An overview of Canadian shale gas production and environmental concerns

Christine Rivard a,⁎, Denis Lavoie a, René Lefebvre b, Stephan Séjourné c, Charles Lamontagne d, Mathieu Duchesne a

a Geological Survey of Canada, Natural Resources Canada, 490 rue de la Couronne, Québec, QC G1K 9A9, Canada
b Institut national de la recherche scientifique, Centre Eau Terre Environnement (INRS-ETE), 490 rue de la Couronne, Québec, QC G1K 9A9, Canada
c Consulting geologist, 5725 rue Jeanne-Mance, Montréal, QC H2V 4K7, Canada
d Ministère du Développement durable, de l'Environnement, de la Faune et des Parc du Québec (MDDEFP), 675 boul René Lévesque Est, 8e étage, boîte 03, Québec, QC GIR 5V7, Canada

⁎ Corresponding author. Tel.: +1 418 654 3173.
E-mail address: crivard@nrcan.gc.ca (C. Rivard).

Abstract

Production of hydrocarbons from Canadian shales started slowly in 2005 and has significantly increased since. Natural gas is mainly being produced from Devonian shales in the Horn River Basin and from the Triassic Montney shales and siltstones, both located in northeastern British Columbia and, to a lesser extent, in the Devonian Duvernay Formation in Alberta (western Canada). Other shales with natural gas potential are currently being evaluated, including the Upper Ordovician Utica Shale in southern Quebec and the Mississippian Frederick Brook Shale in New Brunswick (eastern Canada).

This paper describes the status of shale gas exploration and production in Canada, including discussions on geological contexts of the main shale formations containing natural gas, water use for hydraulic fracturing, the types of hydraulic fracturing, public concerns and on-going research efforts. As the environmental debate concerning the shale gas industry is rather intense in Quebec, the Utica Shale context is presented in more detail.

© 2013 Published by Elsevier B.V.

1. Introduction

Natural gas is often considered a transition fuel for a low-carbon economy because it is abundant, efficient, and cleaner burning than other fossil fuels. Over the past decade, shale has been heralded as the new abundant source of natural gas in North America. The combination of technological advancements in horizontal drilling and in multi-stage hydraulic fracturing (“fracking” in industry jargon) techniques, as well as the progressive decline in conventional oil and gas reserves in North America, made shale gas the “energy game changer” over the last years. In addition, the fact that recoverable reserves of natural gas and oil in shales have been estimated to be large enough to potentially free the United States from a decade-long dependence on oil imports, and replace nearly all coal-generated electricity (Soeder, 2013), has probably largely contributed to making shale gas exploration and production increasingly appealing in this country. The United States was the first to economically produce shale gas from the Barnett Shale more than a decade ago; in 2013, there are over 40 000 producing shale gas wells spread across 20 states. However, natural gas prices have significantly decreased over the past several years, so that many shale dry gas plays (without liquid hydrocarbon production) are currently at the lower limit of economic profitability.

Shale gas formations targeted by industry are generally located more than 1 km deep and under pressures sufficient to allow natural flow. Vertical wells must progressively be deviated to the horizontal to reach the target zone because the latter is typically relatively thin (50–100 m). Therefore, the horizontal part (termed a “lateral”) optimizes natural gas recovery by allowing the borehole to be in contact with the producing shale interval over significantly longer distances (and thus over a much larger surface area) compared to a vertical borehole. Almost all shale reservoirs must be fractured to extract economic amounts of gas because their permeability is extremely low, which impedes gas flow towards the production well. To increase their permeability, shales are typically fractured with fluids injected under high pressure, usually through a cemented liner or production casing that was selectively perforated. The fracking fluid used is specific to each operator and differs from one shale formation to another, depending, among other things, on the pressure gradient, brittleness (Poisson ratio and Young’s modulus), clay content and overall mineralogy, horizontal stresses, and gas to oil ratio (GOR). Historically, the most common fracking fluid used by the shale gas industry has been slickwater (a simple mixture of water, proppants (usually sand), friction reducers and other chemical additives) due to its low cost and effectiveness. More recently, shale reservoirs appear to be increasingly stimulated with a hybrid treatment consisting of slickwater used in alternation with a cross-linked gel purposely designed for a specific viscosity, with hybrid slickwater energized with N₂ or CO₂, or with hydrocarbons such as gelled propane.
Micro-seismic events induced by fracking operations are now being routinely recorded on a fraction of the wells drilled in a new exploitation area using ultra-sensitive seismographs placed either in an adjacent gas well, as a primary buried array or as a surface array. These techniques allow the estimation of fracture height and half-lengths from which a stimulated reservoir volume can be calculated, which helps assess the effectiveness of the stimulation. Generally, induced fractures are reported to extend less than 300 m vertically (Davies et al., 2012; Fisher and Warinski, 2012).

Hydraulic fracturing has been used to stimulate production wells in conventional oil and gas reservoirs (mostly in vertical wells) in North America for more than 60 years. However, in the case of horizontal shale gas wells, the stimulation process requires greater amounts of water, sand and chemicals for a given well, and this mixture must be injected at higher rates and pressures, and a much larger volume of rock is involved compared to conventional reservoirs. Hence, more powerful equipment is required on site (pumper trucks) and much more truck traffic for the transportation of water and sand is involved (if a local source is not available). Due to the horizontal drilling technology and multi-stage fracturing, these activities are taking place several times on multi-well pad sites, instead of taking place in multiple vertical wells on the surface. Environmental concerns are mainly related to seven issues that are themselves related to six main activities, as summarized in Table 1.

This paper presents the historical context and current state of shale gas development in Canada (Section 2), geological contexts of main Canadian shale plays containing dry gas (Section 3), facts on hydraulic fracturing (Section 4), water usage by this industry (Section 5), as well as various research initiatives implemented to investigate different environmental issues mentioned above and to characterize the shale formations themselves (Section 6). Then, public concerns (Section 7) and regulation related to drilling and fracturing (Section 8) are briefly discussed. Finally, the historical background and social context of the Utica Shale (southern Quebec) are described in more detail. Although only limited Utica Shale exploration has taken place, it has raised environmental concerns amongst the general public that have led to a temporary de facto moratorium on hydraulic fracturing in Quebec.

### 2. General context

Over 500 000 oil and natural gas wells have been drilled to date in Canada, of which more than 375 000 are located in Alberta (CAPP, 2012). Petroleum development began in eastern Canada in 1858, where a 15.5 m (51 ft) oil well was dug (not drilled) in Oil Springs, Ontario. This well became the first commercial oil well in North America. Natural gas was discovered in Ontario in 1859, but commercial gas was not produced in the province until 1889. In the late 1800s, some production of natural gas from unconsolidated Quarternary sands for local industrial purposes took place for a short period in the Trois-Rivières area (between Montreal and Quebec City, in southern Quebec). This very small reservoir was, however, rapidly depleted. At that time, shallow conventional hydrocarbons were targeted, mainly in overburden (often at the bedrock/overburden contact). In western Canada, the first gas discovery was accidentally made while drilling for water near Medicine Hat, Alberta, in 1883. A second well was drilled the following year that produced enough gas to light and heat several buildings. The discovery of the world-class Leduc oil field in 1947 by Imperial Oil made the Western Canada Sedimentary Basin the center of Canada’s petroleum exploration and production. The industry started constructing a vast pipeline network in the 1950s, to start developing domestic and international markets. Canada is now the third largest producer of natural gas in the world (1720 billion m³ or 60 200 billion ft³ or Bcf for 2012; National Energy Board, 2012) and the 4th largest exporter, with the U.S. currently being its sole international market.

Canada’s production of “primary” energy, i.e. energy found in nature before conversion or transformation, totalled 16 495 petajoules (PJ) in 2010. Fossil fuels accounted for the greatest share of this production, with crude oil representing 41.4%; natural gas, 36.5%; and coal, 9.2% (NRCan, 2011). The remainder (12.9%) comes from renewable energy sources. About 95% of the natural gas was produced from conventional sources, and the remaining 5% was from unconventional sources such as coal bed methane and shale gas. Recent exploration and exploitation of numerous shale gas plays in Canada have caused a sharp increase in both estimated in-place resources and natural gas reserves. The portion of shale gas in the Canadian energy production could significantly increase in future years because of several factors, notably the large and continuous nature of unconventional reservoirs and declining conventional (oil and gas) production. There are indeed a number of shale gas formations at various stages of exploration and development across the country (British Columbia, Alberta, Yukon, Northwest Territories, Quebec, New Brunswick and Nova Scotia).

Table 1

<table>
<thead>
<tr>
<th>Environmental concerns</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Water quantity</td>
<td>Site development and drilling preparation</td>
</tr>
<tr>
<td>2. Water contamination</td>
<td>2. Drilling activities</td>
</tr>
<tr>
<td>3. Management of fracking and flowback fluid storage</td>
<td>3. Completion and hydraulic fracturing</td>
</tr>
<tr>
<td>4. Radioactive wastes</td>
<td>4. Well operation and production</td>
</tr>
<tr>
<td>5. Nuisances (noise, trucking, light)</td>
<td>5. Fracturing fluids, flowback, and produced water storage and disposal</td>
</tr>
<tr>
<td>6. Atmospheric emissions/air quality</td>
<td>6. Other activities (e.g. plugging and abandonment)</td>
</tr>
<tr>
<td>7. Induced seismicity</td>
<td></td>
</tr>
</tbody>
</table>

1 British Columbia does not distinguish between shale and tight sand gas because they are part of a continuum of very low permeability reservoirs in which economic production can only be achieved through hydraulic fracturing.
Most of the current drilling and production activities for shale gas and liquid-rich shale gas in Canada reside in northeast British Columbia (Fig. 1). Northern BC has now four active plays (Horn River Basin and Montney Play Trend, and, to a lesser extent, the Cordova Embayment and Liard Basin). Active plays in Alberta include the Duvernay and Montney shales. In New Brunswick, testing in the Frederick Brook Shale has resulted in mixed results. This province, which was among the first jurisdictions in North America to develop oil and gas, has been mainly active in tight sands gas since the 1990s. NB currently has one producing shale gas well in the Carboniferous tight gas McCully field in the southern part of the province. In Nova Scotia, five vertical exploration wells were drilled in the Horton Bluff shale without reported success. There is no current exploration activity for shales in Nova Scotia. Quebec presently has a de facto moratorium on shale gas drilling and hydraulic fracturing and the last shale exploration activity in the St. Lawrence Lowlands took place in December 2010. Because of low natural gas prices, industry activity in Alberta and Saskatchewan is currently focused on oil sands, conventional oil and gas, unconventional oil in the extension in Saskatchewan of the prolific oil-rich U.S. Bakken play (part of the Williston Basin), and liquid-rich gas in the Duvernay shale in Alberta.

### 3. Geological overview of main Canadian shale gas targets

The Canadian Phanerozoic successions comprise a significant number of sedimentary basins with thin to thick organic-rich shale intervals (Hamblin, 2006). Of these, some are already at the gas production stage, and others are at various phases of exploration and definition of their potential to release economic volumes of natural gas. This section highlights the main geological characteristics of some of the best-known...
producing and undeveloped shales. The geological character of the Upper Ordovician Utica Shale in Quebec is not presented here, because it is discussed in detail in Lavoie et al. (2013, in this issue). Table 2 presents areal extents, estimated resources and estimated recoverable reserves of gas in these selected shale gas formations or basins.

3.1. Upper Devonian Horn River Basin Shales

The transition from the broad Middle to Late Devonian shallow marine carbonate shelf of the Western Canada Sedimentary Basin (WCSB) into a deeper shale-dominated domain occurs in the Horn River Basin (Mossop et al., 2004).

The Horn River Basin comprises three major Upper Devonian shale units, from base to top: the Evie and Otter Park members of the Horn River Formation and the Muskwa Formation (Ferri et al., 2012). In northeastern British Columbia, these three shale units form a roughly 200 to 500 m thick succession that is either laterally equivalent (Horn River Formation) or overlies (Muskwa Formation) the Middle–Upper Devonian carbonate platform and reefs of the Lower and Upper Keg River and Slave Point formations. In turn, the Upper Devonian shales are overlain by the Mississippian shales of the Fort Simpson Formation (Ferri et al., 2012). The transgressive Muskwa Formation extends significantly into southwestern Alberta where it is known as the Duvernay Formation.

Over most of the Horn River Basin, the Upper Devonian shales are buried to depths of 2500 m and well within the dry gas window (National Energy Board, 2011). The black to dark gray colored shale units in the Horn River Basin consist of marine Type II organic matter with Total Organic Carbon (TOC) values up to 6% (British Columbia Ministry of Energy and Mines, 2005). The Evie and Muskwa shales are siliceous and pyrite-rich whereas the Otter Park shale is more calcareous (National Energy Board, 2011). Porosity values can be relatively high, reaching up to 5% (British Columbia Ministry of Energy and Mines, 2005), whereas average permeabilities range between 100 and 300 nanodarcies (British Columbia Ministry of Energy and Mines, 2005).

3.2. Upper Devonian Duvernay Formation

The Duvernay Formation is an Upper Devonian shale-dominated succession that covers a significant part of west-central Alberta of the Western Canada Sedimentary Basin (Mossop et al., 2004). The southward transgressive shales of the Duvernay (from the platform margin located to the north) did not kill reef growth in the WCSB but are found laterally equivalent and enclosing the oil-poor Leduc reefs for which they acted as source rocks (Allan and Creaney, 1991).

In west-central Alberta, the Duvernay shales are found in the East Shale and West Shale basins (Switzer et al., 1994), both of which differ in the geological setting and characteristics of the Duvernay Formation (see below). In the WCSB, the Duvernay Formation overlies the Upper Devonian carbonate platform of the Cooking Lake Formation and the formation is in turn overlain by the Upper Devonian Ireton Formation of clastics and carbonates (Mossop et al., 2004).

Regionally, the Duvernay Formation is 30 to 120 m thick and consists of three members, from base to top: 1) a black argillaceous limestone, 2) a black shale unit with carbonate detrital beds, and 3) a brown to black shale with argillaceous limestone (Switzer et al., 1994). In the East Shale Basin (Switzer et al., 1994), the slightly thicker Duvernay Formation is dominated by organic-rich lime mudstone. The Duvernay Formation in the West Shale Basin becomes less calcareous and more shale-rich from east to west. Depth from the surface to the top of the Duvernay is about 1000 m near the eastern boundary to about 5500 m in the west, this correlates directly with thermal maturation data which documents a westward trend of increasing thermal maturity (ERCB/AGS, 2012).

The Duvernay shales are dominated by marine-derived Type II organic matter with total organic carbon (TOC) content comprised between 0.1 and 11.1%; the highest values are generally found in the East Shale Basin (ERCB/AGS, 2012). Based on well logs and cuttings, the Duvernay Formation has an average porosity and permeability of 6.5% and 394 nanodarcies, respectively (Dunn et al., 2012).

3.3. Lower Carboniferous Frederick Brook Member

The Frederick Brook member belongs to the Tournaisian (Early Carboniferous) Albert Formation of the Horton Group (St. Peter and Johnson, 2009). The Horton Group is the first sedimentary unit to be deposited in the Maritimes Basin, a successor basin that formed after the Devonian Acadian Orogeny in eastern Canada (Hamblin and Rust, 1989). Post-orogenic sedimentation of the Horton Group was dominated by alluvial to lacustrine environments (Martel and Gibling, 1996).

The Frederick Brook Member is a lacustrine shale overlain and underlain by successions of sandstone, siltstone and shale (St. Peter and Johnson, 2009). The Frederick Brook lithofacies consist of laminated kerogen-rich dolomitic mudstones, microlaminated kerogen-rich shales (oil shales) and kerogen-rich siltstones with minor sandstone interbeds. St. Peter and Johnson (2009) estimated its maximum thickness to be around 350 m, although recent seismic data and drilling in the Moncton sub-basin (Corridor Resources Inc., 2009) suggest that a much thicker succession of 900 to 1100 m is locally developed. From burial depths of 3 to 4 km in the central part of the Moncton sub-basin, the unit shallows to 1 to 2 km at the sub-basin margin.

The Frederick Brook Member lacustrine shales are considered to have sourced the conventional oil and gas fields of Stony Creek and McCully, respectively (St. Peter and Johnson, 2009). The organic matter in the shales are Type I algal material with subordinate Type III land-derived organic matter (St. Peter and Johnson, 2009). The TOC values average 11% in the thermally immature areas (St. Peter and Johnson, 2009), although, in the deeper, gas-prone part of the basin, TOC values are between 1 and 2.5% (Corridor Resources Inc., 2009). The shales are clay-rich (illite) with a similar volume-percent of quartz, diagenetic albite and carbonates (dolomite and calcite) (St. Peter and Johnson, 2009). Well logs indicate that the gas-prone shales have porosities ranging from 3 to 8% (Corridor Resources Inc., 2009). It is noteworthy that...
one vertical shale gas well is currently producing gas from this shale unit within the tight sandstone McCully gas field (St. Peter and Johnson, 2009).

3.4. The Lower to Middle Triassic Montney Formation

The Triassic succession of western Alberta and northeastern British Columbia was deposited on a passive margin marine shelf and slope (Podruski et al., 1988) before the development of a foreland basin in Jurassic time. The Montney Formation unconformably overlies Upper Paleozoic rocks and is overlain by the phosphatic interval at the base of the Doig Formation (Gibson and Barclay, 1989).

The Montney Formation lithofacies are dominated by shale and siltstone with varying degrees of dolomitization and as such, the Montney is not truly a shale gas unit. Fine-grained sandstones and coquinas are also present in the upper part of the siltstone-dominated succession (Gibson and Barclay, 1989). The Montney Formation reflects a transgressive-regressive third order cycle (Gibson and Barclay, 1989) with a lower major transgressive facies and maximum flooding succession (lower shale-siltstone interval) overlain by shallower and coarsening upward facies.

The thickness of the Montney Formation increases westerly from 0 m (at the erosional margin of the basin) up to 300–400 m in both Alberta and British Columbia and similarly, the depth to the top of the Montney increases in the same direction from approximately 500 m in the east to over 4000 m in the west. This variation in burial resulted in the development of oil to dry gas zones in an overall westerly trend. The Montney Formation consists of Type I/III organic matter (Ibrahimbas and Riediger, 2005). The average TOC content of the Montney is 0.8%, with a range of 0.1 to 3.6%. The Montney siltstone (the gas producing lithology) has low porosities (lower than 10%), although the associated sandstone porosity can be as high as 35%. The Montney lithofacies are clay-poor (maximum 20%, BC Oil and Gas Commission, 2012) and show a high content of quartz, carbonates and feldspars. In some areas of BC, the Montney is being actively developed for liquids, with gas being a by-product.

4. Overview on fracturing

Over 175 000 wells have been stimulated by hydraulic fracturing in Alberta alone (mainly vertical wells), with few reported incidents. However, as mentioned above, multi-stage fracturing in horizontal wells involves higher injection pressures and rates and a larger quantity of water. About 14 000 of these wells have been fractured so far across Canada, with most of them being located in relatively remote areas. However, this number includes all types of unconventional reservoirs (shale gas and liquid-rich shales, tight gas and tight oil, and coal bed methane), not all of which require large amounts of water and high pressures to frac. For instance, coal bed methane is typically fractured with nitrogen in Alberta.

In BC, slickwater is used in the Horn River Basin, while Montney liquid-rich gas shales and siltstones are mainly fracked with foams (a mix of gas and water). In Alberta, slickwater, cross-linked fluids (typically guar-based fluids cross-linked with boron ions), and a combination of the two have been used in the Duvernay Formation. In New Brunswick, LPG (predominantly gelled propane) was successfully used in the first vertical shale gas well; the following two horizontal wells used slickwater and were unsuccessful. Industry has mainly used slickwater fracturing and hybrid fracs (cross-linked fluids with guar gum) in the calcareous shales of the Utica so far, with the exception of one vertical well in a liquid-rich domain, where propane was used.

Chemical additives used in hydraulic fracturing are one of the main concerns for Canadians, even though propanes and chemical additives in most slickwaters constitute less than 2–3% of the overall composition (Nash, 2010). To parallel the publically available US hydraulic fracturing chemical registry “fracfocus.org.”, which provides information related to chemical additives, methods of fracking and regulations by state, the province of British Colombia has recently implemented the website http://fracfocus.ca. As of January 1, 2012, disclosure of used additives on this website is required by the BC Oil and Gas Commission (BCOGC); Alberta and New Brunswick have recently announced (April 2013) that they now have the same legal obligation.

All wastewater is collected and stored in enclosed tanks with secondary containment to avoid potential infiltration of slickwater or saline flowback water into the soil in BC and AB. No lined surface ponds are currently being used in Canada. In BC, the vast majority of water is re-injected at depth in deep saline aquifers such as those in the Debot Formation. Seismic events induced by these injections are also a concern for the population (see below). In eastern Canada, deep-well injection of flowback water has not been tested or done because of lack of understanding of potential deep-seated geological storage capacity (QC) or is simply not authorized because of potential leaks resulting from assumed permeability issues of cap rock units (NB).

An increasing number of cases of small but conceivable earthquakes have been reported in seismically quiescent areas where active subsurface high-pressure water injection, either for geothermal tests or hydraulic fracturing, took place. Dense arrays of seismographs have been locally installed (e.g., northeastern BC) to decipher the source of these tremors. In the case of the areas with shale gas development, the issue is to distinguish deep crustal events from shallow events linked either to fracking programs or to wastewater re-injection in deep aquifers. Preliminary results from the research in BC indicate that hydraulic fracturing can lead to limited induced seismicity (BC Oil and Gas Commission, 2012). No damage has been documented as a result of induced seismicity associated with shale gas development sites. The highest magnitude recorded during hydraulic fracturing activities in northeastern British Columbia is 3.8 on the Richter scale. This corresponds to minor damage (event felt only by some people on the Mercalli scale). From preliminary data, the time interval between the start of the fracking program and the induced seismic event (magnitude 2 to 3.8) was between a few minutes to about one day (BC Oil and Gas Commission, 2012). In 2012 and 2013, GSC deployed arrays of seismographs in the Northwest Territories and New Brunswick, in areas of eventual shale exploration and development. The stations are currently monitoring the regional large and fine-scale natural seismicity.

In provinces where no large-scale oil and gas activities had yet taken place, several initiatives have been implemented at the provincial level in the last 3–5 years, including working groups (NB), a strategic environmental assessment (QC) and even a specific hydraulic fracturing review committee (NS). In addition, public consultations and community information sessions were carried out in Quebec in 2010 (BAPE, 2011), leading to the recommendation of a Strategic Environmental Assessment (SEA) dedicated to issues related to shale gas development. During the SEA process, the Quebec Ministry of Environment would only have considered authorizing fracking if the SEA Committee deemed it useful for gaining scientific knowledge. However, because no operator requested a permit to conduct such activities, the SEA Committee proceeded with its studies by other means, which led effectively to a 2-year moratorium on shale gas fracking in Quebec. This moratorium has recently been extended for the St. Lawrence Lowlands until a new legal framework is set to specify deep crustal activities. Additional public consultations (Bureau d’audiences publiques sur l’environnement, BAPE) will be held on the SEA report conclusions in 2014. The SEA committee will end its mandate in December 2013 and the BAPE will provide recommendations in 2014. Public consultations were also held in New Brunswick in 2012 and expressed concerns by stakeholders have certainly influenced the newly published (February 2013) guidelines to regulate the unconventional shale-hosted petroleum industry in the province (New Brunswick, 2013).

Two incidents recently occurred in Alberta in relation to hydraulic fracturing operations. In September 2011 in Grande Prairie, improper
completion work (perforated casing above the base of groundwater protection, at a depth of 136 m) was found to be the cause of contamina-
tion of a near-surface water-bearing sandstone with gelled propane (ERCB, 2012a). However, the impacted zone was not a source of potable water. The base of groundwater protection in Alberta and British Columbia is set at 600 m deep, unless the interface can be proven to be shallower. In January 2012, a spill occurred in Innisfail due to inter-
well bore communication, causing the release of about 500 barrels of fracturing and formation fluid to the surface, affecting 4.5 ha. Frozen ground conditions prevented much of the fluid from seeping into the ground and the majority of the cleanup operations were complete within 72 h (ERCB, 2012b).

5. Water use

Among available fracking techniques, slickwater hydraulic fractur-
ing is the one that uses the most water. It is, however, the least expen-
sive method and has proven to be very effective, mainly because it
maximizes the contact surface by generating complex fracture net-
works in the shale unit, especially in brittle rocks with higher silica or
carbonate content and lower clay content (Johnson and Jonson, 2012). Estimates from Johnson and Jonson (2012) using approximately 500 wells in seven formations and five different basins showed that there
is an order of magnitude difference for water usage between foam and
slickwater fracs: foam fracs in siltstone or shale formations use around 200 m$^3$ of water, while siliceous shale slickwater completions require 25–5000 m$^3$ per frac stage. For this reason, the cumulative water usage for the Montney Play Trend was much lower than that of the Horn River Basin, even though more wells were drilled each year in the former.

Besides water quality issues, there is public concern related to water quantity. It is difficult to estimate how much water will be required for each well until test sites have been studied. Quantities of fluids required depend mainly on the geology, i.e., the lithology, petrophysical and geomechanical properties of the rock and hence, the pressure necessary to fracture the shale, the shale depth, length of laterals, the stimulation technique used, the number of frac stages per well and anticipated water returns (Johnson and Jonson, 2012). In addition, in order to maximize efficiencies and minimize footprints, well pads are designed for many wells, which may be fractured consecutively, thereby increas-
ing water demand over a short period of time. Typically in BC, there are currently six or eight wells per drilling pad, but this number can go up to 21 on a given pad (for example, in the Horn River Basin). Water issues could, therefore, mainly be related to the intensity of shale gas development.

In BC, reported volumes of water use during a well hydraulic fracturing range from 2000 m$^3$ to over 100 000 m$^3$ per well (i.e. approximately 66 to 3300 large tanker trucks, since a large water tank truck is able to carry about 30 m$^3$). Averages of 1900 to 7800 m$^3$ for the Montney Play Trend and 34 900 m$^3$ for the Horn River Basin were reported by Johnson and Jonson (2012), while mean values of 10 000 to 25 000 m$^3$ for the Montney Play Trend and 25 000 to 75 000 m$^3$ for the Horn River Basin are provided in Precht and Dempster (2012). In Alberta, an average of 50 000 m$^3$ is estimated for slickwater fracturing (Precht and Dempster, 2012). In Nova Scotia, volumes for the two ver-
tical wells that have been fracked so far were of 5900 and 6800 m$^3$, while in NB, volumes for the two horizontal wells were ~20 000 m$^3$. In Quebec, volumes ranged from several hundred cubic meters to 15 000 m$^3$ and the average frac stage used 1500 m$^3$. The U.S. literature reports that drilling and hydraulic fracturing of shale gas wells together typically use 7500 to 15 000 m$^3$ (from 2 to 4 million gallons) of water (GWPC and ALL Consulting, 2009). The return water volume combining produced and flowback water in BC varies from 15 to 70%. In the Montney, between 50 and 100% of water is recovered, while much less water is being recovered in the Horn River Basin. In the Utica of Quebec, the average flowback recovery was 45%.

Water sourcing is a key issue for hydraulic fracturing in BC. In some locations, it is difficult to collect sufficient water for a high-volume fracking program due to the highly variable stream flow conditions. In the Prairies (i.e. AB, SK and MB), water usage is also becoming problematic since several river basins in the southern regions have fully allocated surface waters. Initially, the industry preferred to use fresh water, but now companies can use brackish or even saline water for fracking pur-
poses. Saline water from the Debolt Formation (20 000–30 000 ppm of TDS) underlying the Horn River Basin is being used for fracking by some companies. However, this source of water contains H$_2$S and other gases (CO$_2$, CH$_4$) that must first be removed in a treatment facility, and the saline water must often be diluted. Regular friction reducers can be used to a salinity up to about 25 000 ppm. Above this salinity, pipes and infrastructure, as well as chemical additives (mainly friction reducers) have to be adapted to the higher salinity. The industry has developed additives that work at salinities reaching up to 60 000 ppm (Ferguson et al., 2013) and 200 000 ppm is targeted, to reduce flowback water management and treatment as much as possible.

The depth to the base of fresh groundwater aquifers is, unfortunately, poorly known across much of Canada. Water wells are typically too shallow to reach the base of fresh groundwater, while oil and gas wells, targeting much deeper zones, have historically rarely included the systematic report of the water salinity for a given well, especially at relatively shallow depths. Alberta is the only province that has defined this base, using the depth at which water exceeds 4000 ppm of TDS. Work on the definition of the Base of Groundwater Protection (BGP) started in the 1980s by Alberta Environment, based on a series of reference cross-sections; this product was further updated and adapted by AGS and is available on a self-serve database (https://www3.eub.gov.ab.ca/Eub/COM/BGP/UI/BGP-Main.aspx). In the Prairies, groundwater is often brackish, or slightly salty, near the surface. In eastern Canada and BC, the base of fresh groundwater would likely be in the order of 200 to 300 m, except in coastal areas and in areas where saline water from Quaternary sea invasions has not yet been leached out, where it could be shallower. For instance, there is a 2200 km$^2$ area in southern Quebec overlying, for its main part, the Utica Shale, which contains brackish water of Champlain Sea origin that has not been leached away by recharge or fresh groundwater flow in the active zone (Beaudry et al., 2011).

6. On-going research

Although the regulation of shale gas development is primarily a provincial jurisdiction in Canada, the Geological Survey of Canada has initiated in 2011 several new research projects focusing on various aspects of shale gas exploration and development in Canada, in collabora-
tion with the provinces and universities. These studies focus on two themes: 1) evaluation of the gas resource (in place and recoverable) and geological characteristics of shale-hosted petroleum reservoirs, and 2) potential environmental issues related to hydraulic fracturing. The first theme includes three studies. The first one aims at developing a methodology for in-place and recoverable gas resource assessment, which will initially be tested on mature and frontier basins in Alberta, British Columbia and Quebec. The second one focuses on geological characteristics of specific shale reservoirs in Canada and the U.S., so as to better understand the quality and behavior of these reservoirs, using parameters that control their hydrocarbon storage capacity such as mineralogy, nature of organic matter and its porosity evolution through increasing thermal conditions. The third project studies the geological integrity of cap rock in three provinces of eastern Canada: Quebec, New Brunswick and Nova Scotia.

The second research theme on environmental aspects includes two studies: one on potential impacts of shale gas development on ground-
water quality, so as to improve the understanding of a possible risk of natural or artificially-induced link between the shale gas target (>1000 m deep) and surficial aquifers (<300 m), while the second...
aims at increasing the understanding of potential induced seismicity caused by injection for hydraulic fracturing purposes or for disposal by injection of flowback wastewater (which includes the installation of several seismographs as mentioned in Section 4). The groundwater project, which is described in Lavioie et al. (2013, this issue), focuses on a local study area in southern Quebec, while the induced seismicity project is active in western Canada (BC, NWT), and has been expanded in eastern Canada (NB). All these projects are multi-partnered, including active collaboration with the industry, provincial departments of natural resources, energy and environment, and universities. In parallel, Environment Canada is carrying out a Canada-wide project on the development of impact indicators of shale gas activities on groundwater using laboratory work, field data as available, and modeling, while Health Canada, in collaboration with NB, has undertaken a study on air emissions to understand the potential impact that shale gas development may have on air quality in regions where such development may occur. Life-cycle greenhouse gas emissions related to shale gas development have already been the focus of a national compilation ((S&T)2 Consultants Inc., 2011).

Research studies are also being carried out in many provinces, typically in an academic/governmental collaboration. For instance, in Quebec, the SEA Committee is funding many studies, two of which are specific to 1) the theoretical numerical modeling of near-well gas migration and upward fluid migration by Université Laval (Nowamooz et al., 2013a, 2013b) and 2) nature and concentration of natural background dissolved gas in groundwater in the St. Lawrence Platform led by the Université du Québec à Montréal (UQAM) (Pinti et al., 2013). These two studies will be completed by December 2013. In British Columbia and Alberta, detailed research on shale resource characterization and on various development-associated environmental issues is in progress. The Alberta Geological Survey has undertaken in 2009 a study on measurement and location of micro-earthquakes in the province, to monitor natural and fracking-induced seismicity. Researchers from the University of Alberta are studying isotope reversals and gas maturation in various reservoirs, including those in the Appalachians and Western Canada Sedimentary Basin (WCSB) (Tilley and Muehlenbachs, 2012; Tilley et al., 2011). The same research team also currently has a project aiming at understanding the origin of shallow natural gas in the Western Canada Sedimentary Basin using isotope chemistry. Alberta Environment commissioned a few years ago a study on chemical and isotopic characterization of groundwater in Alberta using existing monitoring wells, which included dissolved and free gas, to establish a baseline against which future impacts on groundwater could be evaluated (Cheung and Mayer, 2007). In British Columbia, researchers from Simon Fraser University in partnership with the BC Ministry of Forests, Lands and Natural Resource Operations are presently working on two projects related to shale gas development in northeast BC. One focuses on the characterization of the groundwater system and risk to groundwater quality in the Montney region. The second project will assess water supply/demand and projected climate change impacts in relation to the overall water budget including interconnections between surface water and groundwater. In Ontario, Manitoba and Saskatchewan, the geological features of shale gas and oil formations are currently being characterized by the provinces. Regional scale initial appraisals of the numerous lesser known shale units in Canada are in progress in all southern Canada jurisdictions, as well as at specific sites in the Canadian Arctic through provincial and territorial initiatives. New Brunswick has recently announced the creation of the New Brunswick Energy Institute (http://nbenergyinstitute.ca/) composed of researchers from NB universities and elsewhere, to ensure that credible independent research and monitoring are being carried out in support of energy files, including shale gas exploration and production, and that findings are being communicated to the public. As well, government-academic projects are being carried out to study in situ conditions prior to shale gas production (e.g. geochemistry of water wells near Sussex by the University of New Brunswick and Geological Survey of Canada, Al et al., 2013) and theoretical processes that may affect groundwater quality (e.g. fluid migration mechanisms using numerical simulations by McGill University and INRS, Gassiat et al., 2013).

In addition, other studies are being conducted that are indirectly related to shale gas, including those carried out for water allocation or identification of additional water sources to support gas development (e.g. AB and BC), those linked to optimal measurement of dissolved gas in groundwater, such as the collaborative project between Environment Canada and the University of Calgary (Roy and Ryan, 2013), and those linked to potential impacts of oil development on aquifers such as studies by the Institut national de la recherche scientifique (INRS) in Gaspésie and Anticosti, QC (Peel et al., 2013; Raynauld et al., 2013). Also, many regional scale hydrogeological studies have been carried out in Canada to support water management and aquifer protection over the last decade. These studies are crucial as they provide geological, hydrogeological and often geochemical information and maps, and a better understanding of groundwater flow and aquifer vulnerability. The Groundwater Program of the Geological Survey of Canada (GSC) has been characterizing regional aquifer systems for the last 18 years. So far, the characterization of twelve regional aquifers has been completed and seven others are underway across nine provinces; a total of 30 key aquifer systems are targeted to be mapped and assessed by 2024 (Rivera et al., 2003). All these projects are carried out in a collaborative manner between the federal and provincial governments.

A few provinces have undertaken regional hydrogeological characterization studies (QC, AB, SK, and BC). In Quebec and Alberta, programs started in 2008 with tens of millions of dollars of funding. The Quebec Program (programme d’acquisition des connaissances en eau souterraine au Québec, PACES, http://www.mdepp.gouv.qc.ca/eaussouterraines/programmes/acquisition-connaissance.htm) presently involves six projects that are near completion and five others that will be completed by 2015. These multi-partner research projects are led by researchers at Quebec universities. Some of the innovative aspects of the PACES Program include 1) common databases, methodologies, and deliverables so that final results, tools, maps, and cross-sections will be comparable and/or have similar meanings and 2) the mandatory participation of regional organizations such as regional municipalities and watershed organizations to ensure that what is being studied is of interest and relevance to the region, and that knowledge, maps and tools are transferred to users (for more information, see Ouellet et al., 2011; Séjourné et al., 2013). In 2011, the PACES Program was accelerated in order to cover all regions targeted by the shale gas industry, following recommendations from the public consultation process and needs of the SEA Committee. The Alberta Geological Survey (AGS) has also initiated a vast and comprehensive groundwater Program (Provincial Groundwater Inventory Program, http://www.ags.gov.ab.ca/groundwater/), which is divided into two components: saline and non-saline aquifer systems. Non-saline aquifer studies are carried out in collaboration with Alberta Environment and Water and aims at mapping and understanding the province’s groundwater resources. The saline projects aim at mapping all major saline aquifers of the province, from the crystalline basement to the lowermost aquifer of the Colorado Group. However, AGS and the former Alberta Research Council had conducted hydrogeological mapping since 1968 and most (~85%) of the province has now been covered, except in the northeastern part (see Fig. 4). SK and BC have also characterized aquifers to different levels, mainly providing aquifer vulnerability indices and aquifer classifications. BC has classified most aquifers in highly populated areas, but these only cover ~15% of the province; vulnerability mapping using the DRASIC index was also carried out on Vancouver Island and the Gulf Islands in collaboration with universities and the GSC. These aquifers are in the order of tens of km² and thus, do not appear in Fig. 4. Of note, the northeastern part of BC has recently been the focus of hydrogeological studies where aquifer classification was performed, based on limited available information. The Ontario Geological Survey (OGS) is currently carrying out a baseline groundwater geochemistry.
assessment of the major rock and overburden units, including dissolved gas (e.g. methane) analyses, in southern Ontario. OGS has also worked along the Niagara Escarpment to characterize the Silurian carbonate aquifers. A few other studies were conducted by consultants and funded by a program implemented by a Federal Department (Agriculture and AgriFood Canada). The area covered by these studies are, however, typically smaller than 600 km².

Only study areas larger than 1500 km² were plotted at this scale. In total, more than 500 000 km² are being or have been covered by these hydrogeological characterization programs across Canada. Shale gas formations are shown as a background, to point out which aquifers above them have been studied so far. This map shows only study areas of 1500 km² or larger, due to the size of the map. Saskatchewan has based its characterisation on 1:250 000 mapsheets. Alberta has also mainly worked with 1:250 000 mapsheets until recently; because most of the study delineations are not available in digital format, the coverage shown is based on Lemay and Guha (2009). The inset presents a detailed overview of studied areas in southern Quebec.

7. Public concerns and recommendations

Public concerns and opposition to shale gas development exist, particularly in non-traditional hydrocarbon producing jurisdictions such as Quebec (see Section 9) and New Brunswick. The fact that some shales are located under populated and/or agricultural areas (e.g. Utica Shale in Quebec) and below key Canadian aquifers (such as those shown in Fig. 4) have exacerbated these concerns. Retrospectively, implementing a large-scale new industry such as oil and gas in eastern Canada would have required much more preparation and prior public consultation. In QC and NB, economic benefits for provincial jurisdictions no longer sway public opinion if there is a perception of environmental degradation should the industry be allowed to proceed (Québec, 2011). There is thus a strong need for a transfer of scientific information to the stakeholders. Technology, scientific studies and regulations must also be developed coherently to ensure a sustainable development and an adequate resource development framework.

At a workshop on shale gas and the potential impacts of exploration and development on groundwater held in November 2011 which gathered mainly provincial hydrogeologists and governmental scientists, the following main conclusions were reached (Rivard et al., 2012):

- The use of brackish or saline water, which is not in conflict with other water uses, should be encouraged;
- Baseline studies should be carried out to ensure that groundwater is characterized prior to exploration;
- Research studies must be carried out on potential upward migration of fluids, through improperly cemented casing, improperly abandoned wells, and existing and induced fracture networks;
- Monitoring programs should be developed for all stages of a shale well life cycle (pre-, syn- and post-fracturing and production);
Data from all sources need to be made available (publically or at least to provincial authorities).

The Council of Canadian Academies (CCA), which is a private, non-profit corporation funded by the Government of Canada to perform independent, expert assessments on important public issues, published in 2009 a report on the sustainable management of groundwater in Canada (Council of Canadian Academies, 2009). The CCA recommended that more efforts be focused on characterizing aquifers of populated areas and on installing monitoring wells to ensure sustainable groundwater management, and that data should be publically available. The Council is currently working on a report on potential environmental impacts of shale gas development that should be published in early 2014.

8. Regulation

In Canada, provinces manage and generally own their onshore natural resources, including oil and gas, and are the custodians of surface water and groundwater. However, the federal government responsibilities assumed by the National Energy Board (NEB) and Natural Resources Canada include inter-provincial and international energy trade, cross-jurisdiction pipelines, exports/imports as well as natural resource regulation powers in the Canadian Arctic, offshore marine areas and Aboriginal lands. In Quebec, the mining system is based on a first come, first served basis (mining claims) and is currently in effect for onshore oil and gas exploration permits. Elsewhere in southern Canada, subsurface mineral rights for oil, gas and coal are obtained through a bidding process for all areas open to exploration. In the Arctic frontier area, exploration permits are typically awarded to the operator with the best exploration program that commits to work obligations and meets or exceeds all regulatory requirements, as a means to encourage exploration activities in remote places.

Almost everywhere in Canada, the exploration permit obtained includes the exclusive right to search for mineral and petroleum substances, but does not give ownership of surface rights (implying that landowner permissions are required for surface access to acquire seismic data or conduct any other kind of exploration activities). A contract (surface lease) must be signed between the company and the landowner to drill a well (private or Crown, to the exception of Quebec, where, strangely, no lease is required on public lands). However, in southwestern Ontario (near Lake Erie), landowners own both surface and minerals. As in the U.S., Canada’s energy policy is market oriented, i.e. gas price is based on supply, demand, transport and infrastructure investments. Therefore, both Federal and Provincial governments have jurisdictional powers that are important in energy issues. In addition, Canada requires aboriginal consultation on decisions that may impact aboriginal rights or title on their lands.

Some provinces have regulations that require permits for geophysical work and licences for wells, while others require specific permits to either drill, complete, hydraulically fracture, modify and or abandon a well. Lease agreements are required for surface land access, while withdrawal permits are required for water usage. There are also regulations that require drilling reports (including casing and cementing reports), borehole geophysical log data (rock evaluation), and well testing data (reservoir evaluation) in a timely fashion, which are made public immediately, or after a brief period of confidentiality (3 months to 3 years) depending on the well category and province. Strong provincial and federal regulations govern operational practices to protect the environment including air quality, agricultural and forested area land use, parks, wildlife habitats, fresh surface water and groundwater, although these are not specific to the shale gas industry.

In eastern Canada, regulations go through the Departments of Mines and Energy for NB, of Natural Resources for QC, and of Energy for NS, for exploration and drilling activities (e.g. for geophysical work, drilling, and well completion) and through the Department of Environment for environmental issues (e.g. for water withdrawals, water and air quality, gas flaring and authorization or permits for fracking operations). In western provinces (BC, AB), authority has been delegated to single organisms (BC Oil and Gas Commission and Alberta Energy Regulator, formerly ERCB) that govern most aspects of the industry.

In addition to a cemented surface casing to protect groundwater, a dual-barrier regulation is generally in effect and mandatory in the case of a new basin, formation or region, or if there is significant change in the fracturing technique/design. However, a single barrier may be approved under certain conditions, depending on the jurisdiction. At a minimum, cement integrity must be confirmed visually by observing cement returns at surface, and a cement bond-log must be performed if no returns are observed at surface in AB, BC and NB. A leak-off test after drilling the cement shoe does not appear to be mandatory in all these provinces, but can be performed as a standard best practice, and it is presently mandatory in SK, QC and NB. Casing and cement integrity must be verified before any hydraulic fracturing operation in NB and Alberta, while it is not mandatory in BC and SK (but these operations can again be part of standard best practices). Quebec currently does not have a specific regulation for hydraulic fracturing. However, even when legislation is in place to test the casing integrity, potential environmental issues related to wellbore leakage remains, as these tests can fail to detect cement defects (Jackson et al., 2013). Therefore, the development of better engineering/technical methods is needed, including research and monitoring on cement curing, emplacement techniques and bonding; in parallel, detection and monitoring of the presence of fugitive gas, brine and flowback chemicals in shallow groundwater that could be indicative of leakage should also be carried out on a routine basis (Jackson et al., 2013).

For these reasons and many others, environmental regulation needs to be regularly updated following technological and scientific developments and strengthened to best protect health and environment (Rivard et al., 2012). For instance, groundwater monitoring wells are not required at this time, except for coal bed methane operations. Companies carry out baseline geochemical studies around their sites on a voluntary basis. Members of the Canadian Association of Petroleum Producers (CAPP), which account for 90% of the petroleum production in Canada, pledged to uphold operating practices beyond current legal regulations, such as assessing potential health and environmental risks of each additive, and baseline groundwater testing (http://www.capp.ca/aboutUs/mediaCentre/NewsReleases/Pages/GuidingPrinciplesforHydraulicFracturing.aspx). The BC government installed 6 groundwater monitoring wells in the Monney Basin in 2011, and discussion are on-going to put provincial monitoring wells in the Horn River Basin. In Quebec, one of the SEA projects on sampling dissolved gas across the St. Lawrence Lowlands (Pinti et al., 2013) represents another provincial initiative.

9. The Quebec Utica Shale case

The case of the Utica Shale is discussed here because it is located in Quebec, where a shale gas hydraulic fracturing moratorium is currently in place and large-scale development has not occurred. This section presents information meant to provide insight into the much publicized societal context that led to strong public concerns, the de facto moratorium, and the end in 2010 of all shale gas exploration activities in the St. Lawrence Lowlands. The Utica Shale is found along the St. Lawrence River, mostly on the south shore, as are about 90% of the people (as Montreal is part of the shale gas exploration area) and 90% of the farmlands of Quebec. At the apex of the exploration rush in 2008, operators acquired permits over (and beyond) the entire sedimentary succession of the St. Lawrence Platform (BAPE, 2011); the area covered by exploration permits for the Utica Shale (shown in red in Fig. 5) extends over ~20 000 km², although it contains a zone northwest of the St. Lawrence River that has limited potential for gas since the Utica Shale actually outcrops on the north shore of the St. Lawrence and is
usually too close to the surface to maintain adequate pressure. The area under permits for exploration includes the geological province of the St. Lawrence Platform and the western reach of the outermost Appalachian domain (External Humber Zone; Lavoie, 2008), extending from Quebec City south-westward to Montreal and southward towards the United States. The geological setting of the St. Lawrence Platform, as well as characteristics of the Utica Shale, are presented in detail in Lavoie et al. (2013, this issue).

Gas seeps were identified in the 1950s–1960s on the northern side of the St. Lawrence River (close to the very small reservoir exploited in the late 1800s, see Section 2) and a small gas field in Quaternary sands was put into production from 1965 to 1976 (91 million m³ or 3.2 Bcf, Pointe-du-Lac, near Trois-Rivières; Lavoie et al., 2009). Artisanal gas wells were often drilled during this period and some of these are still being used for heating farm buildings. One conventional gas reservoir in Ordovician dolostones was found by Shell in the early 1970s and production ceased in the early 1990s (163 million m³ or 5.7 Bcf; St. Flavien gas field, 50 km south–west of Quebec City; Bertrand et al., 2003). Thermogenic gas from the Utica Shale was demonstrated to be present in the St. Flavien field whereas a mixture of thermogenic and biogenic gas was recognized in the Pointe-du-Lac reservoir (Lavoie et al., 2008; Saint-Antoine and Héroux, 1993). These two fields have since been converted into storage reservoirs. Presently, there is no natural gas production in Quebec.

Current exploration permits for oil and gas exploration in the entire Province of Quebec cover 31 160 km² (7.7 million acres); most of the permits appear to belong to joint ventures. In total, more than 450 wells have been drilled in Quebec since the 1860s, of which 280 (62%) are located in the St. Lawrence Platform. The Utica Shale subsurface thermal domain is mostly dominated by dry gas conditions, although a liquid-rich (condensate and oil) zone is known in the NW area of the St. Lawrence Platform (Fig. 5). Analyses available in the oil and gas database reveal that gas from the Utica Shale and overlying units (e.g., the conformably Utica-overlying Lorraine Group) is generally composed of at least 90% methane, the remainder being essentially composed of ethane, propane and carbon dioxide; little to no hydrogen sulfide has been reported (Séjourné et al., 2013).

Industry still has to confirm the potential of the Utica Shale and its economical viability. Nevertheless, encouraging gas flow rates were reported in both vertical and horizontal wells. In 2006, two exploration wells were drilled for a conventional gas target. This exploration program also had, as a secondary objective, to collect data to evaluate the shale for its geological character and shale gas potential. The two first wells specifically targeting Utica shale gas were drilled in 2007.
Twenty-five others were drilled between 2007 and 2010. In total, 18 of these wells were hydraulically fractured. In February 2010, an announcement was made that the St-Édouard-de-Lotbièrie horizontal well averaged 0.17 million m³/d (0.006 Bcf/d) of natural gas during the first 21 days of the production test. However, due to several factors, namely, the lack of hydrocarbon-oriented legislative and regulatory frameworks together with the emplacement of very strict rules for fracking, including the need to receive social acceptability to conduct any activity related to shale gas, resulted in the end of all exploration activities in the Utica Shale. One of the major permit holders subsequently wrote-off its investment in the Utica Shale in 2012. In the meantime, the low price of natural gas has led to a reorientation of industry, which is generally now focusing its efforts on producing liquids (oil or liquid–rich gas) and, in Quebec, interest has moved to Anticosti Island where the Utica-coeval Upper Ordovician shale (the Macasty Shale) occurs in the oil and condensate thermal domains. The presence of a dense gas distribution network in the heart of the Utica play as well as a large local market represents, nonetheless, an economic advantage since only short lateral connections from the well head to the pipelines would be needed.

Few studies on the geological framework of the Utica Shale and overlying units have been conducted; the most comprehensive studies are from Thériault (2012a and b). Konstantinovskaya et al. (2012) focused on studying the actual stress regime in the St. Lawrence Platform and defined the conditions that would trigger reactivation of structural discontinuities, including faults. Séjourné et al. (2013), following the initial deep seismic reinterpretation of Castonguay et al. (2006), developed conceptual tectono-stratigraphic cross-sections of the Utica Shale and overlying units that include the main geological constraints (structural discontinuities, stratigraphy and depth/thickness variations) of the region targeted by the industry for shale gas development.

Séjourné et al. (2013) have also synthesized available information to highlight regions or types of data with little or no information to guide future research work devoted, among other things, to evaluate the cap rock integrity above the Utica Shale. These authors have compiled data from water wells and oil and gas wells. They present tables providing areal extent, number of oil and gas wells, and the number of several types of analyses (e.g. gas and water shows, XRD, drill stem tests, production tests, and cores) available in each hydrogeological study area being investigated within the PACES Program. This report mentions that some fluid analyses are available, but they have not been synthesized or statistically analyzed yet. Authors point out that these analyses should significantly contribute to a regional hydrogeological assessment (such as the saline/fresh water interface depth and location of dissolved gas in groundwater) and help constrain petrophysical models. They also underline the fact that the impact of the presence of many dykes on the regional fracturing conditions is poorly known and that there are no known under-pressurized reservoirs in this area. Reports from the Utica Shale operators indicate that an overpressure regime is the norm, confirming that these deep shales are hydraulically isolated from the surface. Therefore, these authors conclude that, given the actual regional knowledge, surficial aquifers should not be connected to the deep Utica Shale unit (in spite of numerous cases of gas in water wells reported since the 1950s), although the presence of (undetected) structural discontinuities at the local scale could alter these conditions.

Public protest against shale gas development has led to the creation of nearly 100 local anti-shale gas protest groups. This opposition can be related to several factors: 1) shale gas is found in relatively populated areas; 2) Quebec does not have a history of large-scale oil and gas industry and has for years promoted its hydroelectricity as “green energy”; and 3) groundwater is an important water supply in this area, characterized by numerous small municipalities. There were indeed in 2012 over 30 local (municipal to or to regional levels) opposition groups, 3 provincial protest groups and 63 municipalities that have announced motions pertaining to no drill zones around water wells, limits on transporting chemicals used for fracking, or restrictions on injecting chemicals. Public concerns are mainly related to water contamination, health impacts, nuisances (traffic and noise) and local economic impacts. Water quantity on the other hand, is usually not a problem. Quebec receives over 1000 mm of annual precipitation and has many rivers and lakes; groundwater is, if not abundant everywhere, always sufficient to supply residential needs. In addition, there is a large saline brackish groundwater zone in the northwestern part of the St. Lawrence Platform (i.e. east and north of Montreal), as mentioned in Section 2.2, which could be used for this purpose since this groundwater has no other use.

A brief historical background of gas exploration leading to the Utica Shale discovery and de facto moratorium can be summarized with the following timeline:

- 19th century: first industry reports of natural gas in Quaternary deposits overlying the Utica Shale.
- 1950s: First geological reports indicating gas in groundwater during water well and oil & gas drilling. First suggestion to try hydraulic fracturing on the Utica Shale in Quebec by Clark (1953).
- 1971–1992: Vertical and horizontal drilling in Villeroy (~45 km south-west of Quebec City) for natural gas in fractured shales (Utica Shale and Lorraine Group), no commercial production due to inadequate technology at the time.
- 1973–2004: Drilling in Saint-Flavien (~30 km south-west of Quebec City); 163 million m³ (5.7 Bcf) production from a conventional carbonate reservoir sourced by the Utica Shale; reservoir connected through horizontal well drilling, now converted for gas storage.
- 2006: Two companies (Talisman and Junex) drill wells through the Utica Shale, targeting underlying conventional reservoirs; first wells to be analyzed for shale gas potential in Quebec after the Villeroy attempts.
- 2007: First two wells (Gastem) fully dedicated to test the potential of the Utica Shale; first two hydraulic fracs on vertical wells (Forest Oil, partner).
- 2008: First three horizontal wells drilled and frac-stimulated and first public release of results and resource estimates (Forest Oil).
- 2009: First public protest: a letter is sent to the government by a group preoccupied mainly by air quality. Release of the movie Gasland.
- 2010: Public hearings/consultations (BAPE) on shale gas development.
- 2011: BAPE report. Announcement of new rules, permitting fracking under very strict conditions that contributed to the pause in industry activities and the de facto temporary moratorium. Creation of a strategic environmental assessment committee (SEA). Start of hearings on Mining Law modifications.
- 2013: The Quebec Ministry of Environment (MDDEFP, ministère du Développement durable, de l’Environnement, de la Faune et des Parcs du Québec) released a draft regulation in May that should be adopted at the end of 2013.
- 2014: Forthcoming new hydrocarbon law and environmental regulations announced by the Quebec Ministry of Natural Resources.

Mainly due to low gas prices and strong public concerns, shale gas production seems unlikely in the near future in Quebec; moreover, the moratorium on fracking may last until 2018. On the other hand, shale oil exploration has commenced and hydraulic fracturing activities have been announced for the coming years on the largely unpopulated Anticosti Island.

10. Conclusion

There are abundant supplies of natural gas in Canada. Unconventional resources have doubled Canada’s natural gas resource base and, as exploration continues, this number could still increase. Presently, large-scale production is occurring only in northeastern British Columbia, where the population is sparse. Four plays are in production, of which the Horn River Basin and the Montney Play Trend are the most

Please cite this article as: Rivard, C., et al., An overview of Canadian shale gas production and environmental concerns, Int. J. Coal Geol. (2013), http://dx.doi.org/10.1016/j.coal.2013.12.004
productive. Modest exploitation of dry gas occurs in the Duvernay Formation (Alberta), where liquids are also being produced at increasing rates. In British Columbia, the unconventional gas production represents nearly 60% of the total natural gas production in the province and about 90% of the drilling activity, while shale gas production in Alberta represents only about 0.1% of the total provincial gas production and usually represents a by-product of the liquid production. Very few shale wells have been drilled in eastern Canada so far. Nonetheless, one well is currently producing in the McCully Field (southern New Brunswick) from the Frederick Brook Member shale (since 2008). Continued exploration and development of natural gas from the Frederick Brook Shale is planned in the future with renewed drilling and fracking in the McCully gas field area in order to determine feasibility of commercial development. The Quebec Utica Shale economic production potential is still to be determined, but promising results were obtained from 2006 to 2010. A moratorium on shale gas exploration and hydraulic fracturing is, however, currently in place in southern Quebec.

Hydrocarbon exploration and production operations involve various surface and subsurface risks of degrading groundwater quality and these hazards need to be assessed and minimized. Driven by improved operational techniques and strategies, competition for water access and public concerns, the industry is evolving toward increasingly environmentally-conscious practices (e.g. use of saline water and “green” additives, groundwater monitoring, flowback and produced water recycling, disclosure of fracturing fluid additives), although these requirements, in many cases, are not regulated yet. Many research projects at different scales and on various topics related to environmental issues of shale gas have been initiated in the last few years at the Canadian federal and provincial levels, as well as in universities. These should provide an impartial scientific base to support the sustainable use of groundwater related to shale gas development.

Acknowledgments

The authors would like to thank the following individuals for their help and willingness to provide information and access to data and statistics for this publication: Annie Daigle from the NB Department of Environment; John Drage and Adam MacDonald from the NS Department of Natural Resources and Energy, respectively; Dr. Kevin Parks, Tony Lemay, Andrew Beaton, Marie-Anne Kirsh, and Dean Rockosh., Tony Lemay, Andrew Beaton, Marie-Anne Kirsh, and Dean Rockosh; François Létourneau for his work on the BC Water Protection and Sustainability Branch. Special thanks go to Dan Palombi from the Alberta Geological Survey, and Mike Wei of the CAPP, 2012. Library and statistics/tables. http://www.capp.ca/library/statistics/

References


BC Oil and Gas Commission. 2012. Investigation of observed seismicity in the Horn River basin. 28 pp. Available at: www.ogc.gov.bc.ca/publications/reports


