPLETED
ATRA01	Conceptual assessment of the need for transportation infrastructures for hydrocarbons extracted on Île d'Anticosti in order to export products to consumer markets	WSP	The objective of this study is to identify environmentally friendly solutions for infrastructures on Île d'Anticosti to transport hydrocarbon products to consumer markets. More specifically, the study will contain a summary description of the transportation infrastructures required and the associated costs for collecting, storing, purifying, treating, and transporting hydrocarbons by ship or pipeline to potential consumer markets. These costs will have a major influence on the commercial profitability of possible future extraction and must be estimated before the government can make an enlightened decision concerning the pursuit of such activities.	COMPLETED

ID	Study title	Agent(s)	Description	Status
ATRA02	Assessment of supplementary needs for road infrastructures on Île d'Anticosti in order to extract hydrocarbons	Government of Québec (MTQ)	The objective of this study is to assess the cost of establishing new road transportation infrastructures and improving existing infrastructures for the possible future extraction of hydrocarbons on Île d'Anticosti, for the transportation of freight, equipment, and workers (excluding secondary roads for access to drilling platforms). Another objective is to assess the extra cost of maintaining the road network in connection with the possible future extraction of hydrocarbons on Île d'Anticosti.	UNDERWAY
GTRA01	Issues concerning intermodal transportation and hydrocarbon transshipment operations	CIRANO	The goal of this study is to list the type and volume of intermodal transportation and transshipment activities for hydrocarbons in Québec and the types and extent of accidents associated with such activities. It will also analyze the legislative and regulatory framework governing the activities, in particular concerning the respective responsibilities of participating enterprises. It will present proposals for improving the safety and supervision of the operations.	UNDERWAY
GTRA02	Control and monitoring measures by Québec government departments and agencies for road, rail and pipeline operations	Government of Québec	The objective of this study is to describe the current situation concerning the control and monitoring measures applied by Québec government departments and agencies to the transportation of hazardous materials, particularly hydrocarbons.	CANCELLED <sup>66</sup>
GTRA03	Examination of the risks associated with water crossings by pipelines	École Polytechnique de Montréal	The objective of this study is to list the best construction techniques applicable to pipelines, and the risks associated with water crossings by pipelines. The study will also propose the prevention and mitigation measures that must be implemented, taking into account the characteristics of the clay soils in the St. Lawrence valley.	UNDERWAY

<sup>66</sup> To avoid duplication, the control and monitoring measures for road, rail, and pipeline operations are covered by studies GTVS01 and GTRA01.

ID	Study title	Agent(s)	Description	Status
ATVS01	Externalities and mitigation and compensation measures	Government of Québec (MDDELCC)	<p>First, this study will list, qualify, and when possible quantify the main social, economic, and environmental effects of hydrocarbon exploration and extraction activities on Anticosti. These effects, whether positive or negative, are considered to be externalities when they are not taken into account by the market. For example, the loss of an ecosystem because of the construction of a road in a fragile environment is considered to be a negative environmental externality. On the other hand, improved access to a hunting zone following the construction of the same road is considered to be a positive economic externality.</p> <p>Second, based on the information available, the study will determine the mitigation and compensation measures that should be considered on Anticosti to avoid or reduce the negative effects of the main externalities.</p> <p>This study will provide key input for the transversal Study ATVS02.</p>	UNDERWAY
ATVS02	Cost-benefit analysis of possible future development of hydrocarbons on Anticosti	Government of Québec (MDDELCC)	<p>Based on the information available in other studies (such as AENV17, AECN01 and AECN02), this analysis will examine the main advantages and costs for society (in Québec and on Anticosti) resulting from possible future hydrocarbon extraction on Anticosti. A qualitative and, when possible, quantitative analysis of the advantages and costs, whether environmental, social, or economic, will determine, first, the main advantages and costs that may arise and, second, the best way to maximize the advantages and reduce the costs for the population on Anticosti and in Québec.</p>	UNDERWAY

ID	Study title	Agent(s)	Description	Status
GTVS01	Examination of emergency prevention, preparedness and intervention measures in the event of a major on-shore incident	JP Lacoursière inc.	<p>This study will include a critical analysis of the laws, regulations, standards, and directives of the governments of Canada and Québec concerning response measures in the event of a major incident (fire, explosion, spill, etc.). It will assess the state of preparedness of various public and private stakeholders, including municipalities, their technical and financial capacity, and the coordination mechanisms they have established between themselves. Last, it will review the capacity of enterprises to support the cost of restoration and compensation measures.</p> <p>The study will include a section specific to Île d'Anticosti.</p>	UNDERWAY
GTVS02	Examination of emergency prevention, preparedness and intervention measures in the event of a major off-shore incident	Innovation Maritime and Université Laval	<p>This study will include a critical analysis of the laws, regulations, standards, and directives of the governments of Canada and Québec governing the risks associated with the transportation of hydrocarbons by sea (ship) and offshore oil and gas extraction activities, as well as response measures in the event of a major incident (fire, explosion, spill, etc.). It will assess the state of preparedness of various public and private stakeholders, including coastal municipalities, their technical and financial capacity, and the coordination mechanisms they have established between themselves. Last, it will review the capacity of enterprises to support the cost of restoration and compensation measures.</p>	COMPLETED <sup>67</sup>

<sup>67</sup> The consultation document takes into account the preliminary observations and areas for improvement since the final version was received recently.





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