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AN ASSESSMENT OF THE ECONOMIC AND COMPETITIVE ATTRIBUTES OF OIL AND NATURAL GAS DEVELOPMENT IN QUÉBEC

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An Assessment of the Economic and Competitive Attributes of
Oil and Natural Gas Development in Québec

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Executive Summary

With the development of its hydro resources beginning in the middle of the last century, the Province of Québec became a Canadian energy powerhouse. Hydro-Québec has continued to grow over the years, supplying the province with a low greenhouse gas (GHG) emitting source of baseload generation and enough excess power to sell profitably to other jurisdictions.

This report shifts the focus to a different, almost untapped, energy resource in Québec: oil and gas. Specifically, shale oil and shale gas from the Macasty and Utica basins. Until recently, shale resources were considered economically infeasible to develop, but advances in technology have made a number of oil and gas producers consider seriously Québec's hydrocarbon potential. This study has two goals: to describe the scale of unconventional oil and gas resources in Québec and to consider the potential of resource development in the province. Resource development is considered under three scenarios: a Reference Case Scenario, a Québec Emissions Plan Scenario, and an International Energy Agency (IEA) World Energy Outlook (WEO) 450 Scenario, referred to hereafter as the WEO 450 Scenario. Data and economic analysis have been procured from numerous sources including the Canadian Energy Research Institute's (CERI) proprietary economic models; findings published by scholars, corporations, and governments; and consultants' reports.

The study period under consideration in this report is 2015 to 2040. It is important to note that the oil and gas industry in Québec will not be in a position in 2015 to begin development, much less production. If and when the industry develops depends on many indeterminate factors – environmental, political, legislative, and economic. As much uncertainty still surrounds Québec oil and gas, the 2015-2040 period was chosen to bring time specificity to the analysis.

Operating and capital expenditures have been calculated using CERI's US Canadian Multi-Regional I/O 3.0 model in order to estimate GDP, employment, and taxation over the period 2015-2040. For capital expenditures, CERI assumes that in the beginning years of the Québec oil and gas industry the majority of spending will occur in Alberta; however, that spending shifts over the years to Québec as the industry grows. For operating expenditures, CERI assumes that a similar shift in spending would occur. The model injection assumptions are explained in detail in Chapter 4 of this report.

This report's findings include:

- Macasty Oil Shale supply costs total CDN$95.50 per barrel
- Québec oil, if eventually exported, will collect Brent prices. But as with natural gas, Québec oil will find itself in a competitive global market
- The Québec Macasty basin should be able to sustain output of 60,000 barrels per day (bpd) over the study period
- Development of oil production in Québec could generate up to $150 billion in provincial GDP, depending on carbon emission constraint policies and market forces

- Utica Shale gas supply costs total CDN$3.72 per mcf
- Québec natural gas may find a place in North American markets, likely depending on developments in the US and emerging East Coast Canadian LNG industry. The supply cost of Québec natural gas, relative to other producers, make its competitiveness marginal
- The Québec Utica basin should be able to sustain output of 1 billion cubic feet per day (Bcfd) over the study period
- Development of gas production in Québec could generate up to $93 billion in provincial GDP, depending on carbon emission constraint policies and market forces

- Production of oil and gas in Québec will decline if the industry is subject to climate change constraints (of its production emissions) proposed in September 2015 by the Province of Québec
- Production of oil and gas in Québec will decline to a greater degree if the industry is subject to emissions constraints (of its production emissions) as proposed in the International Energy Agency's World Energy Outlook 450 Scenario.

Climate change policies will impact demand. If those policies are international in scope, the reduced demand will likely result in a decreased price for oil. For natural gas, the decreased demand may be offset by the substitution of gas for oil. The lower market price means an already challenging competitive position for Québec oil and possibly gas production will become more difficult. Domestic policies will create production restrictions but will not likely impact the market price.

The Macasty Basin, though lightly explored to date, is being evaluated by the Government of Québec and companies interested in the hydrocarbon resources on and around Anticosti Island. This study focuses on the potential for oil production, while exploration companies are focused on Natural Gas Liquids (NGLs). Exploratory drilling must be done on Anticosti in order to understand the resource better, and until that occurs, the makeup of the Macasty hydrocarbon resource remains speculative. Readers interested in the NGLs potential are encouraged to consult study AECNO1-02 under the Government of Québec's Strategic Environmental Assessment, and the websites of Corridor Resources, Petrolia Inc., and Junex Inc. for more information.

Introduction

While the province's oil and gas exploration and production have been minimal to date, Québec's hydrocarbon resources are attracting more attention—particularly shale gas in the Utica Shale and tight oil or shale oil in the Macasty Shale on Anticosti Island.

The profound impact of shale gas and oil cannot be understated, and the impact is truly global. Representing an increasingly larger and growing share of existing production and the recoverable resource base, shale gas and shale oil (as well as tight oil) is garnering a lot of interest, not only in North America, but around the world.

Technological advances are having a profound effect on North America's energy landscape. Advances in horizontal drilling, 3-D seismic technology and hydraulic fracturing (fracking) are opening up new resources, previously determined as non-productive or not feasible to produce, particularly in the ability to economically recover natural gas and oil from shale rock.

Despite the fact that hydrocarbon exploration in the St. Lawrence Lowlands dates back to the 19th century, Québec's natural gas industry is in its early stages of development. The St. Lawrence Lowlands, Anticosti Island and the Gaspé Peninsula, are at the heart of the renewed interest.

This study has two objectives: to describe the unconventional oil and gas resource in Québec and to consider the potential for resource development in the province. As such, it is important to examine the competitiveness of the plays in comparison to other plays. If competitive, resource development is considered under three scenarios: a Reference Case Scenario, a Québec Emissions Plan Scenario and an International Energy Agency (IEA) World Energy Outlook (WEO) 450 Scenario. The potential economic benefits of each development scenario to Québec and the rest of Canada are reviewed.

This study is comprised of five chapters. The first chapter reviews Québec's administration of oil and natural gas resources, against the backdrop of the North American shale gas and tight oil revolution. In addition, as much of Québec's oil and gas potential stems from shale gas and tight oil, this chapter provides a shale gas and oil primer.

Chapter 2 reviews Québec's oil and gas resource potential. This chapter provides a strong foundation of the geology and potential of the St. Lawrence Lowlands (Utica Shale), Anticosti Island (Macasty Shale) and the Gaspé Peninsula. While there are other basins in Québec, these are the basins that are attracting the most attention from oil and gas companies.

Chapter 3 provides a description of Québec's supply costs (in the Utica and Macasty Shale), existing support infrastructure, royalty regimes and the impact on market demand due to carbon emissions constraints.

Chapter 4 discusses the assumptions for the input/output (I/O) model utilized in this study and includes a description of the characteristics of the Macasty and Utica Shale developments, respectively, and the economic impacts of different levels of production

Chapter 5 outlines key findings and concluding remarks. Appendix A illustrates GDP impacts on Québec, Alberta, Ontario and British Columbia. Appendix B provides information on the oil and gas infrastructure and Appendix C details production costs and economic impacts for alternative production profiles.

Chapter 1
Government Administration of Oil and Natural Gas Resources

Several years ago, the United States (US) and Canada began to experience a shale gas boom. Amidst conventional natural gas production declines, the success of East Texas's Barnett Shale created a sense of excitement for exploration and production companies (E&Ps) and the energy sector as a whole. E&Ps utilized horizontal drilling and advances in hydraulic fracturing and other forms of stimulation to turn the Barnett Shale into the most prolific shale gas play in the US at the time.

The techniques learned in the Barnett Shale were soon utilized to produce shale gas in other shale gas plays across North America. Economically- and technically-feasible shale gas on a large-scale arrived and shale plays were 'discovered' by the dozen.

Figure 1.1 illustrates major shale gas basins in North America. While the big five shale plays in North America – the Barnett (Texas), Fayetteville (Arkansas), Haynesville (Louisiana), Marcellus (Appalachia) and Woodford (Oklahoma) Shales, are the most well-known, there are dozens more that are considered minor and are only now being studied for their gas potential, Québec's Utica Shale among them.

Figure 1.1: Major Shale Gas Basins in North America

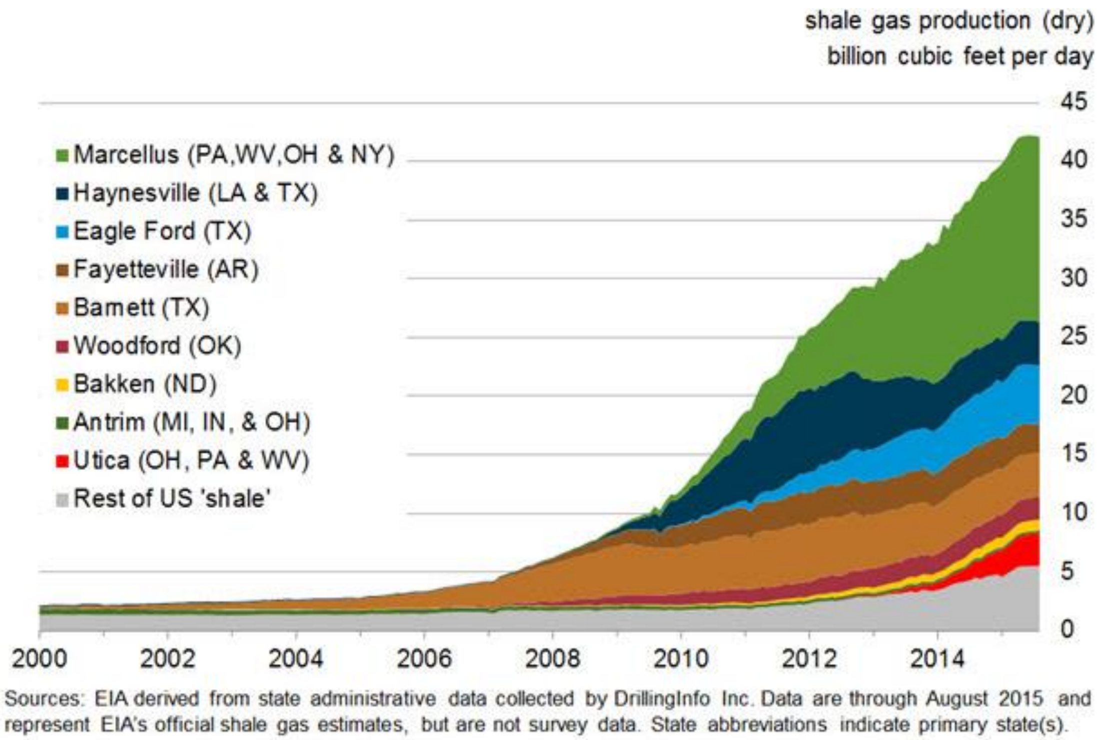
Source: NEB[1]

[1] NEB website, http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyvrvw/cndnnrgyvrvw2009/mg/fg5_5-eng.jpg (accessed on November 23, 2010)

Unconventional production already accounts for nearly half of total US production and this number is expected to increase. According to the Energy Information Agency's (EIA) Annual Energy Outlook 2010, by 2035, 35 percent of domestic gas production will come from shale gas.

Figure 1.2 demonstrates the rapid production of shale gas in the US. Following the initial success of the Barnett Shale, the application of these new techniques resulted in production in other shale formations, particularly the Fayetteville Shale in northern Arkansas, the Haynesville Shale in eastern Texas and north Louisiana, the Woodford in Oklahoma, and the Marcellus Shales in Appalachia.

Figure 1.2: US Dry Shale Gas Production



Source: EIA[2]

This development was facilitated by technology advancement and higher natural gas prices at that time. While increasing natural gas production was nothing short of stunning, the price of natural gas began to fall in mid-2008 and has never truly recovered. Low, lingering natural gas prices have forced many producers to make the transition from producing natural gas (dry) to liquids production – either crude oil or natural gas liquids (NGLs).

The Marcellus Shale has grown into one of the largest producing gas fields in the US in the states of West Virginia, Ohio and Pennsylvania. These jurisdictions have quickly modernized legislation

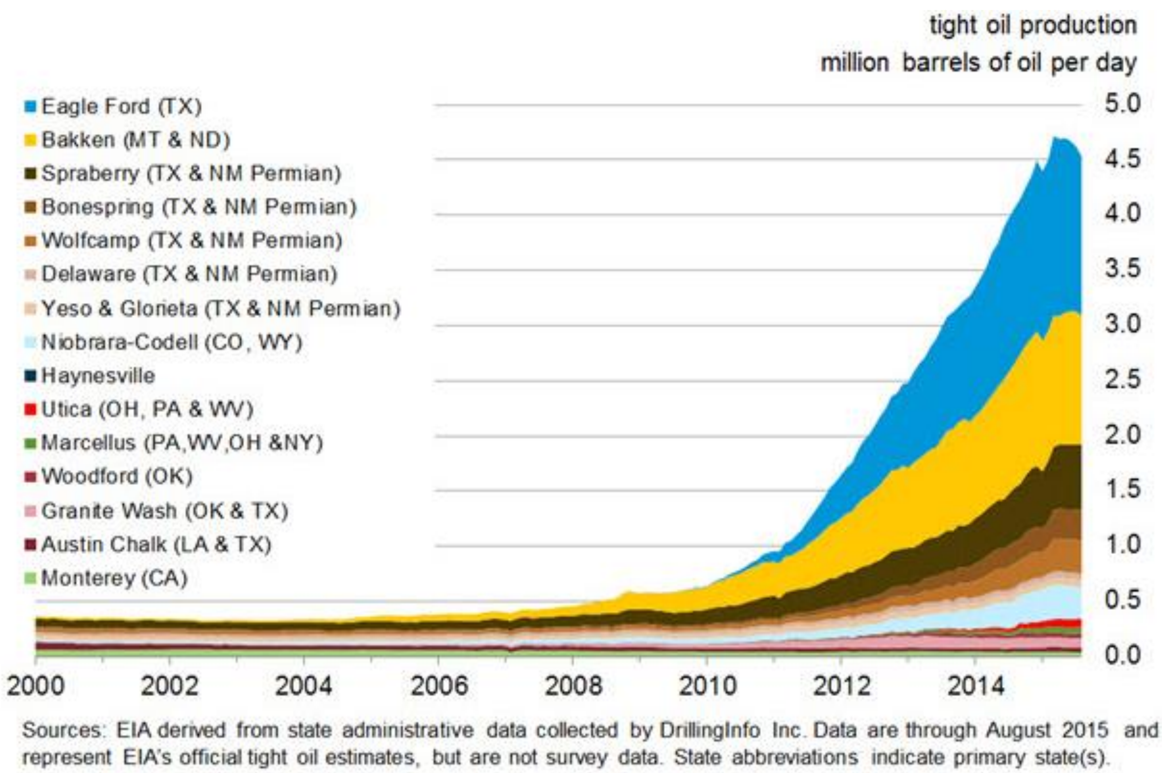
[2] EIA website, Energy in Brief, Shale in the United States, http://www.eia.gov/energy_in_brief/article/shale_in_the_united_states.cfm

and the regulatory framework for oil and activities. Marcellus production has decreased Canadian gas exports to the US, export volumes at Ontario and Québec border points have dropped from 1.25 Bcfd in 2010 to 0.78 Bcfd in 2014.[3]

US gas imports into Canada, delivered into Ontario and Québec border points, have increased from 0.94 Bcfd in 2006 to 2.07 Bcfd in 2014.[4] It is important to note that imports from the US in Canada have actually decreased in recent years, down from to 2.85 Bcfd in 2012.[5]

In terms of oil-bearing shale, the Bakken Formation has resulted in a similar impact in North Dakota and Montana. Figure 1.3 illustrates the shale oil or tight oil production in the US, including the prolific Eagle Ford in Texas and the Bakken Formation in Montana and North Dakota. Portions of the Bakken extend into Canada in Saskatchewan and Manitoba.

Figure 1.3: US Tight Oil Production



Source: EIA[6]

[3] National Energy Board, Canadian Energy Dynamics: Review of 2014 - Energy Market Assessment February 2015, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/dnmc/2014/index-eng.html
[4] National Energy Board, Gas Monthly Summary by Port-Volumes, http://www.neb-one.gc.ca/CommodityStatistics/GasStatistics.aspx
[5] ibid
[6] EIA website, Energy in Brief, Shale in the United States, http://www.eia.gov/energy_in_brief/article/shale_in_the_united_states.cfm

Oil and gas – including shale gas and oil – development and production is regulated by a complex and extensive set of regulations at the federal, provincial and local levels, each jurisdiction with its own particular framework. The federal government has input into resource developments as it relates to interprovincial and export trade, and regulates the construction and operation of interprovincial and international pipelines, including their tolls and tariffs.[7] The National Energy Board (NEB) is the main federal regulator and the main regulatory body in Nunavut, parts of the NWT and offshore areas.[8]

The provinces, however, manage the mechanics of resource development. This includes land use, drilling, intra-provincial pipelines and industrial complexes. Each of the provinces regulates the oil and gas industry, from exploration to development to abandonment. And with the exception of Prince Edward Island, the oil and gas industry is active in the remaining provinces – albeit at different levels. The regulatory structures differ amongst themselves, though there are similarities between British Columbia, Alberta and Saskatchewan.

It is useful to outline briefly the existing regulatory framework and accompanying issues for the oil and gas industry in Québec.

In the fall of 2010, the government mandated the Office of Public Hearings on the Environment (BAPE) to conduct a series of public hearings on the impact of shale gas development in the St. Lawrence Lowlands. In the winter of 2011, the BAPE recommended that a strategic environmental assessment (SEA) further study these impacts. The SEA was scheduled for completion in the fall of 2013. The report by the oversight committee for the SEA was completed in November 2013 and was delivered to the Minister of Sustainable Development, Environment, Wildlife and Parks (MDDEP). The report was subsequently published in February 2014.

Following the SEA, the Minister of MDDEP mandated the BAPE to conduct a public hearing on the subject. The results of the public hearings conducted from March to June 2014 were released in December 2014.[9] The report concluded that there were insufficient economic benefits to pursue development of shale gas.

To facilitate the completion of the environmental assessment of shale gas and further studies, in 2011, the Government of Québec introduced Bill 18 that exempted holders of oil and gas exploration licenses from performing their work obligations until such time as determined by the government. Bill 18 was replaced by Bill 5 in 2014.

[7] National Energy Board, Canada's National Energy Regulator, http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/cndntnlnrgrgltr-eng.html
[8] ibid
[9] http://www.lexology.com/library/detail.aspx?g=b5ccb1c3-8f72-463a-a30f-22e3f7a581f3

The Government plans to introduce its new energy policy in the coming months, as well as the results of its strategic environmental assessment for oil and gas development in the province. New hydrocarbon legislation is expected to be presented in 2016.

Currently, the Québec government is assembling knowledge with the objective of providing suitable conditions for developing its oil and gas resources.[10] They have stated that they are introducing a new law that will address issues of resource economics and regulatory processes.

In Québec, the Ministère de l'Energie et des Ressources Naturelles (MERN) "promotes knowledge acquisition and to ensure the development and optimal use of energy, land and mineral resources in Québec from a sustainable development perspective, for the benefit of the entire population".[11]

MERN is responsible for applying the Mining Act and all regulations with respect to petroleum, natural gas and underground reservoirs. The organization also deals with mining permits and activities. Its mission is to manage public land, mineral and energy resources in Québec. Nearly 92 percent of Québec is public land, managed by MERN.[12] Only 116,910 km^2 is privately-owned, most of which is located in southern Québec in the St. Lawrence Lowlands, around the Gaspésie and Lac Saint-Jean.[13]

All oil and gas exploration activities must receive permits and authorizations from the Ministère du Développement durable, de l'Environnement et de la Lutte contre les changements climatiques (MDDELCC) and Ministère des Forets, de la Faune et des Parcs (MFFP).[14] [15] The MDDELCC's primary responsibilities arise from the application of the Environment Quality Act (EQA) and its regulations, including site development, drawing of water, management of residual materials, and use of flares, greenhouse gas emissions, environmental emergency measures and site restoration.[16] MDDELCC is responsible for sustainable development, the environment and the fight against climate change. MFFP, on the other hand, is responsible to "promote the development and optimal use of forestry, wildlife and parks in Québec from a sustainable development perspective, for the benefit of the entire population".[17] The two components are

[10] Québec Government, Highlights of Hydrocarbon Option, http://hydrocarbures.gouv.qc.ca/documents/faits-saillantsEN.pdf
[11] Ministère de l'Énergie et des Ressources Naturelles, https://www.mern.gouv.qc.ca/english/department/index.jsp
[12] ibid
[13] ibid
[14] Natural Resources Canada, Québec's Shale and Tight Resources, https://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17714
[15] Prospérité Québec & CPQ, Québec's Natural Resources: A Natural Source of Prosperity, Study No. 2, June 2015, https://www.cpq.qc.ca/wp-content/uploads/2015/07/01927_etude_2_prosp%C3%A9rit%C3%A9_ANGLAIS.pdf, pp. 5.
[16] Natural Resources Canada, Québec's Shale and Tight Resources, https://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17714
[17] Ministère de Forets, Faune et Parcs, http://www.mffp.gouv.qc.ca/english/department/index.jsp

the protection of the province's vast forest and wildlife. Forests cover more than 760,000 km^2, of which 90 percent lie on public land.

Shale Gas and Oil Primer

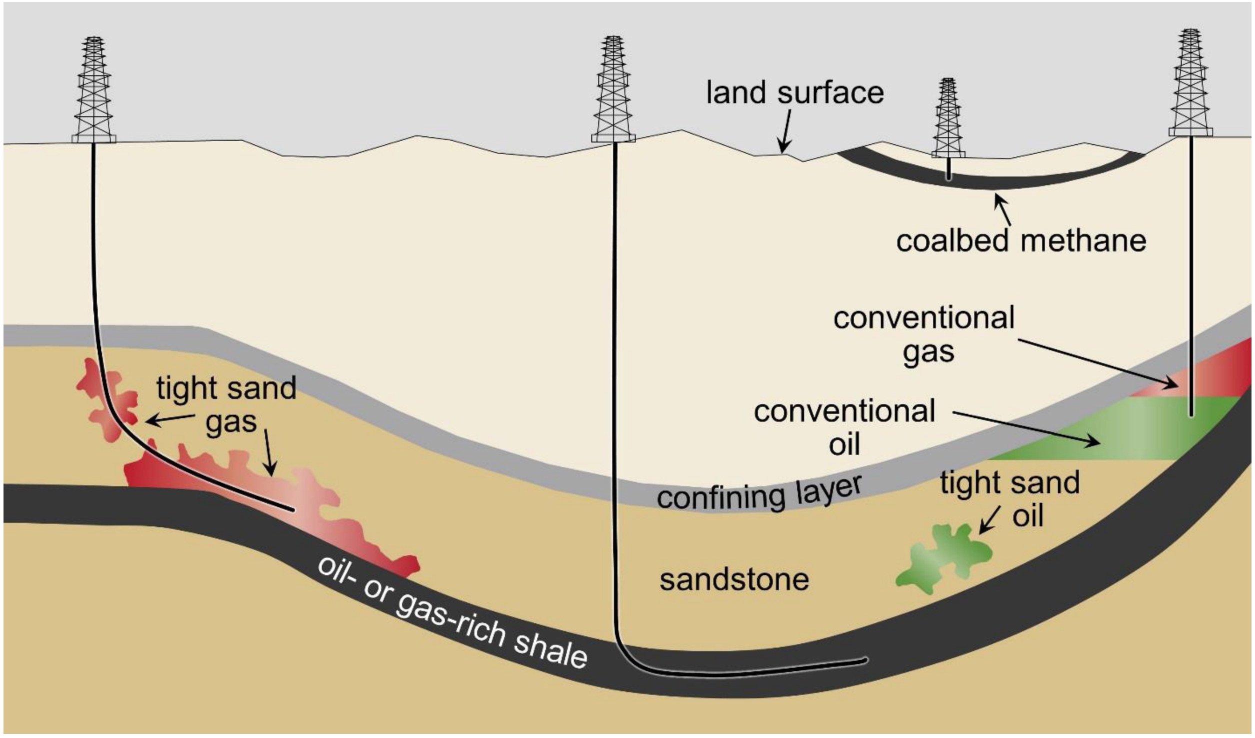
Shale gas is natural gas generated from and contained within dark-coloured, organic rich rocks. Shales can act as the source, reservoir, and seal for natural gas. The natural gas molecules are generally stored in three ways: absorbed into the organic matter in the shales, trapped in the pore spaces of the fine-grained sediments interbedded with the shale, or trapped in fractures within the shale itself.[18] Currently, unconventional natural gas is divided into three parts: shale gas, tight gas and coalbed methane (CBM). It is important that shale gas should not be confused with tight gas. The latter is natural gas trapped, by a variety of mechanisms, in unusually impermeable reservoir rocks—usually sandstone, but sometimes limestone as well.[19]

Shale oil, on the other hand, is an unconventional oil produced from plays that have the oil – medium to light in viscosity – embedded into limestone, sandstone and carbonate, in a low-permeable reservoir.[20] These plays are often referred to as tight oil plays or oil-bearing shale plays. Examples of oil-bearing shales are the Bakken Formation, Pierre Shale, Niobrara Formation and Eagle Ford Formation. Growth in several oil-bearing shales has been impressive, particularly in the Eagle Ford Shale in Texas and the Bakken Shale in North Dakota and Montana. It is very important not to confuse shale oil with oil shale, they are not the same thing, but quite different, leading the IEA to recommend using the term tight oil instead of shale oil.[21]

Most shale plays are characterized by low permeability, with low production rates from the natural fracture system. A schematic of the geology of natural gas and oil resources is illustrated in Figure 1.4, including conventional gas and oil, oil- or gas-rich shale, tight gas, tight sand oil and coalbed methane (CBM).

[18] Aboriginal Pipeline Group, Natural Gas Facts, What is Shale Gas?, http://www.mvapg.com/natural-gas-shale.php
[19] United States Environmental Protection Agency, Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources, EPA/600/R-15/047a, June 15, ES-2.
[20] Understanding Tight Oil, Canadian Society for Unconventional Resources, pp. 2.
[21] International Energy Association (IEA), World Energy Outlook 2013, OECD, pp. 424.

Figure 1.4: Schematic Geology of Natural Gas and Oil Resources



Source: US Environmental Protection Agency[22]

Figure 1.4 illustrates four wells. Two are horizontal wells, targeting a tight sand gas and an oil- or gas-rich shale. The figure also shows two vertical wells, targeting conventional gas and oil, as well as CBM. While vertical drilling is more prevalent when developing more porous and permeable plays, this is not typically the case with shale gas, oil shale or tight oil.

To improve the low permeability of the shale reservoirs, E&P companies in shale gas and oil basins across North America are relying on advances in horizontal drilling and hydraulic fracturing (fracking). Horizontal drilling and multi-stage fracking has been successful for both shale gas and for tight oil, releasing the hydrocarbon trapped in low permeability shale, sandstone or carbonate rock formations.[23] This type of production is not a new concept but horizontal drilling and fracking are considered revolutionary in the large-scale development in shale gas and tight oil. Ohio Shale's Big Sandy Field was first developed in the 1880s and to a greater extent in the 1920s while Michigan's Antrim Shale was being produced as early as the 1940s.[24] The technology,

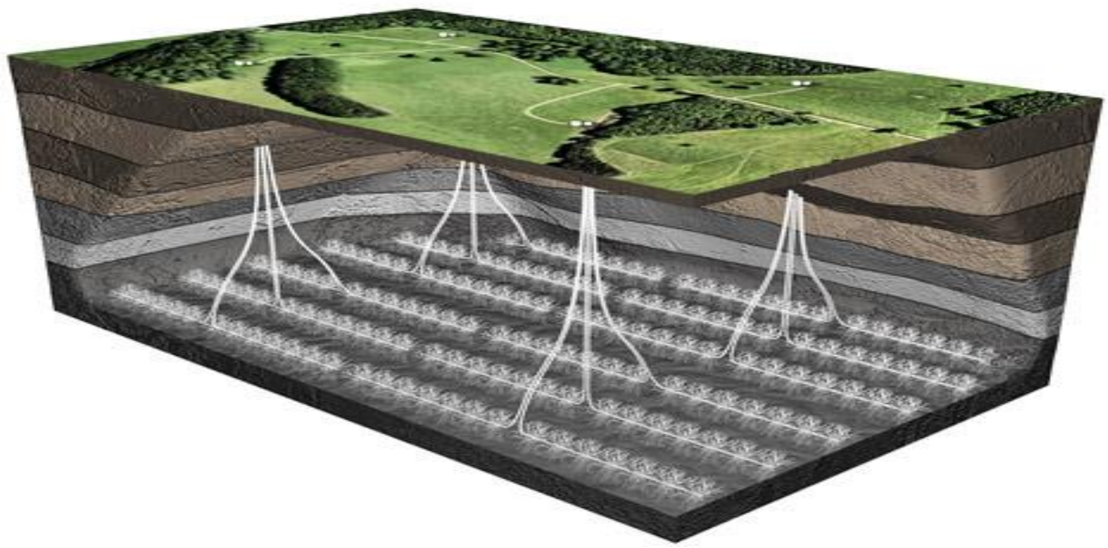
[22] United States Environmental Protection Agency, Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources, EPA/600/R-15/047a, June 15, ES-2.
[23] Natural Resources Canada, North American Tight Light Oil , https://www.nrcan.gc.ca/energy/crude-petroleum/4559#oil1
[24] Indiana Geological Survey, Antrim Shale, http://igs.indiana.edu/Geology/structure/compendium/html/comp3n6s.cfm

however, to make shale gas economically feasible on a large-scale simply did not exist at that time.

Both vertical and horizontal drilling can be used to develop shale gas and tight oil, however the latter is far more common. While more expensive, drilling horizontally exposes the wellbore to more of the reservoir, thereby increasing recovery rates for a lower overall cost compared to vertical wells.[25] The direction of the drill path follows the known natural fractures in the shale.[26] Advances in technology are reducing the cost of horizontal drilling.

Horizontal drilling has several other important benefits, including lowering the surface disturbance and land use dramatically.[27] Figure 1.5 illustrates the concept of multiple horizontal wells from a single well pad and the resulting impact on land use.

Figure 1.5: Multiple Horizontal Wells Drilled from a Single Well Pad



Source: Statoil website[28]

For example, development of a section (one square mile) could require 16 vertical wells, each situated on their own well pad.[29] However, as many as 20 horizontal wells could be drilled from

[25] National Energy Board, “A Primer for Understanding Canadian Shale Gas - Energy Briefing Note”, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.html#s7

[26] ibid

[27] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 46.

[28] Statoil website, Statoil strengthens US shale gas position, http://www.statoil.com/en/NewsAndMedia/News/2010/Pages/26MarMarcellus.aspx

[29] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 47.

a single well pad using horizontal drilling.[30] In the Barnett Shale, drillers are planning to drill up to 24 wells from a single well pad.

Despite the fact that multiple well pads are larger in size compared to their vertical counterparts, the reduction of the number of well pads will result in a reduction of the overall number of access roads, pipeline routes and production facilities.[31] Horizontal drilling can be utilized to minimize wildlife and community impacts. This is the case of the development of the Barnett Shale near the Dallas-Ft. Worth International Airport where horizontal drilling helps overcome the challenges of drilling in the highly-sensitive, densely-populated urban area.[32]

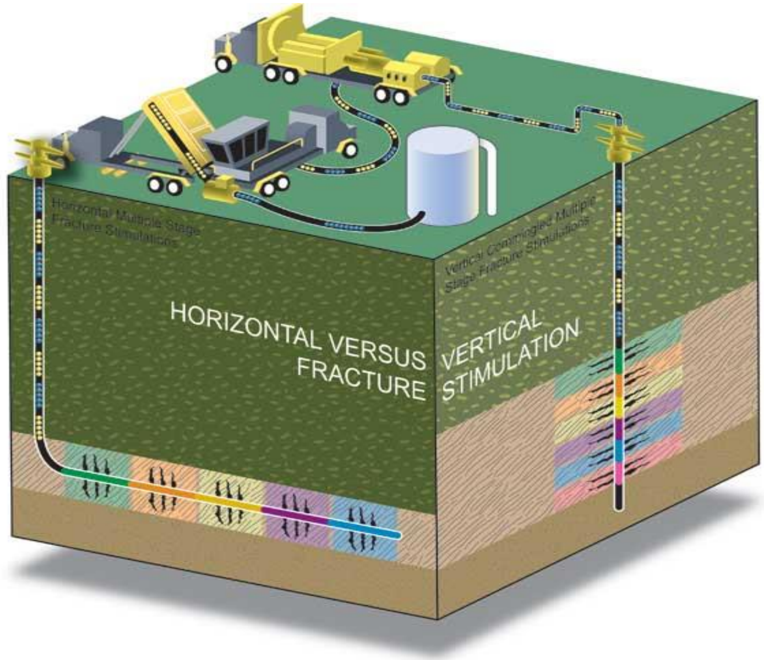
The second integral process to improve production from low permeability reservoirs is fracking. While fracking has been around since the 1940s, first used by Stanolind Oil, it was Mitchell Energy in the 1990s that began utilizing fracking in the Barnett Shale, changing the outlook and role of shale gas in North America.[33]

Due to low permeability, most shale plays require fracture stimulation. This is done by pumping fluids (over 98 percent water) down into a well until the pressure cracks the subsurface rock.[34] This process increases recovery rates dramatically for shale gas and oil, releasing gas and oil trapped within the rocks.[35]

To increase the efficiency of the process further, multi-stage fracking techniques (see Figure 1.6) isolate segments of the wellbore to frac them one at a time.[36] While infrequently felt on the surface, the energy released in this process can cause seismic activity.[37] This seismic activity, or "induced earthquakes", are in the magnitude 3 – 4 range, some large enough to be felt on the surface but small enough to rarely cause damage.[38] These seismic events are typically located within a small region around the well. The greatest risk of these events is damage to the drilling and production equipment and associated infrastructure. A magnitude of 3, for example, is roughly comparable to the vibrations of a passing truck.[39]

[30] ibid
[31] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 47.
[32] Ibid, pp. 49.
[33] www.geology.com website Hydraulic Fracking of Oil and Gas Wells, Drilled in Shale, http://geology.com/articles/hydraulic-fracturing/
[34] ibid
[35] ibid
[36] National Energy Board, "A Primer for Understanding Canadian Shale Gas - Energy Briefing Note", http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.html#s7 (accessed on May 27, 2012)
[37] Canadian Association of Petroleum Producers (CAPP), Natural Gas Development, http://www.capp.ca/canadian-oil-and-natural-gas/natural-gas/natural-gas-development#DiyHNz4iXNrv
[38] USGS, Earthquake Hazards Program, Induced Earthquakes, http://earthquake.usgs.gov/research/induced/
[39] American Petroleum Institute, The Facts about Hydraulic Fracturing and Seismic Activity, 2014, http://www.api.org/~/media/Files/Policy/Hydraulic_Fracturing/HF-and-Seismic-Activity-Report-v2.pdf, pp. 2.

Figure 1.6: Horizontal versus Vertical Multi-stage Fracture Stimulation



Source: NEB[40]

Frac fluids differ depending on the geology of the shale. For example, the presence of hard minerals such as silica and calcite may determine the chemical composition of the frac fluids used.[41] While clay absorbs the frac fluids, silica-rich shales are excellent candidates for fracking.[42] Another factor is the internal pressure of the shale. Over-pressured shales are better candidates for fracking.[43] The composition of frac fluids also depends on company preference.

Water and sand typically accounts for between 98 and 99.5 percent of the fluid but may also contain other materials, such as gelling agents to make the fluid more viscous. [44] [45] This is called slick water fracking. The water fractures the shale while the sand acts a proppant. This keeps the fractures open when the frac fluid is recovered as the well is brought into production.[46]

[40] National Energy Board, "A Primer for Understanding Canadian Shale Gas - Energy Briefing Note", http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009-eng.html#s7
[41] ibid
[42] ibid
[43] www.geology.com website Hydraulic Fracking of Oil and Gas Wells, Drilled in Shale, http://geology.com/articles/hydraulic-fracturing/
[44] American Petroleum Institute (API), Hydraulic Fracturing at a Glance, 2008.
[45] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 25.
[46] ibid

The overall concentration of additives in most slickwater fracturing fluids is a relatively consistent 0.5 to 2 percent.[47] The additives include chemicals such as friction reducers, corrosion inhibitors, gelling agents and scale inhibitors. Questerre's mixture is 99.5 percent water and sand with the remainder comprised of: acid, friction reducer, surfactant, gelling agent, scale inhibitor, PH adjusting agent, breaker, crosslinker, iron control, corrosion inhibitor, antibacterial agent and clay stabilizer.[48]

While the additives vary, most frac fluid chemicals are materials found in most households. For example, iron control is used as a food additive to flavour food and beverages, while gel, used to thicken water in fracks, is used in the cosmetic industry, as well as an ingredient of toothpaste. It is, however, important to note that some chemical additives are considered to be hazardous, if not handled properly. Diluted Acid (15 percent), for example, is primarily comprised of hydrochloric acid (HCL). Lubricants, drilling fluids, corrosion inhibitors, fracking fluids and biocides are subject to the Chemical Management Plan and New Substances Program.[49]

In the US, the proposed FRAC Act suggests that frac fluids be fully disclosed. This act also proposes to give the EPA authority over the process of fracking. Several state regulatory agencies are pressing for disclosure as well, including: Arkansas, New York, Pennsylvania, Texas, and Wyoming.[50] Currently, in Canada and the US, disclosing frac fluid composition is voluntary; many companies are hesitant due to commercial confidentiality being revealed in a competitive corporate environment. Haliburton, a pioneer in fracking technology, lists the frac fluids for its shale plays in the US, naming and explaining the fracking solutions, and its household and industrial uses of its additives.[51]

With the bulk of frac fluid being comprised of water, ranging between 98 and 99.5 percent of the fluid,[52] water is critical to developing shale gas and tight oil. For this reason, water usage and management issues, from managing withdrawals, to transporting large volumes, to recycling, to disposal issues, are important to stakeholders and regulators.

Table 1.1 illustrates the volume of fracking water per well in various gas producing shales in the US and Canada. The volume of frac fluid and water depends on the unique geological qualities of the particular shale and the size and number of stages of the frac operations.[53] It is common to use between 924,602 gallons (3,500 m^3) and 3,962,580 gallons (15,000 m^3) of water in a deep, multi-stage horizontal well, whereas a shallow single zone may only require 20 m^3 to 100 m^3 of

[47] ibid

[48] Hydraulic Fracturing, Questerre Energy Corp., September 2010

[49] Canadian Society for Unconventional Gas (CSUG), Understanding Hydraulic Fracturing, January 2011, pp. 6.

[50] Arthur, J. Daniel and Jon W. Seekins, Water and Shale Gas Development, ALL Consulting, Presentation at the National Association of Royalty Owners, Pittsburgh, October 7, 2010, pp. 21.

[51] Haliburton website, Hydraulic Fracturing Fluids Disclosure, http://www.halliburton.com/public/projects/pubsdata/Hydraulic_Fracturing/fluids_disclosure.html

[52] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 25.

[53] Canadian Society for Unconventional Gas (CSUG), Understanding Hydraulic Fracturing, January 2011, pp. 18.

water.[54] While water volumes may be large, they represent a small percentage of overall usage (compared to agriculture, industry and residential), from less than 0.1 percent to 0.8 percent.[55] For example, while the Marcellus Shale may use 4.5 million gallons per well, nearly 150 million gallons per day are consumed for electrical generation in the Susquehanna River Basin.[56] Other sources of water usage include public supply, industrial and mining, irrigation and livestock.

Table 1.1: Water Requirements for Various Shale Gas Plays

Shale Gas Play	Volume of Fracking Water per Well (gal)
Barnett Shale	2,800,000
Eagle Ford Shale	4,300,000
Bakken Formation	1,500,000
Haynesville Shale	5,700,000
Horn River Basin	15,800,000
Marcellus Shale	4,500,000

Source: USGC[57]

To date, most of the water used in shale development is fresh surface water or groundwater.[58] On occasion, water is trucked or piped to the well site, where it is stored in large tanks or large ponds.[59] In areas where water demands are high or supply is limited, in arid regions or during times of low precipitation, operators are utilizing alternative sources, including recycling recovered water and non-potable brackish water.[60]

[54] ibid
[55] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 65.
[56] ibid
[57] USGS, Hydraulic Fracturing FAQs, http://www.usgs.gov/faq/categories/10132/3824
[58] Canadian Society for Unconventional Gas (CSUG), Understanding Hydraulic Fracturing, January 2011, pp. 18.
[59] ibid
[60] ibid

Chapter 2
Québec Basins: Oil and Gas Potential

While the first oil drilling in Québec dates back to the 1860s, the province's oil and gas exploration and production have been minimal to date. Québec's hydrocarbon resources are, however, attracting more attention—particularly shale gas in the Utica Shale and tight oil in the Macasty Shale on Anticosti Island.

Québec's oil and natural gas resources are defined by six separate sedimentary zones: St. Lawrence Lowlands, Lower St. Lawrence, St. Lawrence Estuary (Anticosti Island), Gaspé Peninsula, Gulf of St. Lawrence and Northern Québec.[1] Exploration and production companies (E&Ps) have primarily focused their search for oil and natural gas in the area from the St. Lawrence Lowlands extending up the St. Lawrence River.

This study focuses on the St. Lawrence Lowlands, Anticosti Island and the Gaspé Peninsula. The gas-rich Utica is located in the St. Lawrence Lowlands and contain Québec's largest estimated natural gas resources. The Macasty Shale, on the other hand, are located on Anticosti Island within the St. Lawrence Estuary. While this region is both gas- and oil-rich, it is estimated to contain Québec's largest estimated resources of oil. It is located in the Gulf of St. Lawrence. While the amount of hydrocarbons in the Gaspé Peninsula region is unclear, there are several important exploratory projects in the northeast portion of the peninsula that warrant discussion.

As such, this Chapter is divided into three parts: St. Lawrence Lowlands (the Utica-Lorraine Shale), Anticosti Island (the Macasty Shale) and the Gaspé Peninsula.

St. Lawrence Lowlands: The Utica Shale

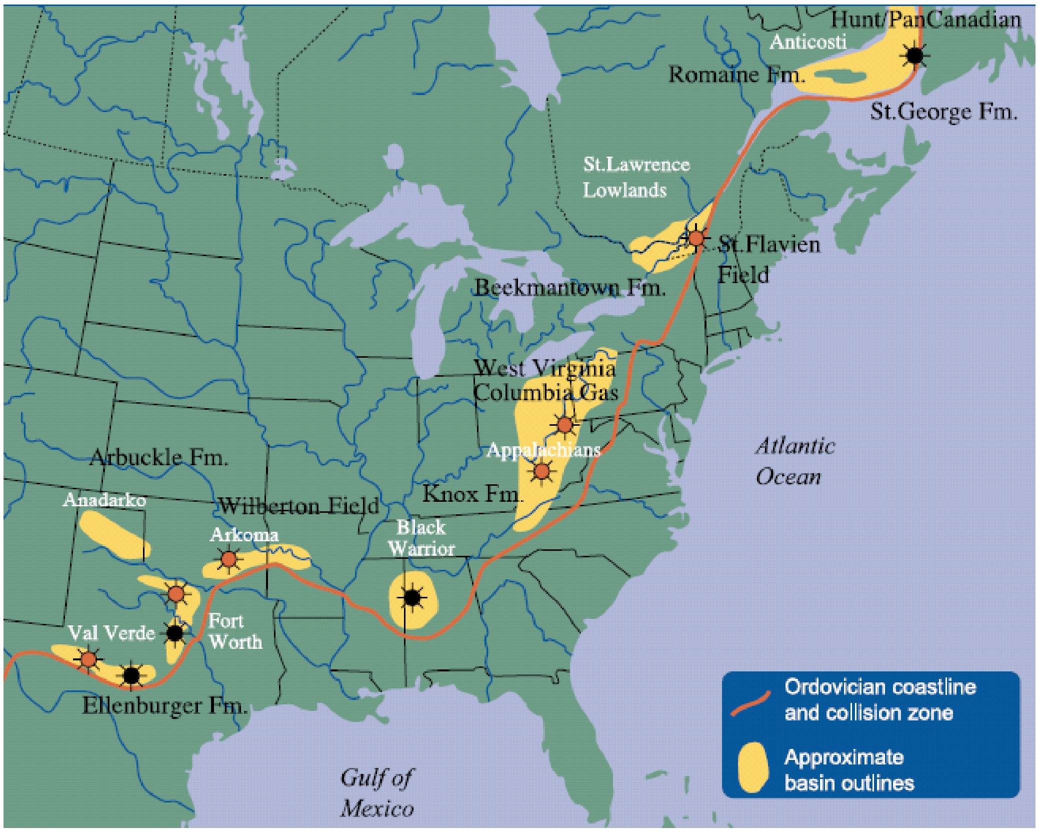
Québec's Utica Shale has attracted a lot of attention from North American E&P companies. Many, however, draw comparisons between Utica and Barnett Shale – one of the most prolific shale formation in North America. Given the Utica's proximity to US Northeast markets, the gas is expected to command a premium to NYMEX (commodity price setting exchange as all other gas used in the province is imported and bears transportation costs), whereas the more developed and active shale plays in northeastern BC are located far from consuming markets. This means gas from those plays incur transportation costs.

The Utica Shale is among the oldest and most widespread of black shales in North America, stretching from Pennsylvania and New York to Québec. The Ordovician-aged shale is located in the enormous Appalachian Basin and derives its name from Utica, New York.

[1] Ministère de l'Énergie et des Ressources Naturelles, Oil and Gas Exploration in Québec: A Future of Discovery, http://www.mern.gouv.qc.ca/english/publications/energy/Exploration.pdf, pp. 1.

Figure 2.1 illustrates the ancient Cambro-Ordovician coastline in eastern US and Canada. While the geology is complex, there are several similarities of the St. Lawrence Lowlands to other shale plays in the US, several of which are prominent. It is also important to note the similarities of the Utica Shale to the Romaine Formation in which Anticosti Island is located.

Figure 2.1: Cambro-Ordovician Basins in Eastern US and Canada



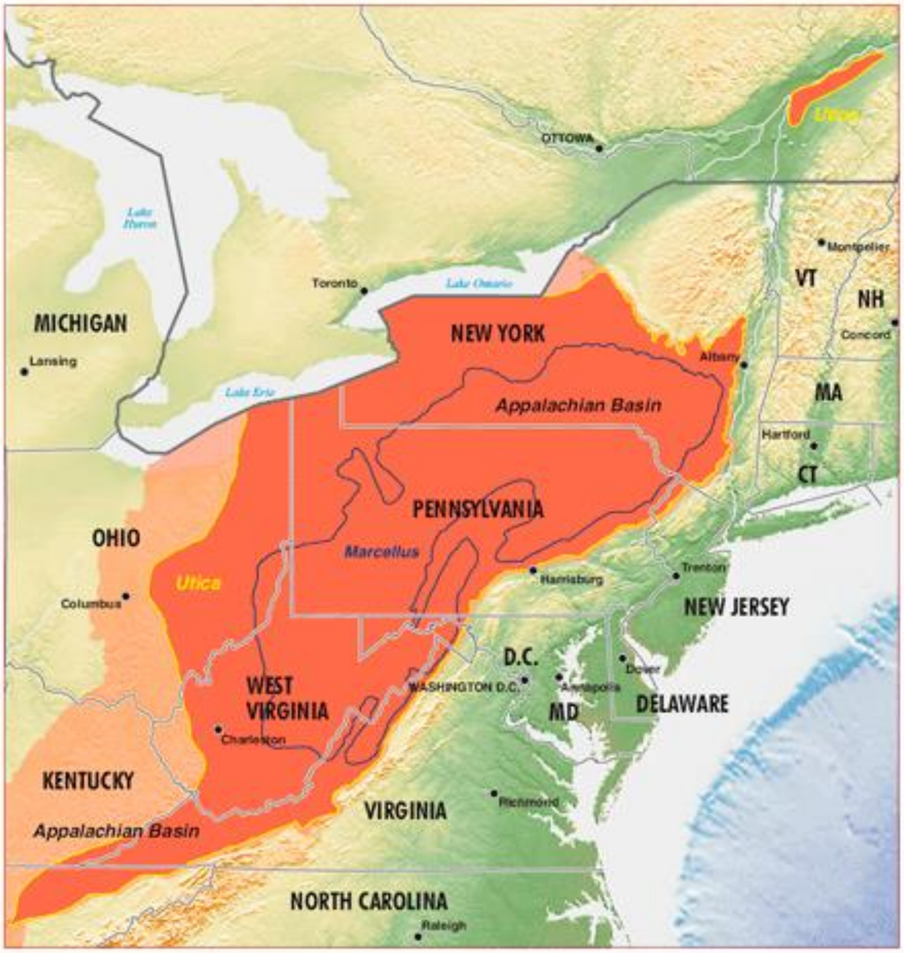
Source: Canaccord Adams[2]

The Utica is the deepest, oldest and most widespread of black shales, while the Devonian/Ohio shales are the shallowest and youngest. The Marcellus Shale, located in New York, Pennsylvania, West Virginia and eastern Ohio, is of intermediate age and depth, and is the largest subset of the enormous Appalachian Basin, which is the largest hydrocarbon-bearing basin in the contiguous US.[3]

Figure 2.2 shows the location of the Utica Shale. Québec's Utica is shown in the top right of the figure.

[2] Canaccord Adams, Energy – Oil and Gas, Exploration and Production, Irene Haas, April 8, 2008, pp. 5.
[3] www.geology.com website, Utica Shale the Natural Gas Giant Below the Marcellus, http://geology.com/articles/utica-shale/

Figure 2.2: Map of the Utica Shale

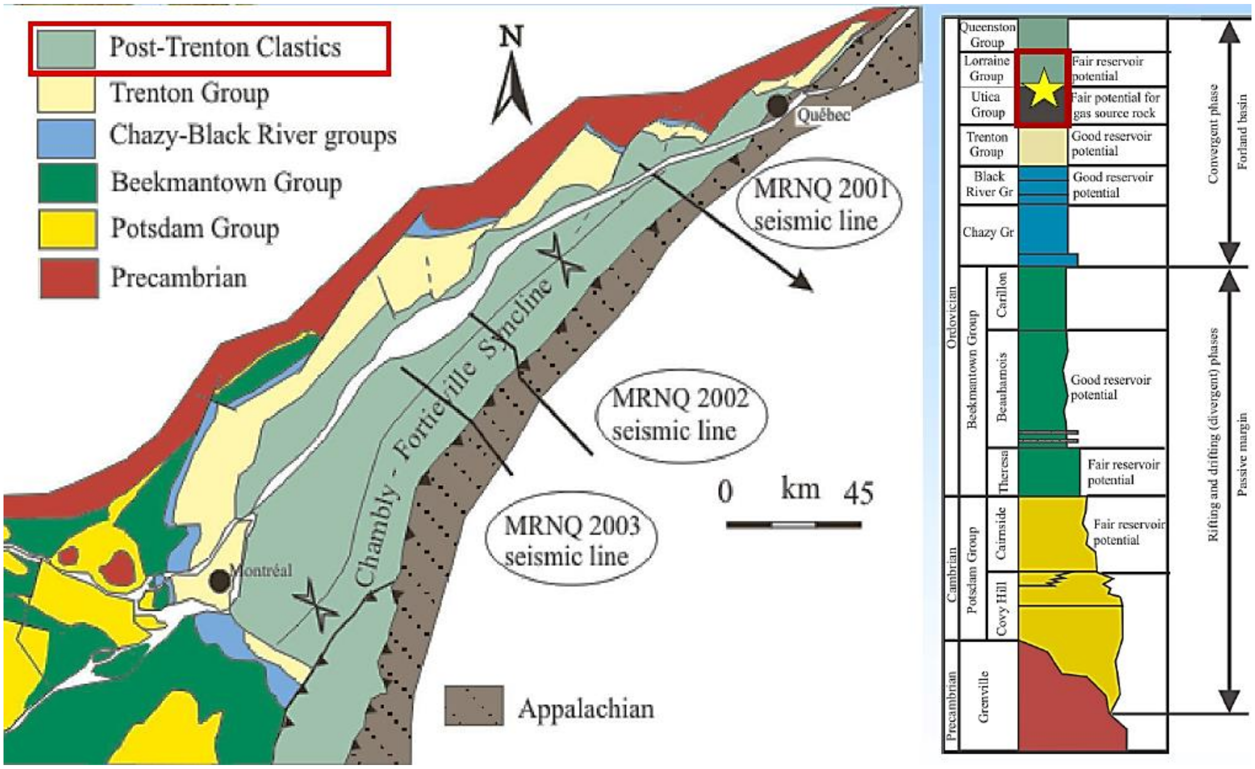


Source: Utica Shale News and Maps[4]

Within the Utica formation, it is the Post-Trenton Clastics interval that show some potential. They are divided into the Utica Group and the Lorraine Group. The former underlies the latter and is comprised of organic-rich shaley marl and calcareous shale.[5] Both form a thick, deep-marine clastic succession that overlies the Cambro-Ordovician Platform.[6] This is illustrated in Figure 2.3, a simplified geological map of the St. Lawrence Lowlands is on the left while the stratigraphy of the geology is on the right. The three seismic lines indicated were recorded in 1978 for the Ministère de l'Énergie et des Ressources du Québec (MRNQ) and were recently reinterpreted.[7]

[4] Utica Shale News website, Utica Shale Map, http://www.uticashalenews.com/wp-content/uploads/2011/08/utica-shale-map-3.gif (accessed May 24, 2012)
[5] Denis Lavoie, Robert Theriault and Michel Malo, The Upper Ordovician Utica and Lorraine Shales in Southern Québec: Sedimentological and Geochemical Frameworks, Institut National de la Recherché Scientifique, pp. 1.
[6] ibid
[7] Stephan Séjourné, Jim R. Dietrich, and Michel Malo, New interpretations of industry seismic lines, southern Québec Appalachians foreland, Current Research 2002-D1, Geological Survey of Canada, 2002, pp. 3.

Figure 2.3: Geological Map of Québec's Utica Shale

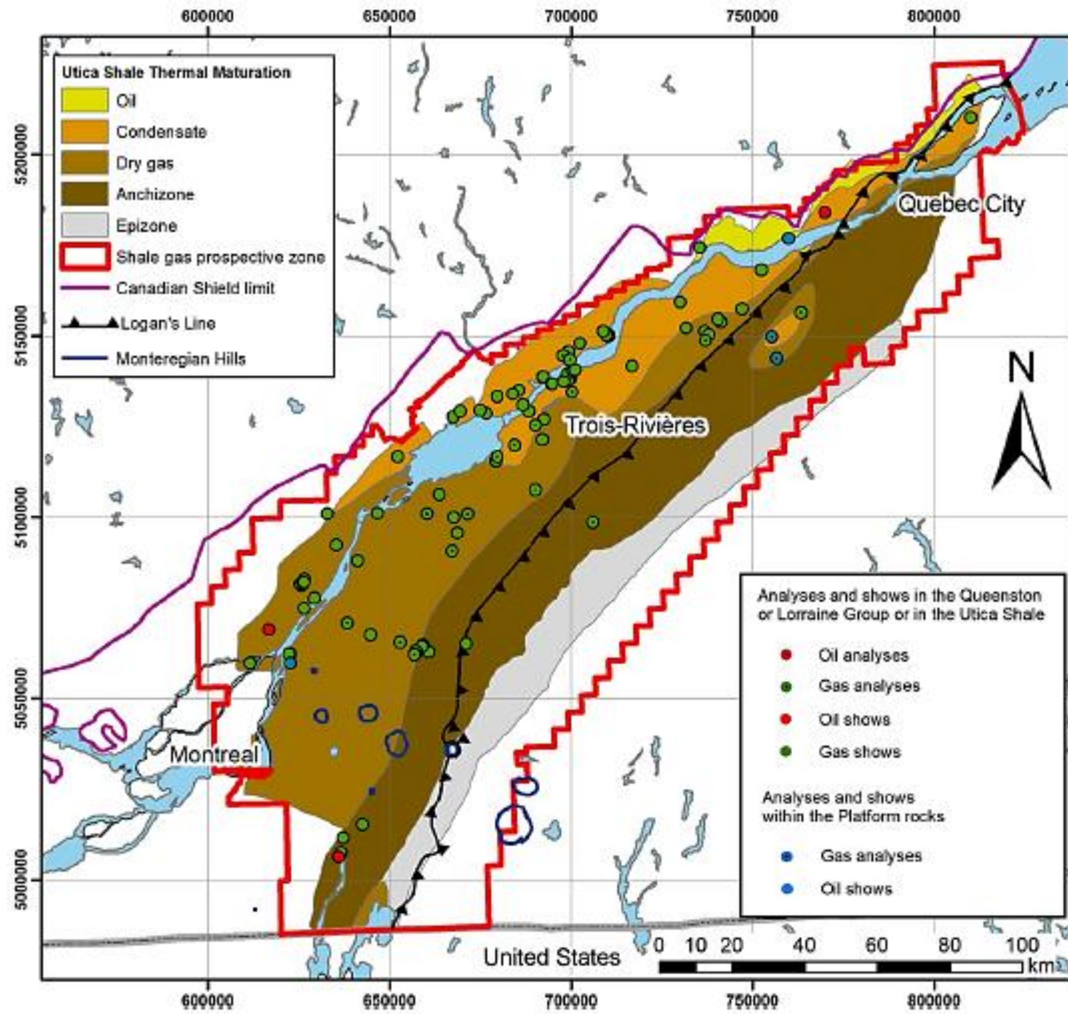


Source: Geological Survey of Canada Open File 5900[8]

Figure 2.4 illustrates a spatial distribution of the Utica Shale's thermal maturity. Dry gas- and condensate-rich are shown in orange and light brown while oil-rich portions of the Utica and Lorrain are shown in yellow, located in the Upper Ordovician Utica Shale in the northern part of the play, near Québec City. While there are oil targets in the Utica shale, the vast majority of the play targets the gas potential.

[8] D. Lavoie, A.P. Hamblin, R. Thériault, J. Beaulieu and D. Kirkwood, The Upper Ordovician Utica Shales and Lorraine Group flysch in southern Québec: Tectonostratigraphic setting and significance for unconventional gas, Geological Survey of Canada Open File 5900, pp. 8.

Figure 2.4: Spatial Distribution of the Utica Shale



Source: Rivard, Christine et al[9]

Wellington West Capital Markets suggest that initial estimates of the resource potential play could be 25 Tcf of recoverable resources, with the best prospects lying within a corridor that runs parallel with the St. Lawrence River southeast of Montreal up to Québec City.[10] Questerre Energy Corporation, an E&P company with just under one million acres, has its original gas-in-place (OGIP) for the Utica Shale estimated between 135 Tcf and 232 TCF on a gross basis with a best estimate of 155 Tcf and unrisked recoverable prospective resources ranging from 6 Tcf to 55 Tcf with a best estimate of 18 Tcf. Junex, the largest net acreage landholder in the Utica Shale play,

[9] Rivard, Christine et al. "An Overview of Canadian Shale Gas Production and Environmental Concerns, International Journal of Coal Geology, 23013, pp. 10.

[10] Energy Strategy – The Utica Shale Gas Play, Part II, May 28, 2008.

estimates a total undiscovered OGIP resources of approximately 49 Tcf and net recoverable unrisked resources of 3.5 Tcf.[11]

Table 2.1 summarizes the various resource estimates of the St. Lawrence Lowlands by sedimentary basin. The oil and gas potential of the Utica Play can be divided into three separate basins: Lower Ordovician Hydrothermal Dolomites, Middle to Upper Hydrothermal Dolomites and Upper Ordovician Utica Shale.[12] All three basins are gas-rich with Shallow to Medium Depth Thermogenic Shale Gas, Medium to Deep Thermogenic Shale Gas and Structured Thermogenic Shale Gas, respectively.[13] The Upper Ordovician Utica Shale, with a thickness of 100 to 220 m, is both gas- and oil-rich. This portion of the St. Lawrence Lowlands shale, located near Québec City, is liquids rich.[14]

Table 2.1: Summary of the Estimates of the St. Lawrence Lowlands

Play type	Nature of the Resource	Estimated Median Volume (BCF or barrels)	Reference Study and Publication Year
Lower Ordovician Hydrothermal Dolomites	Gas	20	Lavoie et al. (2009)
Middle to Upper Ordovician Hydrothermal Dolomites	Gas	114	Lavoie et al. (2009)
Upper Ordovician Utica Shale	Gas	176,730	Lavoie et al. (2009)
	Oil	1,870,000,000	Chen et al. (2014)

Source: National Institute for Scientific Research[15]

[11] Petroleum & Natural Gas Resource Potential of Québec Shales - Exploration & Production, Junex, Presented by Peter Dorrins, January 24, 2012, p. 3.
[12] Stephan Séjourné & Michel Malo, Geology and Hydrocarbon Potential of Southern Québec Sedimentary Basins, National Institute for Scientific Research, Water Earth Environment Centre, Research Report R1552, January 2015, pp. 5.
[13] The Utica Shale Play – It All Started in Québec Nature & Potential, Junex, Presented by Peter Dorrins, September 12-13, 2012, pp. 17.
[14] ibid
[15] Stephan Séjourné & Michel Malo, Geology and Hydrocarbon Potential of Southern Québec Sedimentary Basins, National Institute for Scientific Research, Water Earth Environment Centre, Research Report R1552, January 2015, pp. 5.

Québec-based Junex Inc. holds more than 5 million net acres.[16] The company has holdings in the St. Lawrence Lowlands, Gaspé Peninsula and Anticosti Island. Junex holds 584,338 hectares (1,443,931 acres) under exploration licenses in this sedimentary basin.[17] The company estimates 3.7 Tcf of recoverable natural gas under its acreage.[18]

Following a successful vertical test well program in 2008 and 2009, operators in the Lowlands led by Talisman Energy, Forest Oil and Questerre, began a pilot horizontal well program to assess commerciality of the Utica Shale in 2010. The initial results from the first three wells, St. Edouard, Leclerville and Gentilly, drilled in different parts of the fairway provided the impetus for further activity. Over $100 million was invested until additional drilling was suspended pending the results of the environmental assessment.

Anticosti Island: The Macasty Shale

Anticosti Island is located just off Québec's Gaspé Peninsula in the Gulf of St. Lawrence. It is a part of the St. Lawrence Estuary region. While the island, roughly 220 km long and approximately 56 km wide, has been a target for exploration since the 1960s, the island's Macasty Shale is drawing considerable attention of late. Five stratigraphic surveys were completed in 2014 and another seven were realized in 2015.[19]

Known for its hunting and fishing and tourism, the island is home to 240 inhabitants, who primarily reside in the only town on the island, the village of Port-Menier.[20] Anticosti Island is also home to Macasty Shale, containing major oil and gas-bearing potential, comparable to that of the Ohio Utica shales, of which it would be the lateral equivalent.[21] The Macasty Shale on Anticosti Island has been identified as the mother rock of the hydrocarbons of Anticosti Island sedimentary basin. Anticosti Island belongs to a sedimentary basin of the Lower Paleozoic that encompasses all the surface and subsurface rocks of the island down to the Precambrian bedrock of the Canadian Shield.[22]

Figure 2.5 illustrates the location of Québec's Ordovician-aged shale plays. The shale is black and organic-rich and is stratigraphically equivalent to the Utica Shale in the St. Lawrence Lowlands and analogous shale gas plays in the Northeastern US.[23] Similar to the fact that the St. Lawrence Lowlands is comparable to other shale plays in the US, the Utica Shale has comparable similarities

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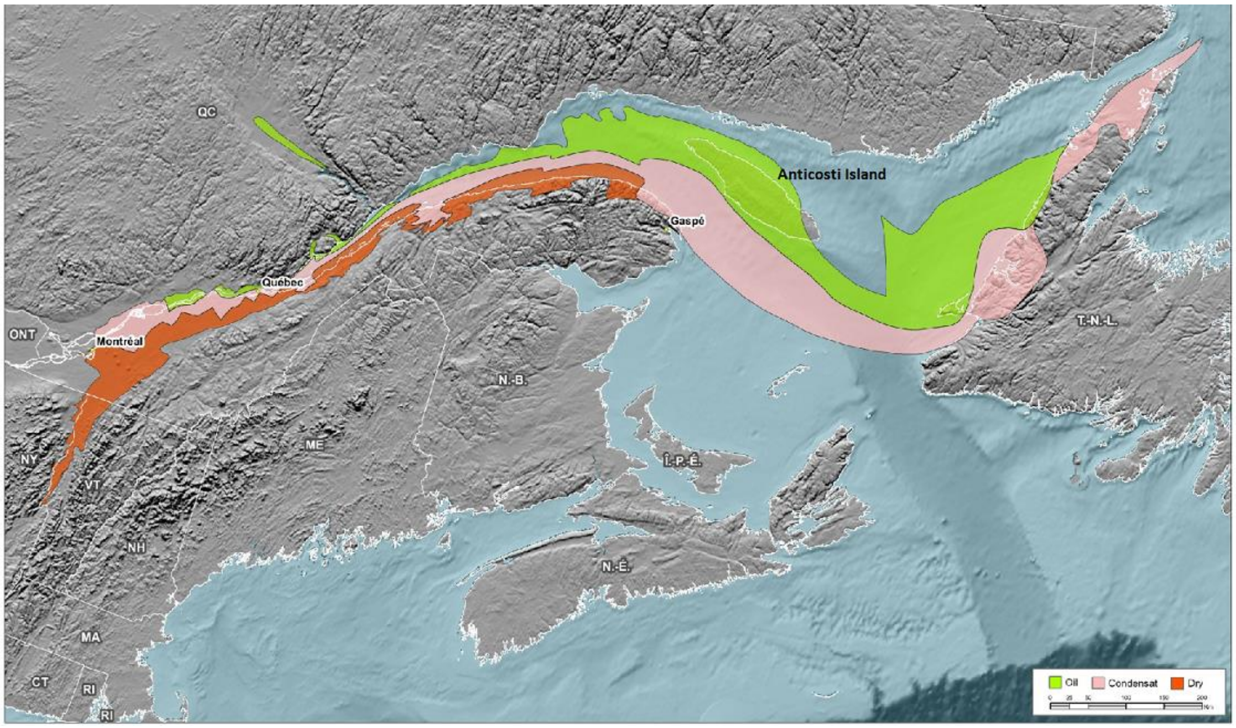
[16] Junex website, Des Millions D'Acres A Explorer: Six millions d'acres à explorer Trouver du pétrole et gaz naturel au Québec, http://www.junex.ca/explorer-Québec
[17] Junex website, St. Lawrence Lowlands, http://www.junex.ca/basses-terres-st-laurent
[18] ibid
[19] Natural Resources Canada, Québec's Shale and Tight Resources, https://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17714
[20] Québec Government, Exploration a Anticosti, Portrait de l'Île, http://hydrocarbures.gouv.qc.ca/ile-anticosti.asp
[21] Corridor Resources, Macasty Formation, http://www.corridor.ca/oil-gas-exploration/macasty-formation.html
[22] Natural Resources Canada, Québec's Shale and Tight Resources, https://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17714
[23] Hydrocarbures Anticosti website, Geology of the Anticosti, http://hydrocarbures-anticosti.com/en/project/geology

to the Macasty Shale of Anticosti Island. The Utica Shale and the Macasty Shale are both Ordovician-aged shale plays.[24] This is important because it is a geological environment that yields larger amounts of crude oil, natural gas and natural gas liquids in Ohio and Pennsylvania.[25]

Figure 2.5: Québec's Ordovician Shale Thermal Maturity Regimes



Source: Junex[26]

Figure 2.5 also illustrates oil, condensate and dry gas. As previously mentioned, the Utica Shale contains all three. While the Utica Shale of the St. Lawrence Lowlands is gas-rich, the Macasty Shale is primarily oil-rich.

Figure 2.6 illustrates the stratigraphy of Anticosti Island. In comparison to the St. Lawrence Lowlands, both are Upper Ordovician-aged and are indicated by the black labels. The Macasty shale overlies the Mingan Formation, comparable to the aforementioned Trenton Clastics.[27]

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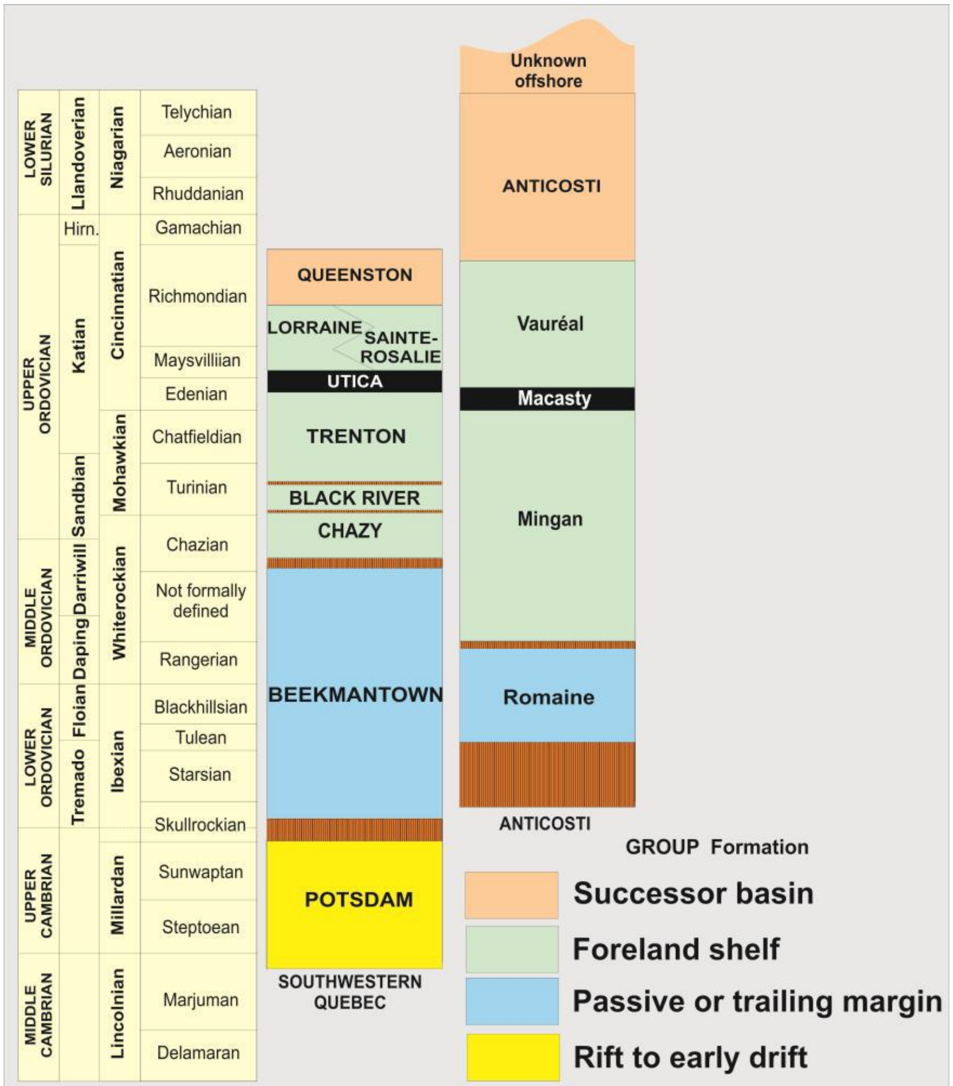
[24] ibid
[25] Geology.com website, Utica Shale - The Natural Gas Giant Below the Marcellus, http://geology.com/articles/utica-shale/
[26] The Utica Shale Play – It All Started in Québec Nature & Potential, Junex, Presented by Peter Dorrins, September 12-13, 2012, pp. 21.
[27] Hydrocarbures Anticosti website, Geology of the Anticosti, http://hydrocarbures-anticosti.com/en/project/geology

Figure 2.6: Stratigraphy of the Macasty Shale

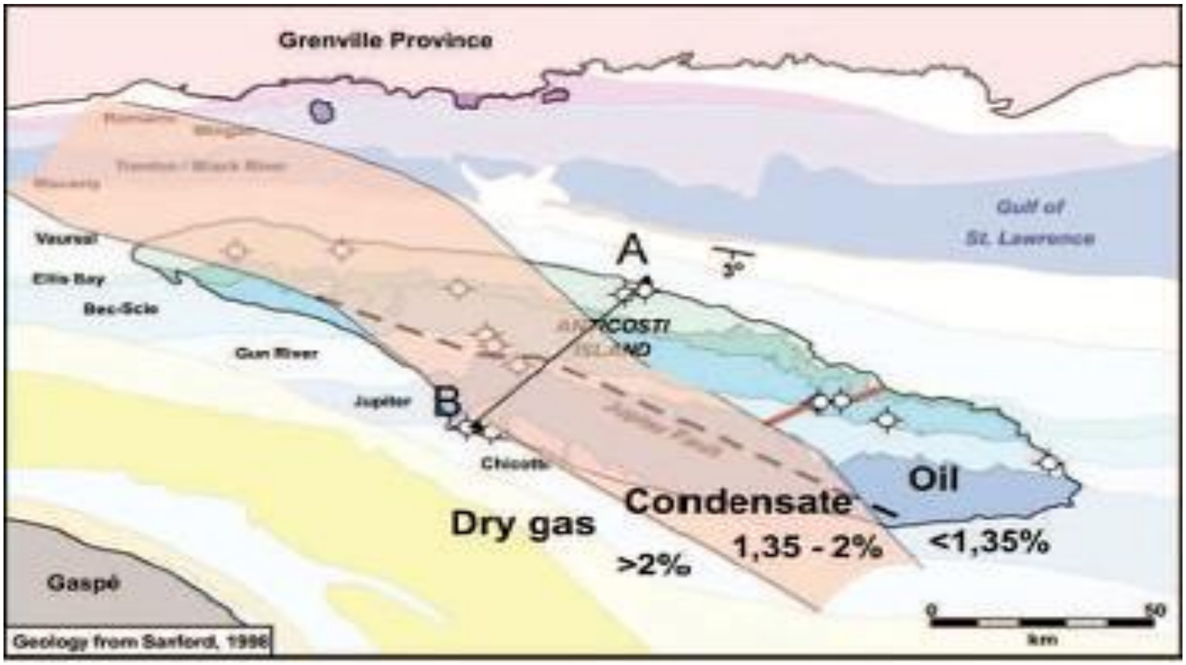


Source: Denis Lavoie and Robert Theriault,[28] pp. 3.

Figure 2.7 illustrates the thermal maturity regimes in greater detail. Anticosti Island is divided between condensate and tight oil targets. The northern and eastern part of the island is oil-rich while the south and western part of Anticosti is dry gas-rich and a swath extending in a northwestern pattern across the island is condensate. The shallower Macasty Shales are the oil window while the deeper shales are the gas window.

[28] Denis Lavoie and Robert Theriault, Upper Ordovician shale gas and oil in Québec: Sedimentological, geochemical and thermal frameworks, GeoConvention 2012: Vision, http://www.geoconvention.com/archives/2012/030_GC2012_Upper_Ordovician_Shale_Gas-and_Oil_in_Québec.pdf, pp. 3.

Figure 2.7: Anticosti Island's Thermal Maturity Regimes



Source: Stephan Séjourné and Michel Malo[29]

Table 2.2 illustrates a summary of the various resource estimates of Anticosti Island. While there are five sedimentary basins on Anticosti, the oil and gas potential of the island can be divided into three separate basins: Lower Ordovician Hydrothermal Dolomites, Middle to Upper Ordovician Hydrothermal Dolomites and Upper Ordovician Shales.[30]

The Lower Ordovician Hydrothermal Dolomites and the Middle to Upper Ordovician Hydrothermal Dolomites are rich in both oil and natural gas. The Upper Ordovician Shales, on the other hand, are only oil-rich and have garnered a lot of attention from E&Ps. They contain the largest estimate of oil in Québec; Table 2.2 shows two estimates, one from Petrolia and the second from Junex. Both are major players on Anticosti Island.

[29] Stephan Séjourné & Michel Malo, Geology and Hydrocarbon Potential of Southern Québec Sedimentary Basins, National Institute for Scientific Research, Water Earth Environment Centre, Research Report R1552, January 2015, pp. 80.
[30] Ibid, pp. 81.

Table 2.2: Anticosti Island's Estimates of the Main Plays

Play type	Nature of the Resource	Estimated Median Volume (Bcf or barrels)	Reference Study and Publication Year
Lower Ordovician Hydrothermal Dolomites	Gas	17	Lavoie et al. (2009)
	Oil	22,600,000	Lavoie et al. (2009)
Middle to Upper Ordovician Hydrothermal Dolomites	Gas	103	Lavoie et al. (2009)
	Oil	40,700,000	Lavoie et al. (2009)
Upper Ordovician Shales	Oil	43,600,000,000	Pétrolia (2011b)
	Oil	102,400,000,000	Junex (2011b)

Source: National Institute for Scientific Research[31]

Corridor Resources suggests that undiscovered petroleum initially-in-place is between 20.9 Bboe and 45.2 Bboe.[32] Petrolia Inc., on the other hand, estimates undiscovered petroleum initially-in-place is between 19.8 Bboe and 48.2 Bboe.[33] Junex estimates that on its 233,275 acres on Anticosti alone could contain a total undiscovered Original Oil in Place (OIIP) of 12.2 billion barrels.[34]

Corridor and Petrolia became partners in 2010, creating Anticosti Hydrocarbons L.P.[35] The Québec government, through Ressources Québec and France-based Maurel & Prom (M&P)

[31] Ibid, pp. 5.
[32] Corridor Resources website, Summary of Estimates of Total Unrisked Undiscovered Petroleum Initially-in-Place, as of April 30, 2015, http://hydrocarbures-anticosti.com/imports/medias/documentations/table-s-1-an.pdf
[33] Resource Assessment of the Macasty Formation in Certain Petroleum and Natural Gas Holdings on Anticosti Island, June 1, 2011, http://www.petroliagaz.com/imports/medias/pdf/rapports-financiers/2011-rapport-51-101-anticosti-en.pdf, pp. 1.
[34] Petroleum & Natural Gas Resource Potential of Québec Shales - Exploration & Production, Presented by Peter Dorrins, Junex, pp. 37.
[35] Resource Assessment of the Macasty Formation in Certain Petroleum and Natural Gas Holdings on Anticosti Island, June 1, 2011, http://www.petroliagaz.com/imports/medias/pdf/rapports-financiers/2011-rapport-51-101-anticosti-en.pdf, pp. 15.

acquired a 50 percent share in the Anticosti Hydrocarbons company.[36] The resulting interests in the company are Ressources Québec (35 percent), Corridor (21.67 percent), Petrolia (21.67 percent) and M&P (21.67 percent).[37] The Québec government announced in mid-February 2014, an agreement with Petrolia and Corridor to determine the petroleum potential of Anticosti Island.[38]

The joint partnership is most well-known for drilling the Petrolia Corridor Chaloupe No. 1 on the southeastern portion of Anticosti Island. Drilled in 2010 by Corridor and Petrolia, the well indicates the Upper Ordovician Shales are indeed oil-rich.[39] The test well averaged 4 to 6 percent porosity and its parameters are similar to the Ohio Shale, in terms of thickness, total organic carbon, clay content and hydrocarbon saturation.[40] The average thickness of the shale is between 20 and 175 meters thick, slightly less thick compared to the Utica Shales (50 to 300 meters thick).[41]

E&Ps on Anticosti Island could possibly take advantage of a unique geographical characteristic. Recall, with the bulk of frac fluid being comprised of water, ranging between 98 and 99.5 percent of the fluid, [42] water is critical to developing shale gas and tight oil. While the volume of frac fluid and water depends on the unique geological qualities of the particular shale and the size and number of stages of the frac operations,[43] one unique option on Anticosti Island, is to utilize seawater for fracking.

Companies have used seawater as a base fluid in different parts of the world, but it is generally used for offshore fracking, such as Haliburton's SeaQuest Service.

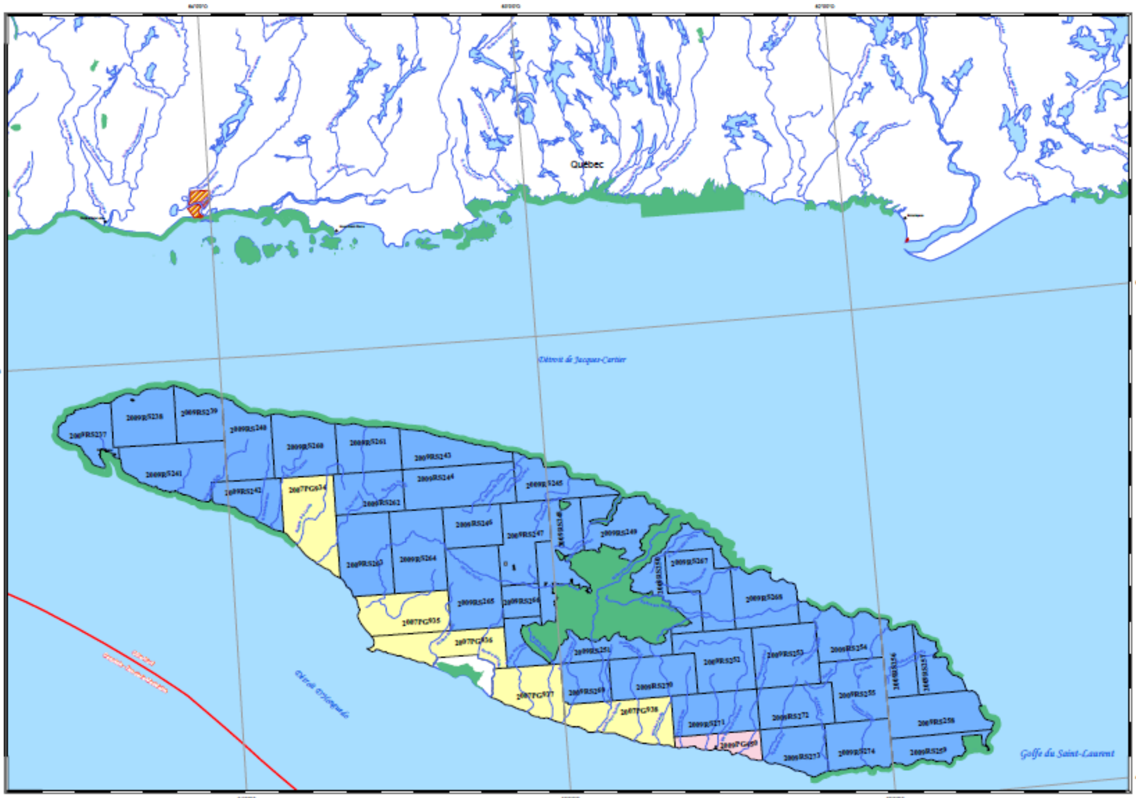
Using seawater, however, depends on the reservoir's unique chemistry, some minerals in the rock might react to the minerals present in the seawater. For example, one of the disadvantages is the presence of sulfate in seawater causing sulfate scales to form.[44] For most shale gas fields, trucking seawater makes little sense. That being said, seawater fracturing could be an interesting

[36] Corridor Resources website, Anticosti Joint Venture, http://www.corridor.ca/oil-gas-exploration/anticosti-jv.html
[37] Hydrocarbures Anticosti website, Company, http://hydrocarbures-anticosti.com/en/company
[38] Québec Government, Ententes en cours, http://hydrocarbures.gouv.qc.ca/ententes-anticosti-petrolia-maurel.asp
[39] Petrolia Gaz website, First resources assessment of Macasty shale, Anticosti Island, Québechttp://www.petroliagaz.com/en/investisseur/communique_detail.php?nou_id=405
[40] Rig Zone, Petrolia: Anticosti Macasty Comparable to Utica Shale, February 21, 2012.
[41] Denis Lavoie and Robert Theriault, Upper Ordovician shale gas and oil in Québec: Sedimentological, geochemical and thermal frameworks, GeoConvention 2012: Vision, http://www.geoconvention.com/archives/2012/030_GC2012_Upper_Ordovician_Shale_Gas-and_Oil_in_Québec.pdf, pp. 3.
[42] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 25.
[43] Canadian Society for Unconventional Gas (CSUG), Understanding Hydraulic Fracturing, January 2011, pp. 18.
[44] Carl Montgomery, Chapter 2 Fracturing Fluid Components, http://cdn.intechopen.com/pdfs-wm/44660.pdf, pp. 25.

option for Anticosti due to its proximity to the Gulf of St. Lawrence, but it would likely be dictated by the shale itself.

Figure 2.8 illustrates the oil and gas landholders on Anticosti Island. One of the distinction from other regions in Québec with oil and gas potential, is that the island has only a handful of players: Anticosti Hydrocarbons, Junex Inc. and Transamerican Energy. Imperial Oil, Consolidated Paper, Atlantic Richfield, New Associated Developments, Gamache Exploration and Mining, SOQUIP, Shell, Encal and HQPG are other companies that have drilled on the island in the past.

Figure 2.8: Oil and Gas Permits Map on Anticosti Island



Source: Ministère de l'Énergie et des Ressources Naturelles[45]

The largest landholder being the aforementioned Anticosti Hydrocarbons; net acreage indicated by blue in Figure 2.8. Total expenditures are expected to be C$100 million to conduct stratigraphic surveys and drill exploratory wells in the next couple of years.[46] The project is scheduled to be conducted in two phases. The first totals C$55 million and is comprised of approximately 15 stratigraphic surveys (2014 and 2015).[47] The first phase includes drilling three

[45] Ministère de l'Énergie et des Ressources Naturelles, Oil and Gas Permits on Anticosti Island, http://mern.gouv.qc.ca/publications/energie/exploration/Permis_anticosti-ouest.pdf
[46] Hydrocarbures Anticosti website, The Agreement, http://hydrocarbures-anticosti.com/en/project
[47] ibid

multi-frac horizontal wells (2016).[48] The second phase totals C$45 million and will be determined by the results of Phase 1.[49] The partnership works closely with the population of Anticosti, as well as adheres to environmental requirements for the sensitive ecosystem on the island.[50] All exploration work is supervised by the Ministère de l'Énergie et des Ressources Naturelles and the Ministry of Sustainable Development, Environment and the Fight Against Climate Change (MDDELCC).[51]

Junex is the other large player on Anticosti Island. The Québec-based company holds 233,275 net acres on Anticosti Island—primarily for its oil potential in the Macasty Shale.[52] Net acreage is indicated by yellow in Figure 2.8. Junex has no exploration program on Anticosti for the moment.

Gaspé Peninsula (Gaspésie)

The Gaspésie region has attracted oil drilling since 1865.[53] Today, the bulk of exploration is located in the northeast part of the peninsula. Various exploratory wells have identified several separate sedimentary basins in the region.

Figure 2.9 illustrates Silurian-Devonian geology of the region, including the four major hydrothermal dolomite (HTD) occurrences in the Lower Silurian carbonates: 1) the Ruisseau Isabelle section, 2) the Saint-Cleophas quarry, 3) the Petit-Rocher-Belledune (New Brunswick), and 4) the New Richmond wharf section.[54]

[48] ibid

[49] ibid

[50] Québec Government, Ententes en cours, http://hydrocarbures.gouv.qc.ca/ententes-anticosti-petrolia-maurel.asp

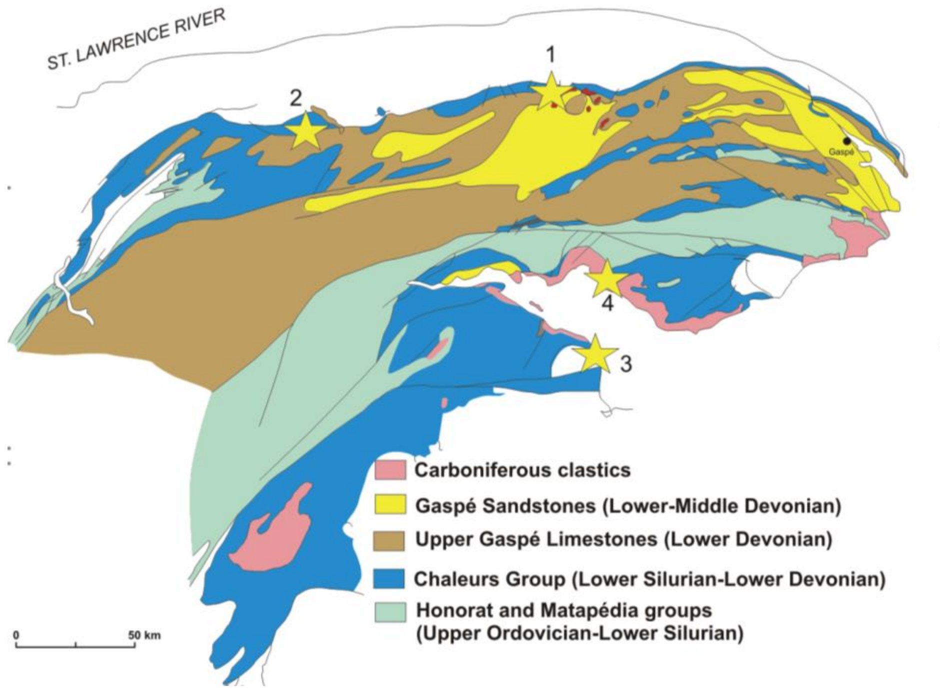
[51] Québec Government, Exploration a Anticosti, http://hydrocarbures.gouv.qc.ca/exploration-petroliere-anticosti.asp

[52] Energy Digital website, Junex Announces Exploration Operations on its Macasty Shale Oil Play on Anticosti Island http://www.energydigital.com/press_releases/oil-and-gas/junex-announces-exploration-operations-on-its-macasty-shale-oil-play-on-anticosti-island (accessed on June 5, 2012)

[53] Québec Government, Exploration en Gaspésie et dans le Bas-Saint-Laurent, http://hydrocarbures.gouv.qc.ca/gaspesie-exploration-hydrocarbures.asp

[54] Denis Lavoie and Nicolas Pinet, Mapping the Basement – Assessing the Potential for Hydrothermal Dolomitization in the Paleozoic of Eastern Canada, 2008 CSPG CSEG CWLS Convention, http://www.geoconvention.com/archives/2008/010.pdf, pp. 2.

Figure 2.9: Geology Map of the Gaspésie



Source: Denis Lavoie and Nicolas Pinet[55]

There are six separate sedimentary basins that are defined in the Gaspésie: Taconic Band–Cambro Ordovician Clastic Sediments, Upper Ordovician and Lower Silurian Carbonate, Lower Silurian Sandstone, Lower Silurian to Lower Devonian Hydrothermal Dolomites, Lower Devonian Carbonate Brecciation Dolomitized, and Lower Devonian Fluviatile Sandstone. It is the latter two that are attracting attention (Lower Devonian Carbonate Brecciation Dolomitized and Lower Devonian Fluviatile Sandstone).

Table 2.3 illustrates these two sedimentary zones. Petrolia and Junex are involved with three exploratory projects that warrant mention: Haldimand, Bourque and Galt.

[55] ibid

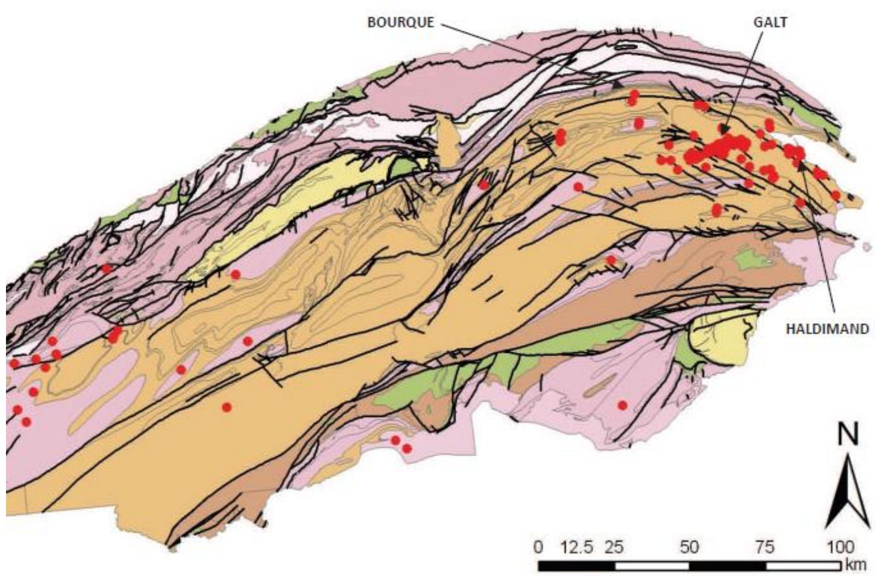
Table 2.3: Gaspésie's Estimates of the Main Plays

Play type	Nature of the Resource	Estimated Median Volume (ft^3 or barrels)	Prospect or Reference Reservoir in Québec	Reference Study and Publication Year
Lower Devonian Carbonate Brecciation Dolomitization	--	--	Galt; Bourque	--
Lower Devonian Fluviatile Sandstone	Oil	102,000,000	Haldimand	Lavoie et al. (2009)

Source: National Institute for Scientific Research[56]

From 2008 to 2013, more than C$40 million was spent on exploration for these three projects.[57] Figure 2.10 shows the location of the three exploratory projects as well as the wells drilled since 1860 (red spots).

Figure 2.10: Location of the Wells Drilled in the Gaspésie



Source: Séjourné and Malo, 2015[58]

[56] Stephan Séjourné & Michel Malo, Geology and Hydrocarbon Potential of Southern Québec Sedimentary Basins, National Institute for Scientific Research, Water Earth Environment Centre, Research Report R1552, January 2015, pp. 5.
[57] ibid
[58] Ibid, pp. 65.

The Haldimand Project is geologically known for its oil potential. Petrolia conducted the drilling of the Haldimand No. 1 well in 2005 and Haldimand No. 2 in 2009.[59] Petrolia's Haldimand No. 4 was completed on December 30, 2014.[60] The horizontal well was drilled without fracking to a total length of 2,630 m.[61] An independent assessment by the firm Sproule Associates Limited estimated resources initially in place at 69.7 million barrels and the recoverable portion at 7.7 million barrels.[62]

Petrolia is also heading up the Bourque Project, a reservoir with oil and natural gas potential.[63] After Petrolia conducted the drilling of the Bourque No. 1 & 2 wells in 2012,[64] Sproule Associates Limited in April 2013 estimated resources initially in place at more than 1 Tcf of volume of wet gas.[65] Petrolia concluded the confirmation of a reservoir containing oil, condensate and natural gas. Petrolia announced on August 5, 2015 that it is developing a resource program for the Bourque Project, to better understand the resources in place and potential recoverable volumes.[66]

The Galt Project is headed up by Junex. The company holds more the 300,000 hectares.[67] With a flow rate of 300 barrels of oil per day, the Galt No. 4 was drilled in 2014.[68] On July 31, 2015, Junex spudded the Galt No. 5 and drilled to a total depth of 2,500 m, half of which is horizontal.[69]

Netherland, Sewell & Associates Inc. recently provided an estimate of original oil-in-place (OOIP) of 557 million barrels for the Forillon sandstone and Indian Point formations in Québec. The operator's net share of the recoverable resources is 55.7 million barrels of oil.[70]

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[59] Québec Government, Droits accordés et détails sur les projets en cours, http://hydrocarbures.gouv.qc.ca/gaspesie-droit-accorde.asp
[60] http://www.marketwired.com/press-release/petrolia-inc-haldimand-4-drilling-is-completed-tsx-venture-pea-1980584.htm
[61] ibid
[62] Petrolia website, Haldimand Project, http://www.petrolia-inc.com/en/corporate/projects/haldimand-project
[63] Québec Government, Droits accordés et détails sur les projets en cours, http://hydrocarbures.gouv.qc.ca/gaspesie-droit-accorde.asp
[64] ibid
[65] Maretwired.com website, Petrolia: New Outlook for the Bourque Project, August 5, 2015, http://www.marketwired.com/press-release/petrolia-new-outlook-for-the-bourque-project-tsx-venture-pea-2045219.htm
[66] ibid
[67] Junex website, Gaspésie, http://www.junex.ca/gaspesie
[68] Oil & Gas Journal, Junex spuds fifth well on Québec's Galt prospect, July 31, 2015, http://www.ogj.com/articles/2015/07/junex-spuds-fifth-well-on-Québec-s-galt-prospect.html
[69] Ibid.
[70] Ibid.

Chapter 3
Production Costs and Market Demand

Québec Supply Costs

In order to gauge the competitiveness of oil and gas development in Québec, it is important to estimate the supply costs associated with the two commodities. The supply cost is derived as the price (in 2015 Canadian dollars) of oil or gas required to recover all capital expenditures, operating costs, royalties, taxes, and a specified return on investment for each well.

For an oil or gas well to be economic, total revenue from the production of oil or gas less costs has to offset the upfront capital and land costs. If supply costs are lower than the current market prices for oil and gas, the well is able to recover its full cost over its lifetime and make a positive return on investment. Conversely, if the supply costs are greater than the current price, then the well would not be able to recover its costs and would be considered uneconomic. Supply cost is calculated on a per well basis.

The supply cost is calculated with a cash flow model where net cash flow equals total revenue less any costs and other payments such as taxes and royalties.

The net cash flow is discounted back over the lifetime of the well (on average 25 years) to the first time period (2015) using a specified discount rate of 10 percent (real), thereby allowing the price of oil or gas to vary and solve for the supply cost. The supply cost is the oil price per barrel or gas price per thousand cubic feet (Mcf) that sets the Net Present Value (NPV) of the cash flow to zero.

Companies may evaluate individual projects and investments using higher or lower discount rates than those used in this analysis. This would result in higher or lower supply costs than those presented here.

The analysis has been undertaken for two study areas (Macasty Shale and Utica Shale), and the results represent the supply cost for a “typical well” located in each area.

Macasty Shale

Oil supply costs in the Macasty Basin are calculated based on specific assumptions of capital and operating costs and a production profile of a horizontal well with 12-stage multifracturing at an initial production (IP) rate of 95 bbl/d and a harmonic decline curve. The capital cost is assumed to be $5.78 million per well; operating cost is $60,000 per well per year. Royalties and tax calculations are determined according to the current provincial royalty structure and provincial and federal corporate tax rates.

The reader should note that IP rates can vary widely. In this case due to the dearth of information specific to the Macasty Shale, the uncertainty of the IP rates is represented by two assumptions.

The information below explores the CERI assumption of an IP rate of 95 bbl/d. Appendix C explores a second assumption developed by the Québec government, a rate of 135 bbl/d. The effect of the different IP rates is discussed in Chapter 5.

Based on the CERI assumptions, the supply cost of greenfield oil production in the Macasty Shale is $95.50/bbl at the plant gate, as shown in Table 3.1.

Table 3.1: Net Present Value Supply Costs – Macasty Shale Oil

Costs $/bbl	Reference Costs	Cap cost +25%	Cap Cost -25%	Op Cost +50%	Op Cost -50%
Capital Costs	$79.42	$99.27	$59.56	$79.42	$79.42
Operating Costs	$8.57	$8.57	$8.57	$12.85	$4.28
Royalties	$0.82	$1.00	$0.63	$0.85	$0.78
Taxes	$6.69	$8.37	$5.02	$6.69	$6.69
Total Supply Costs	$95.50	$117.21	$73.78	$99.82	$91.18

Source: CERI

To demonstrate the sensitivity of these estimates, CERI varied the capital and operating costs by 25 percent and 50 percent plus and minus, respectively. This shows that if capital costs can be minimized the outcome provides a greater competitive benefit than focusing on operating cost containment.

The Government of Québec and companies active in the area are evaluating the Macasty Basin, based on geological and geophysical data that has been collected over the past few years in the rapidly developing Point Pleasant shale play in Ohio – an area that shares many geological characteristics with the Macasty. Exploration companies are considering the potential of Natural Gas Liquids (NGLs) in future Macasty developments. However, exploratory drilling must take place on Anticosti to grasp better the nature of the resource. Until that happens, the makeup of the Macasty hydrocarbon resource remains largely unknown. This report focuses on the potential for oil production and NGL development is beyond the scope of this report. Readers are encouraged to consult study AECNO1 under the Government of Québec's Strategic Environmental Assessment, and the websites of Corridor Resources, Petrolia Inc., and Junex Inc. for more information.

Utica Shale

Natural gas supply costs in the Utica Basin are calculated based on specific assumptions of capital and operating costs and a production profile[1] of a horizontal well with 12-stage multifracturing at an IP rate of 7.5 million cubic feet per day (MMcfd) and a harmonic decline curve.

Again, the reader should note that the IP rate differs from those assumed by other organizations. In this case, the alternative IP rate was taken from a Talisman report which stated an IP of 9.75 MMcfd. The information below explores the CERI assumption and Appendix C explores the Talisman assumption. The effect of the different IP rates is discussed in Chapter 5.

The capital cost is assumed to be $9.47 million per well; operating cost is $1 per Mcf/d per well. This cost varies over time as a portion is fixed and the remainder changes with the production rate. In this case, CERI assumes a 50:50 split between fixed and variable operating costs. Royalties and tax calculations are determined according to the current provincial royalty structure and provincial and federal corporate tax rates. Based on these assumptions, the supply costs of natural gas production in the Utica Shale, including drilling and production of a 12-stage fractured horizontal well, and including field processing are $3.72/Mcf at the field, as Table 3.2 illustrates.

Table 3.2: Net Present Value Supply Costs – Utica Shale Natural Gas

Costs $/Mcf	Reference Costs	Cap cost +25%	Cap Cost -25%	Op Cost +50%	Op Cost -50%
Capital Costs	$2.41	$3.01	$1.80	$2.41	$2.41
Operating Costs	$0.77	$0.77	$0.77	$1.05	$0.49
Royalties	$0.35	$0.42	$0.28	$0.38	$0.32
Taxes	$0.19	$0.24	$0.14	$0.19	$0.19
Total Supply Costs	$3.72	$4.43	$3.00	$4.02	$3.41

Source: CERI

Again we see the impact of varying the cost estimates. At current estimates, natural gas is marginally competitive.

These supply costs are calculated for typical greenfield wells. The cost estimates do not include economies of scale of horizontal drilling with multi-stage fracking for shale gas or oil. Nor does it include costs associated with infrastructure to get the gas and oil to market. On the other hand, there is a transportation cost savings for Québec if it were to source gas within the province (ranging from $0.50 to $1.00 per Mcf).

[1] An alternative production profile for oil and gas is explored in Appendix C. Changing the production profile has a significant impact on the production cost calculations and the assessment of economic impacts.

In order to recapture all costs and earn a 10 percent return on investment, producers in Québec must see a price of CDN$95.50 per barrel of oil and CDN$3.72 per Mcf of gas. In today's market where crude is priced at approximately CDN$55 per barrel, and gas is priced at approximately CDN$4 per Mcf, Québec oil play is not competitive but the gas play could be. For gas, it very much depends on the added cost of infrastructure compared to the savings from not having to transport the gas to market.

CERI's cost calculations are sensitive to capital and operating cost assumptions as well as an assumed rate of return. Individual producers might evaluate projects using lower (or higher) rates of return or lower (or higher) costs. This would result in different supply costs.

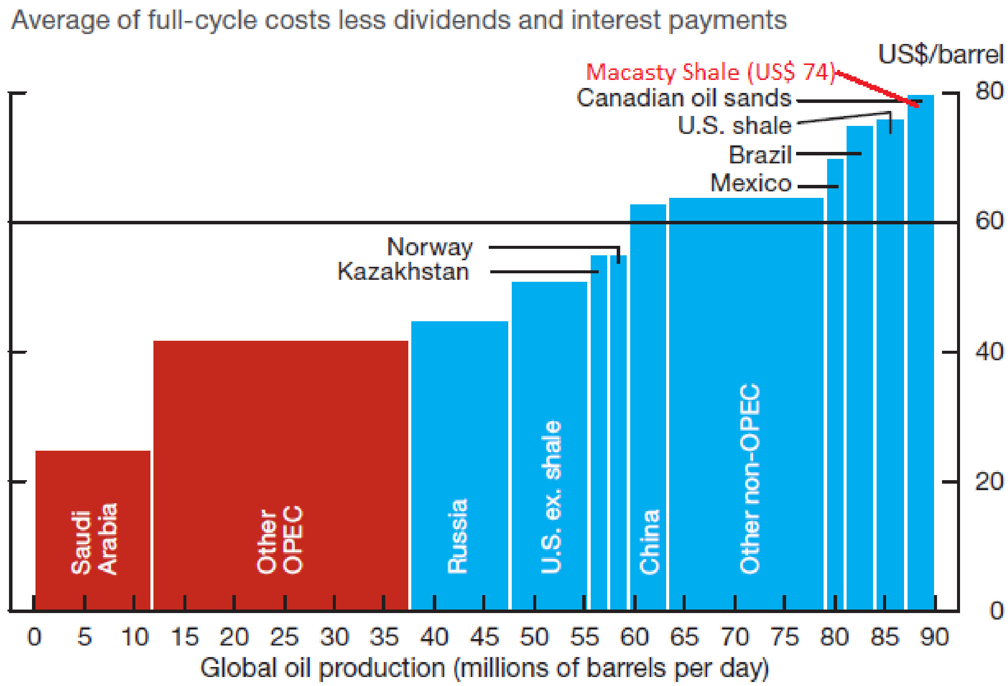
Oil and gas supply costs are sensitive to economies of scale and efficiency improvements of producers. CERI's estimates do not reflect the potential for cost savings as producers learn more about the local resource and develop more appropriate extraction procedures. Costs can be reduced by increasing the number of wells per pad, using data analytics, and increasing the number of fracs per well. Total, the French supermajor, recently stated a 20 percent cost reduction over one year using a variety of techniques in their US production activities.[2]

Québec Supply Costs Compared to Other Jurisdictions

Figures 3.1 and 3.2 indicate the competitive landscape, in terms of costs, that Québec will have to navigate in order to become established as an oil and natural gas producer. In terms of oil, Macasty costs would be among some of the highest cost producers in the world, roughly on par with the Alberta oil sands. Figure 3.1 shows that Québec would be uncompetitive at US$60, along with Brazil, Mexico, and the oil sands. As of this writing, Brent prices are approximately US$50 per barrel, which adds several more jurisdictions to the list of uneconomic producers.

[2] New York Times, Drillers Answer Low Oil Prices With Cost-Saving Innovations. Clifford Krauss, May 11, 2015

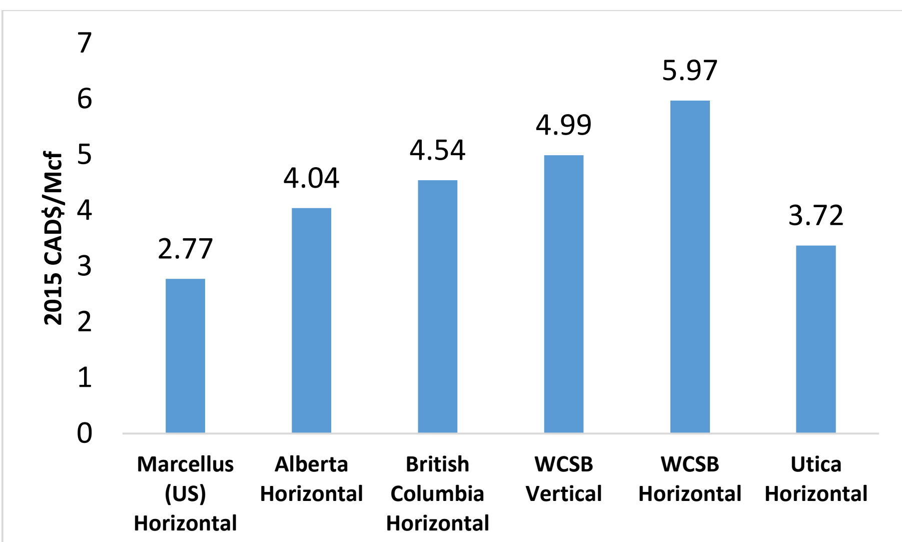
Figure 3.1: 2015 Global Oil Supply Costs Comparison



Sources: Energy Aspects, Bank of Canada, CERI.

Figure 3.2 shows Québec's Utica Gas production cost against that of other Canadian gas producing areas and the US Marcellus shale. There is a spread of less than $1.00/Mcf between Utica Shale gas and Marcellus, meaning that if Utica production is to compete with Marcellus production, and natural gas prices remain low (Henry Hub is approximately $2.50/Mcf as of this writing), costs will need to stay contained and infrastructure costs kept to a minimum.

Figure 3.2: 2015 North American Natural Gas Supply Costs Comparison



Sources: CERI, Bloomberg.

The number of natural gas gathering lines, or feeder lines, is negligible in Québec. The most likely scenario for future development in Québec would be organic growth, connecting the gathering lines and feeder lines from the producing fields to the existing North American pipeline network.

Liquids pipelines are used to transport crude oil or natural gas liquids from producing fields to refineries, and in some cases of refined petroleum products, from refineries to distribution centers. Crude oil storage and pipelines are missing from the Québec market. The crude oil consumed in Québec is shipped by pipeline, rail, or tanker into two large oil refineries, including Levis (Jean-Gaulin refinery - Énergie Valero) and Montreal (Suncor).[3] Énergie Valero's capacity is 265,000 bpd while Suncor's Montreal refineries capacity is approximately 140,000 bpd.[4] The former is supplied by oil shipped by tanker while the latter is mainly supplied by the pipeline (Portland-Montreal Pipe Line) and more recently by train.

Therefore, along with the production costs of the producing wells, the analysis of a competitive hydrocarbon market must consider the infrastructure costs. These have not been included in the CERI estimates, creating a bigger economic challenge for a Québec-based hydrocarbon industry.

Royalty Regimes

Royalties are an important consideration in determining production cost for a specific jurisdiction. These frameworks can affect the overall productivity of the oil or natural gas play.

In 2014-15, the Québec government collected $1.057 billion in duties and royalties from mining, forest, water-power and oil and natural gas.[5] This is up from $1.037 billion collected in 2012-13 and $1.008 million collected in 2013-14.[6] The highest amount of duties and royalties was $752 million from water-power, followed by $240 million from the forest industry. The Québec government has not collected any royalties from the oil and natural gas industry.

There have been numerous changes in the past several years with regard to Québec's royalty regime. Changes have been proposed to the royalty structure for shale gas and the new structure for onshore oil is in the process of being reviewed. The following reviews the new royalty regime for shale gas and the principles of the proposed royalty regime for onshore oil.

Québec's Ministry of Finance published its new royalty regime for the development of shale gas in the province on March 17, 2011.[7] The new royalty regime has never been the object of

[3] Québec Government, Québec Energy Policy 2016-2017: Fossil Hydrocarbons, http://www.politiqueenergetique.gouv.qc.ca/wp-content/uploads/Document6%E2%80%93hydrocarbons.pdf, pp. 24.

[4] Ministère Énergie et Ressources Naturelles, Raffinage du Pétrole, http://www.mern.gouv.qc.ca/energie/statistiques/statistiques-production-petrole.jsp

[5] Finances Québec, The Québec Economic Plan, Budget 2015-2016, March 2015, http://www.budget.finances.gouv.qc.ca/budget/2015-2016/en/documents/BudgetPlan.pdf, pp. D.72.

[6] Finances Québec, The Québec Economic Plan, Budget 2014-2015, June 2014, March 2015, http://www.budget.finances.gouv.qc.ca/budget/2014-2015a/en/documents/BudgetPlan.pdf, pp. D.19.

[7] http://www.budget.finances.gouv.qc.ca/Budget/2011-2012/en/documents/SchisteEN.pdf

legislation As such, the old royalty rate is still in effect. It is still prudent to discuss the new proposed royalty regime as well as the current system.

The current royalty regime is based on a fixed rate of 10-12.5 percent, depending on the production level of a well.[8] The two-tier structure, however, does not take into account the characteristics of the reservoir or deposit or the market. And, as no gas wells have reached the production stage, the Québec government has not received any royalties.[9] If the productivity was equal to or less than 2,966 Mcfd, the royalty rate was 10 percent of market value at the wellhead. If the production was greater than 2,966 Mcfd, the royalty rate was 10 percent of market value at the wellhead for the first 2,966 Mcfd and 12.5 percent of market value at the wellhead on the remainder.[10]

Québec's new proposed royalty regime for shale gas is based on two factors: production rate and sales gas price. Depending on these two factors, the new rate varies between 5 and 35 percent.[11] The new rate is progressively adjusted and takes into account market price, transportation cost and processing cost.[12] The 5 percent royalty applies where the price of the resource and production volumes are at their lowest whereas the 35 percent rate applies where the price of the resource and production volumes are the highest.[13]

Table 3.3 illustrates how the rates vary according to price and production volumes (between 5-35 percent). For example, the lowest rate applies in a situation where the price is $4.00 - $5.00 per Mcf and the well is producing only 250 Mcfd.[14]

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[8] ibid
[9] http://www.blakes.com/English/Resources/Bulletins/Pages/Details.aspx?BulletinID=1351
[10] Finances Québec, A Fair and Competitive Royalty System: For Responsible Shale Gas Production, 2011-2012 Budget, pp. 17.
[11] Ibid, pp. 18.
[12] Osler website, Sylvain Lussier Ad. E., Alexandre Fallon, Québec Announces Creation of New Royalty Regime for Shale Gas Industry March 24, 2011, https://www.osler.com/en/resources/regulations/2011/Québec-announces-creation-of-new-royalty-regime-fo
[13] Blakes website, Government of Québec's Position on Shale Gas Exploration/Production, Jean Marc Gagnon and Emmanuel Sala, June 20, 2011, http://www.blakes.com/English/Resources/Bulletins/Pages/Details.aspx?BulletinID=1351
[14] Finances Québec, A Fair and Competitive Royalty System: For Responsible Shale Gas Production, 2011-2012 Budget, pp. 20.

Table 3.3: Royalty Rates based on Price and Production

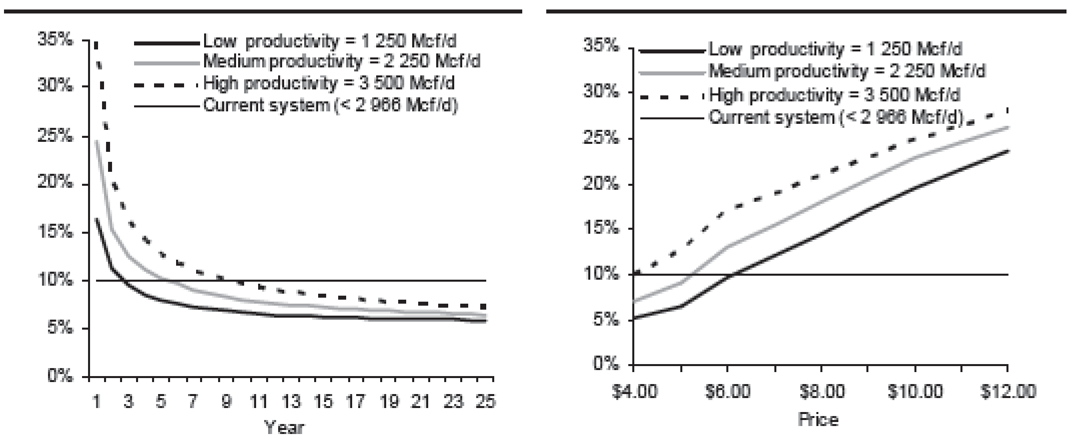
	Average volume per day for a given month (thousand of cubic feet)						
	Low			Medium		High	
Price[1]	250	750	1 250	1 750	2 250	2 750	3 500
$4.00	5.0	6.1	13.0	19.8	26.6	30.0	30.0
$5.00	5.0	11.1	18.0	24.8	31.6	35.0	35.0
$6.00	9.2	16.1	23.0	29.8	35.0	35.0	35.0
$7.00	11.7	18.6	25.5	32.3	35.0	35.0	35.0
$8.00	14.2	21.1	28.0	34.8	35.0	35.0	35.0
$9.00	16.7	23.6	30.5	35.0	35.0	35.0	35.0
$10.00	19.2	26.1	33.0	35.0	35.0	35.0	35.0

[1]The price used to fix the royalty rate will take into account market price, transportation cost, gas processing cost, etc. Terms and conditions will be spelled out in the legal and regulatory framework.

Source: Finances Québec[15]

Figure 3.3 illustrates the change in the royalty rate over a 25-year period for various levels of production (on the left) and the average royalty rate over a 25-year period for various levels of production (on the right). For example, if the average initial production of the well is 2,250 Mcfd, assuming a price of $6 per mcf, the royalty rate will be 25 percent initially and will gradually decline to approximately 5 percent over the production span of 25 years.[16]

Figure 3.3: Change of Royalty Rates (left) and Average Royalty Rates (right) Over a 25-year Production Period



1 At a constant price ($6/Mcf).

Source: Finances Québec[17]

[15] Ibid, pp. 19.

[16] Ibid, pp. 20.

[17] Finances Québec, A Fair and Competitive Royalty System: For Responsible Shale Gas Production, 2011-2012 Budget, pp. 20.

Other jurisdictions in Canada that have adopted progressive rates include British Columbia, Alberta and Saskatchewan.

In the 2011-2012 Budget, Québec announced they will modernize the royalty regime for onshore oil[18] but as of time of writing, it has not been the subject of legislation. The current royalty regime ranges from 5 percent to 12.5 percent of market value at wellhead.[19] This is based on a well's average daily production in a given month. The current regime for oil in Québec is illustrated in Figure 3.4.

Figure 3.4: Current Royalty Regime for Oil in Québec

Average daily production of a well in a given month	Royalty rate
Less than 44 barrels (1)	5% of wellhead price
Between 44 and 189 barrels (2)	5% of wellhead price on the first 44 barrels 10% of wellhead price on the remainder
Over 189 barrels (2)	8.75% of wellhead price on the first 189 barrels 12.5% of wellhead price on the remainder

(1) The Regulation presents the equivalent in cubic meters, i.e. 7 cubic metres.
(2) The Regulation presents the equivalent in cubic meters, i.e. 30 cubic metres.
Source: *Regulation respecting petroleum, natural gas and underground reservoirs*, R.R.Q. c. M-13.1, r. 1, s. 104.

Source: Finances Québec[20]

Similar to the new shale gas royalty regime, the basis of the new proposed onshore oil regime is progressive rates. It is important to note that the royalty rates for onshore oil discussed were never finalized. The proposed new rate will be based on the price of oil and well productivity.[21] The new rate ranges from 5 percent to 40 percent.[22] A royalty of 5 percent would apply when resource prices and well productivity is low and 40 percent applies when the opposite is true.[23] Table 3.4 illustrates how the rates vary according to price and average volume per day for a well in a given month (between 5-40 percent).

[18] Finances Québec, Québec and its Natural Resources: Optimum Development, Budget 2012-2013, http://www.budget.finances.gouv.qc.ca/Budget/2012-2013/en/documents/resources.pdf, pp. 84.
[19] ibid, pp. 85.
[20] ibid
[21] ibid, pp. 86.
[22] ibid
[23] ibid

Table 3.4: Royalty Rates under the New Royalty Regime

	Average volume per day in a given month (in oil barrels)						
	Low			Medium		High	
Price	25	50	75	200	300	600	800
\$50	5.0	5.0	10.0	21.3	25.8	31.8	35.0
\$75	8.3	13.3	18.3	29.6	34.1	40.0	40.0
\$100	16.7	21.7	26.7	37.9	40.0	40.0	40.0
\$125	25.0	30.0	35.0	40.0	40.0	40.0	40.0
\$150	25.0	30.0	35.0	40.0	40.0	40.0	40.0

Source: Finance Québec[24]

Figure 3.5 illustrates the calculation of the rate for the new royalty regime for onshore oil. Recall the rates vary on the two components: price and volume.

Figure 3.5: Calculation of Royalty Rate Components for Onshore Oil in Québec

Price component (R_{price}) (dollars per barrel of oil)	Calculation (percentage)
From \$0 to \$50	(Price(1)) x 0.5 – 20
From more than \$50 to \$125	(Price – \$50) x ⅕ + 5
More than \$125	30
Volume component (R_{volume}) (in barrels of oil per day for a given month)	
From 0 to 100 barrels	Volume x 0.2 – 10
From more than 100 to 260 barrels	(Volume – 100 bbl) x 0.0625 + 10
From more than 260 to 760 barrels	(Volume – 260 bbl) x 0.02 + 20
More than 760 barrels	30

(1) The price used to establish the royalty rate will take into account market price, transportation costs, etc. Regulations will specify the terms and conditions.

Source: Finance Québec

Overall cost, considering the actual production cost estimates, the lack of infrastructure and the royalty framework, means that Québec's oil fundamentals are not currently economically competitive and the gas fundamentals are marginal. Cost reductions in the form of business process improvements, government policy or higher market prices may be necessary to enable a hydrocarbon supply industry to develop and grow.

Market Demand

Hydrocarbon demand can come from domestic requirements within Québec; or external demands in Canada, North America and globally. Natural gas markets differ from oil markets as

[24] ibid

described below. Market demand affects both opportunity and the market clearing price. This is an important consideration of the viability of a Québec oil and gas industry.

Domestic Natural Gas Demand

Québec domestic demand will only affect the market for natural gas. This report assumes Macasty oil will be shipped to world markets from a future port to be built on Anticosti.

Natural gas is primarily used in Québec for industrial, commercial and residential heating. Natural gas could also be used to replace other hydrocarbons in Québec to help meet the province's emissions targets. Québec is one of the largest importers of fuel oil in Canada, accounting for approximately 33 percent of the country's domestic sales.

Generally in North America, the largest opportunity for domestic demand in the short term is natural gas-fired electricity generation. However, in Québec's case this is unlikely. Québec is highly reliant on hydropower, with that resource providing 95.5 percent of total energy in the province in 2014.[25] In the past, the 675-MW Gentilly nuclear power generating station contributed to baseload generation, but that plant closed in 2012, with hydropower making up the difference.

Hydro-Québec production generates power to supply the Québec market and generates enough power beyond its own needs to sell on the wholesale market. In 2014, Hydro-Québec's hydroelectric production and development included 62 generating stations, 27 large reservoirs, 668 dams and 98 control structures.[26] The storage capacity of the reservoirs is 176 TWh.[27]

Hydro-Québec has the installed capacity to generate 36,643 MW.[28]

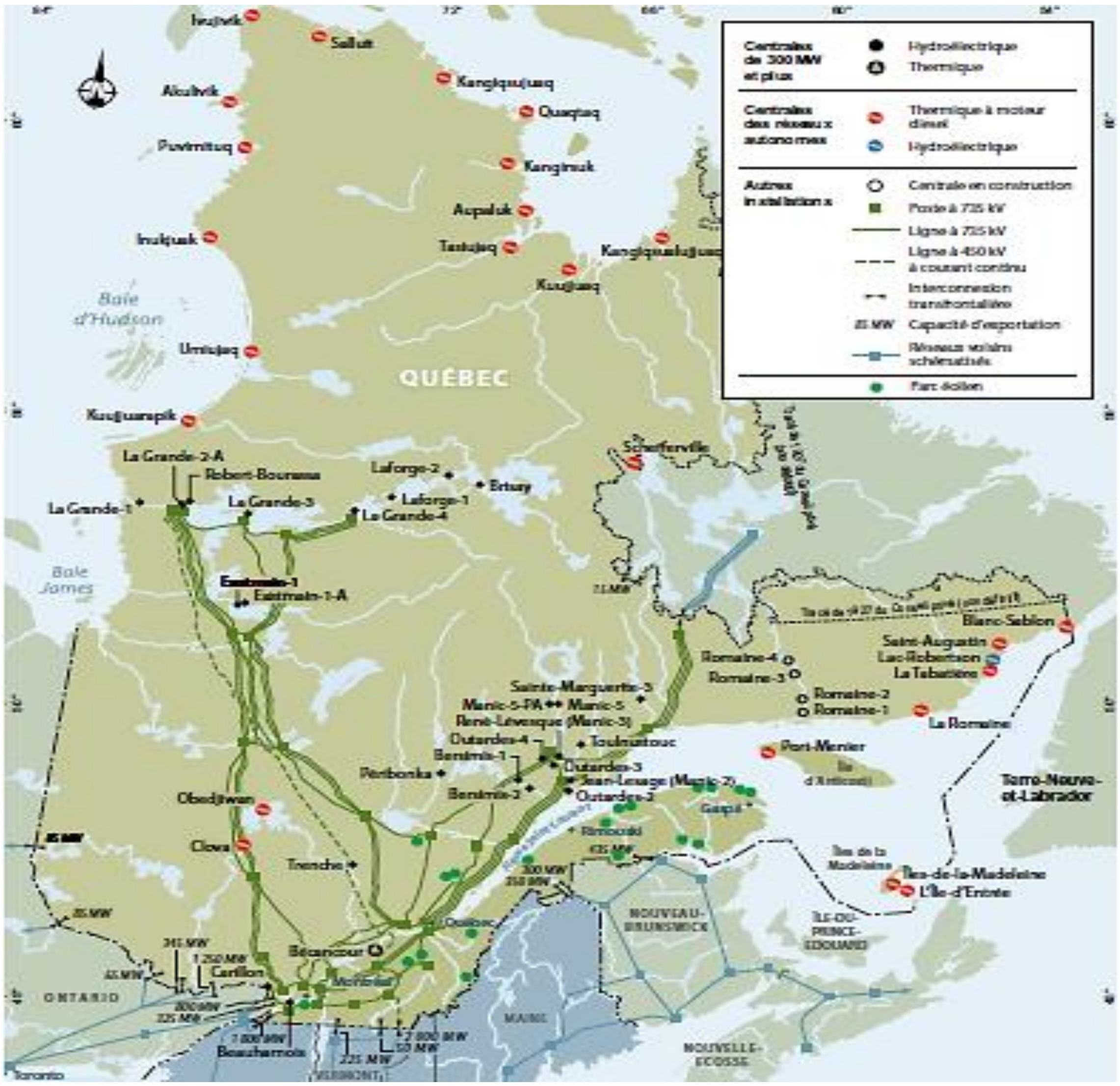
Figure 3.6 illustrates Québec's electricity system. In addition to illustrating hydroelectric and thermal generating stations rated at 300 MW or more, the figure shows generating stations under construction and planned generating stations. The figure also shows off-grid generating stations in Québec. The majority of off-grid stations are diesel (which could be converted to LNG facilities) and are located in small communities along the coastlines, isolated from the main power grid. All of the off-grid facilities are owned by Hydro-Québec Distribution, the branch of Hydro-Québec that is in charge of retail sales to most customers in Québec.

Currently, thermal generation plays a minor role in the province. Diesel-powered stations supply power to remote areas, the Madeleine Islands, Anticosti Island, and isolated communities in

[25] Hydro Québec website, Hydro-Québec's Electricity Facts: Electricity Supply and Air Emissions, http://www.hydroquebec.com/sustainable-development/pdf/energy-supplies-and-air-emissions-2014.pdf
[26] Hydro Québec website, Hydro-Québec at a Glance, , http://www.hydroquebec.com/about-hydro-quebec/who-are-we/hydro-quebec-glance.html
[27] Ibid.
[28] Ibid.

Nunavik, the Basse-Côte-Nord and in the Haute-Mauricie regions.[29] There are 24 diesel-powered stations in Québec, with a total installed capacity of 130 MW.[30] Beyond supplying power to remote areas, the only facility over 300 MW is the gas-fired Bélancour.[31] The Bélancour facility has four units and an installed capacity of 411 MW.[32]

Figure 3.6: Québec's Electricity System



Source: HEC Montreal[33]

[29] Hydro-Québec website, Fossil Fuels, http://www.hydroQuébec.com/learning/autres-sources/fossile.html
[30] Hydro-Québec website, Thermal Generating Stations, http://www.hydroQuébec.com/generation/centrale-thermique.html
[31] Hydro-Québec website, Fossil Fuels, http://www.hydroQuébec.com/learning/autres-sources/fossile.html
[32] Hydro-Québec website, Thermal Generating Stations, http://www.hydroQuébec.com/generation/centrale-thermique.html
[33] HEC Montréal, État de L'Energie au Québec, 2015, pp. 14.

There is little room for more oil and gas in Québec's generation mix because of hydropower's massive presence. For localized natural gas distribution, any Utica gas potentially fed into the Québec system will need to be competitive with North American gas prices.

Liquefied natural gas (LNG) can replace much of the diesel generation at some of the remote coastal communities, but required volumes will be minimal for this kind of thermal generation, not enough on its own to warrant development of the Utica basin. It could be argued that peak winter demand in Québec could be met by Utica gas supply, but because of the lack of natural gas storage in Québec, the peak price would need to support a year-round industry; this would be challenging because adequate supply and infrastructure exist elsewhere in North America.

External Natural Gas Demand

Natural gas markets, both global and North American, have seen momentous changes over the past 5 years. The Marcellus Shale in northeastern US, one of the most highly developed shale gas plays in North America, has grown from a 1 Bcfd play in 2008, reaching 14 Bcfd in 2014; if the trend continues, the Marcellus could surpass 30 Bcfd by 2025.[34] This increased supply in the east and elsewhere has put sustained downward pressure on North American natural gas prices.

LNG supply has also seen dynamic international growth, with dozens of liquefaction plants and scores of regasification plants being built worldwide. It is this LNG demand that could benefit North American gas producers, including Québec.

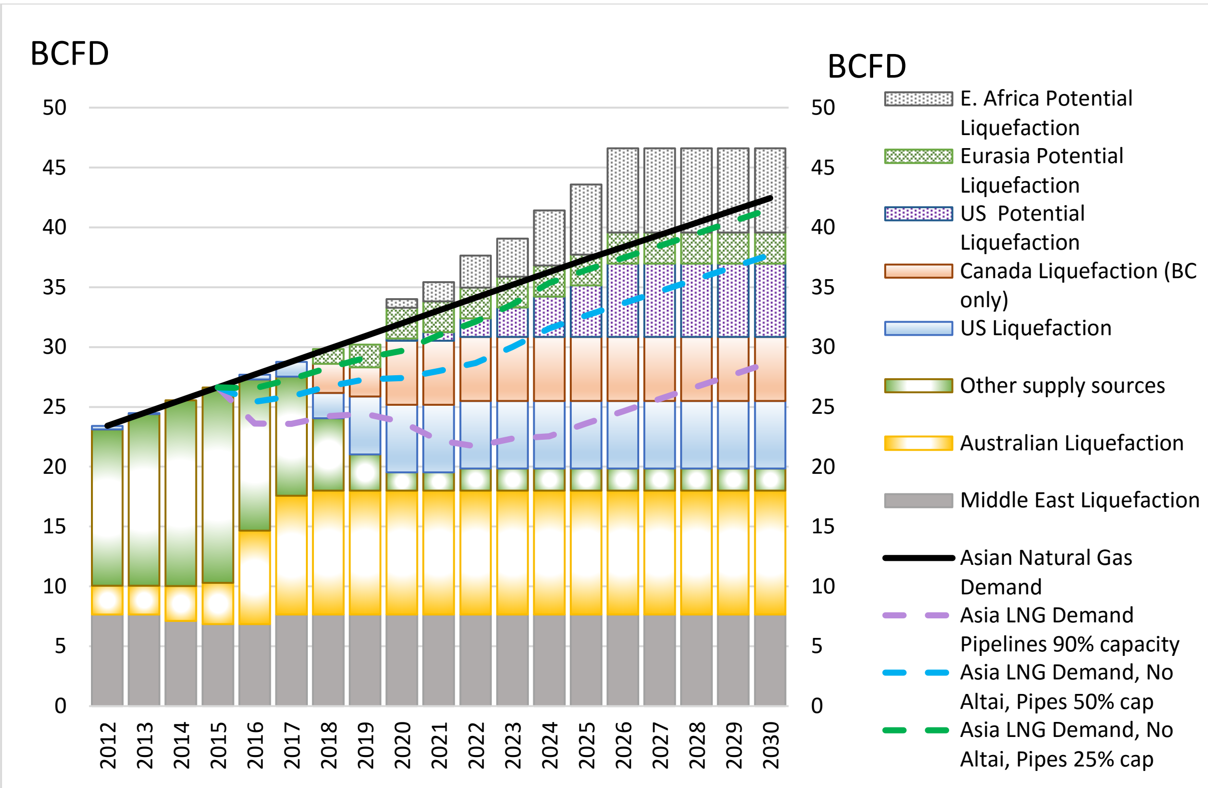
Much of the new international LNG supply has been sent to Asia, which is home to the five largest LNG importing countries in the world (Japan, South Korea, China, India, and Taiwan).[35] Furthermore, ongoing economic growth in China, new growth opportunities in India, and a shifting supply mix, both in Japan and Korea, created widespread optimism up until very lately that natural gas demand in the region was on a steep growth trajectory. As recently as 2014, there was much talk of arbitrage opportunities in Asia for LNG exporters, but this year, delivered LNG prices have plummeted even in Asia. This is owing mostly to an economic slowdown in China; new liquefaction coming online in Australia; and greater volumes of piped gas entering China from Central Asia, Burma, and soon, Russia.

Figure 3.7 considers expected Asian natural gas imports demand (straight line) superimposed upon expected liquefaction capacity buildup (vertical bars) over the coming years. The natural

[34] Howard, Peter. "Western Canada Natural Gas Forecasts and Impacts (2015-2035). Canadian Energy Research Institute. Study 149. July 2015. See www.ceri.ca.
[35] BP Statistical Review of World Energy. June 2015. Available at http://www.bp.com/en/global/corporate/about-bp/energy-economics/statistical-review-of-world-energy.html

gas imports demand line is based on data from the IEA's 2014 New Policies Scenario. LNG demand in 2015 is slow, but the IEA still expects it to grow over the next 15 years.[36]

Figure 3.7: Asia-Pacific LNG Supply and Demand: 3 Pipeline Scenarios 2012 to 2030



Sources: IEA, CERI, Various

Also superimposed on the figure are three dotted lines. Each line represents possible effects on LNG import demand if a certain percentage of expected piped natural gas arrives in China. The purple line shows effects on LNG demand if all pipelines to China, both operating and proposed, are brought online running at 90 percent capacity. The blue line indicates the effects on LNG demand if the central Russian Altai pipeline is cancelled but all other lines run at 75 percent capacity, and the green line specifies a situation where Altai is cancelled and all the other lines run at 25 percent capacity.

If proposed liquefaction infrastructure in the US, Eurasia (i.e., Russia), and East Africa is built, supply will exceed demand, no matter how many Asian pipeline projects are built, cancelled, or run at low capacity. There remains a window for Canadian LNG proposed facilities to gain access

[36] It should be noted that the New Policies Scenario is not the IEA's most pessimistic scenario in terms of hydrocarbon demand growth. The 450 Scenario, which presumes concerted global action on climate change beginning in 2020, still assumes natural gas demand growth in Asia and the rest of the world, but at a slower pace (WEO P. 607).

to these markets. However, if development significantly lags in other countries, the demand will be met by other exporters.

Is there room for Québec shale gas in the North American market? The road ahead could fork in several directions. There is today over 8 Bcfd of new LNG liquefaction capacity under construction in the Gulf of Mexico and US Atlantic Seaboard; there is another 28.5 Bcfd that is being proposed.[37] From a Canadian point of view, the liquefaction demand may attract Marcellus gas away from New England and Eastern Canada, permitting Canadian supply, potentially including Utica gas from Québec, to find a place in the continental market.

Another possibility, less likely because so far there have been no Final Investment Decisions (FID's), is that some major Canadian LNG liquefaction projects could be built in Nova Scotia, New Brunswick, and Québec. These, too, would attract some of the Marcellus supply, Western Canadian supply, and possibly some Québec Utica gas. Much of the LNG would be directed towards Europe and India, though it could also be moved to East Asia via the expanded Panama Canal. Export volumes could be as low as 5 MTPA (0.67 Bcfd) if the Canaport facility in New Brunswick is retooled for liquefaction and no other projects go ahead.[38] However, in the best case scenario, as much as 47.5 MTPA (7.4 Bcfd) would be required to run all of the projects at capacity. In this case, Marcellus and Western Canadian gas would be drawn, as could Utica gas, from Québec.

A more likely situation is that one or two of the Eastern Canadian liquefaction plants would be constructed. Two interesting projects are Canaport – because of its small size and low cost structure – and Goldboro, which has secured a European buyer (the German utility E.ON.) to take half of its projected 10 MTPA LNG output. Bearhead is also a project with potential, having much of its civil engineering requirements in place.

If these projects proceeded, natural gas supply of greater than 1.5 Bcfd would be needed from various sources. Sales gas from Québec Utica could be sustained at a rate of 1 Bcfd until 2040, on its own being able to account for a large share of the required gas for these projects. If natural gas is produced in other areas of the province such as Gaspé, admittedly outside the scope of this study, it is feasible that Québec gas could on its own supply these LNG projects.

The Western Canadian LNG industry is looking likely to develop now that a conditional Final Investment Decision (FID) has been taken on one of the projects; Petronas' 19.2 MTPA (2.6 Bcfd) Pacific Northwest LNG. This development may proceed slowly, but if one more large liquefaction project in British Columbia gets the go-ahead, Canada becomes a significant LNG player in the world. The gas supply for the Petronas and other possible projects will be sourced from northeastern British Columbia and Alberta. There is also the possibility of Alberta and BC gas

[37] Rozhon, Jon and Allan Fogwill. "LNG Liquefaction for the Asia-Pacific Market: Canada's Place in a Global Game", CERI Study 148, www.ceri.ca

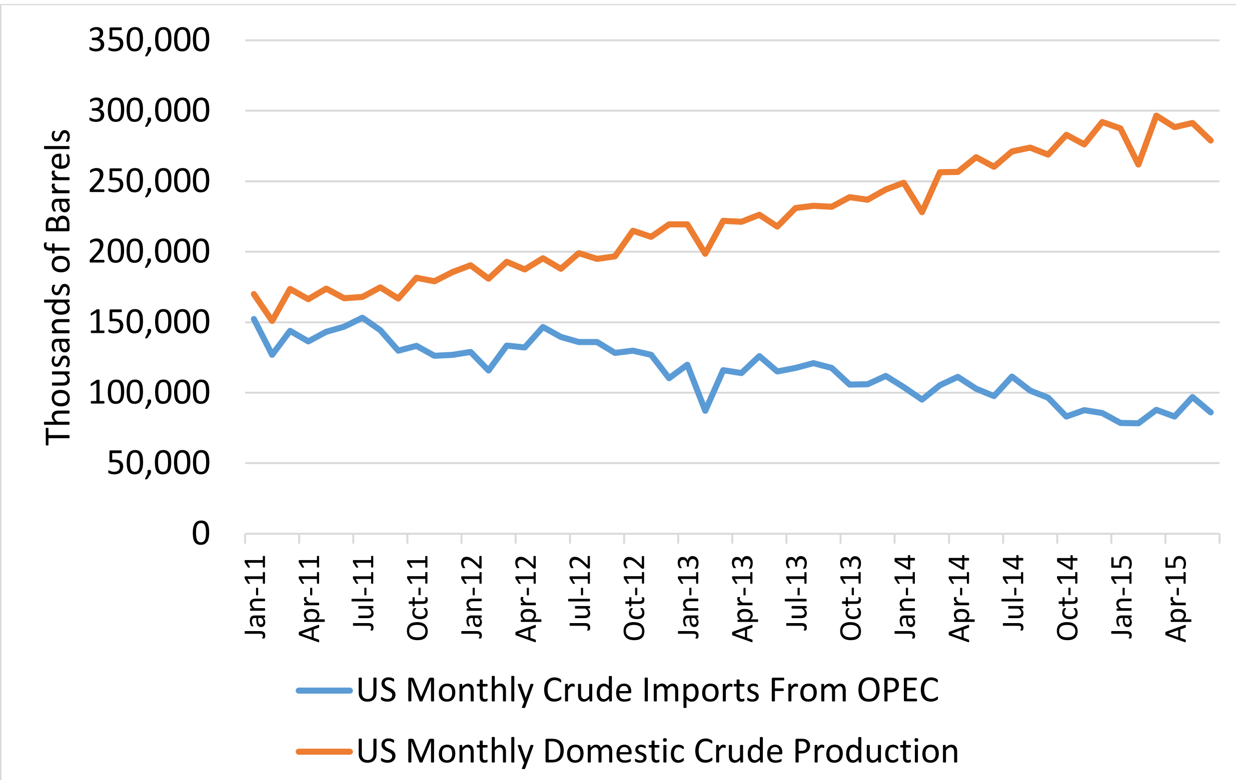
[38] The Stolt LNGaz could potentially export natural gas to Europe, but its main function will be to liquefy gas to be shipped by boat to industrial sites along Québec's coastline and to other parts of Atlantic Canada.

moving to Oregon to supply two proposed LNG projects there, altering flows, destinations, and volumes elsewhere on the continent, potentially including Québec.

Oil Demand

The price of oil has declined, especially since the middle of 2014. Technological advances have certainly played a part in this, and in this area the US has led the way. Since 2011, the US has been using advanced fracking methods and horizontal drilling to increase production of light, sweet crude in areas such as the Eagle Ford Shale and Permian Basin in Texas and the Bakken Shale in North Dakota. This has pushed out much of the light, sweet crude that the US once imported from OPEC nations, as Figure 3.8 shows.

Figure 3.8: US Monthly Crude Production and Monthly Crude Imports from OPEC

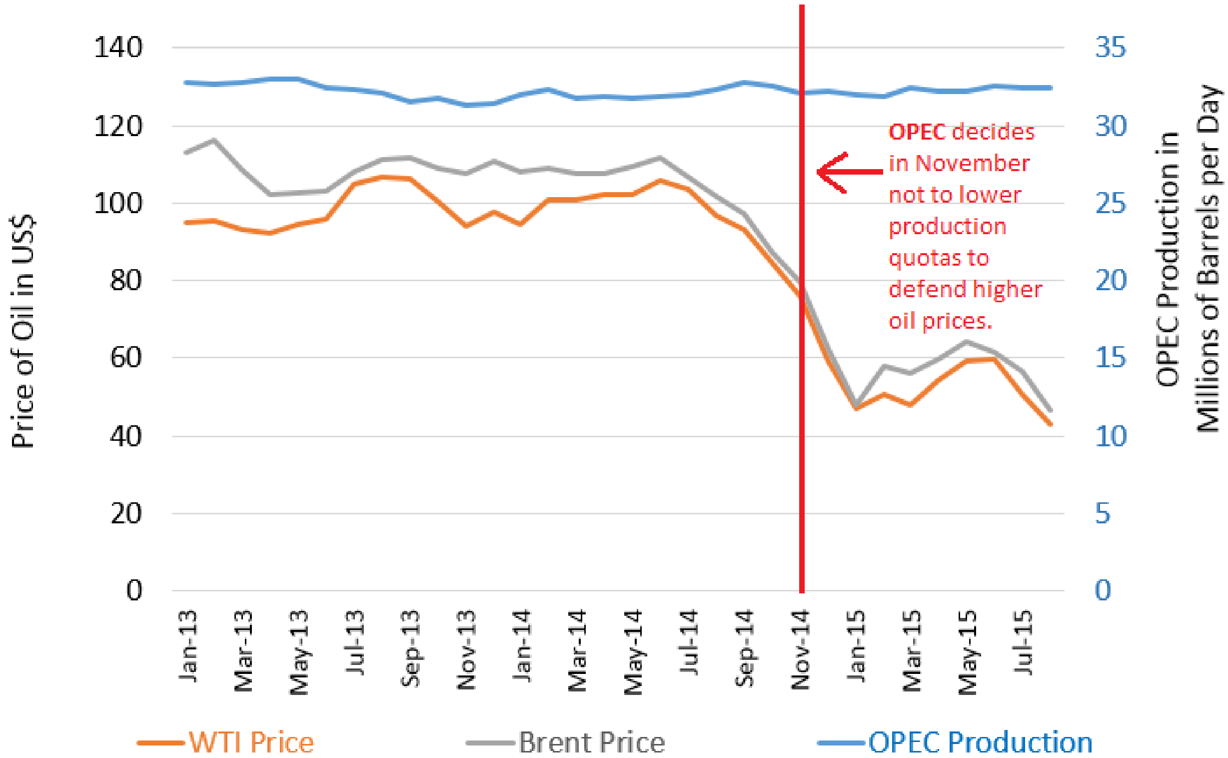


Source: EIA

OPEC has for several years tried to mitigate volatility in its production levels, so OPEC nations have had to find alternative destinations for the crude that was previously sent to the US. Prices were as stable as production levels, remaining mostly in the $100 to $110 range for more than three years, but with reduced call for imported oil from China and Europe, oil supply began outpacing demand. Downward pressure has been strong ever since Brent reached $115 in late

June 2014,[39] and as Figure 3.9 shows, prices have fallen since then, staying mostly within the $40 to $60 range since the beginning of January 2015.

Figure 3.9: OPEC Production Levels and Oil Prices: 2013 to 2015



Sources: IEA, CERI.

A new development has further intensified the downward price trend: Saudi Arabia has given up, at least for the time being, its historical role as global oil's swing producer. In the November 2014 OPEC meetings, the decision was taken to maintain production levels of all member states, including Saudi Arabia. Instead of adjusting supply downward to sustain a higher oil price, Saudi Arabia stated that it was content to see prices fall and place the onus on US shale oil producers to cut their own production. So far, this has been a painful process for all producers involved, with US companies having to find new efficiencies, or take losses; OPEC has forfeited as much as $200 billion in revenues, according to JP Morgan, with Saudi Arabia on its own losing $90 billion in the time since the decision was taken.[40]

Québec's Macasty shale oil, found in and around Anticosti Island, is similar in many respects to US shale oil. It is light and sweet, and the production costs will be comparatively higher to conventional plays, just as they are in the US shale plays. Québec oil, with a port built on Anticosti, will have access to world markets much like Newfoundland oil and unlike US crude that has been bound by no-export legislation. However, finding a market will not be a simple matter,

[39] EIA. "Europe Brent Spot Price FOB" http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D
[40] Business Insider. http://newscentral.exsees.com/item/2d200692de14313f998108b6a4ae7118-fecd512d519c3947dd93ffb74fb68a09

with the US relying more and more on its own crude and erstwhile US suppliers likely competing with Québec for other buyers. The world crude market is highly competitive at present with low-cost producers holding a distinct advantage over higher-cost producers.

Carbon Emissions Constraint Policies and Their Effect on Demand

Climate change is a major concern of countries and citizens around the world. Active discussions are underway to establish carbon emissions constraint policies provincially, nationally and internationally. These constraint policies will impact the market demand for natural gas and oil.

From a market perspective, carbon constraint policies will limit demand. This will be either in the form of higher energy prices to address the consumption emissions or from regulatory limitations. Carbon prices will be directly reflected in the retail price. Assigned consumption caps might also be considered. Either way a reduction in demand, without a commensurate supply response will result in lower market prices. Lower prices would make it more difficult for a fledgling Québec oil and gas industry to compete.

Forecasting the specific impacts of a climate change treaty is problematic and unnecessary. Regardless of the elements of a carbon emissions reduction policy it would likely mean the market will respond with a combination of a price reduction and a reduction in supply. Québec's jurisdiction, already at the high end of the cost structure compared to other jurisdictions is unlikely to overcome those market forces and grow an oil and gas production industry.

Chapter 4
Economic Impacts of Oil and Gas Development in Québec

Methodology

This analysis considers the economic impacts of an oil and gas industry if it were to proceed under current carbon emissions policies and alternative scenarios.

The economic analysis is conducted using a proprietary input/output model to assess the impacts to Québec and the rest of the Canadian economy. This necessitates consideration of the production profile of the plays and how different policies might affect production.

The three scenarios used in the analysis assume that production activities are affected in the same way as consumption. This means that if a policy calls for a 10 percent reduction in carbon emissions, it would assume a 10 percent reduction in production. The reasons for this are:

- Emissions associated with production activities are assumed to be included in an emissions constraint policy, and
- Market forces would dedicate an all or nothing response (i.e., the play is economic at a given price or not) which would not provide other scenarios to assess

Fugitive emissions and energy consumed to extract the oil or gas are part of the consumption sector. It is likely that these emissions would be treated no differently than those of other consumption activities. One aspect of this assumption is that the producers do not change their energy efficiency levels or production processes.

Climate change policies would be reflected in oil and gas markets through price. As such, a Québec hydrocarbon industry is either competitive or not based on the new price. If they were not competitive, economic impacts would be zero reflecting zero production. This result would not provide information regarding the changing economic impact based on production levels.

Instead, CERI constructed the scenarios such that carbon emissions management policies would affect energy producers similar to energy consumers. Within the I/O model there is an asymmetrical relationship between changing oil and gas production and changing economic impacts. This relationship is useful for decision-makers to understand. Therefore, the three scenarios were constructed to provide decision-makers with an understanding of these changes.

Scenario Analysis

Scenario analysis is used to provide information regarding the change in results based on changing assumptions. The three scenarios explored in this analysis are:

- A Reference Case scenario – this is based on CERI's understanding of a typical production profile and cost structure. It assumes the production is competitive with the rest of the market and there are no carbon emissions constraints.
- A Québec Emissions Plan scenario – this option is based on adjusting the production forecast based on reducing the oil and gas production emissions to the same degree as consumption activities. This scenario assumes the benchmark for the production emissions is the reference case. Québec's current policy uses a 1990 benchmark. In 1990, there were no oil and gas production-based emissions.
- A World Energy Outlook 450 Scenario (WEO 450 Scenario) – in this scenario, the production forecast is also reduced. In this case, the reduction is greater than under the Québec Emissions Plan scenario. The benchmark in this case is to maintain carbon dioxide concentration in the atmosphere at or below 450 parts per million. Again, it is assumed the production-based emissions are constrained similar to other consumption activities.

Assumptions for the Input/Output (I/O) Model[1]

The Reference Case Scenario modeled in this study assumes that two of Québec's oil and gas basins are exploited for their resources: the Utica Shale (gas) and the Macasty Shale (oil).[2] Though other basins hold potential, and could be developed at a later date, these two basins are estimated to be the most feasible in the emergent days of the Québec oil and gas industry. It is assumed that oil production levels of 60,000 barrels per day (bpd) could be sustained beyond 2040 in Macasty and natural gas production levels of 1,300 million cubic feet per day (MMcfd) could be maintained for the same period of time in the Utica.

The Québec Emissions Plan Scenario reduces Reference Case production levels for both basins to meet a 37.5 percent reduction in Reference Case emissions by 2030. The 450 Scenario reduces Reference Case production levels for both basins to meet a 17 percent reduction in Reference Case emissions by 2020 and then further reductions to 2040, reflecting cross-cutting policy assumptions for the United States as stated in the WEO 2014.[3]

This report estimates a recovery factor of 15 percent and a production life of 30 years. From there, annual and daily production are calculated. Yearly operating and capital costs are then estimated, using Québec data where available as well as proxy data from similar basins elsewhere in North America where the Québec data is unavailable.

Because the lion's share of capital and operational spending occurs within the Province of Québec, it stands to reason that the majority of the economic benefits would be realized there, too. In fact, that is what the results indicate, for each of the three scenarios. However, they also show that provinces such as Ontario, with its large population and industrial base, stand to gain

[1] Appendix C details an alternative production forecast for oil and natural gas produced by the Government of Québec as part of the SEA. This production change will affect production cost estimates and the economic impacts of oil and gas development.
[2] Some studies in the SEA indicate that Anticosti Island is likely an important project for natural gas liquids production.
[3] World Energy Outlook, 2014. International Energy Agency, Paris. P. 621, 688.

from Québec oil and gas activities. Other provinces with mature oil and gas industries such as Alberta and British Columbia, also profit with significant GDP growth, person years of employment gain, and increases in tax revenue.

These data are then injected into CERI's UCM Regional I/O 3.0 model to estimate GDP, employment, salary, and tax impacts in Québec and the rest of Canada over the period 2015 to 2040. For both capital and operating expenditures, it is assumed that the majority of spending first occurs outside of Québec (mostly in Alberta) but as the oil and gas industry develops and matures in Québec, spending shifts to that province.

For each of the three scenarios under consideration in the report, the model is run twice: once to gauge economic impacts of Utica Shale gas development and another time to estimate economic impacts of Macasty Shale oil development. Running the scenarios for oil separately from gas produces higher economic impact results when added together than if they were run together. This was done to show the unique impacts of each hydrocarbon development.

For the I/O modelling exercise, the following assumptions are made:

- The Upper Ordovician Shales in the Macasty basin (Anticosti) are considered. Though the estimated median volume of oil ranges as high as 102.4 billion barrels (Junex 2011), this study considers the more conservative figure of 43.6 billion barrels estimated by Petrolia in 2011.
- The Upper Ordovician Shales in the St. Lawrence Lowlands (Utica) are studied, with an estimated median volume of 176.7 Tcf, as described by Sejourne and Malo (2015). It is also assumed that the St. Lawrence Lowlands are opened up to oil and gas exploration and production; the area is presently under a drilling moratorium imposed by the Government of Québec.
- Recovery of both the oil and gas resource is done by means of hydraulic fracturing and horizontal drilling.
- The Macasty basin well cost and drilling specifications are based on Well SK3C Viewfield, a 12-stage horizontal, fractured well in the Saskatchewan Bakken.[4] Because of the isolated location of – and lack of infrastructure on – Anticosti Island, a 100 percent premium is added for remote area construction. Wells are drilled to a depth of 1750 m and extended horizontally to a total measured depth of 3225 m. There is a 100 percent drilling success rate assumed.
- Each Macasty well has an IP rate of 95 bpd, based on a Bakken proxy, and declines according to a harmonic curve. It should be noted that the Macasty Basin is being evaluated by the Government of Québec and exploration companies for its NGL potential. This report focuses on its oil potential. Readers interested in the NGL potential are encouraged to consult study AECNO1 under the Government of Québec's Strategic

[4] PSAC 2013 Well Cost Study. "Upcoming Summer Costs". PP 280-5. April 2013.

Environmental Assessment, and the websites of Corridor Resources, Petrolia Inc., and Junex Inc. for more information.

- The Utica basin well cost and drilling specifications are based on Well BC2F Parkland, a 12-stage horizontal, fractured well in the BC Montney shale.[5] Because the Utica wells are located within the Montreal to Québec corridor, no premium is added for remote area construction. Wells are drilled to a depth of 1850 m and extended horizontally to a total measured depth of 3500 m. There is a 100 percent drilling success rate assumed.
- Each Utica well has an IP rate of 7.5 MMcfd, based on EIA Utica estimates, and declines according to a harmonic curve.
- Gas processing and transportation are not considered in this study; oil refining and transportation are not considered in this study.
- Production simulations are run for both the oil and gas shales with the results entered into the CERI I/O model. The model then determines possible economic impacts of developing Utica gas and Macasty oil.
- These production forecasts differ from those of the Québec government.

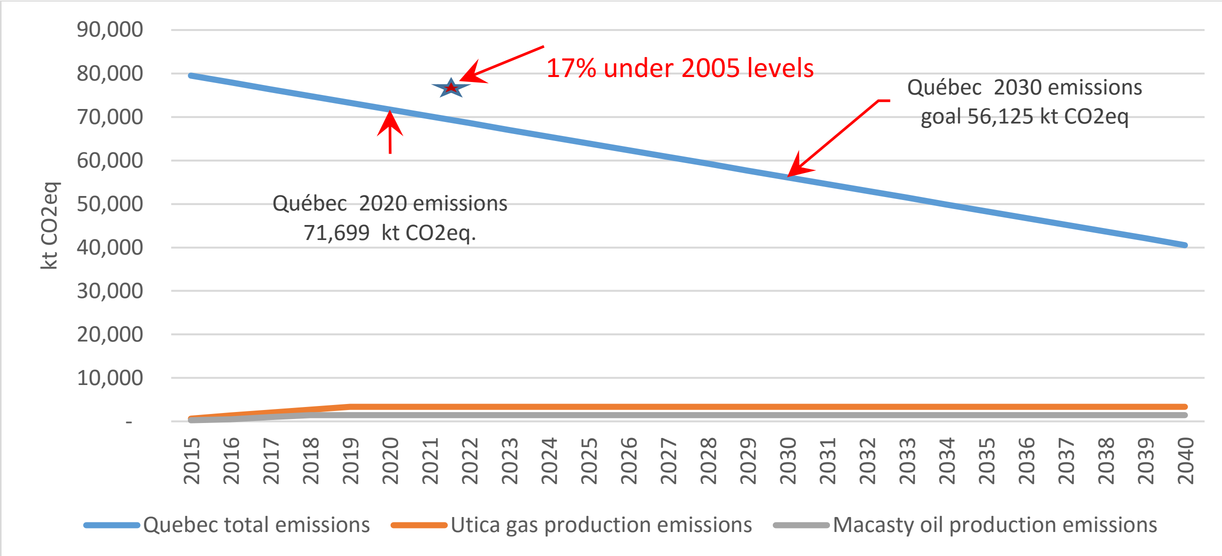
In mid-September 2015, the Government of Québec announced new greenhouse gas emissions targets for the province. By 2030, the Province plans to reduce greenhouse gas emissions to 37.5 percent below 1990 levels. According to the Canadian National Greenhouse Gas Inventory Report,[6] Québec's total greenhouse gas emissions in 1990 was 89,800 kt CO_2eq. Thus, the goal to be reached by 2030 is 56,125 kt CO_2eq. Consulting Nduagu and Gates,[7] upstream emissions for shale gas was estimated between 7.7 and 9.7 kg CO_2eq/GJ, and a median value of 8.75 was chosen for this report. Values for shale oil are considered higher than for those of shale gas, more in line with conventional crude oil production, so a value of 11 kg CO_2eq/GJ was selected. These emissions values were multiplied by expected oil and gas volumes from the two basins, as delineated in the Reference Case Scenario of this report. The results are summarized in Figure 4.1.

[5] PSAC 2013 Well Cost Study. PP 46-51.

[6] Environment Canada. National Inventory Report: 1990-2013. The Canadian Government's Submission to the UN Framework Convention on Climate Change. Part 3. Page 52.

[7] Nduagu, Experience I. and Ian D. Gates. "Unconventional Heavy Oil Growth and Global Greenhouse Gas Emissions." Environmental Science & Technology. 49 (15). P. 2888. June 2015.

Figure 4.1: Québec 2015 Emissions Goals and Potential Emissions from Macasty Oil and Utica Shale Production, Reference Case Scenario.



Sources: CERI, NRCan

Because this report's Reference Case Scenario assumes the level of oil and gas production in both Macasty and Utica stabilizes in 2018 and does not change before 2040, oil and gas emissions from these basins as a percentage of the Québec total grows slowly. In 2015 they represent 1.2 percent of the total emissions, by 2030 they grow to 8.6 percent of the total, and by the end of the study period in 2040, Macasty and Utica production emissions represent an 11.9 percent of the total.

Figure 4.1 shows where Québec emissions should be in 2020 if the Government of Québec's new emissions policy progresses in a straight line towards the 2030 goal. This total of 71,699 kt CO_2eq, if attained, is below the recommendation of the IEA's 450 Scenario to reduce GHG emissions to 17 percent of 2005 levels by 2020. However, from that point onward, the 450 Scenario assumes deeper emissions cuts than the Québec Emissions Plan.

The emissions rates discussed here are representative of upstream emissions only, as the upstream industry is the focus of this report. Total life cycle emissions, which include processing and combustion, can be as much as ten times greater than those of upstream alone.[8]

The 450 scenario theorizes a world where energy efficiency measures are aggressively pursued. As the report's methodology states,[9] until 2020 emissions reductions will be sought through:

- Targeted specific energy efficiency improvements in the industry, buildings and transport sectors

[8] Nduagu and Gates. P. 2888.
[9] http://www.worldenergyoutlook.org/media/weowebsite/energymodel/documentation/Methodologyfor450Scenario.pdf

- Limiting the use and construction of inefficient coal-fired power plants
- Minimizing methane emissions in upstream oil and gas production
- Partial phase out of fossil-fuels subsidies to end users.

From that point onward, CO_2 pricing is adapted wholesale in the Organization for Economic Cooperation and Development (OECD) and elsewhere, fossil fuel subsidies are removed throughout the world (except in the Middle East, where limited subsidies will remain), and there will be a strengthening of energy performance standards. Clearly, this is a scenario where it is expected oil and natural gas will lose value compared to cleaner energy sources.

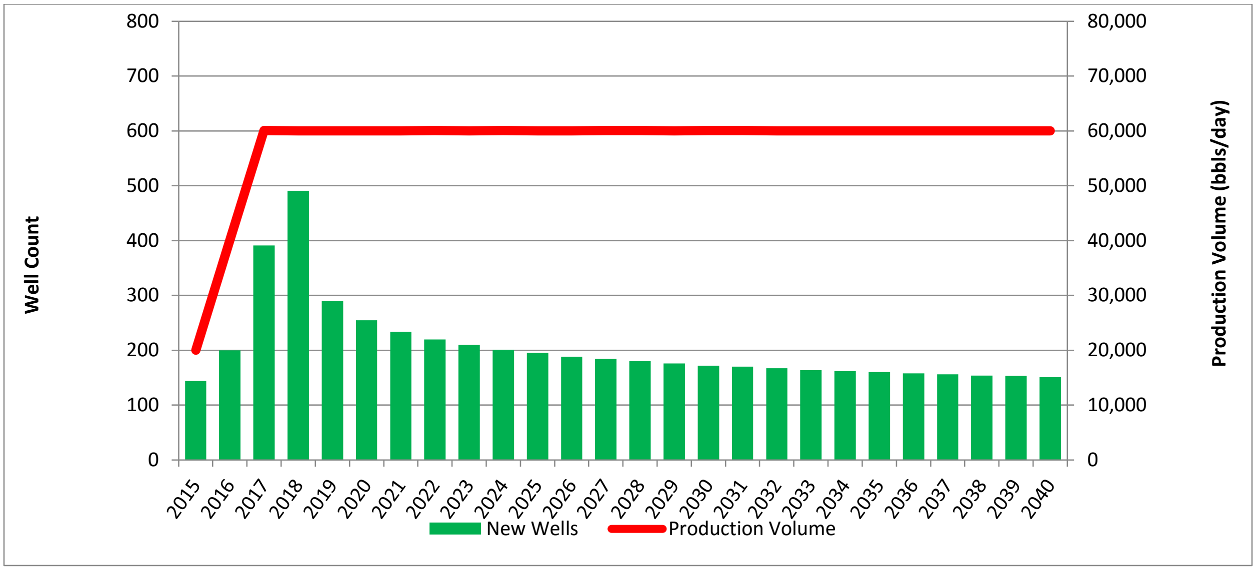
The argument could be made that as the value of oil drops, the value of natural gas could rise, at least over the short- to mid-term, because of natural gas' lower life-cycle emissions. However, over the longer term, a 450 scenario world is a world that will depend less and less on carbon-based fuels. Even if a Québec oil and gas industry were to develop and fit comfortably within the Province's future emissions cap, there may be fewer markets willing to accept those hydrocarbons and this change would be reflected in the market price.

Oil Production Assumptions and Economic Impacts

Assuming that 15 percent of the 43.6 billion barrels in the Macasty is recoverable, that there is an IP rate of 95 bpd, and that the wells in the basin decline according to a harmonic curve, the Macasty could produce oil at a rate of 60,000 bpd from 2015 to 2040. The above calculations are based on limited information available about Macasty, and they assume an unchanging basin. In reality, when new basins are opened up, it spurs further development. More activity could be expected to take place to investigate the Island and its offshore potential. As this activity continues, it may be reasonably expected that the basin's lifespan could increase significantly.

The Reference Case presents Macasty producing at its full capacity of 60,000 bpd by the fourth year of operations. Figure 4.2 indicates the number of new wells to be drilled each year to sustain the flow to 2040 and beyond. Well construction would peak at 491 wells and decline once the 60,000 bpd threshold is reached. Each well is assumed to be a horizontal well requiring a 12-stage fracture. Also assumed is a processing loss factor of 3 percent. These assumptions are based on wells drilled in similar structures in Saskatchewan.

Figure 4.2: Macasty Shale Oil Production Volumes and Well Count Reference Case Scenario

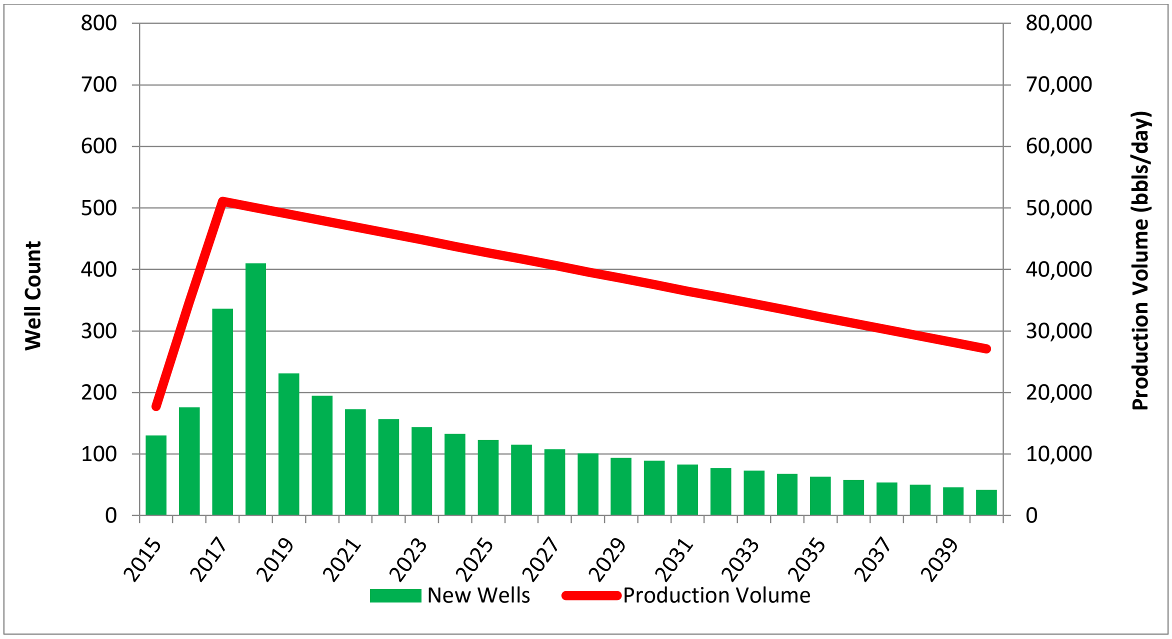


Source: CERI

The Québec Government announced new emissions standards in September 2015 that would commit the Province to reduce its total emissions to 37.5 percent of 1990 levels by 2030. For this report, we have estimated reduction in oil production in Macasty if the oil and gas industry were to reduce its own emissions by the same percentages over the same time period. Also assumed is the same rate of emissions decline will be maintained until the end of the study period in 2040.

To comply with the new emissions reduction plan proposed by the Government of Québec, referred to here as the “Québec Emissions Plan Scenario”, we have forecast Macasty producing at lower capacities to reduce production emissions, peaking at 51,000 bpd in 2018 and declining from that point onward. Figure 4.3 indicates the number of new wells to be drilled each year to 2040. Well construction would peak at 424 wells and decline once the production level is reached in the fourth year of operation. By 2030, 89 new wells would be built, 83 fewer than would be expected under the Reference Case Scenario.

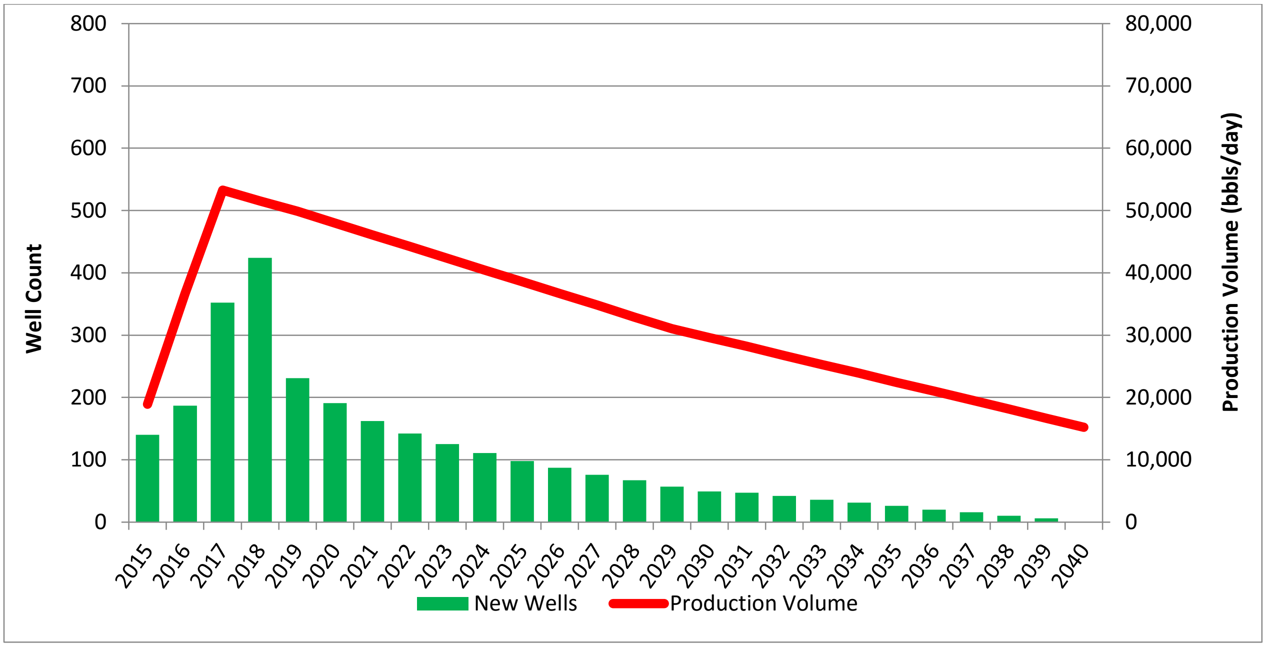
Figure 4.3: Macasty Shale Oil Production Volumes and Well Count
Québec Emissions Plan Scenario



Source: CERI

The third scenario, the WEO 450 Scenario, forecasts production and wells based on the 2014 version of the IEA's rigorous 450 Scenario. This scenario features a high degree of emissions constraints and is reflected in Figure 4.4. Like the Québec Emissions Plan Scenario, well construction would peak at 424 wells but the decline would be slightly greater, with no new wells built at all in the final year of the study. Peak production would be 53,200 bpd in the fourth year of operation. Volumes are restrained throughout the 25-year period of the study, under both the Québec Emissions Plan Scenario and WEO 450 Scenario, which should permit the Macasty Shale to continue producing modestly for many years beyond 2040.

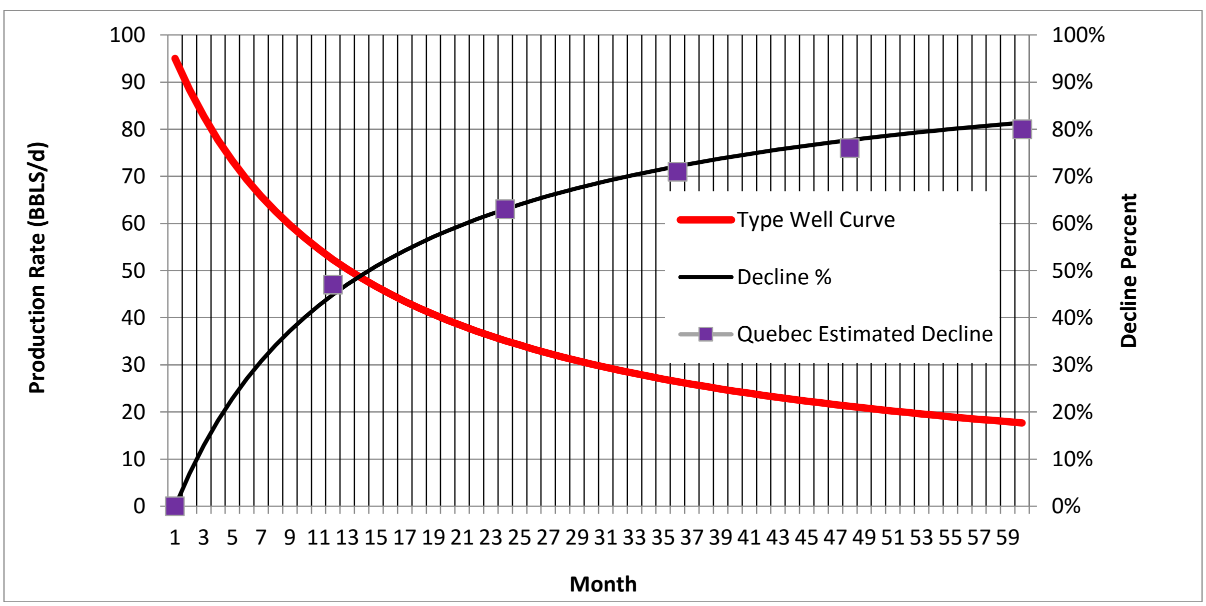
**Figure 4.4: Macasty Shale Oil Production Volumes and Well Count
WEO 450 Scenario**



Source: CERI

All three of the above drilling profiles presume that each of the wells has an initial production (IP) rate of 95 bpd, and declines according to the harmonic curve shown in Figure 4.4. An IP rate of 95 bpd is a five-year historical average calculated in the second month of production for all horizontal shale oil wells drilled in the Saskatchewan Bakken.

Figure 4.5: Production Decline Curves, Macasty Shale



Source: CERI

Having run the I/O model with the above assumptions, Table 4.1 illustrates the economic impacts on the various provinces of a shale oil industry developing on Anticosti Island. Over the 25-year study period, Québec is estimated to gain in excess of $150 billion in GDP impact, or 68 percent of the total. Alberta, at the centre of Canada's oil industry, is projected to gain $57 billion over the same time period. Impacts of more than $8 billion will be felt in Ontario, and British Columbia and Saskatchewan will both realize GDP gains of over $2 billion. Economic benefits are forecast to increase over the period as production increases and the domestic service sector evolves.

The greatest share of employee compensation and person years of employment (direct, indirect, and induced) will also be seen in Québec, 49 percent and 50 percent respectively. Alberta follows with 37 percent and 34 percent, and Ontario takes approximately 7.5 percent in both categories.

Table 4.1: Economic Impacts of Development of Macasty Shale Oil Reference Case Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	57,373	25,758	261
British Columbia	2,861	1,846	26
Manitoba	1,123	702	12
NewBrunswick	153	87	2
Newfoundland/Labrador	87	41	1
Nova Scotia	168	109	2
Nunavut	9	7	0
Northwest Territories	29	18	0
Ontario	8,196	5,094	59
Prince Edward Island	16	10	0
Quebec	150,028	33,512	385
Saskatchewan	2,449	1,419	23
Yukon Territory	12	8	0
Total Canada	222,503	68,611	770

Source: CERI

In terms of tax impacts over the study period, Québec leads all provinces with impacts in excess of $23 billion in all tax categories. This is 64 percent of the total. Alberta is the only other province that will see more than $10 billion in tax revenue, with Ontario realizing the third highest tax impact at just over $1.6 billion (Table 4.2).

Table 4.2 Tax Impacts of Development of Macasty Shale Oil Reference Case Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	3067	1447	6026	10540
British Columbia	77	202	276	555
Manitoba	24	60	54	137
NewBrunswick	3	7	14	24
Newfoundland/Labrador	4	3	7	14
Nova Scotia	5	8	20	32
Nunavut	0	0	1	1
Northwest Territories	1	1	2	4
Ontario	228	447	929	1604
Prince Edward Island	1	1	2	4
Quebec	5617	6522	11842	23981
Saskatchewan	76	146	310	532
Yukon Territory	0	0	1	2
Total Canada	9103	8844	19484	37431

Source: CERI

The reduction in GDP as a result of implementation of the Québec Emissions Plan would be significant, with Québec taking in $59 billion over the study period, as compared to $150 billion under the Reference Case Scenario. Other provinces would be similarly affected, with Alberta GDP down to $24 billion from $57 billion, and Ontario GDP dropping from $8 billion to approximately $3.3 billion (Table 4.3). As expected, employment and employee compensation also fall dramatically.

Table 4.3: Economic Impacts of Development of Macasty Shale Oil Québec Emissions Plan Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	24,807	10,925	113
British Columbia	1,193	743	11
Manitoba	456	271	5
NewBrunswick	64	35	1
Newfoundland/Labrador	36	16	0
Nova Scotia	69	43	1
Nunavut	4	3	0
Northwest Territories	12	7	0
Ontario	3,366	2,012	24
Prince Edward Island	7	4	0
Quebec	59,528	12,524	153
Saskatchewan	1,010	563	9
Yukon Territory	5	3	0
Total Canada	90,554	27,148	317

Source: CERI.

Québec could realize just under $10 billion in taxes, down by $13 billion from the Reference Case Scenario but still 60 percent of the total. Alberta and Ontario follow with $4.5 billion and $659 million in tax revenue over the 25-year period (Table 4.4).

Table 4.4: Tax Impacts of Development of Macasty Shale Oil Québec Emissions Plan Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	1326	623	2606	4555
British Columbia	32	90	115	237
Manitoba	10	24	28	62
NewBrunswick	1	3	6	10
Newfoundland/Labrador	2	1	3	6
Nova Scotia	2	3	8	13
Nunavut	0	0	0	1
Northwest Territories	0	1	1	2
Ontario	94	184	382	659
Prince Edward Island	0	0	1	1
Quebec	2229	2580	4699	9507
Saskatchewan	31	60	128	219
Yukon Territory	0	0	0	1
Total Canada	3727	3570	7976	15273

Source: CERI.

Over the 25-year study period, the 450 Scenario sees the tightest constraints on emissions and therefore the largest fall in GDP, Employee Compensation, and Employment.

Considering the Macasty Shale, over the study period, Québec GDP would total $41 billion, as opposed to $59 billion under the Québec Emissions Plan Scenario. Alberta GDP totals are 19.7 billion in the WEO 450 scenario, a drop of $5.1 billion. Ontario would lose approximately $870 million, falling from $3.36 billion to $2.49 billion (Table 4.5). Employee compensation and employment levels would drop similarly.

Table 4.5: Economic Impacts of Development of Macasty Shale Oil WEO 450 Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	19,770	8,685	89
British Columbia	901	561	8
Manitoba	329	196	3
NewBrunswick	48	26	0
Newfoundland/Labrador	27	12	0
Nova Scotia	51	32	1
Nunavut	3	2	0
Northwest Territories	9	5	0
Ontario	2,495	1,492	18
Prince Edward Island	5	3	0
Quebec	41,441	8,735	107
Saskatchewan	751	419	7
Yukon Territory	4	2	0
Total Canada	65,833	20,170	234

Source: CERI.

Macasty Shale tax totals under the WEO 450 Scenario are shown in Table 4.6.

Table 4.6: Tax Impacts of Development of Macasty Shale Oil
WEO 450 Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	1057	496	2077	3629
British Columbia	24	66	87	177
Manitoba	7	18	18	43
NewBrunswick	1	2	4	8
Newfoundland/Labrador	1	1	2	4
Nova Scotia	1	2	6	10
Nunavut	0	0	0	0
Northwest Territories	0	0	1	1
Ontario	69	136	283	489
Prince Edward Island	0	0	1	1
Quebec	1552	1799	3271	6621
Saskatchewan	23	45	95	163
Yukon Territory	0	0	0	0
Total Canada	2737	2566	5845	11147

Source: CERI.

Over the 25-year period, the reference case shows the highest economic impact of $150 billion in GDP for Québec. This is followed by $50 billion in the Québec Emissions Plan Scenario and $41 billion in the WEO 450 Scenario.

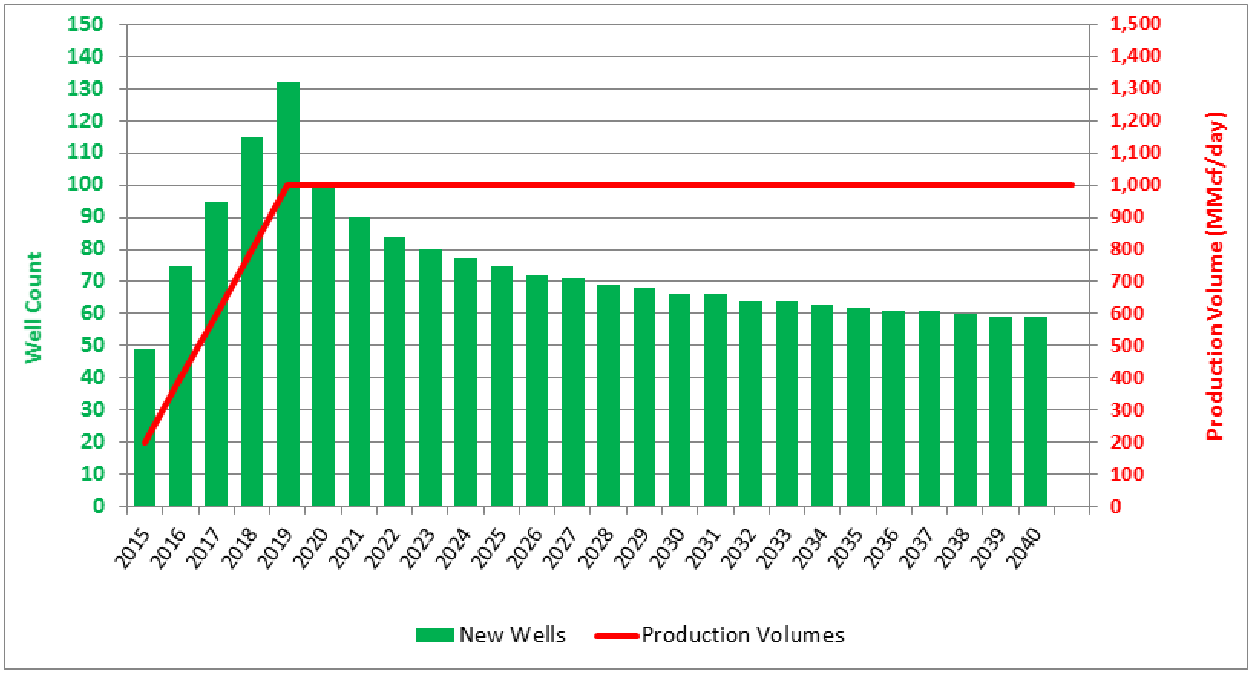
Natural Gas Production Assumptions and Economic Impacts

According to the Energy Information Agency (EIA), general IP rates in the Utica Shale have averaged approximately 7.5 MMcfd[10] in 2015, so that rate is used in this report (this differs from the Québec government). Also assumed is that 15 percent of the 176.7 Tcf in the Utica is recoverable, and that the wells in the basin decline according to a harmonic curve. The basin could, taking these assumptions into account, sustain natural gas production at a rate of 1,000 MMcf from 2015 to 2040. Like the calculations for the Macasty shale, the above estimates for the Utica assume an unchanging basin. More activity could therefore be expected as the Utica develops and matures, but to speculate on the nature and extent of that activity is beyond the scope of this project.

Figure 4.6 illustrates the number of new wells to be drilled each year enabling 1,000 MMcfd of marketable gas to be produced in the Utica from 2015 to 2040 and beyond. The Utica is a liquids-rich basin, so a shrinkage factor of 12 percent has been included in the calculations. The new well count would peak at 132 wells in the fifth year of operation, declining from that point. That is the same year that the production threshold of 1000 MMcfd would be reached.

[10] http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf

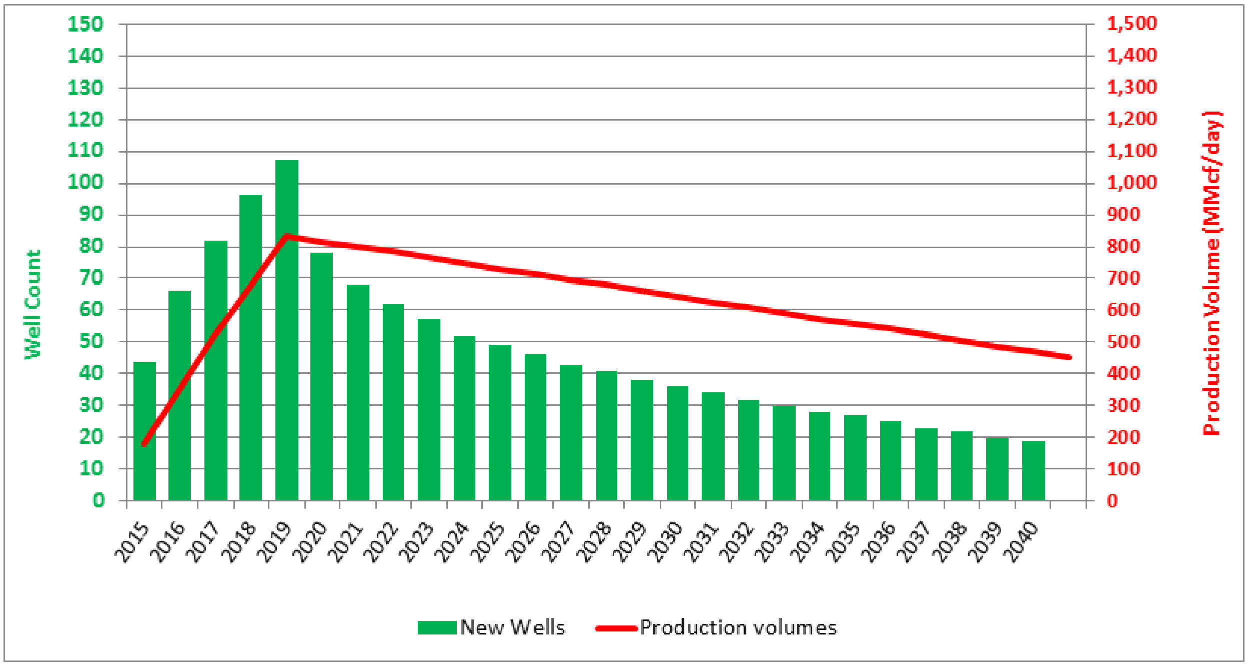
Figure 4.6: Utica Shale Gas Production Volumes and Well Count Reference Case Scenario



Source: CERI

Figure 4.7 shows how production and well counts would shrink under the emissions constraints of the Québec Emissions Plan Scenario. Sales gas would peak at approximately 830 MMcfd in the fifth year and then decline from there. The new well count would peak at 107 wells in the fifth year of operation, declining from that point. That is the same year that the production threshold of 1,000 MMcfd would be reached.

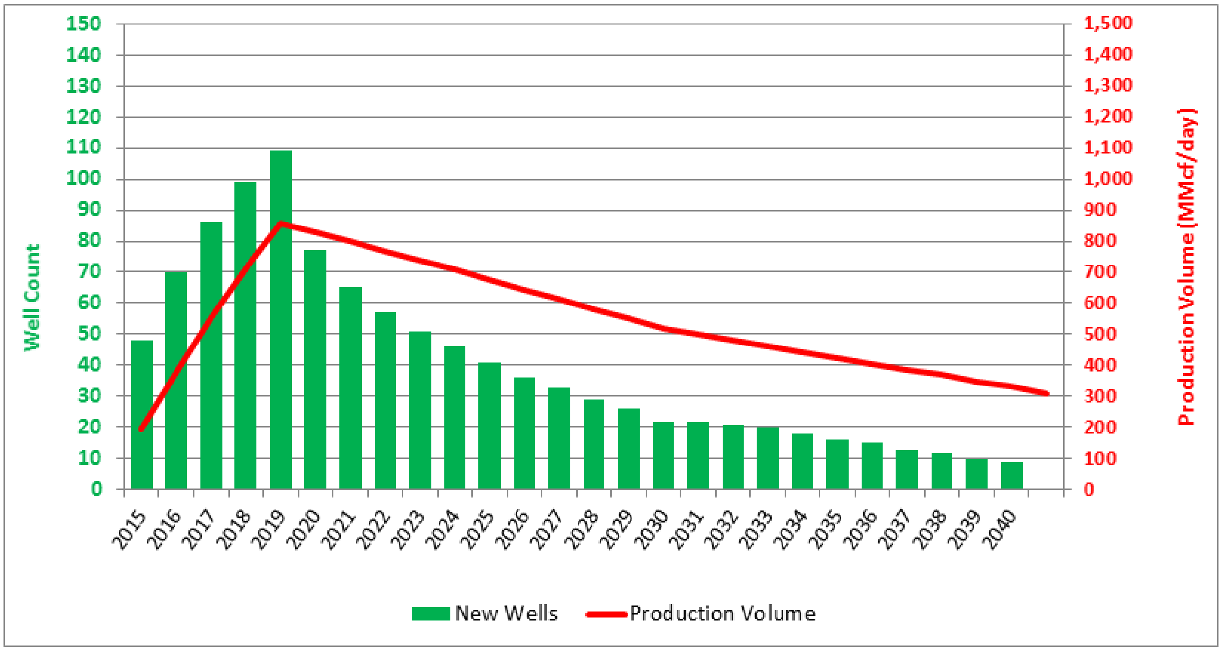
**Figure 4.7: Utica Shale Gas Production Volumes and Well Count
Québec Emissions Plan Scenario**



Source: CERI

As with the Québec Emissions Plan Scenario, production volumes and well counts would decrease rapidly under the 450 Scenario, with further declines in the later years of the study period (Figure 4.8). Only 9 new wells would be built in the final year of the scenario to sustain production volumes of approximately 300 MMcfd. Because volumes are restrained throughout the 25-year period of the study – both under the Québec Plan Scenario and the 450 Scenario – the Utica Shale should be able to produce at these lower levels for many years beyond 2040.

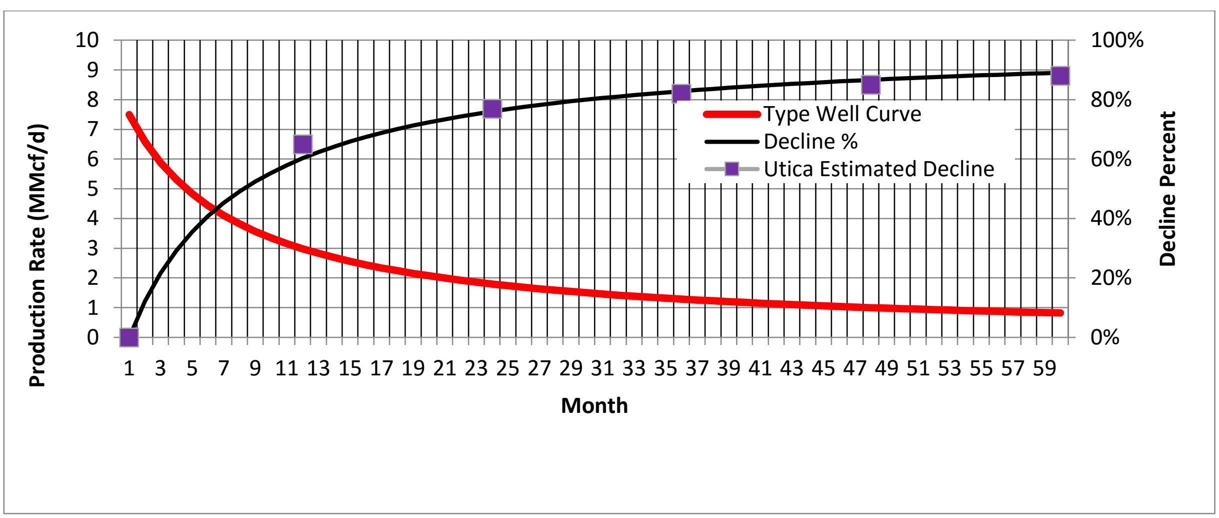
Figure 4.8: Utica Shale Gas Production Volumes and Well Count WEO 450 Scenario



Source: CERI.

As mentioned earlier, the above calculations assume the EIA's Utica IP rate of 7.5 MMcfd. The decline rate in Figure 4.9 is based on decline rates in the Ohio Utica estimated by the Department of Geology and Environmental Sciences at Youngstown State University.[11]

Figure 4.9: Production Decline Curves, Utica Shale



Source: CERI.

[11] http://www.ohio.com/blogs/drilling/ohio-utica-shale-1.291290/decline-curve-revealed-by-growing-utica-shale-production-data-1.555292

Economic impacts of a shale gas industry developing in Québec, though significant, are not as great as those seen as a result of the shale oil industry emerging on Anticosti. Most of this is because development costs in the St. Lawrence Lowlands, an industrialized area with a skilled resident population, are much lower than in Anticosti, an island with few inhabitants, no established infrastructure, and no land links to the rest of Canada. Thus, the Utica Shale is projected to produce more hydrocarbons on a barrel of oil equivalency (BOE) basis, but the impacts on GDP, employment, and tax will be lower.

Table 4.7 shows GDP, wage, and employment impacts on all of Canada's provinces resulting from a shale gas industry emerging out of Utica shale development. Québec is estimated to gain more than $93 billion in GDP impact, or 69 percent of the total. Alberta, as it does in oil development, gains much from Québec gas development, at $33.5 billion. Impacts approaching $3 billion will be felt in Ontario. British Columbia and Saskatchewan realize GDP gains in the $1.5 billion range over the 25-year period.

Québec sees the greatest share of employee compensation and person years of employment, with close to $20 billion in wages being paid out (49 percent) and over 230,000 person years of direct, indirect, and induced employment (51 percent) generated.

Table 4.7: Economic Impacts of Development of Utica Shale Gas Reference Case Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	33,502	14,760	153
British Columbia	1,704	1,060	16
Manitoba	677	403	7
NewBrunswick	91	50	1
Newfoundland/Labrador	52	23	0
Nova Scotia	101	62	1
Nunavut	5	4	0
Northwest Territories	17	10	0
Ontario	4,915	2,933	35
Prince Edward Island	10	6	0
Quebec	93,299	19,198	233
Saskatchewan	1,469	817	14
Yukon Territory	7	4	0
Total Canada	135,848	39,330	460

Source: CERI.

As shown in Table 4.8, Québec's tax impacts are close to $15 billion, far in excess of any other province, and more than 65 percent of the total. Alberta will see just over $6 billion in added tax revenue, with no other province receiving more than $1 billion.

Table 4.8: Tax Impacts of Development of Utica Shale Gas
Reference Case Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	1791	841	3519	6151
British Columbia	46	141	164	352
Manitoba	14	36	51	102
NewBrunswick	2	4	7	14
Newfoundland/Labrador	2	2	4	9
Nova Scotia	3	5	12	19
Nunavut	0	0	0	1
Northwest Territories	1	1	1	3
Ontario	137	268	557	962
Prince Edward Island	0	1	1	2
Quebec	3493	4036	7364	14894
Saskatchewan	45	87	186	319
Yukon Territory	0	0	1	1
Total Canada	5535	5423	11869	22827

Source: CERI.

The Utica Shale under the Québec Emissions Plan Scenario will not see as precipitous a drop in GDP, wages, or employment as the Macasty Shale. Utica development, being in the Montreal-Québec City corridor, is not nearly as expensive as Macasty development on the remote Anticosti Island. Reductions in development on Anticosti represent far larger drops in GDP, wages, and employment than similar reductions in the Utica. As a result, Utica GDP in Québec falls from $93.3 billion to $69.5 billion, a drop of 25 percent – significant, but not nearly as steep a plunge as Macasty GDP in Québec, which falls 60 percent. Employee compensation and employment see similar rates of decline.

Table 4.9: Economic Impacts of Development of Utica Shale Gas
Québec Emissions Plan Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	25,876	11,387	11
British Columbia	1,295	806	1
Manitoba	508	302	0
NewBrunswick	69	38	0
Newfoundland/Labrador	39	18	0
Nova Scotia	76	47	0
Nunavut	4	3	0
Northwest Territories	13	8	0
Ontario	3,714	2,216	2
Prince Edward Island	7	4	0
Quebec	69,570	14,283	14
Saskatchewan	1,111	618	1
Yukon Territory	5	3	0
Total Canada	102,288	29,733	30

Source: CERI.

Tax impacts are not as strong in the Québec Emissions Plan Scenario as in the Reference Case Scenario, as to be expected and shown in Table 4.10.

Table 4.10: Tax Impacts of Development of Utica Shale Gas Québec Emissions Plan Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	1383	648	2718	4750
British Columbia	35	110	125	270
Manitoba	11	27	41	79
NewBrunswick	1	3	5	10
Newfoundland/Labrador	2	1	3	7
Nova Scotia	2	4	9	15
Nunavut	0	0	0	1
Northwest Territories	0	1	1	2
Ontario	103	202	421	727
Prince Edward Island	0	1	1	2
Quebec	2605	3007	5491	11103
Saskatchewan	34	66	141	241
Yukon Territory	0	0	0	1
Total Canada	**4178**	**4070**	**8957**	**17205**

Source: CERI.

As shown in Table 4.11, GDP totals from Utica Shale development in Québec drop from $69.5 billion under the Québec Emissions Plan Scenario to $47.3 billion under the 450 Scenario, or 32 percent. Alberta falls from $25.8 billion to $19.5 billion, and Ontario drops to $2.6 billion from $3.7 billion. Employee compensation and employment figures show similar decline.

Table 4.11: Economic Impacts of Development of Utica Shale Gas WEO 450 Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	19,507	8,567	88
British Columbia	935	581	9
Manitoba	355	211	4
NewBrunswick	50	27	0
Newfoundland/Labrador	28	13	0
Nova Scotia	54	33	1
Nunavut	3	2	0
Northwest Territories	9	6	0
Ontario	2,643	1,578	19
Prince Edward Island	5	3	0
Quebec	47,324	9,742	118
Saskatchewan	792	441	7
Yukon Territory	4	2	0
Total Canada	**71,710**	**21,208**	**247**

Source: CERI.

Tax impacts for the WEO 450 Scenario are shown in Table 4.12 and are even less than the Québec Emissions Plan Scenario.

Table 4.12: Tax Impacts of Development of Utica Shale Gas WEO 450 Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	1043	488	2049	3580
British Columbia	25	77	90	192
Manitoba	7	19	27	53
NewBrunswick	1	2	4	7
Newfoundland/Labrador	1	1	2	5
Nova Scotia	1	3	6	10
Nunavut	0	0	0	0
Northwest Territories	0	0	1	1
Ontario	74	144	300	517
Prince Edward Island	0	0	1	1
Quebec	1772	2048	3736	7555
Saskatchewan	25	47	100	172
Yukon Territory	0	0	0	0
Total Canada	2950	2830	6316	12096

Source: CERI.

Over the 25-year period, the reference case shows the highest economic impact of $93 billion in GDP for Québec. This is followed by $70 billion in the Québec Emissions Plan Scenario and $47 billion in the WEO 450 Scenario. All three production forecast scenarios differ from those of the Québec government.

Chapter 5
Key Findings and Concluding Remarks

The GDP, taxation, and employment projections stated below reveal the results of operating and capital expenditures injected into the CERI I/O model. These are conservative economic impact estimates, reflecting an oil and gas industry that begins from almost nothing, with outside support, but within a few years becomes almost entirely centered in the province of Québec.

As oil and gas develops in the Utica and Macasty, it would be expected to grow and spread to other basins in the province (unless constraints are imposed on that growth), but calculating the extent of that increase is beyond the scope of the study. The results stated in the following figures are therefore conservative estimates. Production costs in this report are high and based on published information on production wells. CERI's estimates do not include:

- Increased production per well based on improved techniques
- Decreased capital or operating costs per well due to economies of scale or efficiency improvements
- An economic quantification of risk which is sometimes represented through Monte Carlo Simulation analysis

Greenfield energy developments often start as high cost endeavours and demonstrate cost reductions over time. CERI's estimates suggest that an initial start to an oil and gas industry in Québec will be challenging. Careful consideration of the risks and benefits should be made by governments and businesses prior to engaging in the development of this industry.

Tables 5.1 through 5.4 present the sum benefits to Canada's provincial economies of oil and gas development in the Macasty and Utica basins, according to each of the three scenarios developed for this study.

Table 5.1: Canada Economic Benefits – Macasty Shale

Canada GDP, Compensation & Employment as a result of Macasty shale development, 2015-2040. Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Reference Case Scenario	222,503	68,611.0	770
Quebec Emissions Plan Scenario	90,554	27,148.0	317
450 Scenario	65,833	20,170.0	234

Source: CERI.

Table 5.2: Canada Economic Benefits – Utica Shale

Canada GDP, Compensation & Employment as a result of Utica shale development, 2015-2040. Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Reference Case Scenario	135,848	39,330.0	460
Quebec Emissions Plan Scenario	102,288	29,733.0	30
450 Scenario	71,710	21,208.0	247

Source: CERI.

Table 5.3: Canada Tax Benefits – Macasty Shale

Taxes collected in Canada as a result of Macasty Shale Development, 2015-2040. 3 Scenarios Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Reference Case Scenario	9103	8844	19484	37431
Quebec Emissions Plan Scenario	3727	3570	7976	15273
450 Scenario	2737	2566	5845	11147

Source: CERI.

Table 5.4: Canada Tax Benefits – Utica Shale

Taxes collected in Canada as a result of Utica Shale Development, 2015-2040. 3 Scenarios. Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Reference Case Scenario	5535	5423	11869	22827
Quebec Emissions Plan Scenario	4178	4070	8957	17205
450 Scenario	2950	2830	6316	12096

Source: CERI.

Overall, the reference case scenario produces the largest economic benefit to Québec and Canada. Carbon emissions constraints have a twofold impact on production. The first is a decrease in demand which is most likely reflected in lower prices. The second is a decrease in production to meet the production emissions limits that would be imposed by those polices.

Potential hydrocarbon development in Québec faces the test of a fiercely competitive marketplace and also the challenges of a rapidly changing world, one that is becoming increasingly concerned with GHG emissions caused by the combustion of fossil fuels. Though it is possible over the short and medium term that oil and gas prices could rise, making Québec hydrocarbon development economically feasible, if the world takes serious climate change measures over the coming years, oil and gas will become less desirable fuels. At that point, Québec oil and gas would be competing with other jurisdictions that have lower supply cost thresholds. Currently with production costs above $95.50/bbl for oil it is not economic to develop. Natural gas production costs at $3.72/mcf means this is a marginal play and is dependent on cost minimization strategies including access to the North American infrastructure.

Alternative production forecasts and costs assumptions were also sourced; the shale oil profile was taken from the "Scénario Optimisé" scenario of the Government of Québec Ministry of Finance Document "Evaluation Financière, évaluation des retombées é conomiques et scénarios de développement possibles de l'exploitation d'hydrocarbures sur l'île d'Anticosti". The Utica shale gas profile was provided by Talisman who are currently exploring development of shale gas in Québec.

This study focuses on the oil potential of the Macasty Shale. For those interested in its NGL potential, they are encouraged to consult study AECNO1-02 under the Government of Québec's Strategic Environmental Assessment, and the websites of Corridor Resources, Petrolia Inc., and Junex Inc. for more information.

The supply costs and economic impacts of those high IP scenarios together with an analysis of differences between those scenarios and CERI's scenarios are presented in Appendix C. For comparison, the CERI assessment versus the alternative scenarios is detailed in Table 5.5.

Table 5.5: Comparison of CERI Assessment to Alternative Production Scenarios: Supply Costs and Economic Impacts

	CERI Reference Case	High IP Scenario
Natural Gas Supply Cost ($/Mcf)	$3.72	$2.55
Oil Supply Cost ($/bbl)	$95.50	$66.00
Québec GDP ($ billion)	$243	$73.3
Québec Employment ('000 person years)	618	186
Canada GDP ($ billion)	$362	$106
Canada Employment ('000 person years)	1,230	367

Source: CERI

This analysis did not uncover any unique position that Québec oil and gas commodities had over other producing regions in North America or elsewhere. Therefore, the key to competitiveness is low cost production and access to markets.

There is easy access for Québec's potential oil industry as it is located at tide water. It can therefore take advantage of Brent crude pricing similar to Newfoundland and for which western Canadian producers work toward. The cost challenge remains with building the necessary infrastructure.

Access to the North American gas market can also be achieved through the expansion of the pipeline network. Again, there is a cost challenge for the industry to invest in this infrastructure.

Québec's potential natural gas industry would likely benefit from the expansion of East Coast Canada's LNG export capability, particularly to Europe.

Today, Québec's high supply costs relative to other established oil and gas producing areas make it challenging for the province to be competitive in North American and world markets (more so for oil than natural gas). Carbon constraints would make matters even more tenuous for Québec, a situation in which the Province would be joined by the world's many other high-cost hydrocarbon producers. Only the lower cost jurisdictions that can be profitable at reduced prices will see their oil and gas production industries continue to develop as the world begins to look beyond hydrocarbons to alternative, lower-emitting sources of energy.

In the end, developing the oil and gas production industry in Québec, or anywhere else, is all about price. If producers can make their necessary profit margins under any three of the development scenarios posited in this study, Québec oil development, Québec gas development, or both, will go ahead and the province will see GDP, employment, and taxation impacts as a result.

Appendix A
GDP Impacts on Major Provinces

Québec

In the province of Québec, as expected, the most impacted industry from oil development in the Macasty Shale over the study period would be conventional oil. In all three scenarios, conventional oil receives more than 10 times the impact of any of the other industries. Gas and NGLs would also be significantly impacted because some of the equipment and skill sets would be applicable to conventional oil construction and operations.

Table A.1: Five Most Impacted Industries in Québec – Macasty Shale Oil Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Conventional Oil	105,865	42,163	29,285
Gas and NGLs	9,741	3,829	2,676
Household (Labour)	6,911	2,736	1,908
Finance, Insurance, Real Estate, Rental and Leasing	6,243	2,306	1,651
Other Mining	3,768	1,481	1,034

Source: CERI.

Similar to oil development in the Macasty, one industry is dominant in Utica Gas Development – Gas and NGLs. Conventional oil is a distant but significant second most dominant industry, followed by the same three industries as in oil development: Household (Labour); Finance, Insurance, Real Estate, Rental and Leasing; and Other Mining.

Table A.2: Five Most Impacted Industries in Québec – Utica Shale Gas Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Gas and NGLs	66,459	49,630	33,697
Conventional Oil	6,322	4,720	3,208
Household (Labour)	4,225	3,145	2,144
Finance, Insurance, Real Estate, Rental and Leasing	3,353	2,429	1,701
Other Mining	2,446	1,826	1,241

Source: CERI.

Alberta

Alberta is the second most impacted province, after Québec, as a result of Macasty Shale oil development. This is because the oil and gas industry in Alberta is mature; Alberta would be a first choice for Québec to source industry expertise and equipment, especially in the early years of Québec's oil industry development. At the top of the list, under all three scenarios, is the conventional oil industry, which would play a major role in Québec.

Table A.3: Five Most Impacted Industries in Alberta – Macasty Shale Oil Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Conventional Oil	26,600	11,683	9,456
Household (Labour)	7,374	3,183	2,532
Finance, Insurance, Real Estate, Rental and Leasing	4,870	2,070	1,662
Owner Occupied Buildings	3,225	1,392	1,107
Professional, Scientific and Technical Services	2,392	1,021	796

Source: CERI.

The reasons why gas and NGLs top the list of impacted industries in Alberta under Utica Gas development are similar to the reasons why conventional oil tops the list in Macasty Oil development: the industry is mature in Alberta and would be a major source of assistance in building Québec gas. Again, the most impact would occur in the early years, as Québec gas grows from almost nothing to a significant industry in the province.

Table A.4: Five Most Impacted Industries in Alberta – Utica Shale Gas Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Gas and NGLs	15,504	12,058	9,216
Household (Labour)	4,300	3,319	2,498
Finance, Insurance, Real Estate, Rental and Leasing	2,713	2,080	1,580
Owner Occupied Buildings	1,881	1,451	1,093
Conventional Oil	1,499	1,132	797

Source: CERI.

Ontario

By virtue of its trained population, Toronto's status as a business centre, and its large industrial base, Ontario would be the third most impacted province in Canada as a result of oil and gas development in Québec. Rather than the oil and gas industries being impacted in Ontario, the finance, insurance, real estate, rental and leasing industry (FIRE) would be most affected. For

Macasty development, FIRE would see a range of impacts from $751 million under the WEO 450 Scenario to almost $2.5 billion under the Reference Case Scenario.

Table A.5: Five Most Impacted Industries in Ontario – Macasty Shale Oil Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Finance, Insurance, Real Estate, Rental and Leasing	2,473	1,013	751
Household (Labour)	944	388	288
Other Manufacturing	884	366	272
Professional, Scientific and Technical Services	634	262	195
Wholesale Trade	539	223	166

Source: CERI.

FIRE is the most affected industry in Ontario as a result of Utica Shale gas development under all three scenarios. There would also be sizeable manufacturing done in the province to support the Québec industry, and Ontario's Professional, Scientific, and Technical services would be utilized, especially in the early years of Utica development.

Table A.6: Five Most Impacted Industries in Ontario – Utica Shale Gas Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Finance, Insurance, Real Estate, Rental and Leasing	1,481	1,118	796
Household (Labour)	565	427	304
Other Manufacturing	527	399	285
Professional, Scientific and Technical Services	377	285	204
Wholesale Trade	322	244	174

Source: CERI.

British Columbia

Though British Columbia is distant from Québec, Vancouver is a large business centre and the province is also home to a skilled workforce, with experience in the oil and gas industry. Over the study period, in Macasty Shale development, British Columbia would witness impacts into the hundreds of millions of dollars in FIRE; Manufacturing; and Professional, Scientific and Technical Services under all three scenarios.

Table A.7: Five Most Impacted Industries in BC – Macasty Shale Oil Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Finance, Insurance, Real Estate, Rental and Leasing	427	178	134
Household (Labour)	363	151	114
Other Manufacturing	320	134	101
Professional, Scientific and Technical Services	248	103	76
Transportation and Warehousing	240	100	75

Source: CERI.

Utica Shale gas development would affect British Columbia similarly to Macasty Shale oil development. FIRE would see the most impact, followed by household (labour). British Columbia would witness growth in manufacturing; professional, scientific and technical services; and transportation and warehousing.

Table A.8. Five Most Impacted Industries in BC – Utica Shale Gas Development (GDP $millions)

Most Affected Industries	Reference Case	Québec Emissions Plan	WEO 450
Finance, Insurance, Real Estate, Rental and Leasing	254	193	139
Household (Labour)	216	164	119
Other Manufacturing	190	144	104
Professional, Scientific and Technical Services	147	111	80
Transportation and Warehousing	144	109	78

Source: CERI.

Appendix B
Oil and Gas Support Infrastructure

Developing an oil and gas industry will depend on support infrastructure, or lack thereof. It is useful to understand the existing infrastructure to assess the challenges to Québec regarding infrastructure investment.

Québec has 12,353 kilometers of transmission and distribution pipelines.[1] To put this in perspective, however, the following illustrate the length of pipeline in other jurisdictions: British Columbia (40,392 kilometers), Alberta (415,152 kilometers), Saskatchewan (102,400 kilometers), and Ontario (114,000 kilometers).[2] Despite being the largest producer of hydrocarbons in Canada, Alberta's lack of pipeline infrastructure, particularly for export, is well documented.

Storage is another matter, as it is valued for managing seasonal demands. In Québec there is limited oil storage and no gas storage. In terms of gas, this is reflected in the much higher price for gas in Québec in the heating season.

There is no oil or natural gas production in Québec, therefore, the number of gathering lines, or feeder lines, is negligible. The most likely scenario for future development in Québec would be organic growth, connecting the gathering lines and feeder lines from the producing fields to the existing North American pipeline network.

This appendix is divided into two parts: Liquids – Pipelines and Rail, and Natural Gas Pipelines. Liquids pipelines transport oil and petroleum products in Québec. Natural gas pipelines in Québec and those just outside the jurisdiction are vital to gas supply in the province.

Liquids – Pipelines and Rail

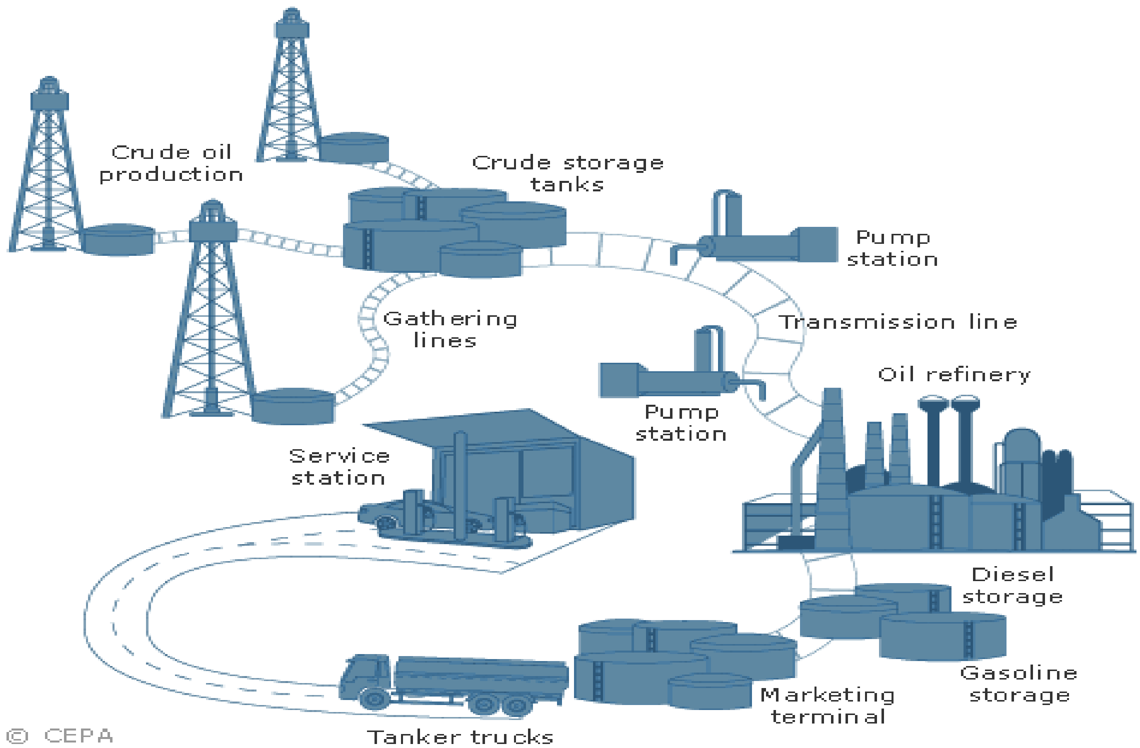
Liquids pipelines are used to transport crude oil or natural gas liquids from producing fields to refineries, and in some cases of refined petroleum products, from refineries to distribution centers. Figure B.1 illustrates the crude oil delivery system: from the production of crude oil, to gathering lines, to oil refineries, to service stations.

There is no oil production in Québec, and the number of gathering lines, or feeder lines, is negligible. Crude oil storage in Québec is also lacking. The crude oil consumed in Québec is shipped by pipeline, rail, or tanker into two large oil refineries, including Levis (Jean-Gaulin

[1] Natural Resource Canada, Québec's Pipeline Regulatory Regime, http://www.nrcan.gc.ca/energy/infrastructure/pipeline-safety-regime/16439
[2] ibid

refinery - Énergie Valero) and Montreal (Suncor).[3] Énergie Valero's capacity is 265,000 bpd while Suncor's Montreal refineries capacity is approximately 140,000 bpd.[4] The former is supplied by oil shipped by tanker while the latter is mainly supplied by the pipeline (Portland-Montreal Pipe Line) and more recently by train. While crude by rail is discussed later in this section, tanker shipment is not, but it is important to note that oil sent to Valero is shipped along the St. Lawrence, more than 250 oil tankers annually.[5]

Figure B.1: Crude Oil Delivery System



Source: CEPA[6]

There are, though, several important liquids pipelines transporting oil and petroleum products to Québec: Enbridge's Canadian Mainline, Portland-Montreal Pipe Line, Trans-Northern Pipeline, Pipeline Saint-Laurent, and TransCanada's proposed Energy East. These pipelines are illustrated in Figure B.2.

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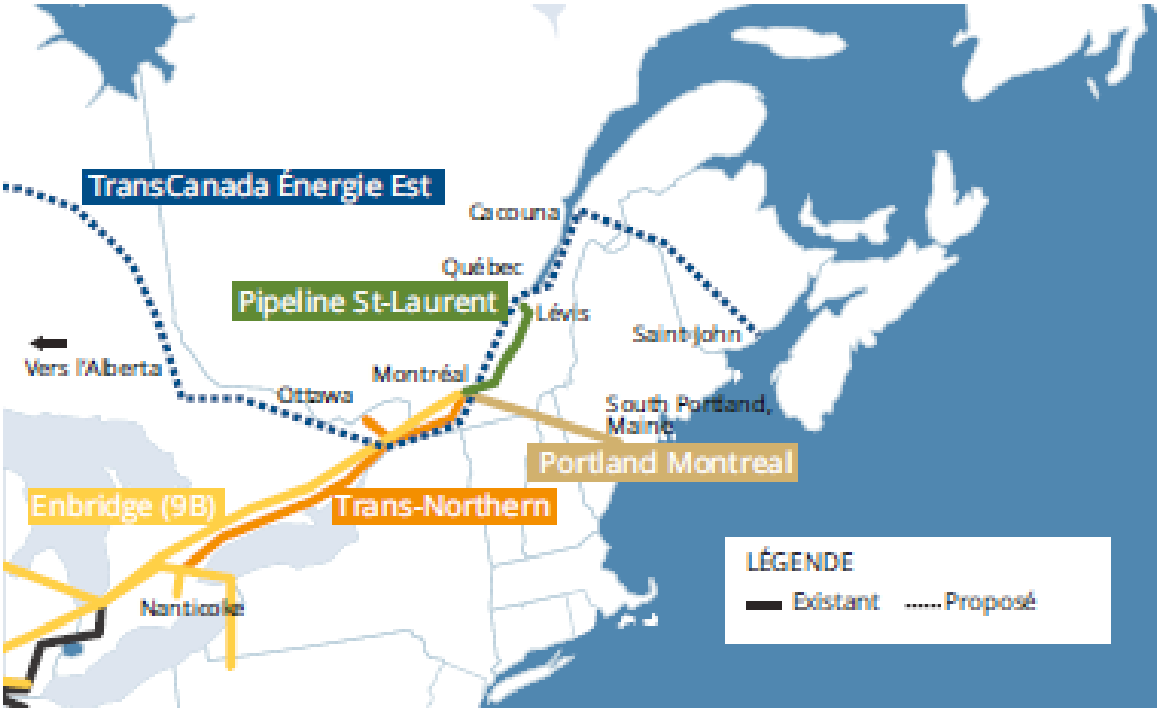
[3] Québec Government, Québec Energy Policy 2016-2017: Fossil Hydrocarbons, http://www.politiqueenergetique.gouv.qc.ca/wp-content/uploads/Document6%E2%80%93hydrocarbons.pdf, pp. 24.
[4] Ministère Énergie et Ressources Naturelles, Raffinage du Pétrole, http://www.mern.gouv.qc.ca/energie/statistiques/statistiques-production-petrole.jsp
[5] Québec Government, Québec Energy Policy 2016-2017: Fossil Hydrocarbons, http://www.politiqueenergetique.gouv.qc.ca/wp-content/uploads/Document6%E2%80%93hydrocarbons.pdf, pp. 24.
[6] Canadian Energy Pipeline Association, Liquids Pipelines, http://www.cepa.com/about-pipelines/types-of-pipelines/liquids-pipelines

Figure B.2: Liquids Pipelines in Québec



Source: HEC Montreal[7]

The following reviews briefly the important liquids pipelines transporting oil and petroleum products in Québec.

Enbridge Canadian Mainline – Enbridge

Enbridge's 2,306-kilometer Canadian Mainline begins in Edmonton and runs to Montreal.[8] The Canadian Mainline ends at Gretna, Manitoba when the pipeline enters the United States and starts again in Sarnia, Ontario, where it runs through Toronto and onto Montreal.[9]

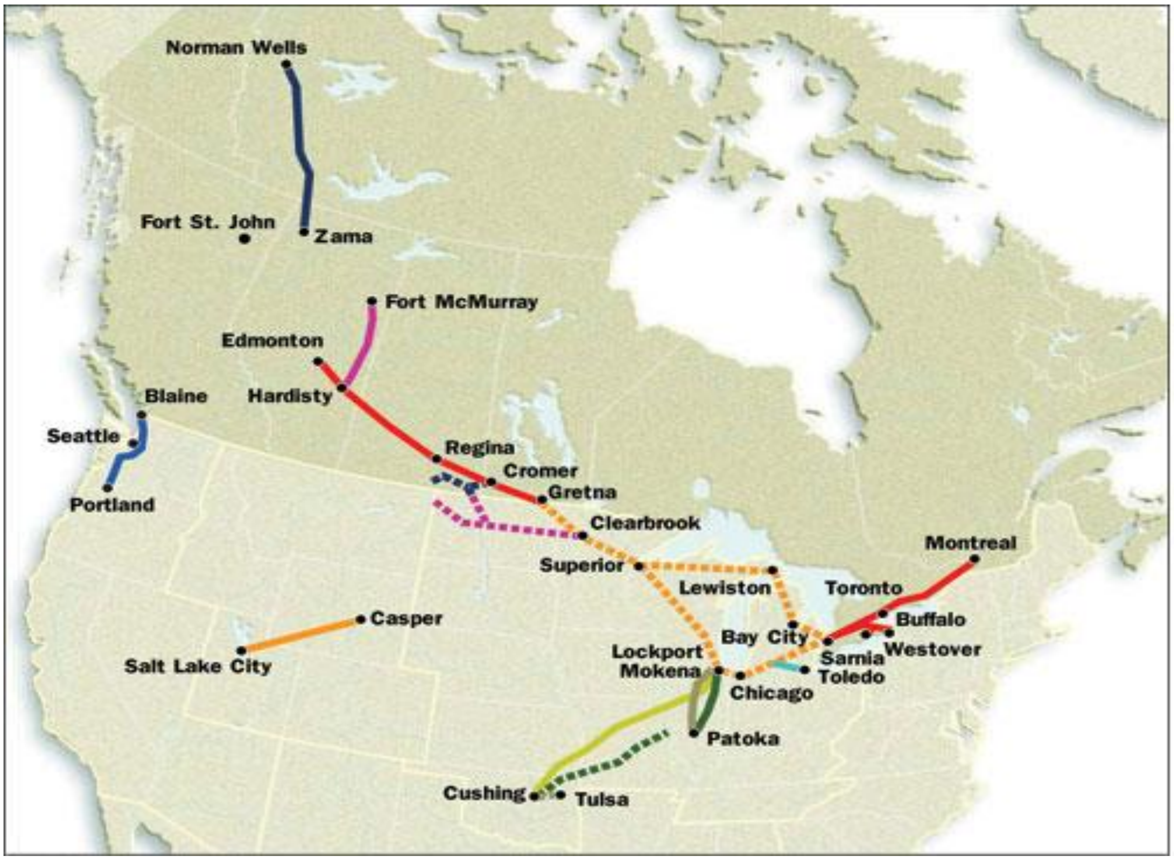
Figure B.3 illustrates the Canadian Mainline, as well as other Enbridge liquids pipelines in North America. The Canadian Mainline is represented by the red line. The yellow-spotted line illustrates Enbridge's Lakehead System, or the US Mainline. The Canadian Mainline transports crude oil and diluted bitumen, while the Enbridge Lakehead transports crude oil, condensate and NGLs.[10]

Line 9 connects Montreal to Sarnia via Westover. Enbridge is in the process of expanding or replacing several lines. Among the various projects, Line 9B is being re-reversed, from Westover,

[7] HEC Montréal, État de L'Energie au Québec, 2015, pp. 11.
[8] Enbridge website, Enbridge Liquids Pipelines, http://www.enbridge.com/DeliveringEnergy/OurPipelines/LiquidsPipelines.aspx (accessed on September 28, 2012)
[9] ibid
[10] CEPA website, Pipeline Map, http://www.cepa.com/map/pipeline-map.swf

Ontario to Montreal.[11] This reversal will complement the plan to reverse Line 9A between Sarnia and Westover.[12] The Line 9B project has important ramifications for Québec, to provide refineries in Montreal crude oil from Western Canada and the Bakken region in North Dakota. With the National Energy Board's (NEB) final approval on September 30, 2015, Line 9B could be in service before the end of this year.

Figure B.3: Enbridge Liquids Pipelines

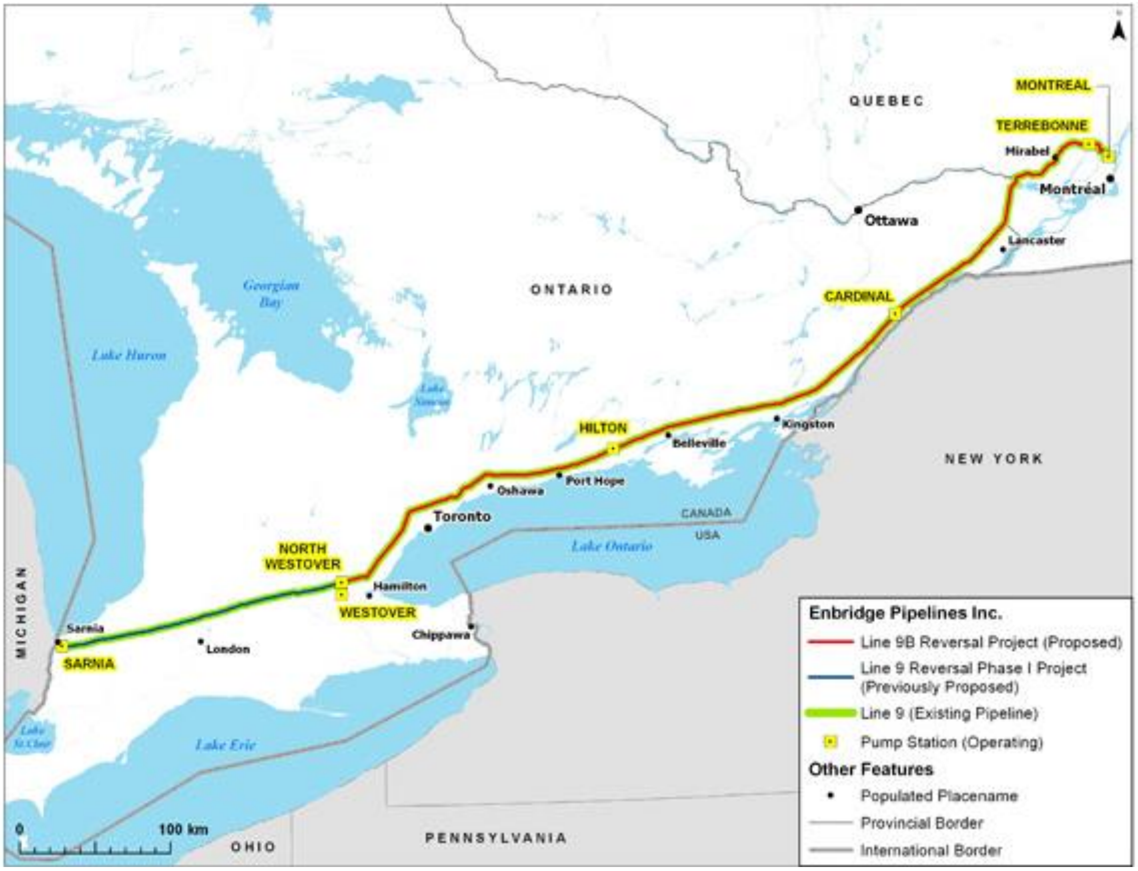


Source: Enbridge website

Figure B.4 shows Enbridge's Line 9 projects.

[11] Enbridge website, Enbridge and Enbridge Energy Partners project expansions May 2012, http://www.enbridge.com/EEP-and-ENB-project-expansions-May-2012.aspx (accessed on September 28, 2012)
[12] ibid

Figure B.4: Enbridge's Line 9 Projects



Source: https://www.neb-one.gc.ca/pplctnflng/mjrpp/ln9brvrsl/index-eng.html

Trans-Northern Pipeline

The Trans-Northern Pipeline is an 850-kilometer pipeline transporting refined products such as gasoline, diesel fuel, aviation fuel and heating fuel.[13] It is sometimes referred to as the Ontario-Québec Pipeline. The pipeline flows east to west, linking Montreal and Oakville and west to east between Nanticoke and Toronto.[14] Imperial Oil's Nanticoke refinery produces 110,000 bpd.[15] There is also a branch that connects Ottawa, as well as Mirabel and Dorval to the system.

This pipeline transports an average of 27,500 m^3 or approximately 172,900 barrels of refined fuel products daily.[16]

The route of the Trans-Northern Pipeline is illustrated in Figure B.5. Metering or pump stations are located at Nanticoke, Oakville, Clarkson, North Toronto and Montreal.

[13] Trans-Northern Pipeline website, Our Pipelines, http://www.tnpi.ca/our-pipelines/
[14] ibid
[15] Imperial Oil website, Operations, Nanticoke, http://www.imperialoil.ca/Canada-English/operations_community_nant.aspx
[16] ibid

Figure B.5: Trans-Northern Pipeline

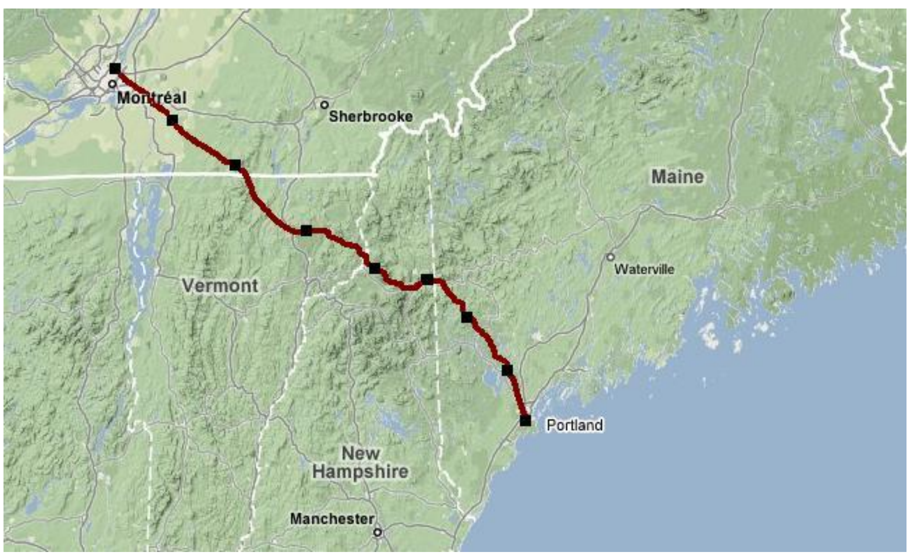
Source: Trans-Northern Pipeline[17]

Portland-Montreal Pipe Line (PMPL)

The Portland-Montreal Pipe Line begins at South Portland, Maine and ends at Montreal.[18] The 379.7 kilometer pipeline transports crude oil directly to Suncor's refinery in Montreal, Québec and through connections with other pipelines in Montreal, the system provides crude requirements for other refineries in the province of Ontario.[19]

The route of the Portland-Montreal Pipe Line is illustrated in Figure B.6, passing through New Hampshire and Vermont.

Figure B.6: Portland-Montreal Pipe Line



Source: http://www.sqwalk.com/q/sites/default/files/Portland-Montreal-Pipeline.JPG

[17] Trans-Northern Pipeline website, Our Pipelines, http://www.tnpi.ca/our-pipelines/
[18] Portland Montreal Pipe Line website, About Us, http://www.pmpl.com/about-us/
[19] CEPA website, Map, http://www.cepa.com/map/index-en.html

The Portland-Montreal Pipe Line is owned and operated by the Portland Pipe Line Corporation in the United States and the Montreal Pipe Line Limited in Canada. The pipeline was commissioned in 1941 and has transported over 4 billion barrels of crude oil to Canada.[20]

Pipeline Saint-Laurent

Pipeline Saint-Laurent is a 243-kilometer pipeline that transports refined products from Levis to Montreal.[21] The pipeline flows east to west, linking the Jean-Gaulin (Énergie Valero) refinery in Levis to its Montreal East terminal.[22]

The route of the Pipeline Saint-Laurent is illustrated in Figure B.7.

Figure B.7: Pipeline Saint-Laurent

Source: http://www.pipelinesaintlaurent.ca/fr/Trace.aspx

TransCanada Energy East (proposed)

The proposed TransCanada Energy East project is a 4,600 kilometer pipeline from Hardisty, Alberta to Saint John, New Brunswick. TransCanada's Energy East project is planned to provide feedstock to refineries in Montreal, Levis and Saint John. The line is estimated to cost around C$12 billion and will have a capacity of 1.1 million bpd.[23]

Figure B.8 illustrates the route of the Energy East pipeline. The blue line indicates the large portion, approximately 3,000 kilometers, of the project that involves converting the existing natural gas pipeline to oil. The green line illustrates new pipeline construction, from Hardisty, Alberta to Saskatchewan and from eastern Ontario, Québec to New Brunswick.[24] Terminals will

[20] Portland Montreal Pipe Line website, About Us, http://www.pmpl.com/about-us/
[21] Pipeline Saint-Laurent, Bienvenue sur Pipeline Saint-Laurent, http://www.pipelinesaintlaurent.ca
[22] ibid
[23] Financial Post website, Keystone Oil Pipeline and the Energy East, http://business.financialpost.com/2014/03/27/keystone-oil-pipeline-energy-east-irving/?__lsa=fad7-eae5
[24] Energy East project website, About the Project, http://www.energyeastpipeline.com/about/the-project/

include three new terminals: a tank terminal in Hardisty, Saskatchewan and Saint John. The latter two are proposed to include marine tanker loading facilities.[25] TransCanada announced that it will not build a marine and tank terminal in Cacouna, Québec; the organization is looking at alternative locations in Québec.[26] Irving Oil is planning to build a new C$300 million terminal at its existing Canaport LNG facility to export the oil from the Energy East Pipeline.

Figure B.8: Energy East Pipeline Planned Route

Source: http://www.energyeastpipeline.com/home/route-map/

The project still requires regulatory approval. It would provide Western Canadian crude oil access to markets in Eastern Canada and Europe.

Crude by Rail

Enbridge's Northern Gateway, TransCanada Pipeline's (TCPL) Keystone XL and Kinder Morgan's TransMountain's (TMX) expansion are all experiencing delays in the regulatory approvals process. With a shortage of pipeline capacity looming, uncertainties over key pipeline projects are inspiring other solutions to deliver Canada's crude oil to the US East Coast, US Gulf Coast or other markets. One option is transporting crude oil by rail.

Tank railcars are used to transport petroleum fuels (gasoline, diesel, aviation fuels, fuel oil and lubricants), chemical products (ethylene glycol, chlorine, ammonia, vinyl chloride and caustic soda), and liquefied petroleum gas (LPG) products (propane, butane and pentanes).

[25] ibid

[26] Energy East project website, Route Map, http://www.energyeastpipeline.com/home/route-map/

The increase of crude oil exports by rail is dramatic, currently approximately 280,000 bpd,[27] up from 127,943 bpd in 2013 and from 46,000 bpd in 2012.[28] While crude exports by rail make up less than 5 percent of total crude exports, this number is expected to increase.

In 2012, the top 5 commodities in Québec in terms of the number of railcars are Mixed Loads or Unidentified Freight (701,919 railcars), Iron Ores and Concentrates (262,422 railcars), Automobiles and Mini-Vans (38,497 railcars), Fuel Oils and Crude Petroleum (36,348 railcars) and Other Basic Chemicals (34,698 railcars).[29] The top 5 commodities in Québec in terms of tonnes are Iron Ores and Concentrates (24,064,884 tonnes), Mixed Loads or Unidentified Freight (10,252,059 tonnes), Fuel Oils and Crude Petroleum (2,946,190 tonnes), Other Basic Chemicals (2,938,680 tonnes), Gasoline and Aviation Turbine Fuel (2,190,598 tonnes).[30]

Figure B.9 illustrates the Canadian National (CN) and Canadian Pacific (CP) rail networks in Québec and its interconnectedness with other parts of North America, as well as key ports and refineries. CN-served ports in Québec include Port Montreal and has ties to the Port de Québec and Port de Belledunes. CP-served ports in Québec include Port Montreal; while the rail network terminates in Montreal, CP has a transloading facility in Ville de Québec.

The Montreal-based CN owns and operates a total of 5,409 kilometers of track in Québec.[31] CP's rail network stretches from Vancouver to Montreal, serving several major US cities, such as Minneapolis, Detroit, Chicago and New York. CP owns and operates a total of 895 kilometers of track in Québec.[32]

In addition, Québec shares 6 rail crossings with the US; 2 with New York (Trout River/Fort River/Elgin and Rouses Point/Cantic), 3 with Vermont (Highgate Springs/Clarenceville, Richford/Abercorn and Norton/Stanhope) and a single crossing with Maine (Jackman/Lac-Mégantic).

Lac-Mégantic made international headlines for the wrong reasons. The fatal train derailment occurred on July 6, 2013 when an unattended train operated by Montreal, Maine & Atlantic (MMA) carrying crude oil from the Bakken Formation derailed.[33] Forty-seven deaths (42 confirmed and 5 presumed) resulted from the explosion and fire; forty buildings and 53 vehicles

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[27] Canadian Association of Petroleum Producers, Infrastructure and Transportation, Rail, http://www.capp.ca/canadian-oil-and-natural-gas/infrastructure-and-transportation/rail

[28] National Energy Board website, Canadian Crude Oil Exports by Rail – quarterly Data, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/2014/cndncrdlxprtsrl-eng.html

[29] Peter Howard, Paul Kralovic and Martin Slagorsky, Ribbons of Steel: Linking Canada's Economic Future, Canadian Energy Research Institute, CERI Study 146, May 2015, pp. 51.

[30] Ibid, pp. 50.

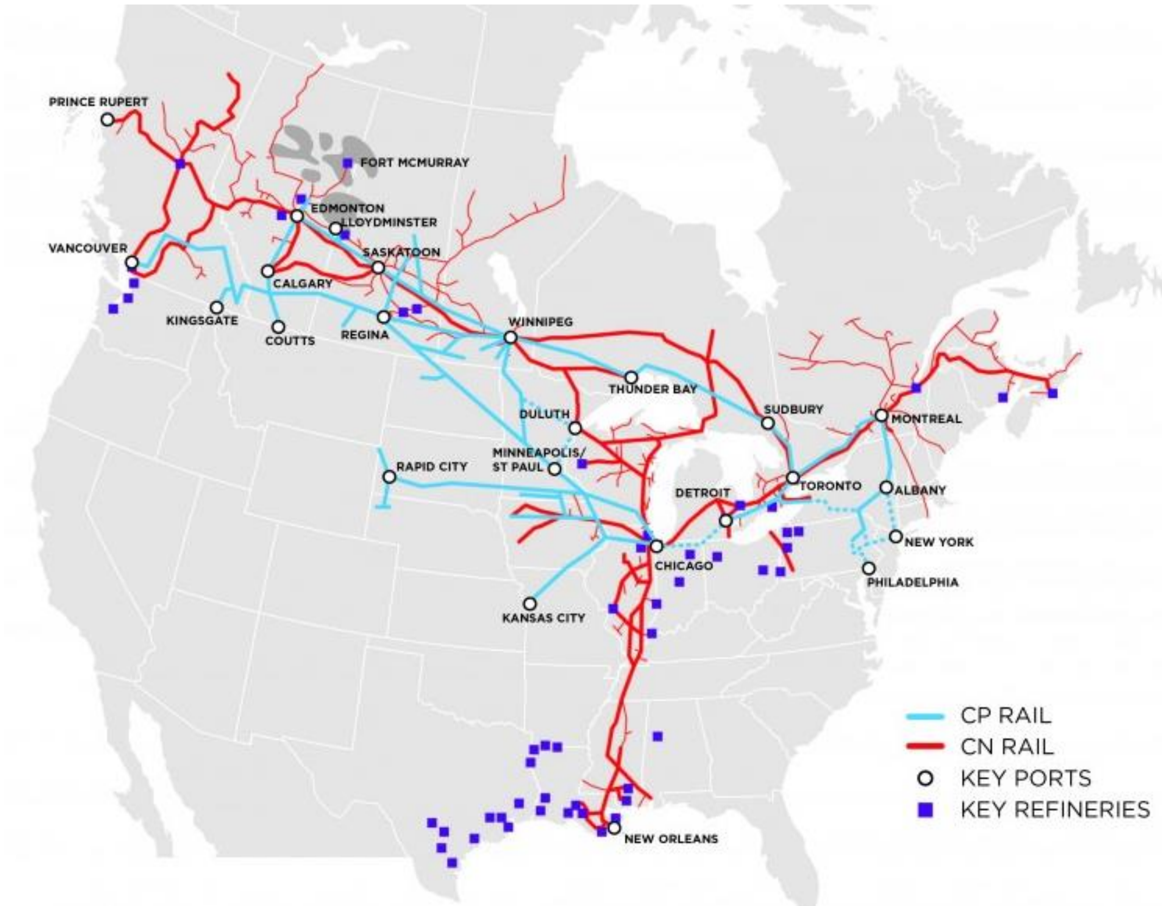
[31] Statistics Canada, Table 5 Rail transportation, Length of track operated, by area, at December 31, all carriers http://www.statcan.gc.ca/pub/52-216-x/2009000/t002-eng.htm

[32] ibid

[33] Transportation Safety Boards, Railway Investigation Report R13D0054, Lac-Mégantic Accident Report, http://www.tsb.gc.ca/eng/rapports-reports/rail/2013/r13d0054/r13d0054.asp

were destroyed.[34] Railway safety has been under an intense spotlight following the accident, particularly for the transportation of dangerous goods, such as flammable liquids.

Figure B.9: CN and CP Rail Networks



Source: CAPP[35]

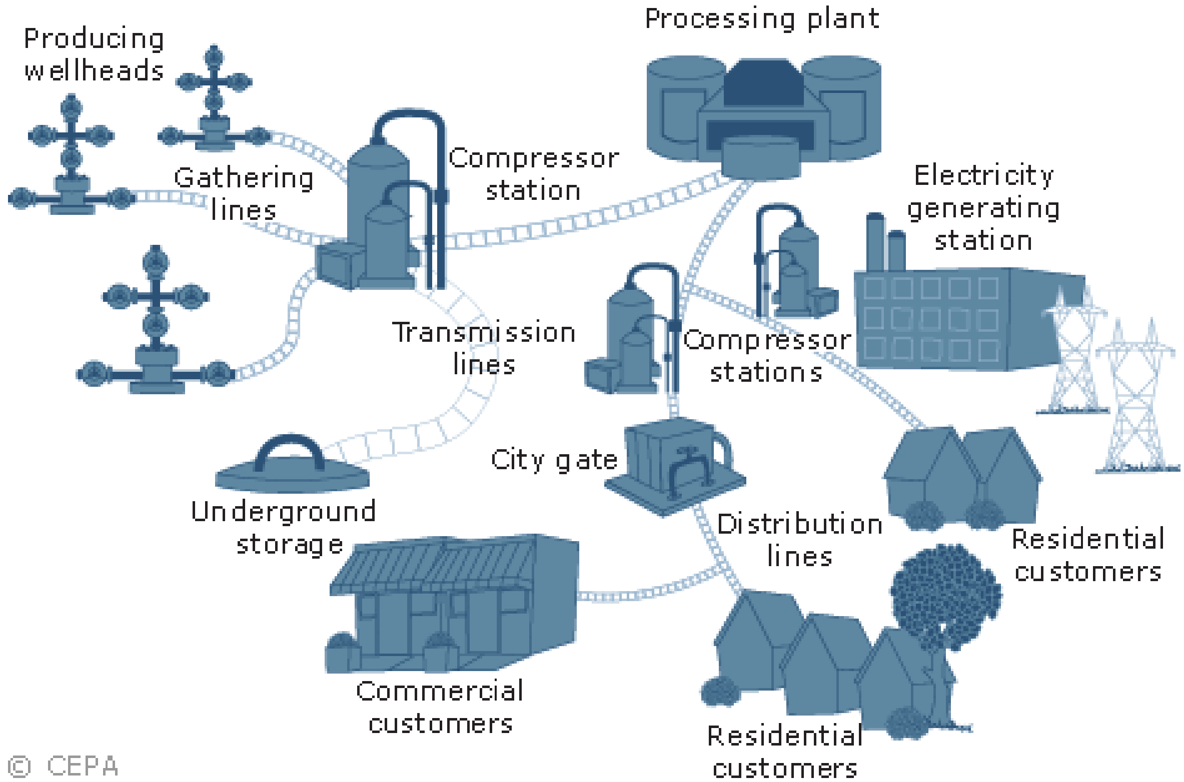
Natural Gas – Pipelines

Natural gas pipelines are used to transport natural gas from producing fields and wells to processing plants, to distribution centers. Figure B.10 illustrates the natural gas delivery system. Unlike oil, which is transported by pipeline, rail and tanker, natural gas in Québec is transported by pipeline. Recall Canada’s only LNG facility is the regasification facility, Canaport LNG, located in New Brunswick. Other facilities are, however, being planned in British Columbia, Québec and the Maritimes.

[34] ibid

[35] Canadian Association of Petroleum Producers, Canadian Rail Map, http://www.capp.ca/~/media/images/customerportal/page-images/canadian-oil-and-natural-gas/rail-map.jpg?la=en

Figure B.10: Natural Gas Delivery Network



Source: CEPA[36]

Similar to Québec's crude oil industry, Québec has natural gas production potential but there is no production or producing wellheads. As such, gathering lines or feeder lines, are negligible. There is also no underground storage capacity.

The vast amount of storage in eastern Canada is located at Dawn, Ontario, located near Sarnia. The latter includes Tecumseh Storage (103 Bcf) and Dawn Storage (157 Bcf), part of Union Gas.[37] Dawn is the largest natural gas hub in eastern Canada. In addition to access to underground storage, it has high transaction volumes and upstream and downstream connectivity.[38]

Figure B.11 illustrates the location of the Dawn Hub and its interconnectedness with Québec and the US Midwest and US Northeast markets. It is important to note that the distance to market of the Dawn storage can influence the winter seasonal supply costs for natural gas in Québec.

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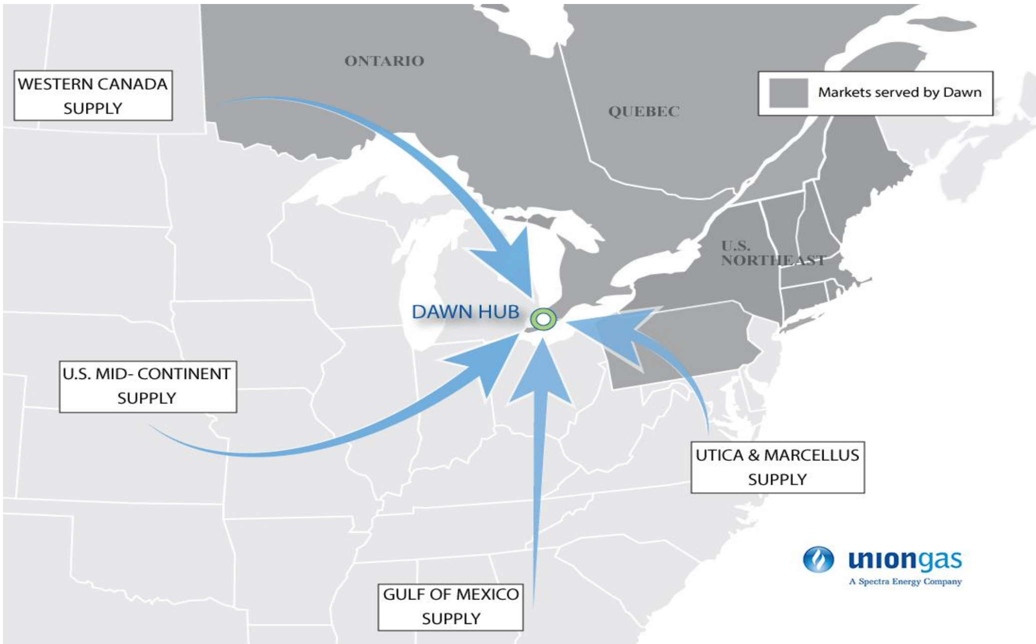
[36] Canadian Energy Pipeline Association, Natural Gas Pipelines, http://www.cepa.com/about-pipelines/types-of-pipelines/natural-gas-pipelines

[37] Union Gas website, About Dawn, Storage and Transportation, https://www.uniongas.com/storage-and-transportation/about-dawn/dawn-hub/about-dawn-hub

[38] Union Gas website, Unlocking Access to Dawn, November 6, 2014, https://www.uniongas.com/~/media/storage-transportation/communications/presentations/ldcforumnov2014/Unlocking%20Access%20to%20Dawn.pdf, pp. 6.

Figure B.11: Dawn Hub



Source: Union Gas[39]

There are several important pipelines transporting natural gas in Québec: TransCanada's Canadian Mainline and Trans Québec & Maritimes Pipeline. Natural gas pipelines utilized for distribution for local delivery include: Gaz Métro and Gazière. While not in Québec, the Portland Natural Gas Transmission System (PNGTS) and the Iroquois Natural Gas System pipelines play an important role in transporting natural gas to Québec and the region.

Natural gas pipelines in and around Québec are illustrated in Figure B.12. The Portland Natural Gas System (PNGTS) and the Iroquois Gas Transmission System are not labelled individually, but rather under TransCanada. The figure also includes Emera, a 145-kilometer pipeline from Saint John, New Brunswick to St. Stephen, New Brunswick and the Maritimes & Northeast, a 1,400 kilometer pipeline that operates from Goldsboro, Nova Scotia to Dracut, Massachusetts. The figure also illustrates Canada's only LNG terminal, the Canaport regasification facility located in Saint John, New Brunswick.

[39] Union Gas website, About Dawn, https://www.uniongas.com/storage-and-transportation/about-dawn/dawn-hub/about-dawn-hub

Figure B.12: Natural Gas Pipelines in Québec

Source: HEC Montreal[40]

The following reviews important pipelines transporting natural gas in Québec: TransCanada's Canadian Mainline, Trans Québec & Maritimes Pipeline (TQM), Portland Natural Gas Transmission System (PNGTS), Iroquois Natural Gas System and Gaz Métro.

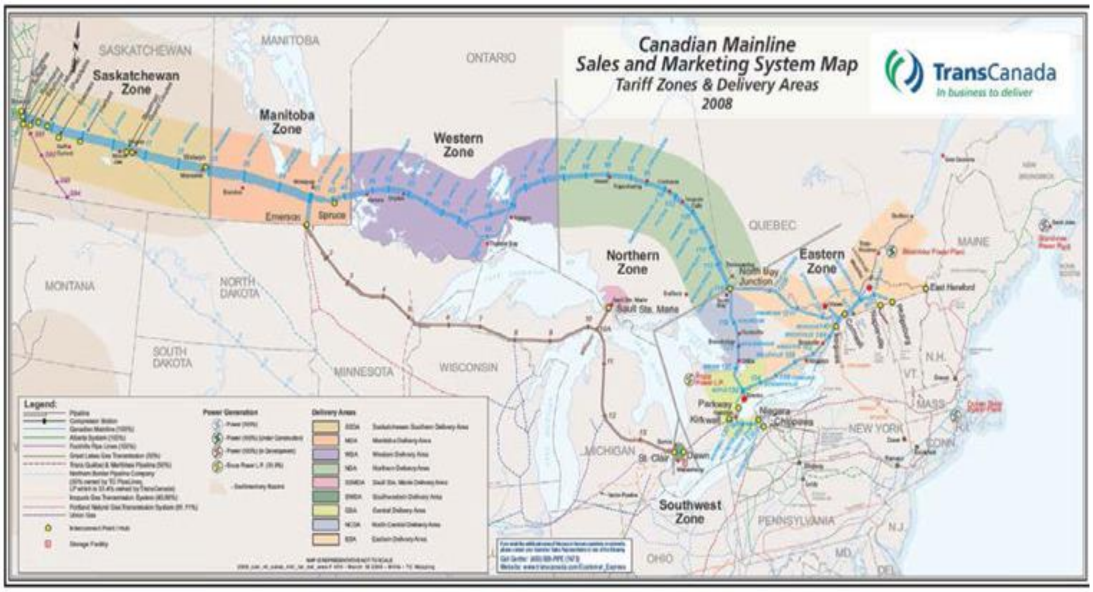
TransCanada Canadian Mainline

TransCanada's Canadian Mainline is a 14,114-kilometer pipeline that transports natural gas from the Alberta/Saskatchewan border and the Ontario/US border to serve eastern Canadian markets. It connects to the Trans Québec & Maritimes Pipeline (TQM Pipeline).

The Canadian Mainline is wholly-owned and operated by TransCanada. The Canadian Mainline can be divided into the Prairie Segment, Northern Ontario Line, North Bay Shortcut (NBSC) and the Eastern Triangle. The Canadian Mainline is illustrate in Figure B.13.

[40] HEC Montréal, État de L'Energie au Québec, 2015, pp. 11.

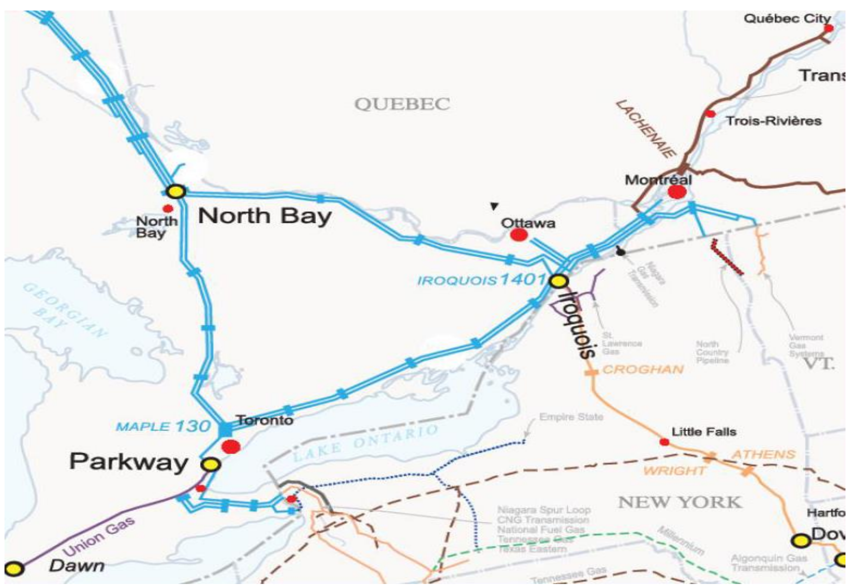
Figure B.13: TransCanada's Canadian Mainline Pipeline



Source: TransCanada Pipelines[41]

Figure B.14 illustrates the Eastern Triangle, between North Bay, Parkway and Iroquois (near Ottawa). The nearest trading hub is Dawn, located at the bottom left corner.

Figure B.14: TransCanada's Eastern Triangle



Source: HEC Montreal[42]

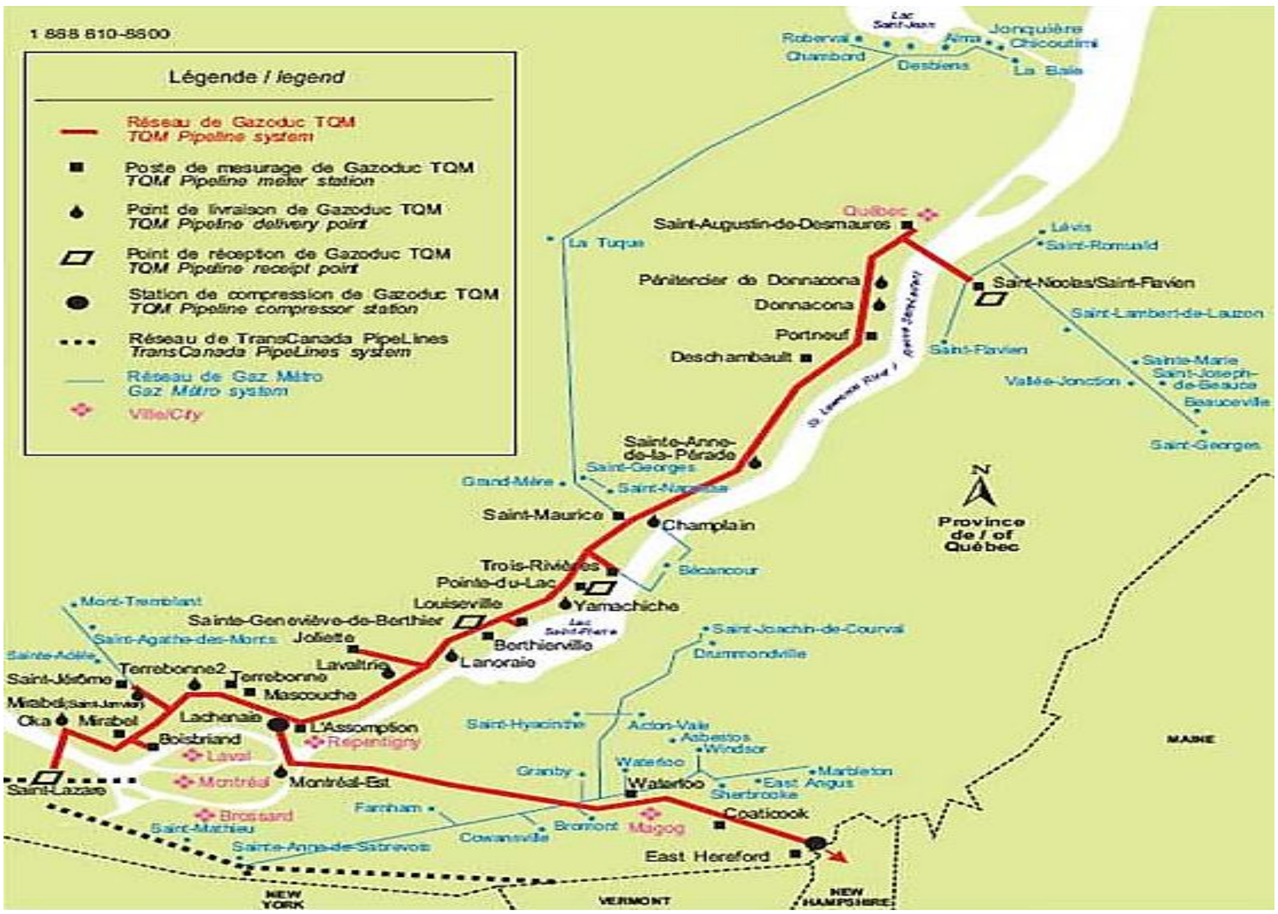
[41] National Energy Board, TransCanada Pipelines, TransCanada Pipelines Limited - Audit Report OF-Surv-OpAud-T211-2012-2013 01 - Appendix I - Maps and System Descriptions - Figure 1: Canadian Mainline

[42] HEC Montréal, Identification des marchés potentiels internes et externes pour la ressource produite et des effets de déplacement potentiels au Québec (G-ECN-04), Pierre-Olivier Pineau and Sylvain Audette, June 8, 2015, pp. 17.

Trans Québec & Maritimes (TQM Pipeline) and the Gaz Métro System

Trans Québec & Maritimes Pipeline (TQM Pipeline) is a 572-kilometre pipeline that connects with TransCanada's Canadian Mainline. It connects near the Ontario/Québec border at Saint-Lazare, Québec and extends to Saint-Nicolas, near Québec City, while the other portion extends from Terrebonne to East Hereford, on the New Hampshire border, connecting to the Portland Natural Gas Transmission (PNGTS) System in the northeast US.[43] The route of the TQM Pipeline is illustrated in Figure B.15. The TQM Pipeline is shown in red while the Gaz Métro System is shown in blue. The TQM Pipeline transports and delivers natural gas to Gaz Métro's distribution system at 31 delivery points.

Figure B.15: TQM Pipeline and Gaz Métro System



Source: http://www.gazoductqm.com/fr/pdf/22-TQM-System-Map-Carte-Sep-2014.pdf

The TQM Pipeline is 50-percent owned and operated by TransCanada. Gaz Métro Limited Partnerships owns the other 50 percent.[44] The company greatly contributed to the usage of natural gas in Québec where its use increased from 2.9 billion cubic metres in 1980 to 6.3 billion

[43] TQM Pipeline, System Map, http://www.gazoductqm.com/en/system_map.html
[44] TQM Pipeline, About Us, http://www.gazoductqm.com/en/about.html

cubic metres in 2000; TQM Pipeline meets more than half of the total demand for natural gas in Québec since 1991.[45]

Gaz Métro also owns the Champion Pipe Line, operating two natural gas pipelines in the Abitibi-Témiscamingue region.[46] The two pipelines link the TransCanada pipeline network in Ontario to the Gaz Métro distribution network in Québec.

Portland Natural Gas Transmission System (PNGTS)

While not located in Québec, the Portland Natural Gas Transmission System (PNGTS) plays an important role in the area. The PNGT begins in Pittsburg, New Hampshire, where the TQM Pipeline ends. The PNGTS pipeline continues to Dracut, Massachusetts, delivering Canadian natural gas to the Boston area. The pipeline provides natural gas to gas utilities, paper mills and power plants in Maine, New Hampshire, Vermont and Massachusetts.[47]

The PNGTS connects the TransQuébec and Maritimes Pipeline (owned by TransCanada Corporation and Gaz Métro) at the Canadian border and the Maritimes and Northeast Pipeline at Westbrook, ME (owned by Spectra Energy Partners, ExxonMobil and Emera, Inc.). TransCanada owns 61.7 percent ownership stake in PNGTS system. The pipeline is 474-kilometers in length.[48]

Iroquois Gas Transmission System

While not running within the borders of Québec, the Iroquois Gas Transmission System impacts both Ontario and Québec. The Iroquois Pipeline begins at the Canada-US border at Waddington, New York and extends through to Commack, New York and from Huntington to the Bronx, New York.[49] The pipeline transports gas to one of North America's largest markets. Commencing operations in 1992, the pipeline delivers Canadian natural gas to the New York area.[50]

The Iroquois connects on the northern terminus with TCPL's Canadian Mainline. Iroquois's pipeline route is shown in Figure B.14. With growing production from the Marcellus Shale, the Iroquois Pipeline has seen a decrease in export volumes from Canada to the US.[51] The pipeline is likely to be reversed, bringing US gas into Ontario and Québec. For additional information, please refer to CERI's Western Canada Natural Gas Forecasts and Impacts (2015-2035).[52]

[45] ibid
[46] Gaz Métro, Activities, Natural Gas Transportation, http://www.corporatif.gazmetro.com/lentreprise/activites.aspx?culture=en-ca
[47] TransCanada Pipeline website, Portland Natural Gas Transmission System, http://www.transcanada.com/customerexpress/4320.html
[48] ibid
[49] Iroquois website, About Us, http://www.iroquois.com/environmental-gas.asp
[50] ibid
[51] National Energy Board, Market Snapshot: Pipelines Transitioning to Bring More U.S. Natural Gas to Ontario and Québec , 2015-02-05, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2015/02-01gsflw-eng.html
[52] CERI Study 149, July 2015, www.ceri.ca.

Gaz Métro

Gaz Métro is the largest natural gas distribution company in Québec. It maintains over 10,000 km of underground pipelines, serves 300 municipalities and more than 195,000 customers. Gaz Métro also produces and distributes electricity and natural gas in Vermont, serving more than 305,000 customers.[53]

[53] Gaz Métro Website, About Us, http://www.corporatif.gazmetro.com/investisseurs

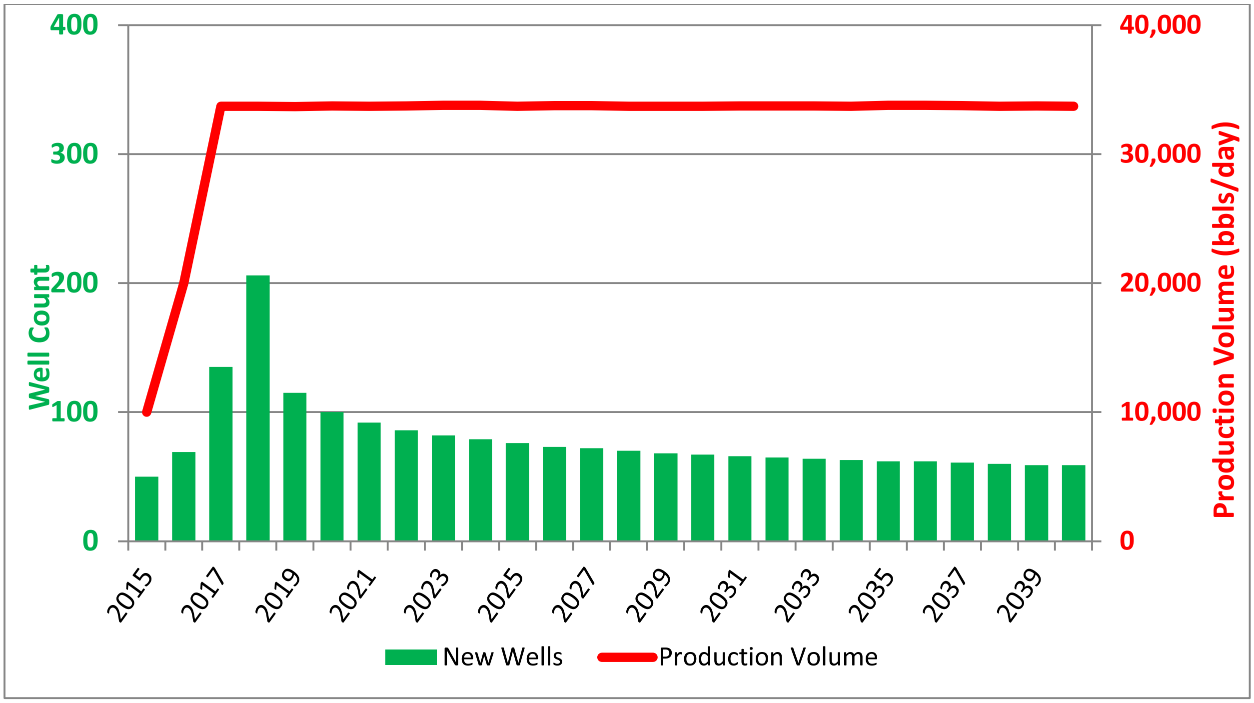
Appendix C Production Costs and Economic Impacts of Alternative Oil and Gas Production Forecasts

Macasty Oil Development – High IP Scenario

The Government of Québec foresees simultaneous oil and natural gas development on Anticosti Island, but natural gas development on Anticosti is beyond the scope of this study. Therefore, the following drilling and I/O results are based on considering Anticosti oil industry development in isolation from any natural gas development. The Government of Québec also considers transportation development options and costs, which are not reflected here.

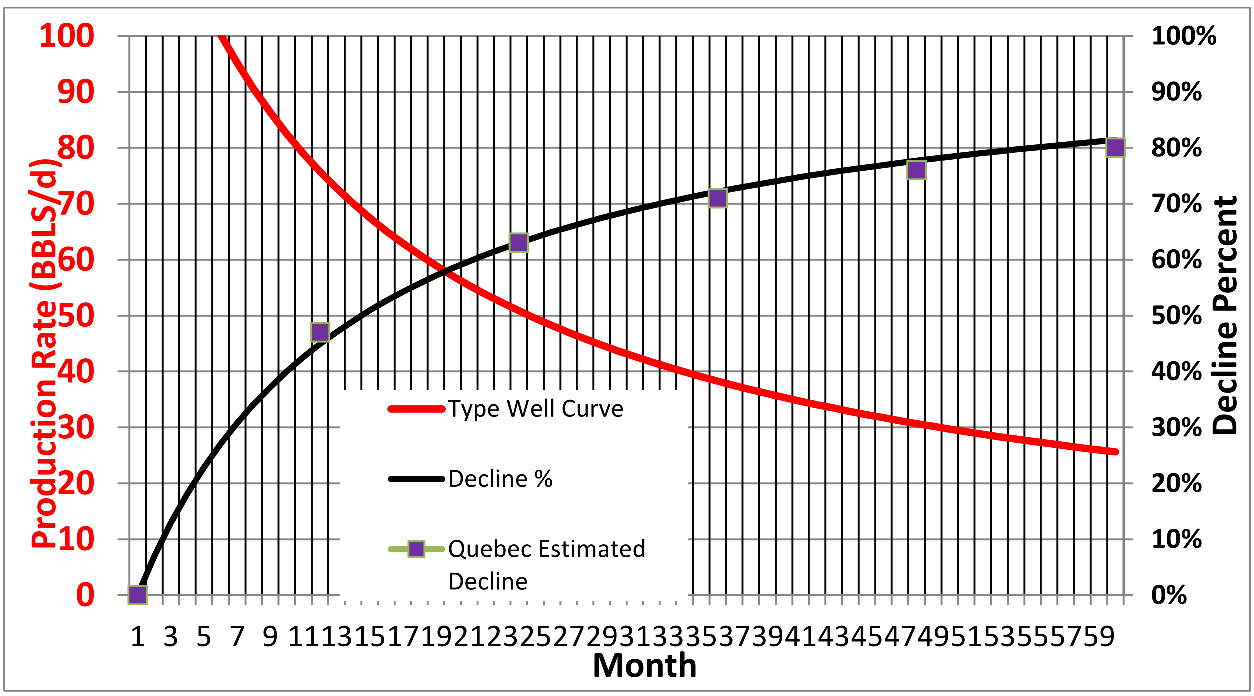
The background data for this scenario is found in the conservative "Scénario Optimisé" scenario of the Government of Québec Ministry of Finance Document "Evaluation Financière, évaluation des retombées économiques et scénarios de développement possibles de l'exploitation d'hydrocarbures sur l' Île d'Anticosti". Cost, decline, production, and other numbers are taken from the document's "Plus Probable" figures. Oil price forecasts are CERI's, and based on the EIA's Reference Case pricing for Brent crude. Important to interpreting the drilling profile and I/O results below is that the Government of Québec foresees a maximum production of 33,700 bpd (based on the decline profile illustrated in Figure C.2), which is just over half of CERI's Reference Case production rate of 60,000 bpd (Figure C.1).

Figure C.1: Anticosti Oil Production Forecast and Well Count



Source: CERI

Figure C.2: Production Decline Curve for Anticosti Oil Development



Source: CERI.

Table C.1 illustrates the economic impacts on the various provinces of a shale oil industry developing on Anticosti Island, according to the Government of Québec document. Over the 25-year study period, Québec is estimated to gain in excess of $31 billion in GDP impacts. Alberta is projected to gain $12 billion over the same time period. Impacts of more than $1.7 billion will be felt in Ontario, and British Columbia and Saskatchewan will both realize GDP gains of over $500 million.

The greatest share of employee compensation and person years of employment (direct, indirect, and induced) will also be seen in Québec, 49 percent and 50 percent, respectively. Alberta follows with 38 percent and 34 percent, and Ontario takes approximately 7.5 percent in both categories.

Table C.1: Economic Impacts of Development of Macasty Shale Oil High IP Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	11,986	5,289	55
British Columbia	597	373	5
Manitoba	235	140	2
NewBrunswick	32	18	0
Newfoundland/Labrador	18	8	0
Nova Scotia	35	22	0
Nunavut	2	1	0
Northwest Territories	6	4	0
Ontario	1,708	1,020	12
Prince Edward Island	3	2	0
Quebec	31,337	6,591	81
Saskatchewan	511	285	5
Yukon Territory	3	2	0
Total Canada	**46,473**	**13,753**	**161**

Source: CERI

In terms of tax impacts over the study period, Québec leads all provinces with impacts in excess of $5 billion in all tax categories (Table C.2). Alberta is the only other province that will see more than $1 billion in tax revenue – $2.2 billion in total. Ontario realizes the third highest tax impact at $334 million.

Table C.2: Tax Impacts of Development of Macasty Shale Oil High IP Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	641	301	1259	2201
British Columbia	16	46	58	119
Manitoba	5	13	15	32
NewBrunswick	1	2	3	5
Newfoundland/Labrador	1	1	2	3
Nova Scotia	1	2	4	7
Nunavut	0	0	0	0
Northwest Territories	0	0	0	1
Ontario	48	93	194	334
Prince Edward Island	0	0	0	1
Quebec	1173	1358	2474	5005
Saskatchewan	16	30	65	111
Yukon Territory	0	0	0	0
Total Canada	**1901**	**1845**	**4073**	**7819**

Source: CERI

It is important to reiterate that the above are strictly oil production-related results. They do not take into account natural gas production on Anticosti or transportation infrastructure development. Oil production is limited to 33,700 bpd. For these reasons, the I/O impacts are lower than those found in both the CERI Reference Case and the Government of Québec document.

The scenario's assumptions on production and costs were also used to calculate supply costs for Anticosti shale oil development. The results are presented in Table C.3.

Table C.3: Supply Costs of Anticosti Shale Oil (CDN$/bbl)

Capital Costs	$ 54.87
Operating Costs	$ 5.92
Royalties	$ 0.58
Taxes	$ 4.62
Total Supply Costs	**$ 66.00**

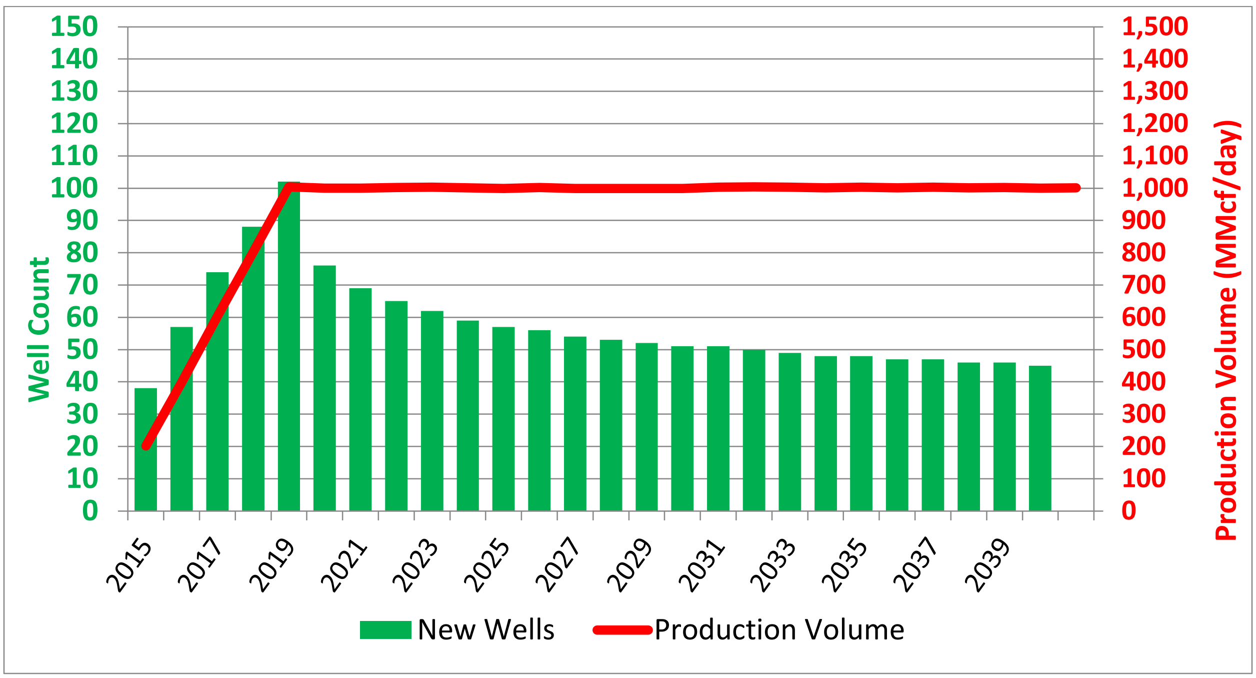
Source: Québec Government, CERI

Given a higher IP rate and lower capital costs in the Québec government's case than in CERI's Reference case, it is not surprising that the supply costs are lower in this scenario. Given the current outlook for increasing oil prices, it might be a case where development of Anticosti shale oil might be economic under these assumptions.

Utica Gas Development – High IP Scenario

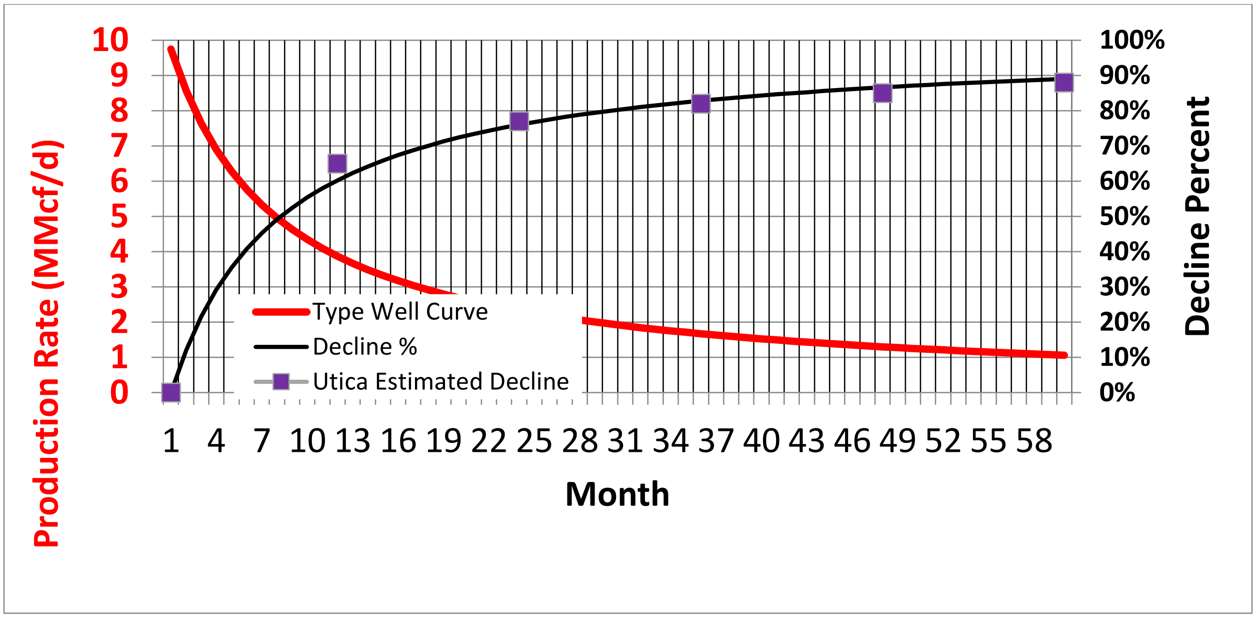
The following drilling and I/O results are based on potential capital and operating costs provided by Talisman, based on that company's preliminary results in Québec. Talisman believes that well costs can be lowered significantly by drilling 8 wells per pad and moving to 2,400m horizontal well lengths. The company also believes that IP rates of 9.75 MMcfd can be achieved, based on recent drilling results elsewhere in the Utica shale. Assuming total sales gas levels of 1,000 MMcfd can be reached by the fifth year of production, well development, production, and decline rates are as follows:

Figure C.3: Utica Shale Well Development and Production Volumes High IP Scenario, 2015 to 2040



Source: CERI

Figure C.4: Utica Shale per Well Production Rate and Decline Percentage High IP Scenario, 2015 to 2040



Source: CERI

Table C.4 shows GDP, wage, and employment impacts on all of Canada's provinces resulting from a shale gas industry emerging out of Utica shale development, according to the High IP Scenario. Québec is estimated to gain more than $42 billion in GDP impact, or 69 percent of the total. Alberta gains much from Québec gas development, at close to $15 billion. Impacts over $2 billion will be felt in Ontario. British Columbia and Saskatchewan realize GDP gains in the $600 to $800 million range over the 25-year period.

Québec sees the greatest share of employee compensation and person years of employment, with close to $8.6 billion in wages being paid out and over 100,000 person years of direct, indirect, and induced employment generated.

Table C.4: Economic Impacts of Development of Utica Shale Gas High IP Scenario, 2015 to 2040

Investment & Operations	$CAD Millions		Thousand Person Years
	GDP	Employee Compensation	Employment
Alberta	14,895	6,560	68
British Columbia	761	474	7
Manitoba	303	181	3
NewBrunswick	41	22	0
Newfoundland/Labrador	23	10	0
Nova Scotia	45	28	0
Nunavut	2	2	0
Northwest Territories	8	5	0
Ontario	2,197	1,311	16
Prince Edward Island	4	3	0
Quebec	42,002	8,611	105
Saskatchewan	657	365	6
Yukon Territory	3	2	0
Total Canada	60,942	17,572	206

Source: CERI.

Québec's tax impacts are close to $7 billion, far in excess of any other province, and more than 65 percent of the total. Alberta will see just over $2.7 billion in added tax revenue, with no other province receiving in excess of $500 million.

Table C.5: Tax Impacts of Development of Utica Shale Gas High IP Scenario, 2015 to 2040

Economic Impacts as a Result of a Shock To Quebec's Economy 2015-2040 Federal, Provincial & Municipal -- Investments & Operations				
CAD Millions	Corporate Tax	Indirect Tax	Personal Income Tax	Sum
Alberta	796	373	1565	2734
British Columbia	21	66	73	160
Manitoba	6	16	26	48
NewBrunswick	1	2	3	6
Newfoundland/Labrador	1	1	2	4
Nova Scotia	1	2	5	9
Nunavut	0	0	0	0
Northwest Territories	0	0	0	1
Ontario	61	120	249	430
Prince Edward Island	0	0	0	1
Quebec	1573	1814	3315	6702
Saskatchewan	20	39	83	142
Yukon Territory	0	0	0	0
Total Canada	2481	2434	5323	10238

Source: CERI.

Because Talisman foresees higher IP rates and lower well development costs than CERI, the above I/O results are lower than the CERI Reference Case. They reflect an industry that develops in a cost-efficient manner and sees wells that are more productive from the outset.

The scenario's assumptions on production and costs were also used to calculate supply costs for the Utica shale gas development. The results are presented in Table C.6.

Table C.6: Supply Costs of Utica Shale Gas (CDN$/Mcf)

Capital Costs	$	1.59
Operating Costs	$	0.59
Royalties	$	0.25
Taxes	$	0.13
Total Supply Costs	**$**	**2.55**

Source: CERI

Given a higher IP rate and lower capital and operating costs than in CERI's Reference case, it is not surprising that the supply costs are lower in this scenario. Given the current outlook for gas prices, development of Utica shale gas might be economic under these assumptions.