Considerations for Responsible Gas Development of the
Frederick Brook Shale in New Brunswick
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Abstract
Shale formations contain ancient plant and animal tissues that have been broken down into oil and gas over millennia during progressive burial through the rock cycle. The presence of natural gas in shale formations (shale gas) has been known for centuries, but commercial production of shale gas is relatively new. A defining characteristic of shale is its inability to naturally allow fluids to pass through it. Recent advances in two industry upstream coupling factors, horizontal drilling and hydraulic fracture stimulation, have made shale gas production economically-viable. This technology combined with the enormous worldwide potential of shale gas has the ability to reshape global energy markets with this cleaner burning fossil fuel.

New Brunswick has an extensive history in oil and gas exploration, development, and production confined primarily to the sub-basins near Moncton and Sackville. Discovery of new potentially large natural gas reserves in the Province occurred by chance. The existence of the natural gas pipeline through the Province, the proximity to large northeastern United States markets, and the premium heat content of the discovered gas sparked new interest in exploration here. Several companies are now exploring the Frederick Brook Shale within the Maritimes Basin of New Brunswick to prove resource potential.

If discovered in commercially-viable volumes, it will take several years for production to ramp up. Accordingly, now is the time for New Brunswick to identify best-practices in other shale gas development areas to ensure that we are ready to accommodate and regulate this industry. Lessons learned in US shale play development can be adopted, adapted, and applied here to develop this non-renewable resource. Regulatory improvements in New Brunswick, including the Phased EIA process, are designed to better protect human health and safety and the environment. Collaborations between industry, regulators, stakeholders, and the public can create innovative environmental solutions. Progressive and comprehensive royalty regimes like those in British Columbia where rates are pegged to commodity price and well production are designed to maximize the amount of government revenue while ensuring that developers earn a fair return on their investment.

This paper reviews the step-wise process undertaken to develop a shale gas resource. Throughout the article, considerations are provided for responsibly developing the Frederick Brook Shale in New Brunswick from an environmentally and socio-economically responsible perspective. The intention of the paper is to spark dialogue in the Province and suggest areas for collaboration between industry, regulators, stakeholders, and the public for creating and implementing innovative environmental solutions.

Introduction
The Frederick Brook Shale in New Brunswick harbours energy stored as natural gas. The natural gas was formed during the breakdown of ancient plant and animal tissues, which were buried as part of the rock cycle. Exploration for areas of commercially-extractable natural gas has begun in the Frederick Brook Shale. Right now, New Brunswick has an opportunity to become a North American leader in all facets of shale gas exploration and development. Lessons learned in other jurisdictions and best-management practices developed in other shale plays provide methods that can be adopted and applied here to ensure that this non-renewable resource is developed in an environmentally and socio-economically responsible manner.

This emerging industry for New Brunswick raises questions about the nature of shale gas exploration, development, production, potential environmental impacts, and the ability of the existing regulatory regime to adequately manage this industry. Shale gas development in other jurisdictions has met with the same concerns. Many of the issues raised appear to stem from a lack of technical awareness regarding the shale gas industry. The public, stakeholders, and regulators all benefit from objective information sources on which to determine the suitability of this industry to the region.
The purpose of this paper is to serve as an instrument to inform the dialogue in the Province on the potential development and opportunities of a shale gas industry. Much of the information reviewed in the preparation of this report is publicly-available. This balanced perspective can be followed up on by others using the electronic links to references.

Shale

Shale is a dense, fine-grained sedimentary rock that is comprised of weathered clay- and silt-sized particles of other rocks and has been hardened over time by increasing temperature and pressure through progressive burial as part of the rock cycle [Craig et al., 1996; Prothero and Schwab, 1996]. The deposition of the particles, often in thin layers, occurred in deep, quiet waters of lakes, inland seas, and oceans. The thin layers of shale are considered to be geologically tight and have limited permeability / ability to allow fluids to flow easily through the layers [Hazen et al., 2009]. Regionally, nationally, and internationally, no two shales are alike; they were formed under distinct circumstances and have been subjected to different conditions over time. Mixed in with the fine grains is organic matter from dead algae, plankton, and other aquatic organisms. The organic matter decomposition products are sought by the shale gas industry.

Shale Gas

Over millions of years, the organic matter that accumulated on the bottom of ancient waters became buried deeper and deeper underground. The increasing pressure and temperature exerted on the organic matter reversed the process of photosynthesis whereby the material was converted to oil and gas. Some of the light oil and gas escaped from the rock layers and migrated towards the surface through porous sandstone and limestone layers until it became trapped in reservoirs capped by impervious rocks.

The inevitable onset of peak oil [Tertzakian, 2007] has led to the search for other forms of energy. After climbing for several decades until the mid-1980s, the number of global conventional oil and gas discoveries has been declining [Halliburton, 2005]. Green and sustainable energy sources, such as bio-fuels, geothermal, solar, wind, and tidal, are not developed enough technically to make them economically-viable across all sectors and make up for the coming energy supply shortfalls. In the interim, transitional fuels, ones that are cleaner to use than the traditional sources of coal and oil, are needed [Considine, 2010; Cornell Cooperative Extension, 2010]. Shale gas has the potential to serve as a transitional fuel.

For a long time, shale was considered the uninteresting source rock that oil and gas had migrated away from and into the profitable reservoir rock of sandstone and limestone [Murphy and Nance, 1996]. Natural gas within shale is found in three forms [Perry and Lee, 2007]: as free gas in the particle pores; as free gas in natural fractures; and as adsorbed gas on mineral surfaces. Like oil, natural gas contained in shale (shale gas), is a non-renewable resource and replacement energy sources have to be found in green and sustainable energy sources to eventually supplant the finite supply.

Natural gas is a colourless, odourless, safe, abundant, convenient to use, versatile, reliable, and economical source of energy [Hefelfinan and Dawson, 2010; Smith, 2010; CSUG, 2011]. The natural gas contained in shale is considered a dry gas because it is typically composed of > 90 % methane [Arthur et al., 2008b]. Compared to other fossil fuels, natural gas produces considerably less carbon dioxide (CO₂) emissions. To produce 1,000,000 British thermal units (Btu) of energy the amount of CO₂ released from burning natural gas is 53 kg compared to 75 kg for crude oil and 98 kg for coal [US Energy Information Administration, 2011]. Natural gas is therefore a more desirable energy source when competing with traditional power generation sources. Although nuclear is considered in some circles as a cleaner energy source with considerable promise [Cohen, 1990], future nuclear development has the potential to stall in the foreseeable future given the recent nuclear incident in Fukushima, Japan [Reguly, 2011].

Shale Gas Globally

Potential shale gas reservoirs are globally ubiquitous [Rogner, 1996] since sedimentary rocks make up a valuable portion of the Earth’s crust [Prothero and Schwab, 1996]. Estimates by Rogner [1996] peg potential global natural gas reserves at 16,103 trillion cubic feet (Tcf). The enormous worldwide potential of shale gas has a promise to reshape global energy markets and generate energy security for major energy sources.
importers by reducing their reliance on foreign oil [McCarthy, 2011].

In 2009, the United States (US) surpassed Russia as the world’s largest producer of natural gas [Medetsky, 2010]. This is primarily because shale gas production is extensively ramping up in the US. With a few exceptions, shale gas resources have largely been overlooked and understudied outside of North America [Perry and Lee, 2007]; however, the US Energy Information Administration (USEIA) predicts that shale gas will comprise 7% of the global gas supply by 2030 [USEIA, 2010]. The transition will extend to other regions because shale gas is available there locally, thus greatly reducing a region’s dependence on external sources of energy. Shale gas production technology developed in the US over the past three to four decades can now be used to recover gas from the significant number of geological shale basins containing unconventional gas reserves globally [Rogner, 1996].

In China, which has reserves of 918 Tcf based on International Energy Agency’s estimates, Chinese state-owned companies are investing billions of dollars in North American shale plays to gain expertise needed to develop their domestic resources [McCarthy, 2011]. Similarly, India has numerous gas shale basins that are just starting to be evaluated based on US success, and the country is eager to exploit its unconventional gas deposits to reduce energy dependence on foreign sources [Kuuskraa and Stevens, 2009].

In Europe, although no production of unconventional gas has yet been established, shale gas exploration for commercial potential is underway in many basins, including the Mikulov Shale of Austria, the Alum Shale of Sweden, the Silurian Shales of Poland, and the Lower Saxony Basin of Germany [Gold, 2009; Kuuskraa and Stevens, 2009]. Among those prospective plays, Poland is believed to have a vast resource with an estimated potential of 48 Tcf [Platts, 2011]. If realized, this would boost the European Union’s proven reserves of natural gas by 47%. For example, Poland, which imported 72% of its gas from Russia in 2009, could be self-sufficient in the near future if shale gas resources are proven [Pagnamenta, 2010].

**Shale Gas in North America**

The first commercial natural gas well in North America was installed in the Dunkirk Shale of Fredonia, New York in 1821 [Arthur, 2009]. Gas produced from that well was largely used to power gas street lamps. Today, shale plays in North America, with an estimated reserve of 3,840 Tcf, could supply domestic energy needs over the next century [GPC and ALL Consulting, 2009; API, 2010; Jarvie, 2010; NEB, 2010; Parfitt, 2010]. Natural gas production from hydrocarbon-rich shale formations is one of the most rapidly expanding trends in onshore oil and gas exploration and production in North America [GPC and ALL Consulting, 2009]. In recent years, two upstream coupling factors have made shale gas production economically-viable: 1) advances in horizontal drilling; and 2) advances in hydraulic fracture stimulation. Without these two advances, extraction would not be commercially possible from low permeability reservoirs, such as shales [Halliburton, 2008; Sumi, 2008; CAPP, 2010a]. The US natural gas industry, which benefited from tax-incentives created in the 1980s, kick-started domestic exploration following several energy crises of the 1970s and 1980s that resulted in high gas prices [Beckwith, 2010]. In Canada, the deregulation of natural gas prices in 1985 sparked an increase in demand for natural gas [CAPP, 2010a].

The Barnett Shale in the Fort Worth Basin of north-central Texas was the first modern commercially developed shale play [Hart Energy, 2007], but it took almost two decades to become the success it is today [Clouser, 2006]. It became the hottest play, compared to others in the US, because it is overpressurized (0.52 psi/ft) and it contains more gas in place (142 billion cubic feet (Bcf)/mi²). Success in the Barnett has resulted in other US shale plays being brought online in the past two decades. Today, the fastest growing shale plays in the US include [Halliburton, 2008]: Woodford; Haynesville; Fayetteville; and Marcellus.

Canada currently provides about 25% of the North American natural gas production [National Energy Board, 2008]. To maintain or increase that production, exploitation technology of shale gas in the US is naturally expanding to Canada. The Horn River Basin in northeast British Columbia has received the most attention in Canadian shale gas development. Natural gas production from Horn River started in 2006 [Arthur et al., 2010]. According to the National Energy Board (NEB) [2008], 98% of Canada’s total natural gas exports come from the West Coast Sedimentary Basin, which includes the Horn River. The remaining 2% of production comes from offshore production in Atlantic Canada (Sable Island). With the start of exploration and production of shale gas in Canada, deliverability of domestic natural gas is expected to make key contributions to the North American supply.
New Brunswick Oil & Gas Industry

New Brunswick has an extensive history in oil and gas exploration and development and it is one of the oldest North American oil producers [St. Peter, 2000]. The first oil well was drilled in 1859 about 15 km southeast of Moncton on the east side of the Petitcodiac River near the village of Dover (Figure 1). In 1909, the first successful gas well began production at Stoney Creek. Although the industry has been relatively confined to the Stoney Creek field, which has yielded about 800,000 barrels of paraffinic oil and 3 Bcf of sweet natural gas [St. Peter, 2000; Smith, 2010], new assets are emerging. This is in part due to the discovery that occurred during investigations into the flooding and subsequent closure of the Cassidy Lake potash mine in 1997 [Pearse, 2000]. Those reserves discovered by Corridor Resources Inc. (Corridor) are potentially large.

The Frederick Brook Shale (FBS) is a member of the Albert Formation, which belongs to the Horton Group [Hinds and St. Peter, Undated]. The grey brown shale was deposited in the deepest portions of a continental lake environment 300 to 360 million years ago during the Lower Carboniferous period [Hinds and St. Peter, Undated]. According to Eaton [2010], the FBS has all of the right ingredients to be a world-class shale play and it is the only hydrocarbon-rich shale in the region.

Part of New Brunswick’s attractiveness for natural development is the existence of the Maritimes & Northeast Pipeline (M&NP), built in 1999, the proximity to large northeastern US markets, and the premium heat content of the produced sweet gas [Eaton, 2010; Corridor, 2010] (Figure 1). If natural gas prices stay as low as they have been in recent years, it is an advantage to be close to transmission infrastructure and large markets. The M&NP pipeline was originally constructed to deliver Sable Island gas to New England, but now provides that valuable infrastructure for expansion.

On 18 June 2010, the first horizontal shale gas well in New Brunswick was spudded by Corridor and Apache Canada Ltd. (Apache) at the Green Road B-41 well in the McCully Gas Field [Eaton, 2010]. Thus began a rush to determine if there are commercially-viable shale gas reserves in New Brunswick. The majority of exploration is focused on shale confined to the Maritimes Basin (Figure 1).

Frederick Brook Shale

The Frederick Brook Shale (FBS) is a member of the Albert Formation, which belongs to the Horton Group [Hinds and St. Peter, Undated]. The grey brown shale was deposited in the deepest portions of a continental lake environment 300 to 360 million years ago during the Lower Carboniferous period [Hinds and St. Peter, Undated]. According to Eaton [2010], the FBS has all of the right ingredients to be a world-class shale play and it is the only hydrocarbon-rich shale in the region.

![Figure 1. Map of New Brunswick showing the lands under licence to search and lease by oil and gas companies for shale gas.](image-url)
the province of Alberta [Apache, Undated], which could be an economic boon for New Brunswick.

The Horn River is considered an analog for the FBS [Eaton, 2010]. Extensive exploration work in the Horn River began in the early 2000s [Heffernan and Dawson, 2010]. Other potential shale basins in Canada have been identified, such as the Montney in Alberta and the Utica in Quebec, but sustained shale gas production in Canada is only occurring in the Horn River [Heffernan and Dawson, 2010]. As with other shale plays, development of the Horn River did not occur overnight; however, it did happen quicker than in the Barnett because the learning curve was shorter as it should be in New Brunswick.

**Shale Gas Development**

Extraction of shale gas is a sophisticated process that involves several steps (Table 1). Lead times to bring commercially-extractable gas to market can be long [Heffernan, 2008] and capital investment can be considerable and spread out over large geographical areas [Schlumberger, Undated]. Because of this, development is typically confined to large experienced companies or juniors partnered with those that are more senior. Normally, companies that are early entrants into the play get the best lands and have the best results [Pickering Energy Partners, 2005], which is the reason why exploration tends to ramp up quickly as is occurring in New Brunswick now.

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Table 1. Step-wise process in the development of a potential shale gas resource.

**Licence to Search**

In New Brunswick, the Frederick Brook Shale is considered an emerging resource play because reserves have not yet been proven [Eaton, 2010]. Before any gas is ever produced, the resource must be discovered in commercially-extractable quantities. Searching for shale gas reserves, which is new to this region, is the first step in the multi-step development process of Table 1.

Currently, there are nine companies involved in New Brunswick’s shale gas industry (Figure 1) [Government of New Brunswick, 2010]. Under the Licence to Search and Lease Regulation [2001-66] of the New Brunswick Oil and Natural Gas Act 
 a licence to search grants a company permission to search for natural gas through limited intrusive methods.

**Searching**

Exploration companies primarily use geophysical methods to search geographically-large areas for shale gas potential. Prior to undertaking geophysical exploration methods in New Brunswick, companies must obtain a geophysical licence and a geophysical permit as outlined in the Geophysical Exploration Regulation [86-191] of the New Brunswick Oil and Natural Gas Act. Gravity and magnetic data collected through airborne surveys are often used to better understand the subsurface structure and identify sedimentary basins for further investigation. 2-D and 3-D seismic imaging on-the-ground is a method employed to further understand subsurface conditions and for further identifying potential shale gas reservoirs at great depth.

Seismic data are collected by generating a sound wave at the ground surface and listening for the reflection and refraction of that sound wave from different geological subsurface layers with sensitive sound receivers called geophones [Davis and DeWeist 1966; Milsom, 1989]. Typically, the sound wave is generated using a small explosive charge or large truck-mounted vibrators and reflections and refractions are recorded by the geophones. Interpretation of the data allows exploration companies to produce pictures of subsurface conditions and identify potential shale gas reserves that can be further explored through test wells.

Seismic lines where data are collected are usually extensive and traverse all types of terrain. In New Brunswick, companies that collect geophysical data on lands they have rights to search must adhere to all applicable Acts and Regulations. For example, to collect data across a large wetland, the exploration company would likely require a Watercourse and Wetland Alteration permit from the New Brunswick Department of the Environment (NBDENV) as per the Watercourse and Wetland Alteration Regulation [90-80] of the New
Brunswick *Clean Water Act*². In addition, surface access agreements must be secured for private lands and a Licence of Occupation must be acquired for Crown lands as mandated under the New Brunswick *Community Planning Act*³.

**Lease**

Under the Licence to Search and Lease Regulation [2001-66] of the New Brunswick *Oil and Natural Gas Act*, a lease gives a company permission to produce natural gas given that Licences to Search can be converted to Leases by making application under Regulation 2001-66. As shown in Figure 1, several companies have leases in New Brunswick, but those are largely for the production of conventional oil and gas resources like those found in the Stoney Creek Field.

**Permitting**

The fundamental aspects of shale gas exploration, development, and production in the US can be expected to be similar here. In the US, there is a lengthy history of actively regulating the oil and gas industry, including shale gas [GPC and ALL Consulting, 2009; Anadarko, 2010]. Comprehensive state and federal laws and programs there regulate all aspects of the shale gas industry in order to protect human health and safety and the environment [Arthur et al., 2008].

New Brunswick’s *Oil and Natural Gas Act* was enacted on 1 November 1976, presumably for a conventional oil and gas industry. The *Act* is administered by the New Brunswick Department of Natural Resources (NBDNR). Although the current regulatory framework in New Brunswick accounts for searching and exploration, there is no requirement for complying with the Environmental Impact Assessment Regulation [87-83] under the New Brunswick *Clean Environment Act*⁴, which is fairly comprehensive and broad-reaching in its application.

The NBDNR and the NBDENV recognize that shale gas exploration, development, and production involve new technologies not accounted for in the *Oil and Natural Gas Act* as it currently exists. Therefore, the NBDNR and NBDENV are actively reviewing the legislation to account for a potential shale gas industry. As outlined on the Government of New Brunswick’s shale gas information website⁵, the NBDENV will require future oil and natural gas wells to undergo a Phased Environmental Impact Assessment (EIA) process. That process will identify potential environmental impacts so they can be appropriately mitigated, or if it is determined that potential impacts cannot be mitigated then the well will not be permitted. The Phased EIA process will begin prior to approval of well pad construction and public involvement and stakeholder engagement are necessary components of the process. The Phased EIA process can be thought of as a ladder; companies must satisfy specific criteria before moving from one rung to the next. This series of checks and balances provides for a transparent regulatory process.

Two companies drilled exploration wells in New Brunswick prior to the launch of the Phased EIA process; Corridor in partnership with Apache drilled two wells in the Elgin area and PetroWorth Resources Inc. (PetroWorth) drilled one well in Rosevale [CCNB, 2010]. As a pilot program, Apache voluntarily registered the first Phased EIA with the NBENV on 2 February 2011⁶. That EIA focuses on the two wells that were previously drilled and hydraulically stimulated in the Elgin area. If favourable testing results are obtained from those two wells, Corridor and Apache will move to their second chapter of testing for determining the prospects of shale gas production. That work will be reviewed by the regulator(s) through the Phased EIA process and no further work on-the-ground will be permitted until approved.

The risks and impacts from a single shale gas well may be negligible and acceptable, but the installation of hundreds or even thousands of shale gas wells in a mature industry may produce significant impacts. Collaborations between industry, regulators, stakeholders, and the public should be encouraged to create innovative environmental solutions. The NBENV’s Phased EIA process is being developed with this spirit in mind.

In New Brunswick, shale gas exploration, development, and production are not exempt from other regulatory approvals or landowner agreements. Other key legislation that may be triggered include, but are not limited to, local by-laws, the New Brunswick *Crown Lands and Forests Act*, the New Brunswick *Clean Air Act*, the New Brunswick *Highways Act*, the New Brunswick *Transportation of Dangerous Goods Act*, the federal *Fisheries Act*, the federal *Migratory Birds Convention Act*, the *Canadian Environmental Assessment Act*, and the federal *Species at Risk Act*.

Many problems can be averted by applying best practices developed from previous experience. Although best-practices are application dependent and should evolve locally, there is a wealth of information available for New Brunswick regulators to draw upon for shale gas to be developed responsibly.
available for New Brunswick regulators to draw upon for shale gas to be developed responsibly. Lessons learned in US shale play development can be adopted, adapted, and applied here. For example, each oil and gas producing state has an agency whose sole responsibility is permitting shale gas wells and overseeing general operations [GPC and ALL Consulting, 2009]. Learning from the US regime, British Columbia and Alberta have created the Oil and Gas Commission and the Energy Resources Conservation Board (ERCB), respectively.

Other jurisdictional best-practices can also be implemented here. For instance, New York [URS Corporation, 2009] and Wyoming [Parfitt, 2010] require hydraulic fracture stimulation companies to provide a full-disclosure of fluid additives the use. Water supplies in Pennsylvania affected by shale gas industry practices must be replaced with a similar or better water supply in terms of quality and quantity [URS Corporation, 2009]. British Columbia limits daily and cumulative water withdrawals [Mitchell-Banks, 2010]. Brine waters produced from shale gas wells in Alberta must be disposed of using deep injection wells [ERCB, 2010].

**Access Road and Well Pad Construction**

Intrusive exploration involves drilling a well at a well pad site. In New Brunswick, most shale gas development will consist of several horizontal wells that extend from a common well pad [CCNB, 2010]. This results in a larger well pad site than conventional drilling operations because additional fluid storage and completion equipment must be accommodated [GPC and ALL Consulting, 2009].

Site preparation activities consist primarily of clearing and levelling an area of adequate size and preparing the surface to support drilling activities. Crushed stone over geotextile is typically placed on the site with perimeter erosion and sedimentation protection measures. Ultimately, well pad size is determined by site topography, number of wells to be installed, pattern layout, and equipment required for installation.

Based on extensive reviews by the New York State Department of Environmental Conservation [2009] and Hazen et al. [2009], horizontal well drilling pads are typically between 1.6 ha and 2 ha, more than double a conventional well pad of 0.85 ha. New Brunswick well pad sites may be slightly larger at 2.5 ha [Apache, 2011]. Although larger than for conventional wells, horizontal well pads are less densely spaced. This greatly reduces the overall cumulative environmental footprint [NYSDEC, 2009] as described in more detail below.

Access roads ranging from 6 m to 12 m wide [NYSDEC, 2009] are required for the movement of heavy equipment to and from the well pad site. Route selection may not always be the shortest distance to the nearest main road, but instead depends on the presence of environmentally sensitive features, lack of land access agreements, etc. The US Department of the Interior, using the Fayetteville as an example, estimated that 1.4 ha of incremental land disturbance is typically required for access roads and associated infrastructure [Arthur and Cornue, 2010]. That of course could vary somewhat to accommodate site specific considerations in New Brunswick.

**Horizontal Drilling**

Vertical wells were originally the installation of choice in the Barnett [GPC and ALL Consulting, 2009]. Due to the urban setting of the Barnett, however, demand for reduced surface impacts forced developers to find a solution while maximizing reservoir exposure [Arthur et al., 2008c]. In 1986 the first horizontal well was drilled there and now 90% of the wells completed in the Barnett are horizontal [Jenkins and Boyer, 2008].

![Horizontal and Vertical Well Comparison](image)

**Figure 2.** Comparison between a horizontal and vertical well drilled to the Frederick Brook Shale. More exposure with the formation is achieved using a horizontal well configuration. Note that the drill rigs and wellbore sizes are exaggerated for clarity and the gross pay thickness and average depth have been used for illustrating the Frederick Brook Shale. Stacked horizontal wells are shown, which may be used for yielding more gas from the Frederick Brook Shale.

Success in the Barnett led to widespread horizontal drilling in other US shale basins [Seale, 2007; Heffernan and Dawson, 2010]. Except for the use of specialized down-hole tools, horizontal drilling is performed using similar equipment and technology as vertical drilling with the same protocols in place for drinking water aquifer protection, fluid containment, and waste handling [NYSDEC, 2009]. In horizontal drilling, driller’s guide the path of the drill at a certain depth in a large arc that produces an L-shaped profile (Figure 2). Through sophisticated controls, the well is drilled horizontally through a formation, which considerably...
increases the exposure of the wellbore with the formation [Cooper, 1994; Perry and Lee, 2007; Hazen et al., 2009]. The horizontal orientation increases gas yield over a strictly vertical or conventional hole as much as ten-fold [Perry and Lee, 2007; Hazen et al., 2009]. Horizontal drilling is now the industry installation of choice.

It is estimated by the National Energy Board [2009] that it costs between $5 and $10 million to drill and complete a horizontal well. Although horizontal wells have a higher individual capital cost, they yield higher returns than vertical wells. A typical vertical gas well yields a 39% return compared to a 100%+ return for a horizontal well [Pickering Energy Partners, 2005]. Therefore, they are more profitable for companies than a vertical well and they generate more royalties.

Resource extraction through horizontal wells is also environmentally-beneficial [NYSDEC, 2009; Arthur et al., 2010; CSUG, 2010]. Horizontal wells can be used to avoid sensitive areas, such as wetlands and watercourses, while still extracting the gas underneath of them. Natural gas beneath existing infrastructure, such as buildings and roads, can also be accessed from a horizontal well. With modern methods, none of these surface features will be disturbed or impacted.

Although larger than a conventional well pad, horizontal well pads are less densely spaced [NYSDEC, 2009]. Therefore, the cumulative environmental footprint of shale gas production can also be minimized using horizontal wells. This minimizes potential habitat fragmentation and disruption of wildlife movement patterns.

Apache [Undated] indicates that one multi-well pad in the FBS may be able to access 5 km to 10 km of reservoir meaning that well access plots could range from 5 km² to 10 km². The low natural permeability of shale requires the spacing for vertical wells to be much denser than in other formations and it typically averages 16 ha [NYSDEC, 2009]. Apache [Undated] predicts that in New Brunswick, 12 to 16 horizontal wells may be drilled per well pad site. Because the FBS is so thick, it is predicted that wells will also be stacked so the full pay thickness can be tapped (Figure 2). The wells branch out from the centre of the well pad where they are spaced at the surface 4 m to 6 m apart. In plan-view the configuration looks like two opposing pitch forks.

Assuming a 7.5 km² / 750 ha plot in the FBS, Figure 3 shows a conceptual layout for accessing shale gas through vertical wells and horizontal wells. Up to 47 pads would be required to extract the resource using conventional vertical wells. Not including roads and associated infrastructure, the total cumulative impact on the landscape would be about 40 ha or 5.3% of a 750 ha plot. In contrast, only one well pad is required for extracting the resource using horizontal wells. The total cumulative impact on the landscape would be about 2.5 ha or 0.33% of a 750 ha plot. This is a very substantial decrease in potential surface impacts.

As demonstrated in Figure 3, horizontal wells have the potential to greatly minimize habitat disturbance, impacts to the public, impacts to the visual landscape, and conflicts with other land-uses, such as forestry and agriculture. Review of horizontal well pad sites through a Phased EIA process will also indicate unavoidable impacts that must be mitigated.

Current well construction requirements consist of installing multiple layers of protective casing and concrete that are specifically designed and installed to protect drinking water aquifers [NYSDEC, 2009]. The multiple concentric casings serve to isolate the gas producing zones from overlying formations. During well drilling considerable data are collected on the formations using highly-sensitive equipment that the wellbore comes into contact with. Casing and concrete are tested throughout the 24/7 drilling process to ensure integrity and that there are no leaks in the system that could result in potential contamination of drinking water aquifers [NYSDEC, 2009].

![Vertical Well Configuration Diagram](image1)

**Figure 3.** Land surface disturbance comparison for extracting shale gas from a 750 ha plot using vertical wells and horizontal wells.
Horizontal drilling technology has been continuously improving since it was first developed for the shale gas industry in the 1980s [Arthur et al., 2008d]. Further advances will continue to occur. For example, rotary drill rigs common in the industry are now up to triples (can hold three sections of drill pipe above the ground at once). Those rigs have a substructure height of 6 m, a mast height of about 46 m, and a surface footprint, which includes auxiliary equipment, of around 1,300 m² [NYSDEC, 2009]. By using these rigs, wells can be drilled faster and thereby decrease the time the overall well pad site is required.

**Multi-Stage Hydraulic Fracture Stimulation**

Most sedimentary rocks have the ability to store natural gas within the small spaces between rock particles, but their ability to transmit the hydrocarbons is controlled by the connectivity between pore spaces. Hydraulic fracture stimulation caused by using pressures between 4,000 Psi and 10,000 Psi [Tom Alexander, personal communication] is a process designed to improve pore space connection in the source rock thereby allowing natural gas to flow out of a wellbore. When pressure is applied to shale, the thin layers break with an irregular curving fracture parallel to the bedding plane [Halliburton, 2005]. Two factors increase the ability of shale to fracture: 1) presence of hard minerals, such as silica, that break like glass; and 2) the shale’s internal pressure [NEB, 2009].

Hydraulic fracture stimulation is a proven technology that has been used for 60 + years in more than a million gas wells to unlock shale gas [Anadarko, 2010; CSUG, 2011]. Stanolind Oil and Gas Corporation conducted the first experimental fracturing in the Hugoton field in Grant County of southwestern Kansas in 1947 [Montgomery and Smith, 2010]. Following that, hydraulic fracture stimulation was introduced to the wider oil and gas community in 1948 through a Stanolind research paper. On 17 March 1949, Halliburton Oil Well Cementing Company conducted the first two commercial fracture treatments in Stephens County, Oklahoma and Archer County, Texas [Montgomery and Smith, 2010].

Hydraulic fracture stimulation is a short-duration, costly, and highly controlled and monitored process [CSUG, 2011]. All hydraulic fracture stimulations are designed to the specific conditions of the target formation [GPC and ALL Consulting, 2009]; there is no one-size-fits-all approach. Simply, the process involves pressurizing the shale with fluids to generate fractures, growing the fractures by increasing the pressure, introducing a proppant, typically sand, resin-coated sand, or ceramic beads, to keep the fractures open when the pressure is released, and releasing the pressure to allow the natural gas to flow into the wellbore [CSUG, 2011].

Shale gas production economics dictate that fractures be limited to the target formation and not extend into adjacent rock strata [Arthur et al., 2009; GPC and ALL Consulting, 2009; NYSDEC, 2009]. Allowing fractures to extend beyond the target formation and into adjacent strata could cause excessive amounts of water to be produced from adjacent wet formations. Confining fractures to the target formation also saves time, materials, and money. Pressures used for hydraulically stimulating a shale are not excessive enough to produce extensive fractures vertically. This is because the weight of the rock layers above is so great that fracture growth is limited vertically. Stresses in the horizontal direction are much lower, which allows fractures to extend much further horizontally.

Today, hydraulic fracture stimulation of wells is done in multiple stages because it is not possible to maintain pressures sufficient to induce fractures over the complete length of a lateral leg that can be several thousand metres long [Arthur et al., 2008d]. Prior to stimulating each section of the lateral leg, a perforating gun is lowered down the production casing to create holes in the wellbore and provide access to the formation. For horizontal wells installed in the FBS, Apache [Undated] predicts that there will be 10 to 20 stages per well. There are sometimes up to 20 sub-stages completed for each stage of hydraulic fracture stimulation. Each sub-stage has a different volume of fluid, specific additives, and proppant levels [Arthur et al., 2008b].

Hydraulic fracture stimulation is continuously being refined as technology improves and more detailed information is gathered on the process. For example, diesel used to be added to fracturing fluids, but to address environmental concerns, the United States Environmental Protection Agency (USEPA) worked with the three service companies that perform 95 % of hydraulic fracture stimulations in the US to voluntarily remove it from their list of additives [USEPA, 2004]. Today, 96 % of all shales are stimulated using slick-water that was developed in the 1990s specifically for shale formations [NYSDEC, 2009; Montgomery and Smith, 2010].

Slick-water consists of sand and a large volume of freshwater that is treated with additives to elicit certain properties and characteristics that aid and enhance the stimulation process. This results in greater gas mobility and more efficient recovery of larger gas volumes [Harper, 2008]. Slick-water has fewer additives than traditional cross-linked gels [Arthur et al., 2008d].
In the Barnett, where the most hydraulic fracture stimulation on horizontal wells has been completed, about 13,000,000 L of freshwater is used for drilling and stimulating a well [Arthur, 2010a]. About 12.5% of the water is used during drilling the well and the remaining 87.5% is used for hydraulic fracture stimulation. The amount of water used for each well varies by shale play and location within the play [Hazen et al., 2009; NYSDEC, 2009; Fischetti, 2010]. In New Brunswick, Apache estimates that about 20,000,000 L of water will be required for the hydraulic fracture stimulation of a single well [CCNB, 2010; Apache, 2011]. Arthur [2010b] notes that although this appears as a snapshot to be a large volume of water, natural gas production uses considerably less water per Btu of energy produced than other fuel sources such as coal, oil, and ethanol.

In New Brunswick, one of the largest natural resource-based economies is forestry. The processing of wood is a water-intensive industry. For example, a standard pulp and paper mill uses 70,000,000 L of water per day to produce 1,000 tonnes of paper [Global Water Intelligence, 2009]. Applying the water volume used for hydraulically stimulating one well and required one time only translates to operating a standard pulp and paper mill for about 7 hours or producing about 300 tonnes of paper. Power-generation is also a large consumer of water in New Brunswick. It takes about 0.5 L of water to produce 1 kWh from a coal-fired thermo-electric power plant [US Department of Energy, 2009]. Therefore, for a typical 600 MW per hour generating station, it takes 7,200,000 L of water to produce a day’s worth of electricity. Applying the water volume used for stimulating one well translates to operating a 600 MW per hour generating station for about 2.8 days. These water usage comparisons do not consider water recycling, which is common in all of these industries to considerably reduce water use.

Sourcing large volumes of water in a region where most rural residents rely on groundwater for potable water could pose a challenge. Industry normally sources water for hydraulic fracture stimulation from local groundwater, local surface water, and municipal systems [NYSDEC, 2009]: however, it is more cost-effective and beneficial for companies to use water that is not suitable for drinking water purposes. In some areas, lined ponds are constructed to harvest rain water and snow melt, which could be a preferred option in New Brunswick. Chesapeake Energy constructed a 620 million litre reservoir to hold water spilled from the banks of the Little Red River [Arthur et al., 2008c].

For shale gas wells, thousands of metres of rock, some of it impermeable, yield a minimal risk for shale gas to migrate into near-surface aquifers that are used for drinking water sources.

Constructing ponds, such as this, along banks of New Brunswick watercourses could be used to harvest excess water during spring freshets, thus reducing flood peaks while not reducing low flows. Another option for sourcing water, which is being tested by Apache in British Columbia [Jim Balcomb, personal communication], is treated brine/salt water. Water from the Bay of Fundy or brine aquifers could be tested for use here.

A typical fracture treatment uses between three and a dozen additives depending on the formation characteristics [GPC and ALL Consulting, 2009]. Stimulation additives may include: acids; friction reducers; surfactants; gelling agents; scale inhibitors; pH adjusting agents; oxygen scavengers; breakers; cross-linkers; iron controls; corrosion inhibitors; and antibacterial agents [Parfitt, 2010]. The number, type, and concentration of additives used are highly variable and depend on the specific reservoir properties [CSUG, 2011]. For example, the additives used in the Barnett are likely different than those that may be used in the FBS; again, there is no one-size-fits-all approach. Some of the many additives used by industry are considered toxic to the environment and harmful to human health [Hazen et al., 2009]. Often, industry does not publicly-disclose the composition of the slick-water additives because they believe it is proprietary information or may give them a competitive edge; however, the Fracturing Responsibility and Awareness of Chemicals Act (the FRAC Act) in the US [Arthur, 2010a] is changing that industry mindset and produces a more transparent process. New Brunswick players are willing to disclose what additives they will be using to complete hydraulic fracture stimulation here.

Typically, 99.5% of the slick-water comprises water and proppant and 0.5% additives [GPC and ALL Consulting, 2009]. For a well in the FBS, this represents about 100,000 L of additives. The public generally expresses concerns about the risks to drinking water aquifers from hydraulic fracture stimulation.

In an extensive research study, the USEPA did not find confirmed evidence that any drinking water wells were contaminated by the injection of hydraulic fracturing fluid in coal-bed methane wells [EPA, 2004; Fischetti, 2010]. Coal-bed methane wells are generally much shallower than shale gas wells. For shale gas wells, thousands of metres of rock, some of it impermeable, yield a minimal risk for shale gas to migrate into near-surface aquifers that are used for drinking water sources. Estimates on the probability for treatable
groundwater to be impacted by the pumping of fluids during hydraulic fracture treatments of newly installed, deep shale gas wells when a high level of monitoring is being performed are about 1 in 100 million [NYSDEC, 2009].

Poorly constructed wells are more likely the culprit of drinking water aquifer contamination than aquifer communication with deep shale formations [CCNB, 2010]. Even then, a number of independent events would have to occur simultaneously and go undetected for contamination to occur [EPA, 2004]. The Ohio Department of Natural Resources, in their investigation into methane gas found in a drinking water aquifer, determined faulty concrete casing as the cause for aquifer contamination by natural gas [Lustgarten, 2009]. Some jurisdictions have implemented enhanced well casing and concrete requirements to reduce the likelihood of communication between deep fractured zones and shallower zones outside of the wellbore [ERCB, 2011]. Moreover, many jurisdictions establish a base of groundwater protection zone to which casing and concrete must reach [CSUG, 2011].

Throughout the stimulation process, numerous data are collected. Wellhead and down-hole pressures are monitored, pumping rates are recorded, fracture fluid slurry density is measured, water and additive volumes are tracked, and equipment function is monitored. The collection of the massive amounts of data constitutes a highly-controlled process and its analysis and interpretation allows operators to ensure there are no unforeseen problems.

Hydraulically stimulating a well is an iterative process. As monitors collect more resource specific data, a more optimized fracture pattern within the target formation is developed to increase gas production while ensuring that the fractures do not grow beyond the formation [Arthur et al., 2009d]. Micro-seismic imaging is often undertaken to actively monitor a multi-stage hydraulic fracture stimulation [Arthur et al., 2008b]. Real-time data collected from micro-seismic imaging is a method that can be used by industry to determine how far, how extensively, and in what directions the shale cracks under induced pressure [NEB, 2009].

The FBS is found at depths of 1,750 m to 4,000 m below the ground surface [Apache, Undated]. The deepest drinking water wells in New Brunswick extend < 200 m below the ground surface [New Brunswick Department of the Environment, 2008]. This results in a minimum separation distance between the shale gas and drinking water of 1,550 m (Figure 2). Above the FBS are other layers of shale [Hinds and St. Peter, Undated]. Because of the extremely low permeability [Freeze and Cherry, 1979], shale is a natural barrier to the vertical migration of fluids and is considered as a confining layer to the vertical migration of oil and gas [Craig et al., 1996], thus adding another level of protection for gas drilling in New Brunswick.

**Resource Assessment**

Production testing of exploratory wells involves flow testing and analysis over several weeks or months. Normally, during that period, the produced gas is incinerated on-site or, in instances of excessive amounts of production, the gas is flared [Apache, 2011]. If gas yields are economically-viable, then the well will be put into production.

Wells are tested prior to going into production because there is an initial spike in gas released from the reservoir in response to high subterranean pressures. Afterwards, gas yields decrease through a normal decline curve [Pickering Energy Partners, 2005]. Typically, there is a 55% decrease in the first year, a 25% and 15%, respectively, decline in the second and third year, and a 10% reduction thereafter. About 50% of commercially marketable gas is yielded from the well within the first five years.

Gas-in-place recovery rates from a horizontal well are about 20% [NEB, 2009]. Assuming predictions for the FBS of about 65 Tcf are realized, that would amount to a potential yield of 13 Tcf. Estimations of the potential reserves will fluctuate as better information is collected through exploration programs.

**Production Setup**

If it is determined that a well or series of wells yield commercially-viable volumes of gas, pumping and treatment infrastructure are installed at the well pad site [Hazen et al., 2009; NYSDEC, 2009]. Small in-line gas heaters are installed to ensure flow lines do not freeze during the initial stages of production. A gas/water separator installed at the wellhead removes production water from the gas. Metering devices installed on the gas line and the water line quantify all wellbore production. Storage tanks erected at the well pad site allow for the temporary collection of production water. A pipeline lateral extends from the well pad site to the regional transmission network where the gas flows to a processing facility.

Produced water varies depending on the formation and well, but is common in all oil and gas wells. Production water can include a range of dissolved minerals and solids, which in some circumstances could include high total dissolved solids, hydrocarbons, heavy metals, and Naturally Occurring Radioactive Material (NORM) [Sumi, 2008; Hazen et al., 2009]. NORM may include trace amounts of uranium and thorium and their daughter
products radium 226 and radium 228. Produced water may require specialized treatment and disposal depending on what minerals and solids are contained within it.

After the first few weeks or months, the amount of water produced from a well considerably decreases. During the initial period, large volumes of spent fracturing fluids, ranging from 15 % to 35 % of the initial hydraulic fracture stimulation fluid volume, are returned to the surface [Arthur and Cornue, 2010].

**Interim Reclamation**

Once a well or series of wells are brought on-line for production, the size of the well pad site can be reduced through footprint minimization. Hazen et al. [2009] indicate that 40 % of the originally constructed well pad site can be reclaimed. The remaining 60 % of the well pad site is required for maintenance access, produced water storage, and the production equipment noted above.

The drill rig and associated infrastructure are dismantled and moved to another site. Drill cuttings, muds, and fluids collected during the course of drilling the well are removed by waste handlers and taken to licensed treatment facilities [Apache, 2011]. At sites where water ponds exist, all of the spent hydraulic stimulation fracture fluids are hauled away and treated appropriately at licensed treatment facilities. Crushed rock and geotextile placed on the space no longer needed at the well pad site can be removed. The reduced site footprint is secured with perimeter fencing and signage is erected. The reclaimed space is typically landscaped as per local ordinances or to standards established in the EIA.

**Natural Gas Production**

Over time, gas yields from a well decrease to a level where they are no longer economically-viable. The life of a well varies; horizontal wells have an average predicted economic production lifespan of 20 to 40 years [Arthur et al., 2008c; API, 2010; CSUG, 2011].

Throughout their lifetime, wells are routinely tested to ensure integrity. Regular testing is effective for identifying any deficiencies in the well casing and concrete. If any issues are identified, remedial measures can be implemented before any impacts are realized.

**Royalty Rates**

The Cornell University Cooperative Extension [2009], reports that natural gas exploration poses significant opportunities for rural economic development. For example, the Barnett Shale has provided jobs, expanded business activity, and generated significant royalty payments throughout Texas [The Perryman Group, 2007].

In Canada, royalties are primarily paid to the provincial government, which owns most of the natural resources [Alberta Department of Energy, 2007]. This contrasts with the United States where most land rights are privately owned and developers pay negotiated royalties to private landowners. Although, individual US states do collect a severance tax on the income remaining after the royalty is deducted [Price Waterhouse Cooper, 2009].

The royalty framework in Canada is often designed to maximize the amount of government revenue from produced oil and gas while ensuring that developers earn a fair return on their investment [BC Oil and Gas Division, 2010]. Determining an optimal royalty rate for government is no simple task. If royalties are too high, investment may choose to migrate to other jurisdictions that provide more competitive rates; if rates are too low, the government will not maximize their revenues.

Natural gas royalties in progressive oil and gas provinces are calculated based on market value and volume of production. British Columbia and Alberta apply a curve structure to their royalty rates. This is different from most US jurisdictions where royalties are either a fixed percentage of total gas produced or an established price per unit gas produced. New Brunswick’s existing royalty regime appears to be modelled after the US norm and was likely developed before large-scale finds of natural gas were postulated. New Brunswick’s royalty regime could be modified to account for the large geographical extent of shale gas potential and the prospects of significant shale gas production.

With respect to the recent shale gas revolution, our review indicates that the royalty framework in most North American jurisdictions provides concessions for the exploitation of this unconventional resource. For example, some jurisdictions promote very low royalty rates for new shale gas wells under certain circumstances, such as for a limited time or volume of production; 5 % for 36 months for new wells in Alberta.
and 2.5% for the first 882 Mcf production in Saskatchewan. Others locales, such as British Columbia and Texas, have various shale gas incentive programs, such as the Deep Drilling Program and the Marginal Royalty Program, to provide rate reductions, royalty credits, or even royalty relief to the development of high-cost, difficult-to-drill or low producing wells. As well, several US jurisdictions, such as Texas and Louisiana, provide royalty incentives for reducing wastewater discharge by reusing, recycling, or injecting produced water from shale gas wells.

Among all the jurisdictions reviewed, British Columbia appears to have the most sophisticated and comprehensive royalty regime. This belief is supported by the Quebec Government’s recent royalty regime analysis [Gouvernement du Québec, 2011]. The fair and competitive royalty system for responsible shale gas production paper notes that Quebec’s new royalty regime will be based on a progressive rate pegged to the price of the resource and well productivity. The new royalty programs in Quebec will be similar to those in British Columbia.

In British Columbia, various programs provide incentives to shale gas companies. For instance, a developer is eligible to receive credits or reduced rates if their well: 1) is drilled in the summer through the Summer Drilling Royalty Credit Program; 2) involves roadway construction through the Infrastructure Royalty Credit Program; 3) is deep through the Deep Royalty Program; or 4) has low productivity through the Marginal Royalty Program. Most of British Columbia’s programs are designed to encourage exploration and production by enabling companies to pay lower royalty rates in the initial stages of development and commercialization in exchange for higher royalty rates in later stages of production once projects have recovered substantial portions of their capital investment [British Columbia Ministry of Energy, Mines, and Petroleum Resources, 2009]. Moreover, several programs can work concurrently as long as all the required conditions are applied. This can result in significant royalty reduction and credits to shale gas companies in extreme conditions and less in more stable conditions.

Discovery of new oil and gas reserves in New Brunswick will result in changes to the socio-economic landscape. If a major discovery is made, a mature shale gas industry could yield $225 million annually in royalties, as reported on the Province of New Brunswick’s shale gas website. The revenue generated by the Province through this potential industry could be a considerable economic engine. Development of the industry would generate thousands of direct and indirect jobs, in such sectors as geology, geophysics, environment, transportation, drilling, production, land, legal, and accounting, to name a few.

Currently, New Brunswick’s oil and gas royalty program is a one-size-fits-all approach. This may be attractive to industry from a long-term development perspective. Based on our review, New Brunswick regulators may wish to revisit the existing oil and gas royalty program and identify methods to improve the revenues that could be generated through this potential industry.

Based on the average annual NYMEX natural gas price for 2010 of $4.38 per Mcf, which is based on the Henry Hub in Louisiana, New Brunswick’s current royalty regime would generate $5.7 billion on 13 Tcf of natural gas. Modifying New Brunswick’s existing royalty regime could increase that potential income generated by the Province. This would be kin to issuing a social licence to operate that provides a maximum collective benefit by allowing more New Brunswickers to enjoy advantages of the industry presence.

A simplistic analysis to describe royalties is difficult to present; however, a generalized approach is provided to demonstrate the varying royalty regimes. A 2 km deep horizontal well with a 1.5 km lateral was considered. A gas market price of $4.38 per Mcf was assumed for a well that yielded 100 MMcf over a one month period. Table 2 shows the royalties for different jurisdictions based on the sale of $438,000 of shale gas. Special programs, such as marginal well programs, were not considered. A new well, one that does not yet have a proven yield, and a normal production well, one that has a proven yield, were assessed.

Table 2. Example of royalties collected on the sale of 100 MMcf of natural gas for different jurisdictions based on the default parameters described in the text.

<table>
<thead>
<tr>
<th>State / Province</th>
<th>Royalty (Thousands $)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>New Well</td>
</tr>
<tr>
<td>Alberta</td>
<td>22</td>
</tr>
<tr>
<td>British Columbia</td>
<td>118</td>
</tr>
<tr>
<td>New Brunswick</td>
<td>44</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>11</td>
</tr>
<tr>
<td>Arkansas</td>
<td>6.6</td>
</tr>
<tr>
<td>Louisiana</td>
<td>12</td>
</tr>
<tr>
<td>New York</td>
<td>No taxes are collected because it is not a top producer</td>
</tr>
<tr>
<td>Ohio</td>
<td>1.8</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>No taxes are collected</td>
</tr>
<tr>
<td>Texas</td>
<td>33</td>
</tr>
<tr>
<td>West Virginia</td>
<td>25</td>
</tr>
</tbody>
</table>
Table 2 suggests that royalties in the US are considerably lower than in Canada; however, there is a difference between the two countries. Canadian royalties are normally only paid to the government. In contrast, landowners in the US are also paid royalties, which are typically around 12.5%. The values presented in Table 2 do not include landowner royalties in the US. The royalty rate in New Brunswick is the same across the board, similar to the pre-March 2011 royalties in Quebec [Gouvernement du Québec, 2011]. Because of this, there may be less incentive to start-up in New Brunswick, but once a company breaks into the industry, there may be considerable incentive to produce gas over the long-term. Not apparent in Table 2 is the comprehensive nature of the British Columbia royalty regime, which from a progressive standpoint makes it attractive.

**Plugging and Abandonment**

Once gas production from a well is exhausted, or a well is determined to be unsuccessful, it must be properly plugged and abandoned. Different regulatory bodies have specific requirements for plugging and abandoning wells [Schlumberger, Undated]. Generally, the equipment installed within a well is removed and concrete plugs are placed across open hydrocarbon-bearing formations, across all freshwater aquifers, and usually at several areas near the surface. For example, some jurisdictions require concreting off of the first 6 m to 15 m of the wellbore in order to protect groundwater, surface water, and soil. All concrete seals must be tested for integrity before the well is deemed abandoned.

**Final Reclamation**

Once a well is plugged and abandoned, surface infrastructure is no longer required. That infrastructure is removed and the site is reclaimed. It may take several years to restore the site to pre-development conditions and to no longer be able to identify that the lands were used for shale gas production. For example, regeneration of a forest can take considerable time.

**Summary**

There is great fiscal potential for New Brunswick in the exploration, development, and production of shale gas. Natural gas production from onshore hydrocarbon-rich shale formations is one of the most rapidly expanding resource industries in North America. New Brunswick’s Frederick Brook Shale is an emerging resource play where exploration work is in progress by several companies to prove resource potential that is estimated at > 65 Tcf. Public confidence is improved through public consultation. Shale gas development in other jurisdictions has met with the same concerned questions being posed by New Brunswickers. It is important to inform the regulators, stakeholders, and public about what they can expect during shale gas exploration, development, and production before it is undertaken. Fostering consultation engages all parties and allows them to act together and develop creative environmental impact solutions.

Encouraging a thorough, yet streamlined, environmental review process will identify potential environmental impacts so they can be appropriately mitigated before they happen. New Brunswick has an environmental review process that includes a public consultation component. The process is being modified to expedite review of shale gas industry impacts before they occur. Industry is subject to scrutiny under several other pieces of legislation in New Brunswick and strict criteria must be met before work can proceed.

Proven technologies exist for companies in New Brunswick to borrow for use here. Horizontal well drilling practices were developed in the 1930s and have been continuously refined. Use of horizontal wells for shale gas production began in 1986 within the Barnett shale in the Fort Worth Basin of north-central Texas. Use of horizontal wells substantially reduces the shale gas industry’s cumulative surface footprint and flexibility exists to avoid environmentally-sensitive areas. Multiple concentric casings and concrete provide several layers of protection between the well and non-target formations. Hydraulic fracture stimulation has been used for 60+ years in more than a million gas wells in North America to produce shale gas. This short-duration highly controlled and monitored process is designed to limit fracturing to the target formation where the gas exists.

New Brunswick has the opportunity to become a leader in all facets of shale gas exploration and development. Industry best-practices are available for New Brunswick to adopt, adapt, and apply to develop this non-renewable resource in an environmentally and socio-economically responsible manner. Several US shale plays have been extensively worked since the 1980s in rural and urban environments. Many potential problems in those jurisdictions were averted by applying best-practices developed through collaborations between the public, stakeholders, regulators, and industry.

A royalty regime review, using examples from the US, British Columbia, Quebec, and New Brunswick’s historical oil and gas industry, may be beneficial for maximizing collective benefits for New Brunswickers. In New Brunswick, existing royalties are set at a fixed rate.
that appears to limit industry start-up but encourages long-term development. Natural gas royalty regime benefits in progressive oil and gas provinces are calculated based on market value and volume of production. Those provinces have seen an increase in industry presence and royalty revenue has been socially beneficial.

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Endnotes

1 http://www.gnb.ca/0062/regs/o-2-1reg.htm
2 http://www.gnb.ca/0062/regs/c-6-1reg.htm
3 http://www.gnb.ca/0062/regs/c-12reg.htm
4 http://www.gnb.ca/0062/regs/c-6reg.htm
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