The Modern Practices of Hydraulic Fracturing:

A Focus on Canadian Resources

Prepared for:

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The cover picture depicts a typical producing well site in the Montney Resource Play. Courtesy of Encana.

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FOREWORD

Tremendous natural gas resource potential has been identified in shale basins in Western Canada. Producing natural gas from these areas has become economically feasible principally due to technological advancements in horizontal drilling and the use of hydraulic fracturing. While hydraulic fracturing of shale gas wells has been in use since the 1950's, its wide spread application in the last several years has raised questions about potential environmental and human health risks.

To address these questions on the potential risks from hydraulic fracturing a research project was undertaken by the Petroleum Technology Alliance Canada (PTAC) and the BC Science and Community Environment Knowledge (SCEK) Fund. Involvement and support was provided by the Canadian Association of Petroleum Producers (CAPP) and its member companies and the Canadian Society of Unconventional Resources (CSUR).

The sponsors of this project are excited to have the research findings that will provide information for use by both government regulators, industry practitioners and other stakeholders. The report has been compiled to provide a review of factual information on the practice of hydraulic fracturing and its importance to the development of Canadian shale oil and natural gas resource plays. This report will help to fulfill a recognized need for information not just in areas where oil and gas exploration is just in its infancy but also for regions in Canada that are familiar with this industry.

This project has met its objectives and we look forward to the dissemination of the research findings to protect the environment and human health—while taking advantage of the huge resource potential of these shale basins.

Howard Madill SCEK Fund Manager	Tannis Such Director, Environmental Research Initiatives, PTAC

EXECUTIVE SUMMARY

This primer has been compiled to provide a review of the practice of hydraulic fracturing and its importance to the development of Canadian shale oil and natural gas resource plays. Discussions address the technology involved with hydraulic fracturing, chemicals used, variations in North American shale geology, oil and gas regulations, best management practices, potential pathways of fluid migration and the risk involved, and past incidents attributed to hydraulic fracturing. The intent of the Primer is to provide a baseline of information that illustrates that no two shales are alike, understanding and designing a fracture requires specific data that must be collected, technology has made many shale gas resources available for extraction but only in the last few years, regulations are in place to protect groundwater and the environment, best management practices are employed by industry, and although there are past incidents the risks of contamination from the act of fracturing the rock are minute.

Hydraulic fracturing is defined as the process of altering reservoir rock to increase the flow of oil or natural gas to the wellbore by fracturing the formation surrounding the wellbore and placing sand or other granular material in those fractures to prop them open. Hydraulic fracturing makes possible the production of oil and natural gas in areas where conventional technologies have proven ineffective. Recent studies estimate that up to 95% of natural gas wells drilled in the next decade will require hydraulic fracturing.[1] This technology has been instrumental in the development of North American oil and natural gas resources for nearly 60 years. It is the combining of hydraulic fracturing with horizontal drilling and innovative earth imaging that has revitalized the oil and gas industry in North America over the last two decades.

Hydraulic Fracturing is a highly engineered, modeled, and monitored process, using precisely selected types and volumes of chemicals to improve performance. These chemicals typically make up less than 1% of fracturing fluid. Experience and continued research have improved the effectiveness of the process and allowed the use of reduced chemical volumes and more environmentally benign chemicals .The natural gas and oil extraction industry is facing ever-increasing scrutiny from governments, the public, and non-governmental organizations (NGOs). These stakeholders rightly expect producers and service companies to conduct hydraulic fracturing operations in a way that safeguards the environment and human health. Many of the concerns raised about hydraulic fracturing are related to the production of oil and gas and can be associated with the development of a well, but are not directly related to the act of hydraulically fracturing a well. It is important to distinguish those impacts that can potentially be attributed to hydraulic fracturing from those that cannot so that mitigation measures and regulatory requirements can be directed towards the proper activities and responsible parties.

While the environmental risks associated with oil and gas development—including the practice of hydraulic fracturing—are very small due to advanced technology and regulation, the use of best management practices (BMPs) can reduce and mitigate those risks that remain. Most of the commonly used BMPs identified for hydraulic fracturing and oilfield operations address issues at the surface. These include reducing impacts to noise, visual, and air resources and impacts to water sources, wildlife, and wildlife habitats. There are also several BMPs that can be used to mitigate risks associated with the subsurface environment. BMPs are generally voluntary, site specific, and proactive in nature. They are most effective when incorporated during the early stages of a development project.

Regulation of hydraulic fracturing has been carried out for decades under existing Federal, Provincial, and Territorial regulations. Although specific regulatory language has not necessarily used the term "hydraulic fracturing," requirements for surface casing, cementing, groundwater protection, and pressure testing have been prevalent in most regulatory regimes, all of which are directly applicable to the minimization of risks associated with hydraulic fracturing. The Federal government regulates oil and gas activities on frontier lands, certain offshore and territorial lands, and those lands set aside for the First Nations people. Each Province with oil and gas production has its own specific regulations governing these requirements. In addition, the government of the Yukon Territory has powers similar to those of a Provincial government. While there are no current shale gas prospects in the Northwest Territories and Nunavut, there are regulations in place that would cover initial development.

The recent increase in oil and gas development activities centers on the technological strides to access the oil and natural gas found in shale formations. As far as the geology of shale goes, it is a sedimentary rock that is comprised of consolidated clay-sized particles that were deposited in low-energy depositional environments and deep -water basins. It has very low permeability, which limits the ability of hydrocarbons in the shale to move within the rock. The oil and gas in a shale formation is stored in pore spaces or fractures or adsorbed on the mineral grains; the volume and type (oil or gas) varies depending on the porosity, amount of organic material present, reservoir pressure, and thermal maturity of the rock.

There is no specific recipe for an ideal shale basin. However, the right combinations of geologic and hydrocarbon properties can make oil and gas production of a shale formation commercially viable. While each shale basin is different, geologic analogues to Canadian shale basins can be found in commercially producing U.S. basins, suggesting technical and operational approaches to producing oil and gas from the Canadian shales.

Along the same lines as the geologic comparison to U.S. shales for the purpose of gaining insight; an effort to identify the potential hydraulic fracturing chemicals that would be used in Canadian shale plays was performed for chemicals used in analogous U.S. shale plays. This data was collected from the voluntary reporting of chemicals used by multiple U.S. operators and service companies and through private communication with operators in various basins in the United States.[2] In addition, water volume data was gathered and analyzed from the same sources. This information is useful because understanding the volumes and types of chemicals anticipated for the various shales across Canada can lead to a reduction in the number and volume of chemicals used. In addition, the Province of British Columbia, as well as many U.S. states are requiring public disclosure of the chemicals used during hydraulic fracturing through both laws and regulations.

Given the public concern about contamination of ground water from hydraulic fracturing, it is important to examine the pathways through which contamination could theoretically occur. The analysis in this report considers only the subsurface pathways that would potentially result from the hydraulic fracturing operation, and not those events that may occur in other phases of oil and gas activities. Five pathways are examined:

- Vertical fractures created during hydraulic fracturing.
- An existing conduit (e.g., natural vertical fractures or old abandoned

wellbores) providing a pathway for injected fluid to reach a fresh water zone.

- Intrusion into a fresh water zone during hydraulic fracturing based on poor construction of the well being fractured.
- Operating practices performed during well injection.
- Migration of hydraulic fracturing fluids from the fracture zone to a fresh water zone.

Analysis of each of these pathways demonstrates that it is highly improbable that fracture fluids or reservoir fluids would migrate from the production zone to a fresh water source as a result of hydraulic fracturing.

Numerous instances of environmental contamination across North America have been attributed in the popular media to hydraulic fracturing. In fact, none of these incidents have been documented to be caused by the process of hydraulic fracturing. The term “hydraulic fracturing” is often confused, purposefully or inadvertently, with the entire development lifecycle. Environmental contamination can result from a multitude of activities that are part of the oil and gas exploration and production process, but none have been attributed to the act of hydraulic fracturing. All of these activities are distinct from the process of hydraulic fracturing. This report presents a summary of many of those incidents, along with information that shows why they have not been caused by hydraulic fracturing, or why further study is needed to determine a cause.

During the last decade shale development has increased the projected recovery of gas-in-place from about 2% to estimates of about 50%; primarily by the advancement and reworking of technologies to fit shale formations.[3] These adapted technologies have made it possible to development vast gas reserves that were entirely unattainable only a few years ago. The potential for the next generation of technology to produce even more energy with advances in hybrid fracs, horizontal drilling, fracture complexity, fracture flow stability, seismic imaging, and methods of re-using fracture water is enormous.

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ACRONYMS AND ABBREVIATIONS

2-BE	ethylene glycol monobutyl ether
ACW	Approval to Alter the Condition of a Well
ADW	Approval to Drill a Well
API	American Petroleum Institute
AUPRF	Alberta Upstream Petroleum Research Fund
B.C.	British Columbia
bcf	billion cubic feet
BHP	Bottom-hole Pressure
BHT	Bottom-hole Temperature
BMP	Best Management Practice
CAPP	Canadian Association of Petroleum Producers
CBL	Cement Bond Log
CDC	(U.S.) Centers for Disease Control
CEAA	Canadian Environmental Assessment Act
CEO	Chief Executive Officer
CEPA	Canadian Environmental Protection Act
CMHPG	Carboxymethyl hydroxypropyl guar
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
CO_2	Carbon Dioxide
COGOA	Canada Oil and Gas Operations Act
CPRA	Canada Petroleum Resources Act
DOE	U.S. Department of Energy
DSL	Domestic Substances List
EA	Environmental Assessment
EDF	Environmental Defense Fund
EIA	Environmental Impact Assessment
EMR	Department of Energy, Mines, and Resources (Government of the Yukon Territory)
EPP	Environmental Protection Plan
ERCB	Energy Resource Conservation Board
FIT	Formation Integrity Test
ft	foot/feet
GHS	Globally Harmonized System
GIS	Geographic Information System
GoC	Government of Canada
GRI	Gas Research Institute
GWPC	Ground Water Protection Council
H_2S	Hydrogen Sulfide
HCl	Hydrochloric acid
HEC	Hydroxyethyl cellulose
HPG	Hydroxypropyl guar
IOGCC	Interstate Oil and Gas Compact Commission

IOPER	International Offshore Petroleum Environmental Regulators' Group
ISP	Intermediate-Strength Proppant
KCl	Potassium Chloride
kg	kilogram
kg/m^3	kilograms per cubic metre
km	kilometre
kPa	kilo Pascals
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
m	metre
m^3	Cubic Metres
mcf	thousand cubic feet
md	millidarcies
MMcf	million cubic feet
MNR	Ministry of Natural Resources
MSDS	Material Safety Data Sheet
N_2	Nitrogen
NDSL	Non-Domestic Substance List
NEB	National Energy Board
NGL	Natural Gas Liquid
NGO	Non-Governmental Organization
NOC	Notification to Complete
NWT	Northwest Territories
NYMEX	New York Mercantile Exchange
OCSG	Offshore Chemical Selection Guidelines
OGAA	[British Columbia] Oil and Gas Activities Act
OGIP	Original gas in place
OGR	Oil and Gas Resources
OGSRA	Oil, Gas and Salt Resource Act
OSPAR	Oslo and Paris Commission
PEI	Prince Edward Island
PMRA	Pest Management Regulatory Agency
ppg	pounds per gallon
ppm	parts per million
psi	pounds per square inch
PTAC	Petroleum Technology Alliance Canada
Ro	Vitrinite reflectance
SCEK	Science and Community Environmental Knowledge Fund
scf	standard cubic feet
tcf	trillion cubic feet
TDS	Total Dissolved Solids
THPS	tetrakis-hydroxyl methylphosphomium sulphate
TMV	Technical Monitoring Vehicle
TOC	Total Organic Content

UIC	Underground Injection Control
U.S.	United States
USEPA	United States Environmental Protection Agency
UV	Ultraviolet (light)
VDL	Variable Density Log
WOC	Wait on Cement
ZOEI	Zone of Endangering Influence

1 INTRODUCTION

This Primer has been compiled to provide a review of the practice of hydraulic fracturing and its importance to the development of Canadian shale oil and natural gas resource plays. Hydraulic fracturing makes possible the production of oil and natural gas in areas where conventional technologies have proven ineffective. Recent studies estimate that up to 95% of natural gas wells drilled in the next decade will require hydraulic fracturing.[4] This technology has been instrumental in the development of North American oil and natural gas resources for nearly 60 years. In fact, it is so important that without it, North America would lose an estimated 45% of natural gas production and 17% of oil production within five years.[5]

The practice of hydraulic fracturing is often misconstrued to represent all parts of the development and production of a well; however, the practice is only one of several stages involved in bringing a well to the point where it produces oil and/or gas. In this document, the term “hydraulic fracturing” means only the act of fracturing the oil- or gas-bearing rock formation using hydraulic means. Hydraulic fracturing uses water under pressure to create fractures in underground rock that in turn allow oil and natural gas to flow towards the wellbore.

The natural gas and oil extraction industry is facing increasing scrutiny from governments, the public and non-governmental organizations (NGOs). These stakeholders rightly expect producers and service companies to conduct hydraulic fracturing operations in a way that safeguards the environment and human health. Many of the concerns raised about hydraulic fracturing are related to the production of oil and gas and can be associated with the development of a well, but are not directly related to the act of hydraulically fracturing a well. It is important to distinguish those impacts that can potentially be attributed to hydraulic fracturing from those that cannot so that mitigation measures and regulatory requirements can be directed towards the proper activities and responsible parties. Issues that *can* be attributed to hydraulic fracturing include the consumption of fresh water; treatment, recycling, and disposal of produced water; disclosure of fracture fluid chemical additives; onsite storage and handling of chemicals and wastes; potential ground and surface water contamination; and increased truck traffic. These issues can be addressed through sound engineering and mitigation practices. Furthermore, as more wells are fractured, lessons are learned that are then used to develop improved management practices to minimize the environmental and societal impacts associated with future development.

An account of the history of hydraulic fracturing can aid in the understanding of the current practice of the technology. The industry first applied the process of fracturing in 1858 when Preston Barmore, one of the first petroleum engineers, fractured a gas well in Fredonia, New York, with black powder. The well was fractured in multiple stages and the resultant flow rate changes were recorded after each stage.[6]

The first hydraulic fracturing experiment was performed in Grant County, Kansas, in 1947 by Stanolind Oil.[7] J.B. Clark of Stanolind Oil then wrote and published a paper to document the results and introduce the new technology. Two years later, in 1949, a patent was issued to Halliburton Oil Well Cementing Company granting them the exclusive right to the new “Hydrafrac” process.[8]

Hydraulic fracturing was first commercially used near Duncan, Oklahoma, on March 17, 1949.[9] On the same day, a second well was also hydraulically fractured just outside Holliday, Texas. That year saw 332 wells hydraulically fractured with an average 75% increase in productivity over wells that had not been hydraulically fractured.

The first application of hydraulic fracturing in Canada was in the Cardium oil field in the Pembina region of central Alberta in the 1950s and hydraulic fracturing has continued to be used in Alberta and Western Canada for over 50 years.[10] Since that time, the use of hydraulic fracturing has become a regular practice to stimulate increased production in oil and gas wells throughout North America.[11]

The use of hydraulic fracturing technology in horizontally drilled shale formations has turned previously unproductive organic-rich shales into some of the largest natural gas fields in the world. In the United States, the Barnett, Fayetteville, and Marcellus gas shale plays and the Bakken oil-producing shale are examples of formerly non-economic formations that have been transformed into prosperous fields by hydraulic fracturing.

Why has the advancement of the horizontal drilling and hydraulic fracturing techniques made possible the development of natural gas from deep underground shale formations? Horizontal drilling increases exposure of the shale resource to the wellbore. This decreases the number of wells that need to be drilled to develop the resource and therefore decreases the overall cost of producing the oil and gas resource, even though each individual well is more expensive. Hydraulic fracturing increases the ability of the oil or gas to flow at a commercially profitable rate. The result has been a newly economic oil and gas supply that has changed the outlook for the future North American energy economy.

The boom in the use of horizontal wells and high volume hydraulic fracturing in many shale basins has not gone unnoticed. The potentially larger scale impacts associated with the lengthier wellbores and increased fracturing volumes have drawn attention to the technology. However, the combination of horizontal drilling and hydraulic fracturing may well have fewer environmental impacts than the use of the conventional vertical wells that would be required to recover the same amount of oil and gas; many more vertical wells would be needed to recover the same amount of oil or gas. Horizontal wells are drilled from centralized multi-well pads that disturb much less surface area and allow for the centralization of many functions, such as water management. This further reduces environmental impacts and risks.

Regulators, especially in Canada, have worked to keep abreast of the evolving technology. As hydraulic fracturing has become a common practice, regulators have updated existing regulations established to protect groundwater and ensure proper well construction to accommodate hydraulic fracturing practices. Comprehensive well construction specifications combined with best management practices (BMPs) for drilling, completing, and fracturing are now widely used and greatly reduce the risk of contaminating groundwater as well as other types of environmental impacts and risks.

While exploration of many shale gas plays in Canada is still in the early stages and the exact hydraulic fracturing process needed for each is unknown, early successes suggest shale gas will be an active part of Canada's energy program for many years. Each natural gas basin is distinct because of its unique geology and the interaction of the stresses, pressures, and temperatures which dictate the specifications of the fracturing technology that will be most effective in producing natural gas and oil. As a result, there are variations of the hydraulic fracturing process used depending on the subsurface conditions.

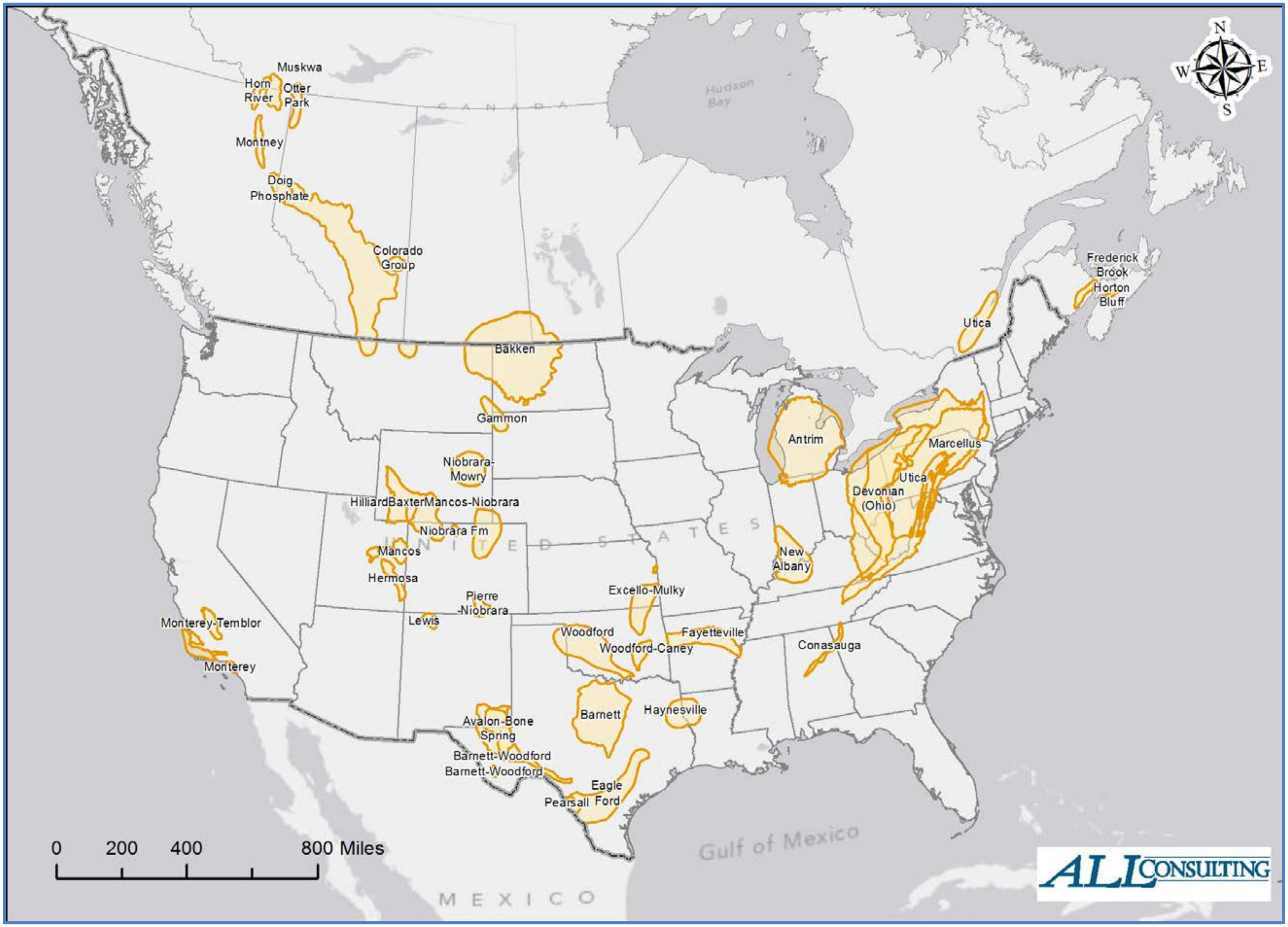
The current developed or explored shale gas resource plays in North America are shown in **Figure 1**. Tremendous natural gas resource potential has been identified in shale basins in Canada. There are potentially 30 x 10^{12} cubic metres (m^3) (approximately 1,000 trillion cubic feet [tcf]) of gas reserves in Canadian shale basins.[12] Recoverable gas resources from the Horn River and Montney shale gas plays alone are estimated at 68 x 10^{11} m^3 (240 tcf).[13] Other less well-defined plays, such as the Cordova, Liard, Doig, and Gordandale, offer the potential for significantly more natural gas to be produced. As shale basins are successfully developed, the advances are being transferred to other shale plays across North America and the world to great success. These advances in technology will assist in the development of shale resources in Canada.

This hydraulic fracturing primer is an effort to provide fact-based technical information about hydraulic fracturing. It provides vetted scientific information to the public regarding hydraulic fracturing and the processes that take place during the fracture phase so that industry and government can engage with affected communities and communicate important information on environmental impacts.

This primer is comprised of the following sections:

- **Technological Assessment of Hydraulic Fracturing:** This section describes the performance of hydraulic fracturing jobs. Included is a review of the current status of hydraulic fracturing used to produce oil and gas from shale.
- **Best Management Practices:** This section reviews BMPs specific to hydraulic fracturing.
- **Chemical Use in Hydraulic Fracturing:** Chemical use during the performance of a hydraulic fracturing job is described and a summary of the chemicals used and their purposes is given by basin.
- **North American Shale Geology:** This section describes the geology of the North American shale plays to provide for geologic analogies between Canadian shale plays and those with more mature development in the United States.
- **Hydraulic Fracturing Regulations:** The national and provincial regulations that have influence on the process of hydraulic fracturing are reviewed and analyzed.
- **Major Pathways of Fluid Migration:** This section assesses the risk potential in the identified pathways for fluid migration associated with hydraulic fracturing during the injection portion of the operation.
- **Incidents Associated with Hydraulic Fracturing:** Past incidents are reviewed to assess if any adverse environmental impacts can be attributed directly to the injection portion of the hydraulic fracturing process.
- **Summary:** A summary of the findings is presented.

Figure 1: North American Shale Gas Plays



2 OVERVIEW OF HYDRAULIC FRACTURING

Hydraulic fracturing is a well completion technique were the reservoir rock is altered to increase the flow of oil or natural gas to the wellbore by fracturing the formation surrounding the wellbore and placing sand or other granular material in those fractures to prop them open. To hydraulically fracture the formation, a fluid specifically designed for site conditions is injected under pressure in a controlled, engineered, and monitored process. Hydraulic fracturing overcomes natural barriers in the reservoir and allows for increased flow of fluids to the wellbore. Such barriers may include naturally low permeability common in shale formations or reduced permeability resulting from near wellbore damage during drilling activities.[14] In either circumstance, hydraulic fracturing has become an integral part of natural gas development across North America in the 21st century. The goal of hydraulic fracturing in shale formations is to increase the rate at which a well is able to produce or provide the ability to produce the resource. Improved production from hydraulic fracturing, especially when it is combined with horizontal drilling, dramatically increases the economically recoverable reserves and enables historically uneconomic resources to be profitably produced.

Horizontal drilling is the process of drilling a vertical well from the surface to a specific point (kickoff point) where the wellbore is curved away from the vertical plane until it intersects the target formation (entry point). The wellbore is then extended laterally within the target formation to a predetermined bottom-hole location. This technique allows a wellbore to contact greater amounts of reservoir formation. The lateral portion of a wellbore does not have to be straight, but can curve to follow the formation, intersect different pockets of resource (in sands), or even follow a lease line.

Officially it is the combination of the technological advances of hydraulic fracturing and horizontal drilling, coupled with innovative earth imaging that has revitalized the oil and gas industry in North America over the last two decades. A brief examination of their development and use in the Barnett Shale in Texas will illuminate how and why they are essential to the industry.

CAPP GUIDING PRINCIPLES FOR HYDRAULIC FRACTURING

Canada's shale gas and tight gas industry supports a responsible approach to water management and is committed to continuous performance improvement. The Canadian Association of Petroleum Producers (CAPP) is committed to following these guiding principles:

- Safeguard the quality and quantity of regional surface and groundwater resources, through sound wellbore construction practices, sourcing fresh water alternatives where appropriate, and recycling water for reuse as much as practical.
- Measure and disclose water use with the goal of continuing to reduce the effect on the environment.
- Support the development of fracturing fluid additives with the least environmental risks.
- Support the disclosure of fracturing fluid additives.
- Continue to advance, collaborate on and communicate technologies and best practices that reduce the potential environmental risks of hydraulic fracturing.

Building upon years of government research regarding the complex geology of tight shale formations, Mitchell Energy partnered with the U.S. Department of Energy (DOE) and the Gas Research Institute (GRI) to develop tools that would effectively fragment the Barnett Shale in Texas.[15] Mitchell Energy utilized the microseismic imaging data developed by GRI coupled with lessons learned from DOE's Massive Hydraulic Fracturing project to employ slickwater hydraulic fracturing to increase production of natural gas from wellbores drilled into the Barnett Shale.[16] The Barnett Shale contains vast amounts of natural gas; however, it seldom relinquished the gas in profitable quantities due to the formation's properties that limit the ability of the gas to flow to the wellbore naturally.

Mitchell Energy recognized that natural gas was trapped in miniscule pore spaces that were separated from one another within the shale rock structure. The shale rock had pore space but lacked the ability to transmit fluids, otherwise known as permeability. Early wells drilled into the Barnett Shale would typically yield some natural gas but usually not enough for economical production. Mitchell Energy solved this problem with the use of hydraulic fracturing to build a splintered network of fissures which connected the pore spaces, thereby enabling the natural gas to flow toward the wellbore in economically viable quantities.[17]

Early difficulties in hydraulic fracturing centered on how to maintain the fissures produced by the hydraulic fracturing. When the pumps were turned off and the water pressure reduced the fissures would close, sealing off the gas flow. In the deep Barnett Shale, such closing was believed to have been caused by pressure from the overlying strata. To solve this problem, sand was added to the fracturing fluid so it would be carried into the rock and prop open the fractures. The injection pressure of the water during the fracturing process forces sand grains into the fissures and these sand grains continue to prop open the fissures when the pressure is released, maintaining the openings and allowing a steady flow of natural gas to the wellbore.

Hydraulic Fracturing Facts

- Hydraulic fracturing was first used in 1947 in an oil well in Grant County, Kansas, and by 2002, the practice had already been used approximately a million times in the United States.
- Up to 95% of wells drilled today are hydraulically fractured, accounting for more than 43% of total U.S. oil production and 67% of natural gas production.
- In areas with deep unconventional formations (such as the Horn River area), the shale gas under development is separated from freshwater aquifers by thousands of metres and multiple confining layers. To reach these deep formations where the fracturing of rock occurs, drilling goes through shallower areas, with the drilling equipment and production pipe sealed off using casing and cementing techniques.
- The Interstate Oil and Gas Compact Commission (IOGCC), comprised of 30 member states in the United States, reported in 2009 that there have been no cases where hydraulic fracturing has been verified to have contaminated groundwater aquifers.
- The Environmental Protection Agency concluded in 2004 that the injection of hydraulic fracturing fluids into coalbed methane wells poses little or no threat to underground sources of drinking water. The EPA is currently studying hydraulic fracturing in unconventional formations to better understand the life-cycle relationship between hydraulic fracturing and drinking water and groundwater resources.

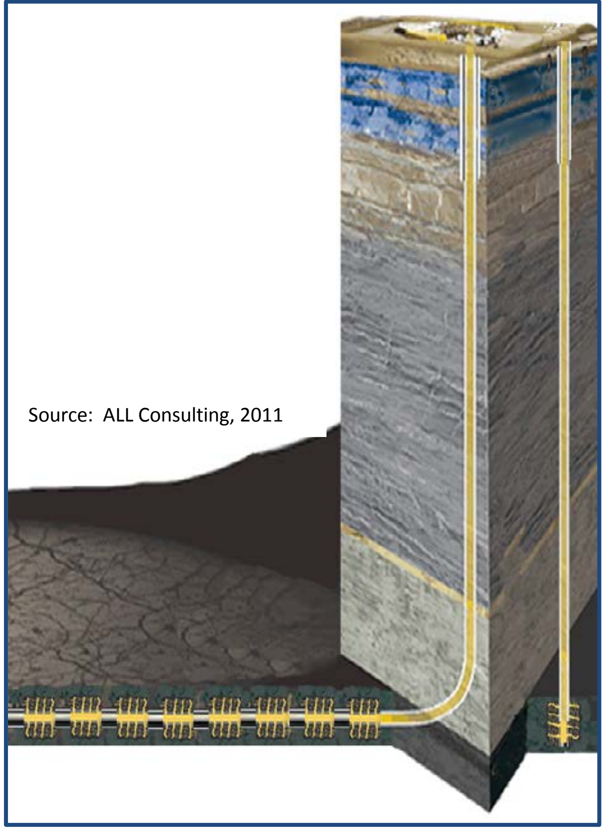
Mitchell Energy next improved the production of the Barnett wells by drilling horizontal wellbores.[18] Horizontal drilling increases the length of the wellbore exposed to the producing formation, thereby increasing production to the well. The Barnett is approximately 120 meters (m) thick so the pay zone is only 120 m in a vertical well. However, in a horizontal well the lateral portion could be 1500 m long through the shale formation, thus increasing the pay zone by more than 12 times compared to a vertical well. In addition to increasing the exposure of the pay zone to the well, this technology reduces the surface footprint required to produce from a given volume of shale.

Mitchell Energy used advanced earth imaging, hydraulic fracturing, and horizontal drilling to increase the productivity of a Barnett Shale well.[19] In fact, developers of the Barnett Shale owe their success to hydraulic fracturing and horizontal drilling, as shale gas wells would not have been economical to produce without these technologies.

2.1 Hydraulic Fracturing: The Process

Hydraulic fracturing treatments are conducted after a well has been drilled, cased, cemented, and the cement has been given time to set up and cure. Hydraulic fracture treatments are designed by engineers based on data obtained during drilling and from nearby wells drilled in the same or similar formations. Since the drilling data contains vital information needed to design the fracture, petroleum engineers and geologists often work to perfect the fracturing fluid and calculate the hydraulic pressures necessary to fracture the production formation while the casing and cement are being installed. This site-specific attention to detail improves the fracture treatment and reduces the time between design and execution of the treatment. As more fracture treatments are performed in an area, the designs of future treatments use the collected data to refine performance.

Figure 2: Vertical vs. Horizontal Formation Exposure and Fracturing Stages.



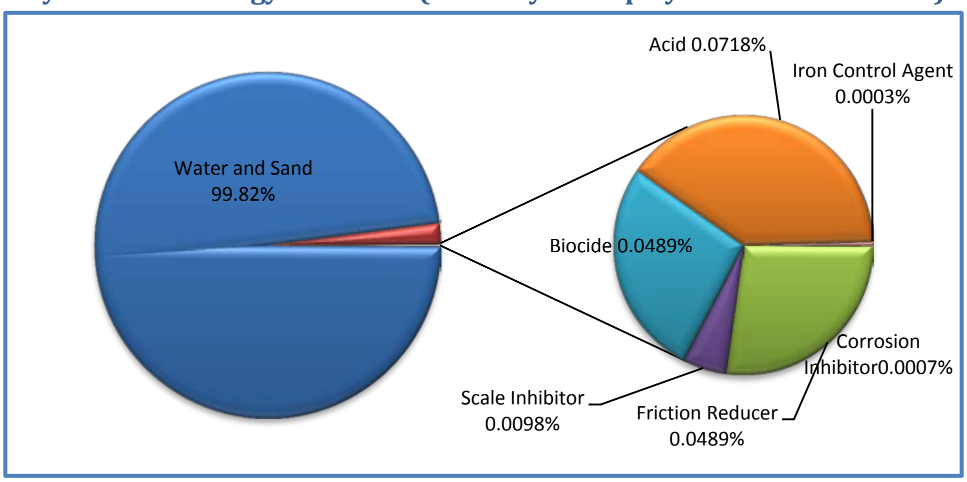
Source: ALL Consulting, 2011

Hydraulic fracture treatments for horizontal shale gas wells are designed to be performed in multiple stages, unlike vertical wells, which are typically fractured with a single stage. **Figure 2** shows a horizontal wellbore with multiple fracture stages and a vertical wellbore with a single fracture stage.

Slickwater fracturing has been one of the most prevalent methods used for hydraulic fracturing of shale formations. The term “slickwater” refers to the use of friction reducing agents added to fresh water to reduce the pressure that is required to pump the fluid into the formation during a fracturing treatment. Slickwater fracturing is the technique that was first used in the Barnett Shale play of Texas during the late 1990s. Slickwater fracturing fluids are generally about 99.5% fresh water and sand, while 0.5% or less is chemical additives.[20] **Figure 3** demonstrates the volumetric percentages of additives that were used for a 15,330 m^3 hydraulic fracturing job in the Montney Shale play in British Columbia.

Slickwater fracture treatments are a departure from previous fracture techniques used for tight gas formations which historically used cross-linked gel fracturing fluids to transport hundreds of tonnes of sand proppants.[21] Gelled fracturing fluids use a polymer base, typically organic guar, to form a viscous gel with a higher capacity to carry the proppant during the fracture treatment.[22] In ultra-low permeable shale formations, however, gelled systems require higher pressures, which are typically lost to friction from the fluid flowing through the wellbore to the formation, are not used to create fractures in the formation, and leave residual gel in the formation after fracturing. These problems led to the innovation of slickwater fracturing. A limiting factor of slickwater fracturing is lower capability to

Figure 3: Volumetric Composition of a Hydraulic Fracture Stimulation by Talisman Energy in Canada (Montney Shale play in British Columbia)



Source: ALL Consulting

transport proppant (e.g., sand) to the created fractures.

The volume of water that is necessary to hydraulically fracture a well varies from one basin to another, but also depends on the type of fracture fluid employed and the number of stages anticipated per wellbore. A horizontal shale gas well can use between 3,500 m^3 and 15,000 m^3 of water, whereas in vertical wells, 100 m^3 to 400 m^3 of water used is more common.[23] In a deep horizontal well, a multi-stage job could use even more water, possibly more than 20,000 m^3 for a slickwater fracture treatment. Water for hydraulic fracturing frequently comes from surface water bodies such as rivers and lakes, but can also come from ground water, private water, municipal water, and re-used produced water sources and deep saline water.

Shale formations may also potentially be fractured with propane-based liquefied petroleum gas (LPG) instead of water.[24] The LPG base fluid is 90% propane and 10% gelling agent and other additives that help the fluid transport the proppants. After the fractures are created, the gelled LPG returns to the surface as propane gas. The propane may be recovered and reused in subsequent operations or collected and sold with the natural gas production. The primary advantage that LPG fluids have over water is that the propane mixes with the gas in the formation and the pumped fluid is recovered after the hydraulic fracturing job. Recovery of the pumped LPG fluid is significantly greater than the amount of water typically recovered during most slickwater operations.[25] LPG fracture jobs can cost 20 to 40% more than water-based fracture treatments on a per unit basis but it is argued that the amount of gas recovered is typically 20 to 30% higher, making the actual costs comparable.[26,27] LPG is not as readily available as water, but no water means no storage ponds, no disposal costs, and possibly less truck traffic. This process has been used approximately 1,000 times over the past 3 years in both Canada and the United States, but little information is publicly available.

LPG fracturing presents other known risks which are distinct from those posed by either slickwater or conventional drilling. The main component of LPG used in fracturing, propane gas, is itself highly flammable, and because it is heavier than air, it naturally pools on the ground when leaked, creating a clear and notable threat of explosion – a risk experienced by two major explosions last year at well sites that injured fifteen workers.[28,29] Additional hazards are possible from trucking thousands of gallons of LPG to the well site, compressing and re-condensing the LPG for reuse, and mixing the LPG with chemicals for use in fracturing.[30] In addition, as with slickwater, LPG fracturing returns chemicals to the surface that must be properly handled and disposed; in this case, flammable gases that would have to be collected in pressurized tanks or flared – a step generating air emissions and possible leaks.[31]

Other compounds used as a base for fracture fluids include carbon dioxide (CO_2) and nitrogen (N_2), which form foams used to transport the proppant into the formation. The use of these compounds also leaves less fluid in the formation and has very rapid recovery periods because the injected gas vaporizes in the formation. However, CO_2 and N_2 are not always readily available or appropriate for every formation. Therefore, their use has been limited.

Before operators or service companies perform a hydraulic fracture treatment of a well (vertical or horizontal), a series of assessments and pre-tests are performed. These tests are designed to ensure that the well, well equipment, and hydraulic fracturing equipment are in proper working order and will safely withstand the application of the fracture pressures and pump flow rates required during the job. The tests include the evaluation of well casings and cements installed during the drilling and well construction process. While construction requirements for wells are mandated by Provincial and Territorial regulatory agencies to ensure that wells are protective of water resources and are safe to operate, engineers must also consider the pressures wells will encounter during fracturing operations to ensure the strength of the casing and cement is sufficient. In some situations, this means the wells may be constructed to higher standards than Provincial or Territorial regulatory agencies require.

The process for a hydraulic fracture treatment is initiated when the first equipment is brought onsite. **Figure 4** provides a process flow diagram for a single stage of a slickwater hydraulic fracturing stimulation. Fracture treatments require multiple pieces of sophisticated equipment specifically designed for hydraulic fracturing. In many cases, multiple pieces of the same kind of equipment, such as pumps, are necessary. The type, size, and number of pieces of equipment needed are dependent on the size of the fracture treatment, type of treatment, as well as the additives, proppants, and fluids that are used. **Table 1** presents a listing of typical equipment used during a fracturing job, and the purpose of the identified equipment.

Once onsite, the equipment is "rigged up." The "rig-up" process involves making all of the iron connections necessary between the fracturing head on the well, the fracturing manifold trailer, the fracturing pumps, and the additive equipment which feed fluids and additives into the pumps. **Figure 5** is a picture of a fracturing wellhead set up used during the hydraulic fracturing of a horizontal shale gas well in Pennsylvania. As mentioned earlier, these connections undergo a series of assessments and pre-tests to ensure that they are capable of handling the pressure of the fracturing job and that the connections have been properly made and sealed.

Lateral lengths in shale gas wells vary by basin and may be limited based on regulatory constraints, but the lengths may range between 400 and 2,000 metres (m). Constraints affecting the lateral length usually center on spacing units. A spacing unit is the area allotted to a well by regulations or field rules issued by a governmental authority; drilling outside the unit is prohibited. Advancements in technology and regulatory practice have enabled the horizontal lengths to be extended to more than 3,200 m in length, although this is not common practice.

The length of the laterals (hundreds to thousands of metres) hinders the ability to maintain adequate downhole pressures to fracture the entire lateral in a single process successfully. As a result, hydraulic fracture treatments in horizontal wells are done by isolating portions of the laterals and fracturing these individually isolated sections (called stages), as can be seen in the horizontal representation in **Figure 2**, which shows a well with eight stages. This isolation of sections for staged fracturing provides better control of the fracturing process, increases the success of individual stage treatments, and provides for better monitoring and design of the individual stages. The average length of each stage of the wellbore that is fractured varies depending on operator preference, experience, and site-specific wellbore conditions. In the Barnett Shale in Texas, Devon Energy studied the fracture development response in comparison to the stage lengths and found that the wellbore production response to shorter stage lengths was greater than for wells with longer frac stage lengths. As a result, most operators are shortening the wellbore stage and performing a larger number of fracture stages on each well. **Figure 6** shows an example where various stages are depicted by different colors representing created fracture networks.

Stages are fractured sequentially beginning with the interval at the furthest end of the wellbore. Typical sections fractured are approximately 90 to 180 min length, but the actual length varies by basin and operator and is part of the design of the job to provide the best success for the well. Each fracture stage is performed by isolating an interval. In order to provide isolation between the fracture intervals, a liner is run and set in place with cement and then a plug/isolation packer is set in the liner, above and below the designated fracture interval. Within this interval of the wellbore, a cluster of perforations is created using a perforating tool, a device which creates holes in the casing and cement extending outward into the formation. Perforations allow fluids to flow outward to the formation during the fracture treatment and also allow gas or oil to flow inward from the formation into the wellbore during the production phase. To access the next fracture interval, a new plug is set and the isolation packer is pulled and reset above the stimulated fractures, the liner is perforated at the next interval up, and this interval is then stimulated. This process is repeated as often as required, but following the final interval, the isolation packer is unset and the plugs milled out.

Figure 4: Process Flow Diagram for a Single Stage of a Slickwater Hydraulic Fracture Stimulation

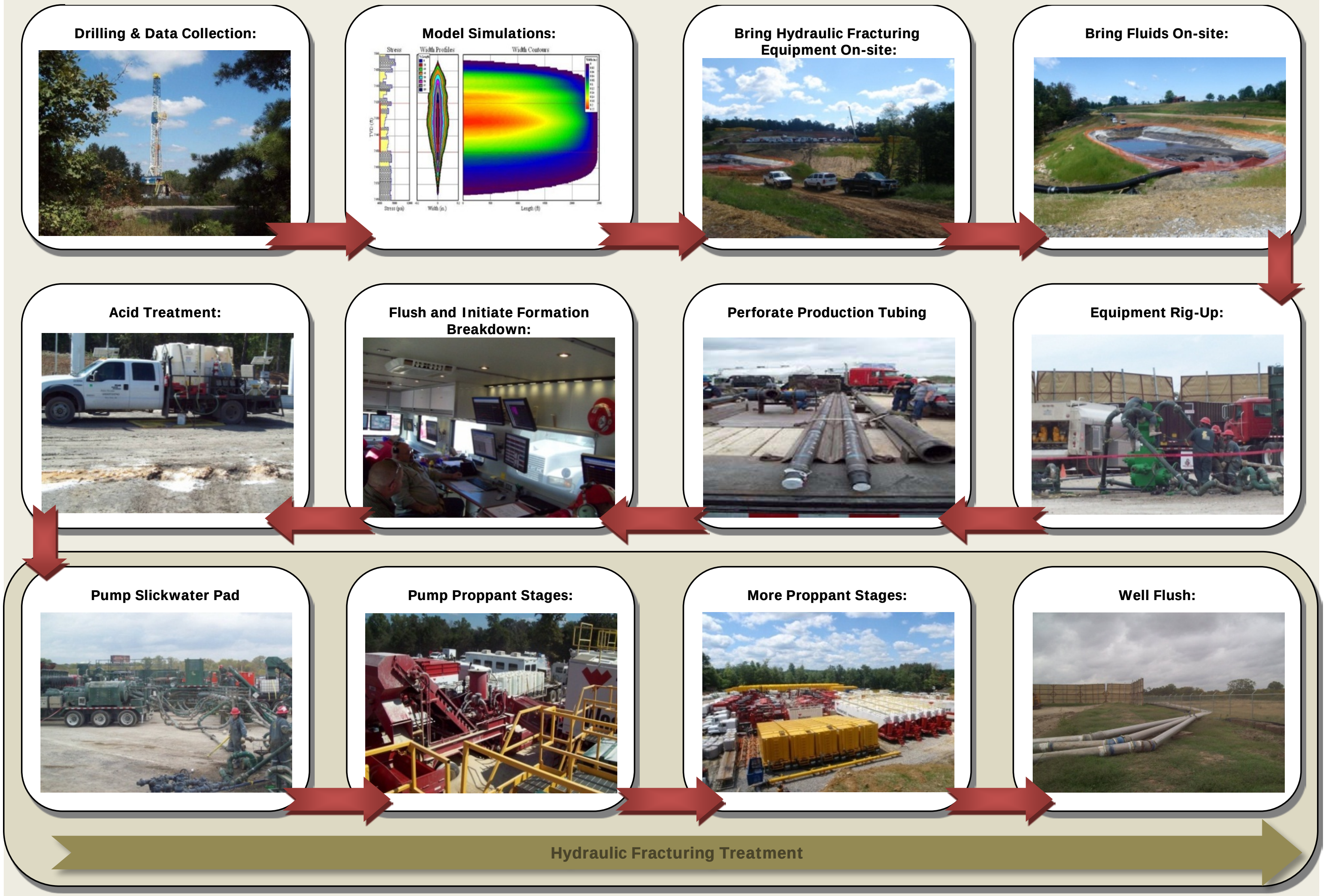


Table 1: Fracturing Equipment			
Equipment Item	**Purpose**	**Number on Site**	**Description (size, capacity)**
Fracturing Head	A well head connection that allows fracture equipment to attach to the well	1	
Fracturing Pumps	Heavy duty pumps that take the fluid from the blender and pressurize it via a positive displacement pump	2+	Number on site depends on the pumping pressure and rates required for stimulation; for horizontal well shale gas fracturing there are usually multiple pumps on site
Blender Pumps	Takes fluid from the fracturing tanks and sand from the hopper and combines these with chemical additives before transferring the mixture to the fracturing pumps	1+	A backup blender is sometimes on location
Transfer Pumps	A trailer-mounted pump and manifold system that transfers fluid from one series of Fracturing Tanks to another, or from ponds to the manifold	1+	Typically used prior to the start of the fracturing job; once the job is started the fracturing pumps perform water transfers
Sand Storage Units	Large tanks that hold the proppant and feed the proppant to the blender via a large conveyor belt	3+	150 to 200 tonnes
Fracturing Tanks - Supply	Water containment tanks that store the required volume of water to be used in fracture stimulations	3+	~80 m^3/tank (Varies)
Fracturing Tanks - Receiving	Water containment tanks that store produced water from hydraulic fracture stimulations	3+	~80 m^3/tank (Varies)
Gel Slurry Tanker Truck	Transports gel slurry to the job site; the equipment has 2 compartments to allow for the gel to be agitated between the compartments to prevent separation or break down	1	15 m^3
Chemical Storage Trucks	Flatbed trucks used to transport chemicals to the job site, may contain a pump to transfer chemical additives from the on-board storage tanks to the required equipment (i.e. blender)	1+	
Technical Monitoring Van	The work area for Engineers, Supervisors, Pump Operators, Company Representatives, and Regulatory Personnel	1	
Acid Transport Trucks	Used to transport acids to job sites; a truck has separate compartments for the transport of multiple acids or additives	1+	19 m^3/truck
Manifold Trailer	Large manifold system that acts as a transfer station for all fluids; mixed fluids from blender pumps move through the manifold on the way to the pump trucks	1	

Multiple sub-stages are pumped during each stage of a fracture treatment, with varying fluid and proppant concentrations at rates ranging from 0.2 m^3 per minute to 12 m^3 per minute.[32] The initial sub-stage is primarily fresh water that is pumped to flush any residue in the wellbore from drilling and perforation operations, and to clean the lines of the fracture equipment. Acid flush typically follows the initial fresh water flush and is designed to clean cement from the perforations and any residue surrounding the wellbore. The acid flush provides a clean pathway for the fracture fluids to reach the formation when pressurized. A water spacer is typically the next sub-stage and pushes the acid into the formation to begin the propagation of fracturing. This water spacer facilitates what is

Figure 5: Wellhead Set Up for Hydraulic Fracturing Operation

Source: Courtesy Chesapeake Energy Corporation, 2010

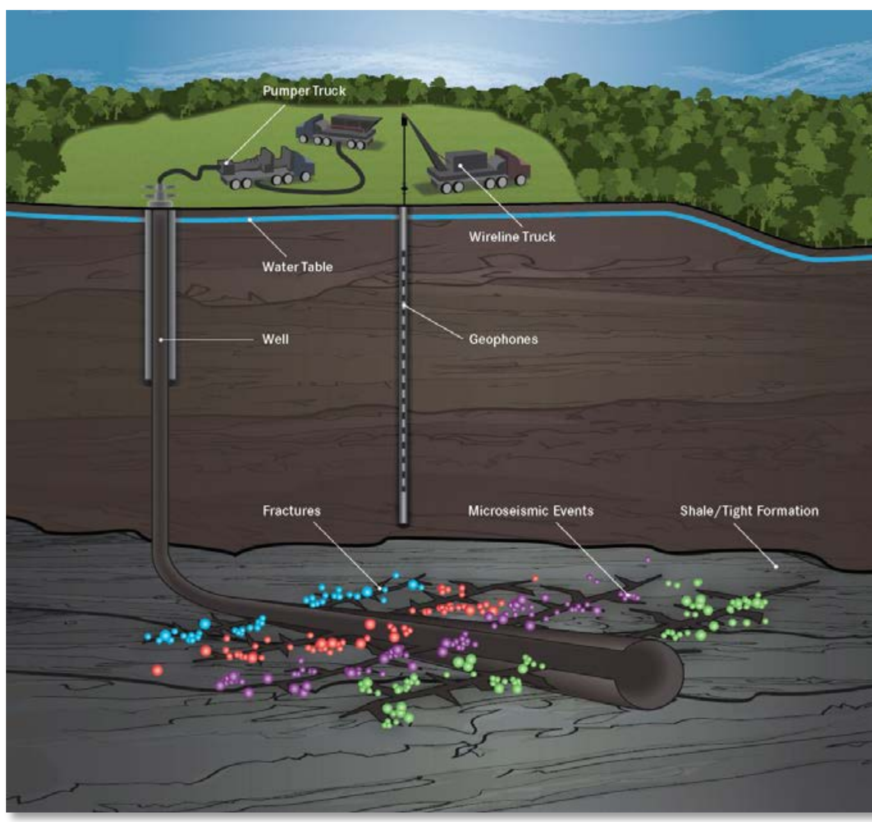
called a "mini-frac" and generates specific data regarding reservoir parameters used to verify the fracture job design. The verification is accomplished by measuring actual reservoir rock performance during the fracturing process. Next, the well is shut-in to determine the fracture gradient and verify the wellbore design. The fracture gradient is a measure of the strength of the rock compared to the pressure necessary to initiate fracturing at a specific depth. When the well is reopened, fracture fluid without proppant (pad) is injected into the formation to extend the fractures and to prepare the formation for the proppant sub-stages. This is done by placing necessary fracturing additives in the formation including friction reducers, clay stabilizers, or other additives which help to maintain the flow rate of the treatment.

The sub-stages that follow are a series of pumping events in which proppant volume is increased to create and maintain the fractures. In some treatments, the proppant size may be increased during the sub-stages. This optimizes the permeability in the fracture to maximize the flow of natural gas to the wellbore.[33]

Fracture treatment procedures vary from well to well and basin to basin. The treatment design often incorporates multiple sizes and types of proppants to ensure that fractures are propped open deep into the formation. Initial proppant placement sub-stages start with low concentrations around 12 to 24 kilograms per cubic metres (kg/m^3) (0.1 to 0.2 pounds per gallon (ppg) of sand) of fluid.[34] Each subsequent sub-stage incrementally increases the proppant concentration; increments of 24 to 40 kg/m^3 (0.2-0.25 ppg) are typical. Proppant concentrations can reach upwards to 240-300 kg/m^3 (2.0 to 2.5 ppg) during the final stage but final concentrations are dependent upon the size of the proppant (see **Table 2**).[35]

The number of sub-stages is determined by the volume of proppant and fracture fluid in the fracture treatment design. For a multiple-proppant treatment, a transition occurs when the first

Figure 6: Horizontal Well Completion Stages



Source: ESG Solutions, "Hydraulic Fracture Mapping (n.d.), www.esgsolutions.com/english/view.asp?x=741 (accessed April 24, 2012).

Table 2: Example of a Single-Stage of a Sequenced Hydraulic Fracture Treatment for Typical Tight/Shale Gas Formations

Hydraulic Fracture Treatment Sub Stage	Volume (m^3)	Rate (m^3/min)
Fresh Water Flush	20	2
Diluted Acid (15%)	20	2
Pad	380	12
Prop 1	190	12
Prop 2	190	12
Prop 3	150	12
Prop 4	150	12
Prop 5	150	12
Prop 6	115	12
Prop 7	115	12
Prop 8	75	12
Prop 9	75	12
Prop 10	75	12
Prop 11	75	12
Prop 12	75	12
Prop 13	75	12
Prop 14	40	12
Prop 15	40	12
Flush	50	12

Flush volumes are based on the total volume of open borehole, therefore as each stage is completed, the volume of flush decreases as the volume of borehole is decreased.

Source: GWPC and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, prepared for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory (April 2009).

proppant volume runs out. The transition involves the pumping of a larger-grain-sized proppant at a concentration near the final concentration of the smaller proppant (for example 120.0 kg/m^3) such that the final slurry density would be the same as the initial slurry density. In a similar fashion to the increasing proppant size, each stage progresses with a certain percentage of the fluid being pumped at a gradually increasing concentration until all the proppant has been pumped. Proppant density is important for ensuring sufficient permeability for fluids to flow to the wellbore; however, care must be taken as high proppant density can result in screenouts (the failed transport of the proppant), which can result in the inability to pump additional fluids. Screen outs occur when the fracture fluid can no longer transport or handle the suspended proppant and the proppant settles out in the piping rather than traveling into the fractures. This creates a sudden and significant restriction to fluid flow that causes a rapid rise in pump pressure.

Once the prescribed volume of fluids and proppant has been placed downhole, a final sub-stage is used to flush the wellbore and tubing clean of any remaining proppant. A packer or other device (e.g. plug, sliding sleeve) is then used to isolate this zone, sealing it from intrusion of any additional fluids during subsequent fracturing stages. After this zone is isolated, a new zone in the wellbore is prepared for fracturing starting with the perforation of the casing. The process described above continues for each stage of the fracture treatment in the wellbore.

A multi-stage slickwater hydraulic fracture treatment of a horizontal gas shale well can have as few as 2 or as many as 100 stages for one well treatment, and each stage may include sixteen or more sub-stages in which acid, pads, and proppant are pumped into each isolated interval of the horizontal wellbore. The time to complete a multi-stage fracturing job is dependent on a number of parameters including lateral length, target formation, number of stages, fracturing technology, etc. For example, in the Horn River Shale in British Columbia where horizontal wells are, on average, drilled approximately 2,000 m in length and fracture stimulated primarily with cemented liners and plug and perf method, an operator (Apache reported that it performed 274 fracture stages in 111-days. [36, 37] **Table 3** presents some of the generalized well and fracturing attributes observed in shale plays in Canada and the United States.

2.2 Hydraulic Fracture Treatment Design

The process of developing a design for a hydraulic fracture treatment begins well before the fracture treatment, typically during reservoir evaluation. The character of the reservoir and the dynamics of existing stress relationships are critical components used in designing hydraulic fracture jobs. Data

Table 3: Well and Fracturing Attributes

Shale Play	Lateral Length, m	Frac Size, tons/frac	Number of stages	Frac Fluid
Barnett	760-915	90-450[38]	6-43[39]	Slick water
Fayetteville	915-1220[40]	135-180[41]	6-10[42]	Slick water
Haynesville	1220+[43]	100	9-11	Gel cross-linked oil
Horn River	2200[44]	100-200[45]	7-23[46]	Slick water
Marcellus	610-2743[47]	136-226[48]	6-28[49]	Slick water
Montney	518-914	100-300	5-7[50, 51]	CO_2 polymer
Utica	1219-1950[52]	100	8-12[53]	Slick water
Woodford	915-1220+[54]	100	6-20[55]	Gel cross-linked oil

Source: "Study Analyzes Nine US, Canada Shale Gas Plays," *Oil and Gas Journal* 106, no. 42 (November 10, 2008), plus individual references.

related to the reservoir may be collected from surface geophysical logging prior to drilling, core analysis during drilling, open- or cased-hole logging, previous stimulation treatment data, and offset well production performance analysis.[56] Collected data includes porosity, permeability, and lithology of the producing formation; fluid saturation data; natural fracture characteristics; and present-day stress regimes that identify the maximum and least principal horizontal stresses. Natural fracture data from core samples may include orientation, height, half length, fracture width, and permeability. These data are used to determine where treatments are applied to complete the reservoir effectively.[57,58] Hydraulic fracturing designs are constantly being refined to optimize fracture networking and to maximize gas production, while ensuring that the induced fractures are confined to the target formation.

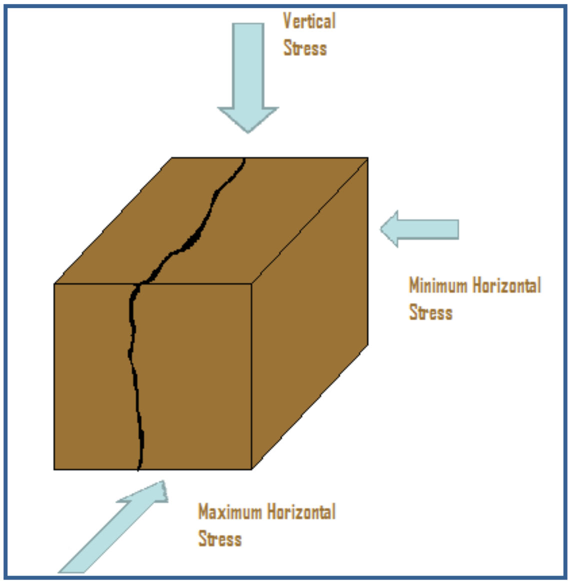
Computer simulators can be used to analyze the collected data for the producing formation and to create a mathematical model design that optimizes the hydraulic fracture treatment. Engineers review the model and are able to alter the variables of the simulation, such as the volumes, proppant type, and pressures, to evaluate how the stimulation may respond and develop within the reservoir without actually conducting the hydraulic fracture job.[59] Engineers use models to design more efficient ways to create additional flowpaths to the wellbore without risking well performance by conducting experimental treatments on physical wells.

There are multiple different models and modeling programs that can be used, each with different options and benefits. Some simulations can predict three-dimensional fracture geometries or ideal fluid additives for specific conditions, or even reverse engineer design stages for specific characteristics. Modeling programs also allow engineers to alter plans as additional data are collected about the specific target formation.[60]

When designing fracture stimulation treatments, operators take into consideration formation stresses to predict probable fracture propagation. Operators often use the details of microseismic monitoring of a vertical well fracture to design the lateral directions in the horizontal portion of the well.

There are three principal categories of stresses that exist in a formation: vertical stress, maximum horizontal stress, and minimum horizontal stress (See **Figure 7** for an illustration of these stresses).[61] Vertical stress is typically the largest stress force in a deep rock layer because it results from the pressure exerted by the overlying formations. When this is the case, vertical fractures are generated during the fracturing process because it takes less force to part the rock to the side, as a vertical fracture does, than to lift thousands of metres of overlying rock with a horizontal fracture. The vertical fractures also tend to parallel the maximum horizontal stress in the formation.[62] To see why this is so, consider **Figure 7**. In order to open a crack in the rock, it is easiest to move the

Figure 7: Stress Fields on a Formation at Depth



Source: J. Daniel Arthur, Brian Bohm, Bobbi Jo Coughlin, and Mark Layne (ALL Consulting), "Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs," presented at the International Petroleum & Biofuels Environmental Conference, Albuquerque, NM, November 11-12, 2008.

rock in the direction of the minimum horizontal stress. That takes the least force. Therefore, the vertical fracture will travel in the direction of the maximum horizontal stress, as in the diagram.

An engineer must understand how these stresses influence the orientation of the fractures developed and use the information to optimize the placement of perforations and the spacing of wells in a production field. The lateral orientation of the perforations can impact the direction of the fractures. In addition, perforation orientation may influence the fracture success and the long-term productivity of the well.[63]

Tortuosity must also be considered when designing a fracture treatment. *Tortuosity* refers to the turning or twisting of a fracture and the resulting resistance this deviated path places on the fluid as it moves through the rock. Tortuosity can lead to premature screen outs and near wellbore friction, which can result in unsuccessful fracture stimulations. Higher pump pressures are often required to overcome tortuosity. When an operator is concerned about tortuosity, procedures are implemented in the fracture design plan to ensure that pumping rates and fracture pressures are not exceeded during the fracture treatment.

During each treatment more information is gathered which can be processed and used to refine future operations. Use of site specific data allows operators to tailor fracture treatments for the conditions in the reservoir, which results in increased well production and better fracture propagation control.

Modern designs take into account not only the individual well fracture job, but also the production of the whole reservoir and the interaction between wells. Fracture treatment design technology has advanced greatly over time and will continue to advance in an effort to optimize fracture networking and to maximize resource production, while ensuring that fracture development is confined to the target formation for both horizontal and vertical wells.[64]

2.3 Hydraulic Fracturing Monitoring

Each hydraulic fracturing operation is monitored closely to assess and verify the details of the entire treatment. During a hydraulic fracture treatment, several monitoring activities are performed onsite in a technical monitoring vehicle (TMV) as well as by the personnel operating the equipment during the job. Treatment pressures, chemicals, proppant density, fluid velocity, and pressure are recorded and reviewed by the fracturing service supervisor, engineers, pump operators, and company representatives. Monitoring of fracture treatments includes the following:

- Tracking wellhead and downhole pressures,
- Estimating the orientation and approximate sizes of induced fractures,
- Observing pumping rates,
- Measuring fracturing fluid slurry density,
- Tracking additive and water volumes, and
- Ensuring that equipment is functioning properly.

Monitoring and tracking of this data helps the onsite personnel assess whether the fracturing job is performing as expected and provides them the ability to address changes in the job as necessary to assure a successful well completion. The constant monitoring of a hydraulic fracturing job helps the engineer and onsite personnel mitigate risk factors that occur during the performance of the job. In the rare case where a failure occurs, activity can be stopped to prevent an environmental incident or safety or health hazard.

In addition to direct monitoring of the job performance, other monitoring technologies such as microseismic and tiltmeter measurements can be used to map where the fractures occur as the stimulation is progressing. Microseismic monitoring uses similar technology to what is used to monitor earthquakes. The process can be used in real time to measure changes in rock stress caused by the injection of treatment fluids and proppant and provide a picture of the orientation, location, and size of the induced fractures. This information can later be used by engineers to place in-fill well locations that will take advantage of the natural reservoir conditions, permeability created by the fracturing treatment, and anticipated hydraulic fracture stimulation performance.[65]

Tiltmeters can be used to provide information on the orientation, location, and size of fractures. Tiltmeters are passive monitoring devices that record the deformation of rocks. Tiltmeters are placed on the surface to measure orientation or downhole in adjacent wellbores to determine fracture dimensions. Surface tiltmeters can record rock deformations that occur at depths greater than 1,830 m.[66] Surface tiltmeters can be used independently of downhole tiltmeters or run simultaneously to get a more thorough picture of the fracture treatment results. The refinement of monitoring technologies increases the quality of the data collected and analyzed, and thus provides information operators can use to improve future fracture treatments. This in turn will help to support future efforts to mitigate risks encountered through the process of hydraulic fracturing of wells and increase the prudent recovery of the natural resource.

2.4 Hydraulic Fracturing Fluids

The first hydraulic fracture treatments were performed with gelled crude oils and kerosene. However, in 1952, operators saw a benefit in using water as a fracturing fluid. A gelling agent was developed that would allow the water to carry the proppant in suspension during the fracture treatment. As developers improved the fracturing technology, additional additives, including surfactants, clay-stabilizing agents, and metal cross-linking agents, were developed to make the process safer, more efficient, and more successful. Modern slickwater fracture treatments used in shale gas formations are comprised of over 99% water and proppant, with the remaining 1% consisting of chemical additives similar to those that were developed for the original stimulations.[67] The following presents an overview of hydraulic fracturing fluids used in shale formations.

Given the variability in shale formations, it is no wonder that no single technique for hydraulic fracturing has worked universally. Each shale play has had unique properties that need to be addressed through fracture treatment and fracture fluid design. Each fracture job is refined based on the information collected from the previous job(s). For example, numerous fracture systems have been applied in the Appalachian basin alone, including the use of CO_2, foam N_2 and CO_2, and slickwater fracturing.

The composition of fracturing fluids must be altered to meet specific reservoir and operational conditions, precluding one-size-fits-all formulas. For example, slickwater hydraulic fracturing, which is used extensively in Canadian and U.S. shale basins, is suited for complex reservoirs that are brittle and naturally fractured and are tolerant of large volumes of water, such as the Horn River Shale in British Columbia.[68] In reservoirs with brittle rock properties, such as the Horn River Shale, fracture patterns are complex. The number of effective fractures is dependent on pumping a large volume of water to achieve the desired complex fracture network. Ductile reservoirs require more effective proppant placement to achieve the desired permeability.

Other fracture systems, including CO_2 polymer and N_2 foams, are occasionally used in ductile rock, such as the Montney Shale. Hydraulic fracturing stimulations in some wells in the Montney formation in British Columbia have been using a CO_2 polymer fracture fluid. The base fluid contains emulsified CO_2 in a 5% water and 20% methanol mixture as a carrier for the polymer and proppant. CO_2 fluids eliminate the need for large volumes of water while providing extra energy from the gas expansion to shorten the flowback time.[69] This method is only possible under the right conditions and generates greenhouse gases as a by-produce of the completion. Understanding and matching geologic conditions, including formulating fracture fluids based on analogies to other, similar shale basins, is critical for early success in new shale plays.

Water and sand are the most common constituents of most fracturing fluids. The volumes of fresh water used for hydraulic fracturing of shale gas wells have led to concerns about the potential impacts to local and regional water supplies as well as potential impacts to aquatic wildlife. Recently, advances in water use management practices have resulted in reduced demands on fresh water sources. Many regulatory requirements are designed to ensure that water withdrawals do not adversely affect the environment. In addition, many operators are pursuing reuse of produced water from fracture job to subsequent fracture job. This reuse of produced water decreases demands on fresh water and reduces impacts associated with transportation of fresh water from the source to the well pad, such as traffic congestion, road damage, dust, and engine emissions. Reuse of produced water also reduces the amount of water to be disposed. Several parameters affect the volume of fracture fluid required for a successful stimulation:

- Propping agent amount and type
- Rock type/stimulation objective
- Designed fracture conductivity
- Rock closure stress/fracture width
- Fluid leak off characteristics
- Proppant transport
- Formation permeability
- Injection rate
- Reservoir thickness[70]

Total fluid volume is a critical parameter of the fracture treatment design and one that can be controlled by the engineer. Thus the decision about fresh water sourcing should not to be taken lightly.

The main components of a fracturing fluid, besides the base carrier fluid (typically water), are discussed in the following subsections. **Figure 3** shows a typical breakdown of a fracture fluid. The following additive discussions are provided as background information to explain why the different components are used during a hydraulic fracturing job. Common additive purposes and examples of chemicals used for these purposes are presented in **Table 4**.

2.4.1 Disclosure

Concerns about the chemicals used in hydraulic fracturing have led to calls for public disclosure of this information. While some Provinces such as British Columbia and many U.S. states have added rules requiring chemical disclosure for hydraulic fracturing, the requirements are not consistent. In addition, in order for such disclosures to be useful, the information must be readily available. To address the concern about chemical use in the United States and to make the information more standardized and easily accessible, industry has teamed with the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC) to create a voluntary disclosure and information website called FracFocus (http://www.FracFocus.org). This website has been adopted as a compliance tool for several states that are requiring disclosure submissions. A similar program (FracFocus.ca) has been licensed to British Columbia, and the website became live January 2012.[71]

2.4.2 Proppant

After water, the largest component of a fracture fluid utilized to treat a shale gas well is proppant. Proppant is a granular material, usually sand, that is mixed with the fracture fluids to hold or prop open the created fractures in order to allow gas to flow to the well.[72] Other commonly used proppants include resin-coated sand, intermediate-strength proppant

Table 4: Fracturing Fluid Additives, Main Compounds and Common Uses

Additive Type	Main Compound	Use in Hydraulic Fracturing Fluids	Common Use of Main Compound
Acid	Hydrochloric acid or muriatic acid	Acids are used to clean cement from casing perforations and drilling mud clogging natural formation porosity, if any, prior to fracturing fluid injection (dilute acids concentrations are typically about 15% acid)	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Fracture fluids typically contain gels that are organic and provide a medium for bacterial growth. Bacteria can break down the gelling agent reducing its viscosity and ability to carry proppant. Biocides are added to the mixing tanks with the gelling agents to kill these bacteria.	Cold sterilant in health care industry
Breaker	Sodium Chloride	Breakers are chemicals that are typically introduced toward the later sequences of a fracturing job to "break down" the viscosity of the gelling agent to better release the proppant from the fluid enhance the recovery or "flowback" of the fracturing fluid.	Food Preservative
Corrosion Inhibitor	N,n-dimethyl formamide	Corrosion inhibitors are used in fracture fluids that contain acids; they inhibit the corrosion of steel tubing, well casings, tools, and tanks.	Crystallization medium in Pharmaceuticals
Crosslinker	Borate Salts	There are two basic types of gels used in fracturing fluids: linear and cross-linked. Cross-linked gels have the advantage of higher viscosities that do not break down quickly.	Non-CCA wood preservatives and fungicides
Friction Reducer	Petroleum distillate or Mineral oil	Friction reducers minimize friction, allowing fracture fluids to be injected at optimum rates and pressures.	Cosmetics, nail and skin products
Gel	Guar gum or hydroxyethyl cellulose	Gels are used in fracturing fluids to increase fluid viscosity, allowing them to carry more proppant than straight water solutions. In general, gelling agents are biodegradable.	Food-grade product used to increase viscosity and elasticity of ice cream, sauces and salad dressings.
Iron Control	Citric acid	Iron controls are sequestering agents that prevent precipitation of metal oxides.	Used to remove lime deposits. Lemon Juice is ~ 7% Citric Acid
KCl	Potassium Chloride	KCl is added to water to create a brine carrier fluid.	Table salt substitute
Oxygen Scavenger	Ammonium bisulfate	Oxygen present in fracturing fluids through dissolution of air causes the premature degradation of the fracturing fluid; oxygen scavengers are commonly used to bind the oxygen.	Used in cosmetics
Proppant	Silica, quartz sand	Proppants consist of granular material, such as sand, mixed with the fracture fluid. They are used to hold open the hydraulic fractures, allowing the gas or oil to flow to the production well.	Play box sand, concrete or mortar sand
Scale Inhibitor	Ethylene glycol	Scale inhibitors are added to fracturing fluid to prevent precipitation of scale (calcium carbonate precipitate).	Automotive antifreeze and de-icing agent
Surfactant	Naphthalene	Surfactants are used to reduce interfacial tension and promote more efficient clean-up or flow-back of injected fluids.	Household fumigant (found in mothballs)

Source: GWPC and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, prepared for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory (April 2009).

(ISP) ceramics, and high-strength proppants such as sintered bauxite and zirconium oxide.[73] Resin-coated sands are utilized regularly in the shale gas plays during the final stages of a fracture. Resin coating may be applied to improve proppant strength or may be designed to react and act as a glue to hold some of the coated grains together. Resins are generally used in the end stages of the job to hold back the other proppants, i.e., to prevent them from flowing back into the wellbore after the well is put on production. In this way the resins help maintain near-wellbore permeability.[74]

Numerous propping agents have been used throughout the years, including plastic pellets, steel shot, Indian glass beads, aluminum pellets, high-strength glass beads, rounded-nut shells, and resin-coated sands, but from the beginning, standard 20/40 mesh sand has been the most popular.[75] Sand concentrations in fracture stimulations have been steadily increasing, with a spike in recent years due to advances in pumping equipment and improved fracturing fluids.[76]

While sand has been the most popular proppant for hydraulic fracturing in oil and gas operations, due to its availability and low cost, other options that outperform common mesh sand are being developed:

- Ceramic proppants with uniformly sized and shaped grains have been developed. This provides maximum porosity resulting in improved production of oil and gas in a variety of different reservoir types.[77]
- New proppants are being developed to pose less risk to the health and safety of those handling the materials at the well site.
- Another new innovation is a high-strength spherical proppant with integrated proppant flowback control. *Integrated flowback control* refers to the coated proppant's ability to harden and form a highly conductive, consolidated proppant bed which is resistant to washout.
- Changing the geometry of the proppant has been proven to improve the conductivity beyond what is attainable with spherical proppants.[78]
- Non-radioactive traceable proppants are also being used. These identify proppant coverage and fracture height and there are no limitations on the types of wells on which they can be used.[79] The technology was first developed for offshore completions to identify failures on an offshore platform.[80] The naturally occurring chemical markers are added to the proppant during manufacturing. Non-radioactive traceable proppants are safe and environmentally responsible and require no special disposal of the flowed-back proppant.[81]

Lightweight proppants reduce the gel viscosity needed, which significantly reduces gel costs. In addition, proppant flowback is virtually eliminated.[82]

Choosing the proppant that will best optimize production from a particular formation requires data on a number of important variables, including

- Formation permeability
- Stress on proppant pack
- Achievable proppant concentration, and
- Conductivity reduction factors (fluid damage, multi-phase flow, and non-Darcy flow (high speed turbulent flow)).

Once these variables are understood, engineers evaluate the different types and sizes of available proppants. Proppants are generally classified as lightweight, intermediate, and sintered bauxite. Lightweight proppants are more economical but have lower strength ratings. Intermediate proppants offer a combination of strength and price. Sintered bauxite proppants are designed to hold up to the extreme pressure and closure stresses of the deepest wells.

Different sizes are available within each of these categories. Size is indicated by numbers that correspond to standard mesh sieves sizes. For example, the smallest proppants are designated as 30/50, meaning they'll pass through a fine 30/50 mesh. Other standard proppant sizes are 12/18, 16/30, and 20/40.

2.4.3 Chemical Additives

Fracturing fluids may require the use of multiple additives to address different conditions specific to a well undergoing stimulation. No two wells are identical. As a result, fracture fluid formulations vary from basin to basin and well to well. Challenges such as scale buildup, bacteria, etc., require specific additives to prevent degradation of the well's performance. Not all wells require every additive for treatment. Furthermore, there are many different formulas for each additive. Typically only one of each type of additive is used in a well to address a specific concern. For example, only one biocide may be used at a time, even though there are many different biocides. Criteria used to select fracture fluids and chemicals may include but are not limited to the following:

- Wellbore and formation conditioning
- Formation compatibility
- Formation damage
- Hydrostatic loads
- Relative permeability
- Proppant transport
- Cost analysis
- Fluid availability
- Improved environmental performance[83]

The following presents some of the chemical additive types used to address these concerns. A summary is provided in **Table 4**. Note, several if not all of the chemicals discussed have common household uses or can be found in everyday products, however, it is important to realize that while at the well site they are in industrial concentrations and volumes and as such handled and stored appropriately according to their material safety data sheets (MSDS).

2.4.3.1 Acid

Hydrochloric acid (HCl) is generally used in fracturing operations to remove cement from the perforations and provide an accessible path to the formation.[84] HCl is one of the least hazardous strong acids to handle.[85] It is produced in concentrations up to 38% but is most commonly used for fracturing in concentrations of 15% HCl (15% HCl and 85% water). HCl has a very fast reaction rate with acid-sensitive material in the reservoir, which means that most of the acid is spent dissolving the cement at the perforations and doesn't travel deep into the formation. Once the acid reaches approximately 10% of its original concentration, it is no longer capable of performing and becomes "spent," leaving behind a chloride salt or brine that is resurfaced with produced water.

CAPP – Hydraulic Fracturing Operating Practice:

FRACTURING FLUID ADDITIVE DISCLOSURE

CAPP and its member companies support and encourage greater transparency in industry development. To reassure Canadians about the safe application of hydraulic fracturing technology, this practice outlines the requirements for companies to disclose fluid additives and the chemical ingredients in those additives that are identified on the Material Safety Data Sheet (MSDS).

Purpose: To describe minimum requirements for disclosure of fracturing fluid additives used in the development of shale gas and tight gas resources.

Objective: To enable and demonstrate conformance with the CAPP Guiding Principle for Hydraulic Fracturing:

We will support the disclosure of fracturing fluid additives.

Under this Operating Practice, companies will disclose, either on their own websites or on a third-party website, those chemical ingredients in their fracturing fluid additives which are identified on the MSDS. The ingredients which must be listed on the MSDS are identified by federal law. The well-by-well disclosure includes:

- The trade name of each additive and its general purpose in the fracturing process.
- The name and the Chemical Abstracts Service number of each chemical ingredient listed on the MSDS for each additive.
- The concentration of each reportable chemical ingredient.

CAPP continues to support action by provincial governments to make fracturing fluid disclosure a mandatory component of shale gas and tight gas development.

2.4.3.2 Gelling Agents

The viscosity of fresh water tends to be low, which limits water's ability to transport the proppant necessary for a successful fracture stimulation. As a result, some hydraulic fracturing fluids use a gel additive to increase the viscosity of fracture fluids. Typically, either a linear or a cross-linked gel is utilized.[86] Linear gels are formulated with a dry-powder polymer that hydrates or swells when mixed with an aqueous solution. Polymers that are commonly used to formulate linear gels include guar, hydroxypropyl guar (HPG), carboxymethyl HPG (CMHPG), and hydroxyethyl cellulose (HEC).[87] Crosslinked gel fracturing fluids utilize various ions to crosslink the hydrated polymers and provide increased viscosity at higher temperatures. Crosslinking is the coupling of molecules via a reaction between multiple-strand polymers and typically a metallic salt. Common cross-linking agents include borate, titanate, and zirconium ions.

Gellant selection is based on how the reservoir reacts with the gel and on reservoir formation characteristics, such as thickness, porosity, permeability, temperature, and pressure.[88] One such gellant is guar gum. Guar gum, usually transported in powder form, is added to the water, causing the guar particles to swell and creating a viscous gel. Generally, 1 kilogram (kg) of guar gum mixed with 265 litres of water will yield a fluid with a viscosity that is able to transport approximately 45 kg of proppant in suspension.[89] However, as temperatures increase, these gel solutions tend to thin dramatically. Cross-linking agents are often added to aid in increasing the viscosity to an effective level by forming interpolymer chemical bonds which are less affected by the higher temperatures.[90] The crosslink obtained by using borate is reversible and is triggered by altering the pH of the fluid system. The reversible characteristic of the crosslink in borate fluids helps them clean up more effectively, resulting in good regained permeability and conductivity. Borate crosslinked fluids have proved to be highly effective in both low- and high-permeability formations. Gels known as organometallic crosslinked fluids are widely formulated with zirconate and titanate complexes of guar, HPG and CMHPG. Organometallic crosslinked fluids are routinely used to transport the proppant for treatments in tight gas sand formations that require extended fracture lengths. The organometallic crosslinked fluids can also be used in fracturing fluids containing carbon dioxide.[91] These organometallic gels provide

- Extreme stability at high temperatures (excellent proppant transport capabilities at temperatures from 15 to 204°C),
- More predictable rheological and friction pressure properties,
- Better control of the crosslinking properties of the fluid, and
- Versatile applicability for job design in acidic, neutral, and alkaline pH fluid conditions.

2.4.3.3 Breakers

In a fracture stimulation where a gelling agent is used, a breaker is also required. The breaker is used to degrade the viscosity of the gelled fracturing fluid sufficiently, thus allowing the thinned fracturing fluid to flow back to the well while leaving the proppant in the induced fractures. The timing of the placement of a breaker is critical as immediately upon the addition of the breaker to the fracture fluid, the breaker begins breaking down the gel structure and reducing the viscosity.[92] If the gel breaks prematurely, the proppant can settle out of the fracturing fluid, resulting in inadequate fracture propagations, ineffective propping of the created fractures, or screening out of the proppant in the well casing.[93] Moreover, breakers that work too slowly can result in slow recovery of fracturing fluids, which can hinder production. As a result, the fractures can partially close as proppant becomes dislodged. Therefore, initiating the breaking process at the time the fluids have been completely pumped into the formation creates optimal results. Some gels, such as the guar polymers commonly used in slick-water fracturing operations for shale gas wells, break naturally, without the use of additional chemical additives; however, the process is slow. Chemical agents such as oxidants or enzymes are often added to the gel to expedite the process. A common breaker for shale gas fracture stimulations is sodium chloride or common table salt.

Ammonium persulfate is another common breaker used in hydraulic fracturing operations. It is highly soluble in water and will decompose via reaction with water into sulfate or bisulfate salts.[94] Ammonium persulfate has a half-life, or the time required for decomposition of half its concentration, between 20 hours and 210 hours. As a result of the decomposition properties, ammonium persulfate does not adsorb or accumulate in soils or water. Persulfates are common elements in hair dyes and cosmetics, in pulp and paper board manufacturing, and as a non-biological treatment in swimming pools.[95]

2.4.3.4 Biocides

Water is an ideal medium for bacteria growth. Fracture fluids also typically contain gels that are organic, which makes the fluid more susceptible to bacteria growth. In hydraulic fracturing operations, bacteria can cause significant problems, such as the production of hydrogen sulfide (H_2S) gas, which can result in reservoir souring, metal corrosion, and health hazards.[96] As a result, most water-based stimulations require the addition of a biocide to prevent degradation of the fracturing fluids (oil-based fluids do not typically require a biocide).[97] Of special concern with the biocides commonly used is their compatibility with the other additives utilized in the fracturing fluid.

There are many different biocides, and selection of the appropriate one is partially based on the pH of the fracturing fluid and the temperature of the formation. Bronopol (1,2-Bromo-2-nitropropane-1,3-Diol) is one chemical that is frequently used as a biocide. In addition to its use in oil and gas operations, it is commonly found as a preservative in shampoos and other cosmetic products. Other commonly used biocides in slick-water fracturing operations are quaternary amines; glutaraldehyde (glut); and tetrakis-hydroxylmethylphosphomium sulfate (THPS).[98] Quaternary amines are a cationic amine salt in which the nitrogen atom has four groups bonded to it and carries a positive charge, independent of the pH of the solution they are added to. Glutaraldehyde is a common medical sterilant and is used in water treatment facilities. THPS has a very low toxicity and can be utilized at concentrations that are nontoxic to aquatic life.[99] It has a rapid breakdown rate and no bioaccumulation, significantly reducing the potential for environmental impacts. THPS has been classified by the United States Department of Transportation as nonhazardous.[100]

2.4.3.5 Corrosion Inhibitors

Corrosion inhibitors are commonly added to fracturing fluids to mitigate the probability of corrosion on metal surfaces, such as casing and tubing.[101] Corrosion inhibitors work by creating a thin film on the metal surface, preventing the corrosive substantives from contacting the metal. If the correct inhibitor is utilized, the addition of 0.1% to 2% by volume can be up to 95% effective at preventing corrosion.[102] Concentrations of corrosion inhibitor depend on downhole temperatures and the casing and tubing materials. At temperatures exceeding 121 degrees Celsius (250 degrees Fahrenheit), higher concentrations of corrosion inhibitor, a booster, or an intensifier may also be necessary.

Commonly used corrosion inhibitors include benzalkonium chloride and methanol. Benzalkonium chloride is known as one of the safest inhibitors on the market and is commonly used in leave-on skin care products and as a preservative in eye and nasal drops. It is also used as an additive in antibacterial wipes. Methanol is a non-drinking type of alcohol used for industrial and automotive purposes. Methanol is generated naturally and released to the environment from volcanic gases, vegetation, and microbes.[103] Some of the products methanol can be found in include antifreeze, canned heating sources, deicing fluids, fuel additives, paint remover, and windshield wiper fluids. Methanol is extremely poisonous and a small amount (<8 ounces) can be deadly.[104] Methanol is rapidly biodegraded in water. As a result, accumulation of methanol in both surface waters and groundwater is unlikely.[105]

2.4.3.6 Scale Inhibitors

Scale inhibitors are used in most fracture fluids when there is the potential for scale to form.[106] Minerals such as calcium and magnesium are often found in soluble compounds in formation water but can easily precipitate in the presence of sulfates or carbonates forming scale, which can reduce permeability. The most common scales encountered in shale gas wells are calcium carbonate, calcium sulfate, and barium sulfate. Scale inhibitors are also used during the production phase to stop the scaling of the rock formation, which restricts pore size, thus reducing the hydrocarbon production rate.[107] Scale can also cause problems with equipment, such as buildup inside the production tubing, resulting in blockage and reduced production rates, see picture.

Barium sulfate in Haynesville Shale flowline after one month.

(Picture Courtesy of Baker Hughes Reservoir Blog, "Water Issues for Petroleum Engineers: Introduction" November 15, 2010, http://blogs.bakerhughes.com/reservoir/2010/11/15/water-issues-for-petroleum-engineers-introduction/)

Scale buildup can occur as a result of incompatibilities between hydraulic fracturing fluids and the natural formation water.[108] The fluids injected during the stimulation can dissolve the mineral salts present in the formation, which can lead to scale deposition elsewhere in the formation and the well. Scale inhibitors are pumped as an additive in hydraulic fracture stimulations when necessary. The inhibitor adheres to the rock surface and is slowly released into the production waters over time, reducing the number of solid particles that form.

Each scale type is treated with a different chemical inhibitor depending on the thermal stability, calcium tolerance, and efficiency required to treat the scale type. Polyphosphate-based scale inhibitors are used to retard calcium carbonate precipitation. Slowly soluble polyphosphates were among the first products used for scale inhibition in producing wells. The early solid polyphosphate inhibitors were added, along with propping agents, and injected during hydraulic fracturing treatments. This allowed their placement at a considerable distance from the wellbore, where they slowly dissolved during production of the well. The major disadvantage of the polyphosphate inhibitors was their poor thermal stability, which limited their use to low or moderate temperatures.[109]

Acrylic acid is used in the scale inhibitors that are most successful at treating calcium carbonates and calcium sulfates and is a suitable alternative when polyphosphate inhibitors cannot be used. Acrylic acid is a common ingredient in polishes, paints, coatings, adhesives, plastics, textiles, rug backings, and paper finishes. Acrylic acid is biodegradable in formation water, and it is also destroyed by sunlight in soils or surface waters.[110] Ultimately, most of the acrylic acid that is injected is degraded by the time the produced water resurfaces. The acrylic acid that remains in the formation is degraded in a short time, eliminating any risk of groundwater contamination.[111]

2.4.3.7 pH Adjusters or Buffers

Maintaining the pH of a fracturing fluid is essential to the success of the stimulation treatment as many additives are stable over only a limited pH range. As the fracture additives are exposed to increased temperatures in the wellbore, the pH of the fracture fluid will decrease unless a buffer is added.[112] The amount of pH adjuster used in the fluid is directly proportional to the amount of adjustment that is necessary for the fluid to reach the optimum pH range. For example, a pH buffer can be used to reduce the pH to aid in or increase the ability of a polymer to be hydrated.[113] Another pH buffer can be used to increase the pH in a future stage to facilitate crosslinking of the polymer. The selection of the pH adjusters and their function varies from one fracture treatment to the next. Sodium and potassium carbonates are the most common type of buffer agents used to control high pH and low pH. These buffering agents are added to fracturing fluids in the form of their organic acids or salts, depending on which way the pH needs to be adjusted.[114]

2.4.3.8 Friction Reducer

Friction reducers are added to slickwater fracturing systems to assist the fluid in overcoming the friction that results from the proppant-laden base-carrier fluid traveling through the well tubulars.[115] This reduces the pumping pressure that is needed. Friction reducers are generally polyacrylamide polymers that are selected based on the chemistry of the source water that is used for the fracturing fluid.[116] There are a variety of products available for varying salinities. One of the more common friction reducer used in slickwater fracturing fluids is potassium chloride (KCl). An average concentration of friction reducer in fracturing fluid is 500 to 1,000 parts per million (ppm) (approximately 0.05% to 0.1% of total volume pumped). Friction reducers are used through the entire fracture stimulation.[117] KCl has the added benefit in shale gas fracture treatments of acting as a clay stabilizer (see below). KCl is sold in grocery stores as a salt substitute.

2.4.3.9 Surfactants

Surfactants are primarily used to reduce surface and interfacial tension between two liquids or between a liquid and a solid. It is everyday knowledge that oil and water are immiscible, or do not mix. For example, Italian salad dressing will separate, forming an oily layer above the water layer until vigorously shaken. Almost immediately after the shaking is complete, the separation begins again. Surfactants function to minimize the separation and thus maintain the viscosity. Another use of surfactants is the utilization of change in its ionic properties with pH to control the break mechanism of the gel. As the pH of the system is increased, the glycinate de-stabilizes the micellar structure, resulting in the break of the gel, allowing for easy post -frac cleanup.[118]

One surfactant often utilized in shale gas plays is ethoxylated alcohol, which is a naturally derived, nonionic wetting agent. Ethoxylated alcohol is most commonly derived from linear or branched primary alcohols obtained from olefins found in normal paraffin or coconut oil.[119] It is the same chemical that is used in many eco-friendly laundry soaps and household cleaners,[120] where it is responsible for breaking apart the stains on fabrics and holding the dirt suspended in the water to prevent re-deposition onto the original surface.[121]

Another common surfactant in use is ethylene glycol monobutyl ether (2-BE). The use of 2-BE as a surfactant in the hydraulic fracturing process has been the subject of great attention from opponents of hydraulic fracturing because it can cause hemolysis (breakdown of red blood cells) when exposure is chronic.[122] 2-BE has a half-life in soil and water of one to four weeks and degrades rapidly in water.[123] Therefore, most of the additive has completely decomposed before produced water resurfaces with the hydraulic fracturing fluids.

2.4.3.10 Clay Stabilizer

If a formation contains certain clay minerals (smectite and smectite minerals) that are known to swell when exposed to water, permeability can be significantly reduced when these clays are exposed to water that is of a different salinity (typically fresher water) than the formation water. As a result, a solution containing 1% to 3% salt is generally used as a base liquid when clay swelling is an issue. Potassium chloride (KCl) is a common chemical utilized as a clay stabilizer due to its ability to prevent hydration and swelling from injected water.

2.5 Green Chemical Development and Processes

The environmental sensitivity of offshore operations has led oil and gas service companies to develop and improve what has been termed as “green” chemicals for hydraulic fracturing offshore (see Section 3.3).[124] The Oslo and Paris Commission (OSPAR) is a group that advises North Sea countries on environmental policy and legislation. OSPAR has been influential in establishing North Sea legislation on drilling fluids that has served as the model for other operating areas. OSPAR has published lists of environmentally acceptable and unacceptable products, referred to as the "green," "grey," and "black" lists.[125] The increased use of high-volume hydraulic fracturing and the associated public concern over chemical usage has prompted the marketing of more environmentally friendly chemical substitutes for fracturing additives in Canada and the United States.[126] Green chemicals are designed to achieve similar results as their non-green counterparts but the green chemicals are typically designed to degrade after use, breaking-down into non-toxic substances in the environment.[127] These green chemicals reduce potential surface hazards and subsurface hazards, both at the time of the hydraulic fracturing treatment and in the future.

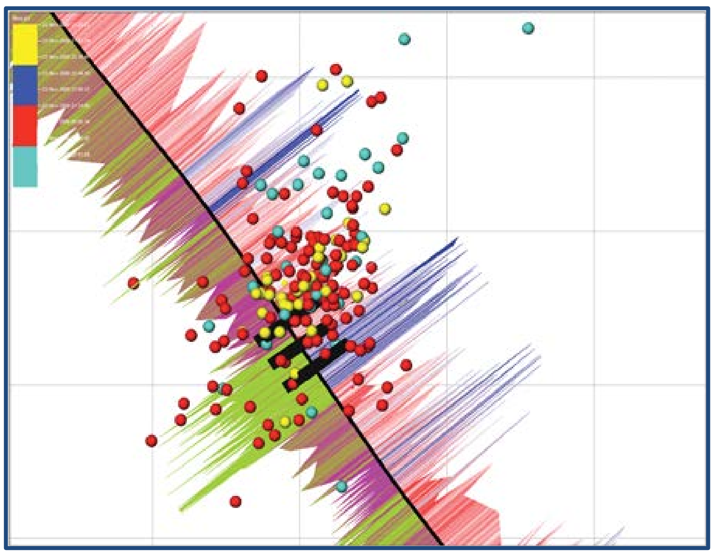
Reducing the amount of chemicals that are used in hydraulic fracturing is another technique that companies are using to "green" their operations. Chemicals cost money, so a reduction in the amount of chemical needed without compromising the production from the well is in the best interest of the company from both a financial and environmental standpoint. The reduction of chemicals used in hydraulic fracturing can also reduce the steps necessary to recycle the water for future hydraulic fracture treatments. For example, oxidizers such as ultraviolet light can be used to replace biocides to reduce the amount of chemicals used in hydraulic fracturing.[128]

A reduction of chemicals does not achieve a safer outcome in all situations. Elimination of certain chemical additives could create greater environmental risks than if those chemicals were used.[129] Each chemical additive serves a specific function and the use of chemicals allows the operator to control the chemistry of the fracturing fluids, which minimizes the risks associated with hydraulic fracturing. Analyzing the full lifecycle of the chemical constituents is necessary to weigh risks against the benefits of using each chemical in a fracture stimulation.

2.6 Measurement of Success

The information collected during a fracture treatment is used in an after-action assessment to help identify areas for improvement and successes that can be transferred to future stimulations. After the well has been fractured and put on production, the volumes produced are monitored and measured to evaluate the success of the job. Additionally, the use of data obtained from monitoring technology, such as microseismic equipment, provides a means to determine the location and size of fractures developed. Computer outputs, such as those in **Figure 8**, can show fracture height and growth that can be compared to the projected conditions to verify the treatment occurred as planned. These post-fracturing measurements are essential to improve the design of future treatments. Each time that information is analyzed from hydraulic fracturing treatments, future designs are refined to optimize fracture patterns within the formation, enhance proppant placement, and improve the control of fracture growth within the zone. Understanding the reasons for success helps operators duplicate the successes from one job to another, while increasing resource recovery and decreasing costs.[130] This refinement of the fracture process was instrumental in the success of the Barnett Shale[131] and will be key in the future success of shale gas development in Canada.

Figure 8: Plan View of Well Trajectory with Microseismic Events from Hydraulic Fracture Monitoring



The red/blue curve on top indicates the fracture gradient displayed in dynamic range. The green/purple curve underneath indicates brittleness. The circles indicate microseisms from different pumping stages. Microseismic data from the field clearly show that while the perforations were placed into the "brittle" high-stress interval, the fractures actually diverted into the nearby low-stress interval.

Source: Jeff Alford, Ed Tollefsen, Jeffrey Kok, Shim Yen Han, Eric Vauter, Raj Malpani, Jason Baihly, Andrew Perry, and Steve Blanke, "LWD Provides Solutions For Bolstering Shale Gas Economics," *E&P* (February 8, 2011), http://www.epmag.com/Exploration-Reservoir-Evaluation/LWD-solution-bolstering-shale-gas-economics_76930 (accessed January 4, 2012).

3 NORTH AMERICAN SHALE GEOLOGY

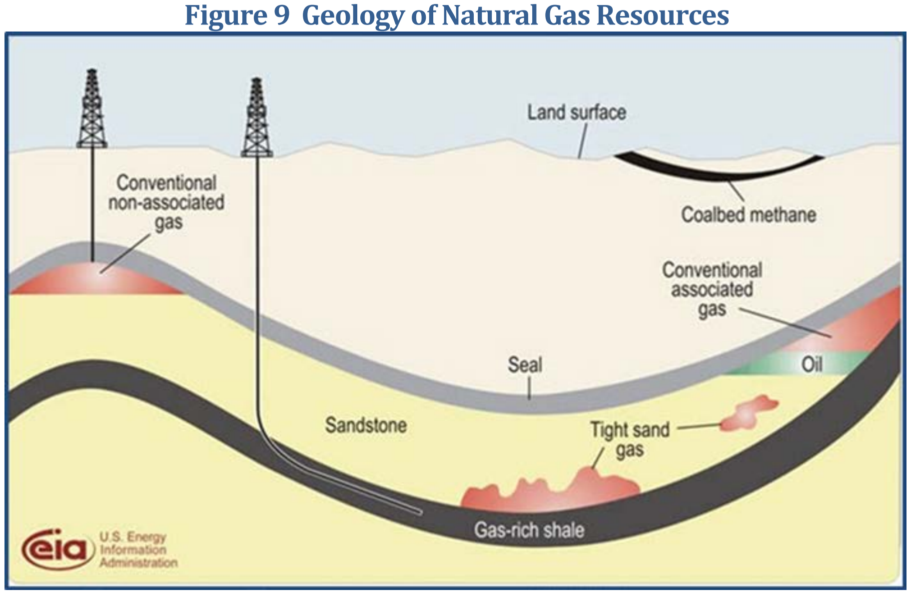
Shale is a sedimentary rock that is comprised of consolidated clay-sized particles that were deposited in low-energy depositional environments and deep water basins. During the deposition of the sediments, organic matter, such as algae, plants and animal debris were simultaneously deposited and all the sediments become compacted. Typical unfractured shales have permeabilities as low as 0.01 to 0.00001 millidarcies (md).[132] This low permeability limits the ability of hydrocarbons in the shale to move within the rock, except over geologic expanses of time (i.e., millions of years).

Shales have historically been known as source rocks for hydrocarbons produced from conventional oil and gas formations. Shales contain kerogen, or organic matter, that produce hydrocarbons as the rock matures over time. In addition to being source rocks, most shales also function as seals, or traps, because of their low permeability. Over geologic time hydrocarbons migrate through fractures and pores out of the source rock and into overlying permeable formations (reservoirs) until the hydrocarbons encounter a trap. Low permeability formations like shales are common trapping mechanisms (seals) called stratigraphic traps. For unconventional shale gas reservoirs, the shale functions as the source, trap, and reservoir rock. **Figure 9** demonstrates some of the different natural gas reservoirs and plays that exist, including both conventional and unconventional plays.

Most of the gas found in shales is thermogenic, although some shales, such as the Antrim shale in Michigan, have large quantities of biogenic gas. Thermogenic gas was formed when organic material was compressed at high temperatures and pressures for an extended duration of time. Thermogenic gas can contain significant quantities of heavier hydrocarbons or it can be nearly pure methane. Biogenic methane is generally formed at shallow depths and results from microorganisms that chemically break down organic matter to form methane. Some biogenic methane is released to the atmosphere. However, some is trapped and buried in shales. The gas is stored in the shale in the pore spaces as free gas, adsorbed onto the organic material or surface walls in the shale (free gas), or mixed with other liquids, such as bitumen and oil (solution gas). The volume of adsorbed gas typically increases as organic matter increases. Higher free-gas content results in higher initial production rates because it resides in the fractures and pores and is easier to produce than adsorbed gas, which requires a pressure drop to get the gas molecules to detach from the organic matter.

The volume of natural gas that is stored in a shale varies depending on the porosity, amount of organic material present, reservoir pressure, and the thermal maturity of the rock.[133] The key properties of shales, when considering gas potential are permeability, total organic content (TOC) and thermal maturity.[134] Permeability is the ability of the fluids within the shale to move from one pore space to another. The effective bulk permeability is typically less than 0.1 md in shales, although there are exceptions, such as the Antrim shale in the

Figure 9 Geology of Natural Gas Resources

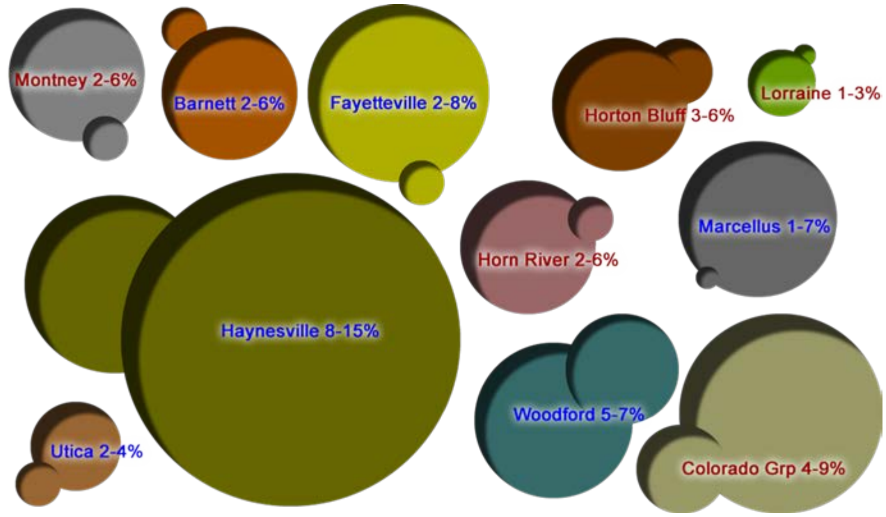


Source: U.S. Energy Information Administration, "Natural Gas: Schematic Geology of Natural Gas Resources" (January 27, 2010), http://www.eia.gov/oil_gas/natural_gas/special/ngresources/ngresources.html (accessed December 27, 2011).

Michigan Basin that is well fractured and has a higher bulk permeability. Shale formations that have large percentages of sandstone and siltstone generally have high permeability. In contrast, shales with limited sands and silts have less permeability.

The oil and gas in a formation is stored in pore spaces or fractures or it is adsorbed on the mineral grains. The amount of pore space or voids in the rock, called porosity, is generally low in shales, ranging from 0 to 10 %.[135] However, some shales, such as the Haynesville, have a higher porosity than typical shales (See **Figure 10**). The higher the porosity a rock has the more oil or gas its pore spaces can contain.

Figure 10: Porosity of United States and Canadian Shale Basins



Source: Modified from "Canadian Unconventional Resources: Energy Security and Investment Opportunities," presentation given by Mike Dawson, President ,Canadian Society for Unconventional Resources at NAPE International Forum, Houston, Texas February 16, 2011.

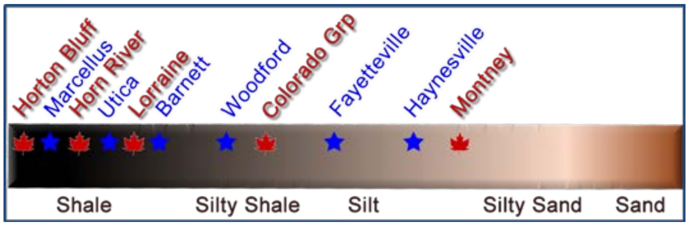
The total organic content (TOC) of shale is the measure of the amount of organic material, or kerogen, present in the rock.[136] TOC is expressed as a percentage by weight. As a general rule, the higher the TOC, the better potential the shale has for hydrocarbon generation. The TOC of shale can be determined from cores or geophysical logs, such as a density log.[137] A TOC value of 5% or more is ideal for shale gas development.[138] TOC values are not constant within a shale formation and can vary laterally and throughout the thickness of the formation. Furthermore, as hydrocarbons are produced from the source rock, the TOC value decreases.[139]

The thermal maturity of a shale is a measure of the degree to which the organic material in the rock has been heated over time and potentially converted to oil or gas.[140] It is measured using vitrinite reflectance (Ro). The most thermally mature shales have gas production, such as in the Haynesville Shale play in north Louisiana.[141] Shales that are less mature can have gas and condensate production, such as in the Eagle Ford Shale in south Texas. The least mature shales produce oil, such as in the Bakken Shale play in North Dakota. Shales with a Ro in the ranges of 0.5-1.3 are said to be in the "oil window" and those with a Ro in the range of 1.3->2 are in the gas window.[142] For example, since the Marcellus shale has a Ro of 2.8, it is thermally mature and gas is the most prevalent hydrocarbon.

Another factor that affects the suitability of shale gas reservoirs for commercial development is the gas quality. Some reservoirs, such as the Horn River, have high CO_2 concentrations (10-12%) that must be removed before the sellable gas can be placed in a pipeline.[143] In shales where gas is present, an operator evaluates the completion techniques that are required to develop the resource. Hydraulic fracturing has provided industry with an opportunity to develop a resource that would not be commercial to drill, develop, or produce otherwise. As a result, understanding the properties that make specific shales good candidates for fracture stimulations is a vital component of the reservoir evaluation.

The lithology and mineralogy of the shale can impact how the rock will fracture. *Lithology* refers to the macroscopic nature of the mineral content, grain size, texture, and color of the rocks. Mineralogy refers to the chemistry, crystal structure, and physical properties of the minerals. Not all plays that are classified as "shales" are actually shale lithology. Shale is a fine-grained sedimentary rock that is a mixture of clay minerals

Figure 11: North American Shale Lithology



Source: Modified from "Canadian Unconventional Resources: Energy Security and Investment Opportunities," presentation given by Mike Dawson, President ,Canadian Society for Unconventional Resources at NAPE International Forum, Houston, Texas February 16, 2011.

and tiny fragments of other minerals such as quartz, dolomite, and calcite. The ratio of clay to minerals varies in each of the basins, and even within each basin. For example, the Montney Shale in British Columbia is approximately 45% quartz, 45% dolomite, and 10% other minerals.[144] The Montney Shale looks like a shale on a log but it is primarily a tight gas sand (see **Figure 11**).

The mineral content of a given shale determines how easy or difficult it will be to fracture. Hard minerals like silica and calcite break like glass under pressure, but clay minerals typically absorb more of the pressure and bend during hydraulic fracturing rather than break like hard minerals.[145] In general, the greater the silica content, the more easily fractured the reservoir rock. Shale hardness ranges from brittle, such as in the Barnett shale, to ductile, like in the Bossier shale play.

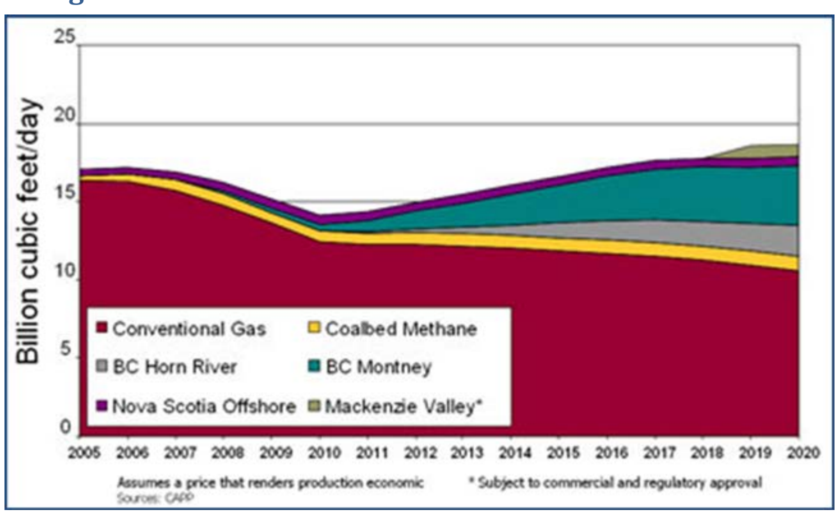
The internal pressure present in a shale formation also impacts the operator's ability to fracture the formation successfully.[146] Overpressurized shales develop during natural gas generation. However, because of the low permeability, the gas cannot escape and the internal rock pressure increases. In a shale, *overpressurized* generally means that the subsurface pressure is abnormally high, exceeding hydrostatic pressure in its pore structure at a given depth. In overpressurized shales, hydraulic fractures can propagate further into the formation because the shale is closer to the breaking point than in normally pressurized shales. The Horn River, Montney, and Utica Shales are all considered to be overpressurized.[147] The Colorado Shales are considered underpressurized.

Natural gas and oil resources in North America are typically discussed in terms of conventional or unconventional resources. Conventional gas is found in formations with permeabilities greater than 1 md and can be extracted with vertical wells and limited stimulation.[148] This type of gas is relatively easier to extract and typically less expensive to produce than unconventional sources.

Unconventional gas is found in formations with extremely small permeabilities (less than 1 md) and cannot be commercially extracted by conventional development methods. Some shale has permeability as low as 0.00001 md. Most unconventional gas must undergo stimulation such as hydraulic fracturing to be productive. The most common types of unconventional gas are tight gas, coal bed methane, and shale gas. While conventional gas is the primary source of gas production in Canada, unconventional gas is anticipated to contribute more to natural gas production in the next decade (see **Figure 12**).

This section reviews the geology of several U.S. and Canadian proven and prospective shale plays. There is no specific formula for an ideal shale basin. However, the right combinations of the properties

Figure 12: 2010 Canadian Natural Gas Production Forecast



Source: Canadian Association of Petroleum Producers (CAPP), "Conventional & Unconventional" (© 2009), http://www.capp.ca/canadaIndustry/naturalGas/Conventional-Unconventional/Pages/default.aspx#Zce9tkSvt2pJ (accessed December 27, 2011).

discussed above can make a shale formation commercial. Comparisons of these properties are made between the basins in each of the sections.

3.1 The Barnett Shale

The Barnett Shale is approximately 1,980 m to 2,590 m deep throughout the Fort Worth Basin of north-central Texas.[149] The Barnett Shale is a Mississippian-age shale that is bounded by the Marble Falls Limestone formation above and the Chappel Limestone below. **Figure 13** is a stratigraphic chart identifying the formations in the Barnett Shale. Formations are in ascending age from top to bottom.

The Barnett Shale has been a model for development of gas shale plays in Canada and the United States. As of September 28, 2011, there were over 15,300 wells drilled in the Barnett Shale, with over 3,200 additional permitted locations waiting to be drilled with the Railroad Commission of Texas.[150] Technologies have been developed, tested, and improved in the Barnett. The Barnett Shale has been a proving ground for the use of hydraulic fracturing with horizontal drilling for shale gas development. Current drilling operations in the Barnett Shale have focused on expanding the play outwards and on infill drilling within the developed areas to increase the amount of gas recovered. Well spacing for horizontal well completions in the Barnett ranges from 24 to 65 hectares (60 to 160 acres).[151]

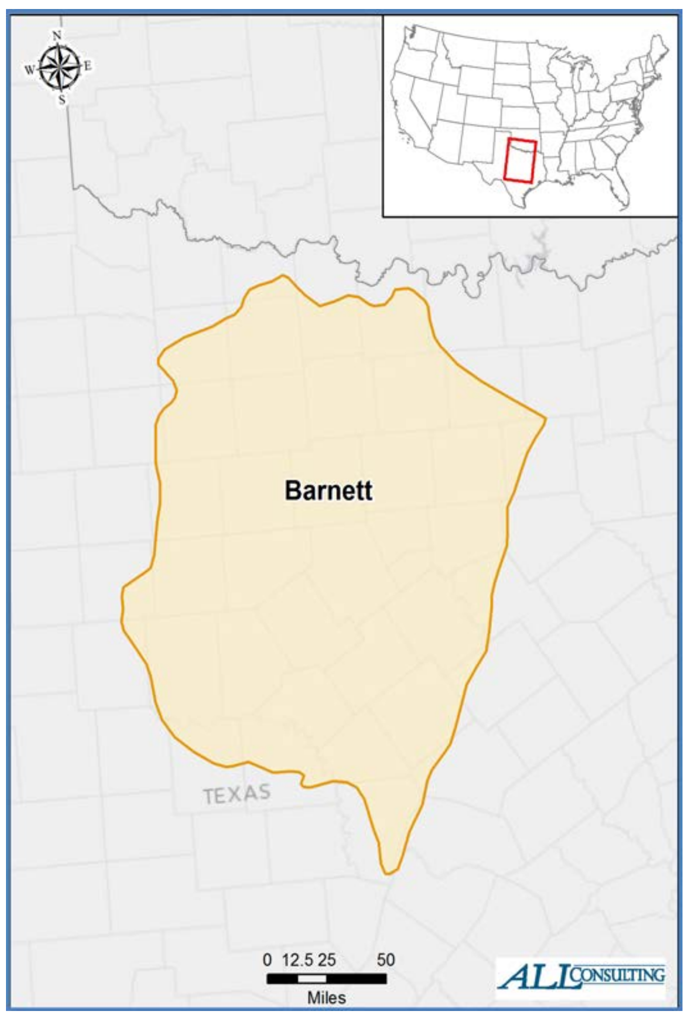
The thickness of the Barnett Shale ranges from 30 m to more than 180 m across an area of approximately 12,950 square kilometres.[152] The general location and extent of the Barnett Shale is shown in **Figure 14**. The shale has approximately 9.26 x 10^{12} m^3 (327 trillion cubic feet [tcf]) of original gas in place (OGIP), with an estimated recoverable reserves of 1.25 x 10^{12} m^3 (44 tcf).[153]

Figure 13: Stratigraphy of the Barnett Shale

Period		Group/Unit
Permian	Leonardian	Clear Fork Grp
		Wichita Grp
	Wolfcampian	Cisco Grp
Pennsylvanian	Virgilian	
	Missourian	Canyon Grp
	Desmoinesian	Strawn Grp
	Atokan	Bend Grp
	Morrowan	Marble Falls Limestone
Mississippian	Chesterian - Meramecian	Barnett Shale
	Osagean	
		Chappel Limestone
Ordovician		Viola Limestone
	Canadian	Simpson Grp
		Ellenburger Grp

Source: Ground Water Protection Council (GWPC) and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, prepared for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory (April 2009), 18.

Figure 14: Barnett Shale



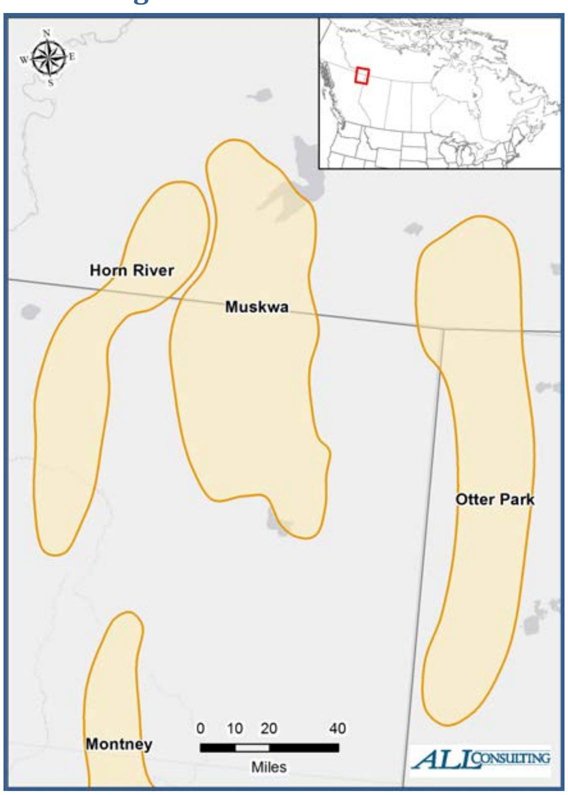
The gas content is the highest among the major North American shale plays, ranging from 9.4 m^3/tonne to 10.9 m^3/tonne of rock.

3.2 The Horn River Basin

The Horn River Basin in northeast British Columbia is at a depth that is similar to the Haynesville Shale (U.S.) at 2,500 to 3,000 m,[154] but is geologically comparable to the Barnett Shale in Texas, despite being deeper.

The Horn River Basin is a Devonian-age unit in the Western Canadian Sedimentary Basin that extends from northeastern British Columbia northward to Fort Liard in the southern Northwest Territories (see map in **Figure 15**) [155] The Bovie Fault Zone separates the basin from the Liard Basin to the west.[156] The basin is bounded to the east and south by the Devonian carbonate platforms of the Keg River, Sulphur Point, and Slave Point formations. As shown in the stratigraphic chart in **Figure 16**, shale formations of the Horn River are overlain by the Fort Simpson, a thick sequence of shale, and are underlain by the Keg River, a low-permeability carbonate formation.[157]

Figure 15: Horn River Basin



The shale formations of the Horn River Basin have been subdivided from the bottom up into the Evie, Otter Park, and Muskwa. The Evie and Muskwa shale members have high silica and organic contents, making them attractive for shale gas development. To date, operators have focused primarily on development of the Muskwa.

According to the Canadian Energy Research Institute's *Shale Gas Plays in North America* report, the decline rate for first year Horn River wells is 50%, a much lower rate than other shale plays, which can have first-year decline rates as high as 90%.[158] Initial production rates have reached up to 450,000 m^3/day (16 million cubic feet per day [MMcf/day]).[159] The basin encompasses approximately 1.28 million hectares.[160] An estimate for gas-in-place for the Horn River basin is $14x10^{12}$

Figure 16: Stratigraphy of the Horn River Basin

Period	Group/Unit
Mississippian	Debolt
	Pekisko/Shunda
	Banff
	Exshaw
Upper Devonian	Kotcho
	Tetcho
	Trout River
	Kakisa Member
	Hedknife
	Jean Marie Member
	Fort Simpson
Middle Devonian Middle Devonian	Muskwa
	Otter Park
	Slave Pt/Sulphur Point basinal equivalents
	Evie
	Lower Keg River

Source: Storm Gas Resource Corp., "Devonian-Mississippian Stratigraphic Correlation Chart," http://www.rundleenergy.com/storm/storm_stratigraphchart_zoom.html (accessed December 13, 2011).

m^3 (500 tcf), of which approximately 20% is anticipated to be recoverable.[161]

The major challenge of Horn River Basin development is the lack of infrastructure in place to transport the produced gas from remote areas to market. In August 2010, construction of the TransCanada Groundbirch pipeline began. The pipeline will transport gas from northeast British Columbia to Kitimat, British Columbia, 645 km north of Vancouver for transport to Asia Pacific export markets.[162] A Liquefied Natural Gas (LNG) facility is also being constructed on Bish Cove on First Nations land.[163] The initial phase will have the capacity to transport approximately 1.96×10^7 m^3 (700 MMcf/day) from Summit Lake, British Columbia, to Kitimat. Shipments are anticipated to start in 2015.[164]

Another challenge is the short drilling season and harsh environment during that time. Development of much of British Columbia is limited to the winter months (December to March) when the ground is able to sustain the weight of drilling equipment.[165]

3.2.1 Evie Shale

The Evie Shale is identifiable using geophysical tools by high gamma ray readings and high resistivity.[166] The uppermost portion of the shale has more silt and lower radioactivity and resistivity. In the Horn River Basin, the Evie Shale is more than 75 m thick and thins westward to less than 40 m thick as it nears the Bovie Lake structure. The Evie Shale overlies limestone and dolostones of the Lower Keg River Formation.[167]

3.2.2 Otter Park Shale

In the southeastern portion of the Horn River Basin, the Otter Park Shale is more than 270 m thick.[168] The Otter Park Shale is identifiable on logs as having lower radioactivity and resistivity than the Evie and Muskwa Shale formations. The Otter Park Shale thins towards the north and west. The mineralogy varies across the basin, losing potential for shale gas development to the south where limestone is more prevalent than shale.[169]

3.2.3 Muskwa Shale

In the Horn River Basin, the Muskwa Shale is approximately 30 m thick adjacent to the Presqu'ile barrier reef on the east and thickens westward, exceeding 60 m at the Bovie Lake Structure.[170] The Muskwa has been the primary target in the Horn River Basin over the last few years. Unlike the other shale formations that make up the Horn River Basin, the Muskwa is not limited to this basin alone. The Muskwa Shale extends through the rest of northeastern British Columbia and is the stratigraphic equivalent of the Duvernay Shale in Alberta. The Muskwa Shale has limited faulting and the underlying carbonate has no sinkholes.[171]

The Muskwa is composed primarily of quartz (26% to 87%) with illite clays averaging 16%.[172] When compared to other North American shale formations, the Muskwa has the highest quartz volume and lowest clay volume. The quartz makes the Muskwa brittle and successfully responsive to hydraulic fracturing. The Muskwa Shale is less porous than other shale formations, but has similar organic volume to the Haynesville Shale. Gas saturation is high and water saturation is low, which is a benefit of Muskwa development.

The Horn River Shale properties are similar to those of the Barnett shale. The Muskwa Shale is thicker and more brittle than the Barnett Shale, which should maximize the extent of the induced fracture network during hydraulic fracturing. The Muskwa Shale has higher gas pressure than the Barnett and has less complicated geology. The well depths in the Horn River are approximately 2,435 m and the pay zone thickness is 160 m , which contributes to the increased gas in place in the Horn River as compared to the Barnett.[173] The quartz content in the two basins is relatively similar. In the Horn River, the gas content is higher than in the

The Cordova Embayment

The Cordova Embayment is also associated with the Horn River Basin and has shale gas potential, although evaluation is still very premature. It is located north of Fort Nelson in British Columbia. Initial estimates of gas is place are 5.7x1012 m3 (200 tcf). As of May 2009, $40 million had been spent by industry to secure resource rights in the Cordova Embayment area, a significantly less amount than the $2 billion in the Horn River Basin.

Barnett.[174] **Table 5** compares properties of the Muskwa and Barnett Shales.

Table 5: Muskwa, Horn River Shale vs. Barnett Shale

Parameters	Muskwa, Horn River Basin	Barnett Shale
Thickness, m	160	108
Permeability, md	230	250
Gas-Filled Porosity, %	4	4.5
Maturity, Ro	2.8	2.2
Silica content, %	65	55
Gas in Place (m^3/km^2)	2.9×10^9	2.11×10^9

Source: Alan Petzet, "BC's Muskwa Shale Shaping Up as Barnett Gas Equivalent," *Oil & Gas Journal* 106, no. 12 (March 24, 2008): 40–41.

3.3 The Haynesville/Bossier Shale

They Haynesville/Bossier Shale is an Upper Jurassic-age shale located in the North Louisiana Salt Basin in northern Louisiana and eastern Texas.[175] The depth of the shale ranges from 3,200 m to 4,150 m deep. As shown in the stratigraphic chart in **Figure 17**, the Haynesville is between the Cotton Valley Group and the Smackover Limestone. Although the Haynesville Shale made headlines as a potentially significant gas reserve in 2007, additional development and testing is ongoing to identify the full extent of the play.[176] The development of the Haynesville Shale presents several challenges as a high-pressure, high-temperature drilling environment with associated higher well costs.[177] Bottom-hole temperatures (BHTs) reach up to 193°C and bottom-hole pressures (BHPs) can exceed 82,740 kPa .[178] These high temperatures and pressures create challenges for fracturing equipment. In addition, premium casing and high-strength proppants are required.

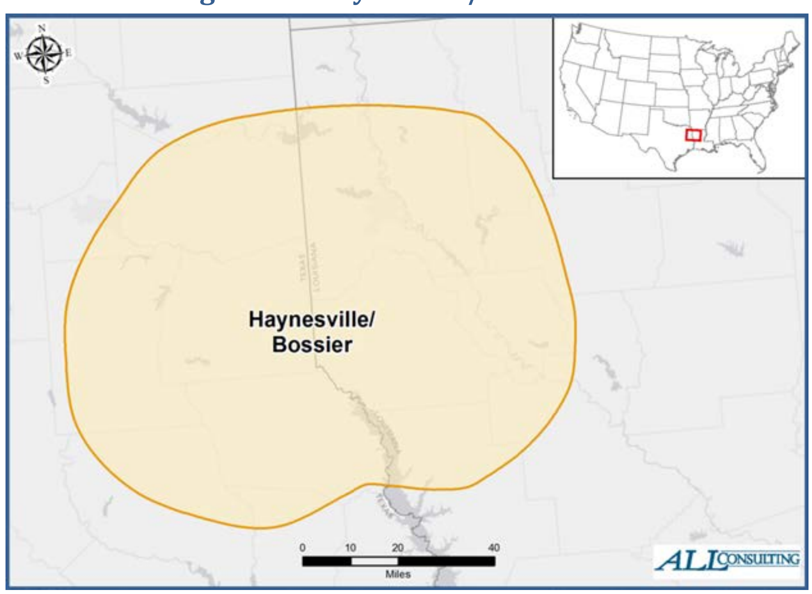
The aerial extent of the Haynesville Shale covers approximately 23,300 km^2 (9,000 square miles) and is shown in **Figure 18**. The thickness of the shale ranges from 60 m to 90 m deep. Well spacing within the basin

Figure 17: Stratigraphy of the Haynesville Shale

Period		Group/Unit
Cretaceous		Navarro
		Taylor
		Austin
		Eagle Ford
		Tuscaloosa
		Washita
		Fredericksburg
		Trinity Group
		Nuevo Leon
Jurassic	Upper	Cotton Valley Group
		Haynesville
		Smackover
		Norphlet
	Middle	Louann
	Lower	Werner
Triassic	Upper	Eagle Mills

Source: GWPC and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, prepared for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory (April 2009), 20.

Figure 18: Haynesville/Bossier Shale



ranges from 16.2 to 22.7 hectares. Gas content estimates for the play are 3.1 m^3/tonne to 1.24 m^3/tonne (100 scf/ton to 330 scf/ton). The OGIP estimates of 20.3 x 10^{12} m^3 (717 tcf) and technically recoverable resources estimated at 7.11 x 10^{12} m^3 (251 tcf) indicate that the Haynesville Shale has the potential to become a significant gas resource in the future.[179]

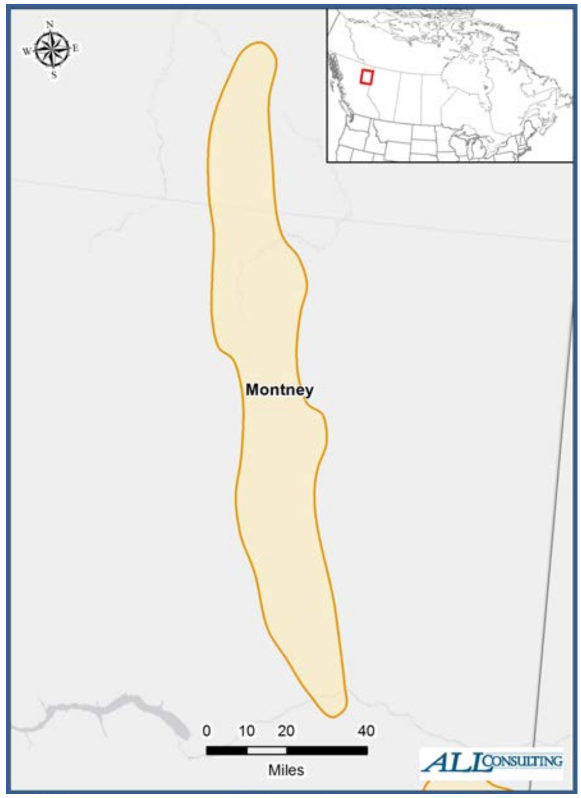
The Bossier Shale is an over-pressurized, organic-rich shale with petrophysical characteristics very similar to the Haynesville.[180] It is often considered part of the Haynesville Shale, but it is 150-245 m above the Haynesville[181] and is considered part of the Cotton Valley Group.[182] The matrix porosity in producing areas is 8-15%, making it the most porous of all the U.S. and Canadian plays analyzed in this paper (See **Figure 10**).[183] While the Haynesville Shale has low clay content, that clay content gradually increases up through the Bossier,[184] making the water content in the Bossier higher and gas in place slightly lower.

3.4 Montney Shale

The Montney Shale is a hybrid of a shale reservoir and tight gas reservoir, similar to the Bossier sand and shale play on the Texas and Louisiana border.[185] It exhibits properties of both conventional and unconventional reservoirs and ranges from 2450 m to 2650 m deep..

The main Montney Shale play trend covers approximately 1 million hectares in the South Peace region of northeast British Columbia and north central Alberta (see map in **Figure 19**).[186] The play area varies, from traditional shale gas along the Alberta/British Columbia border to tight calcareous sandstone in central Alberta.[187] The primary targets of the Montney play include the Upper and Lower Montney, Doig, and Cadomin Formations as shown in the stratigraphic chart in **Figure 20**.[188] The Montney Shale generally increases in depth from east to west and has decreased porosity, increased reservoir pressure and increased thickness at the greater depths to the west. In addition, the gas content on the western edge of the formation is higher.

Figure 19: Montney Shale



The Montney Shale is rich in silt and sand, similar to tight gas, but the natural gas originates from the organic matter in the formation, making it a shale.[189] The Montney is shallow and brittle, making hydraulic fracturing operations more successful than in some of the other Canadian shale basins.[190] However, due to the presence of siltstone and sand throughout the formation, it has extremely low permeability and requires higher levels of fracture stimulation for successful extraction.[191]

The Upper Montney has seen production growth in recent years from the Swan, Dawson, Saturn, and Monias fields.[192] The Montney Shale is rich in natural gas liquids (NGLs), which trade at approximately 80% of oil prices, making the economics of the play even more attractive.[193]

While development of the Montney Shale is only in the preliminary phases, the industry interest has broken records. In July 2008, the right to drill a total of 134,196 hectares in the Montney Shale in British Columbia was auctioned for a record $610 million dollars. As of May 2011, a total of 455 vertical wells and 801 horizontal wells were

Figure 20: Stratigraphy of the Montney Shale

Period		Group/Unit	
Cretaceous	Upper		Edmonton
		Brazeau Solomon SS	Belly River
		Alberta Group	Wapiabi
			Cardium
			Blackstone
			Dunvegan
			Shaftsbury
	Lower		Mountain Park
			Luscar Group
			Cadomin
Jurassic	Upper		Nikanassin
		Fernie Group	Fernie Shale
	Middle		Nordegg
	Lower		
Triassic	Upper	Schooler Ck Group	Pardonet
			Baldonnel
			Charlie Lk
			Halfway
	Middle	Daiber Group	Doig
			Montney
	Lower	Beekman-town	Tribes Hill-Chuctanunda

Source: Gerhard Pflug, "North American Shale Gas Overview," presentation (September 22, 2009),. http://www.necanews.org/dev/documents/090922_pflug_gerhard_1.pdf (accessed November 30, 2010).

producing in the Montney,[194] primarily the Heritage pool of British Columbia.[195] Initial production rates range from 85,000 to 141,000 m^3/d (3 to 5 MMcf/day) but have reached as high as 280,000 m^3/d (10 MMcf/d) followed by rapid declines. Total production from the wells averages 1.59 x 10^7 m^3/day (1457 MMcf/day), with 89% of that production coming on-stream since September 2008.[196]

3.5 The Marcellus Shale

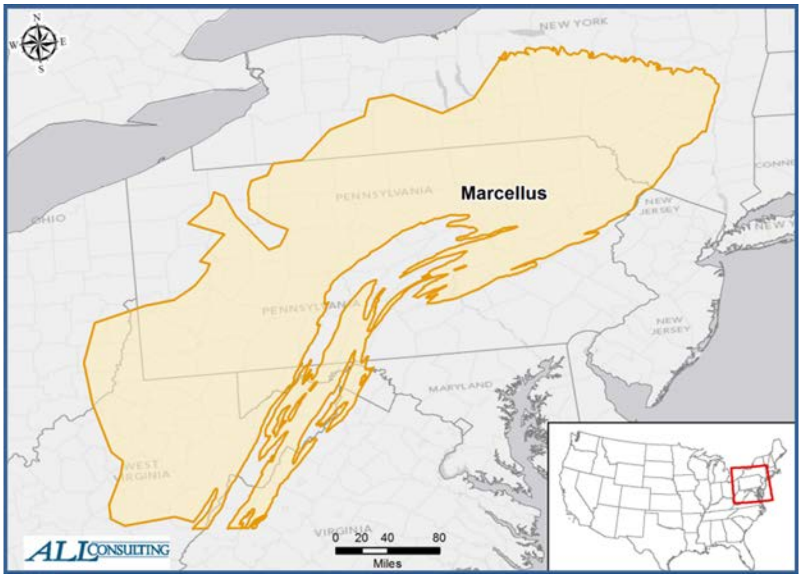
The most expansive of the shale gas plays in the United States is the Marcellus Shale, which spans six states in the northeastern portion of the country. It is Middle Devonian-age shale bounded by the Hamilton Group shale formations above and the Tristates Limestone below. These can be seen in the stratigraphic chart in **Figure 21**. The shale is located between 1,220 and 2,590 m deep.[197] The first modern economical developed well in the Marcellus formation was drilled in 2003 in Pennsylvania.[198] As of December 2011, there were a total of 9,481 Marcellus wells permitted in Pennsylvania and 4,468 of the approved wells have been drilled.[199] **Figure 22** shows the location and extent of the Marcellus Shale. It covers approximately 246,000 square kilometres (95,000 square miles) with a thickness averaging 15 m to 60 m. Compared to the other shale basins in U.S., the Marcellus has a lower relative gas content of 1.9 m^3/tonne to 3.12 m^3/tonne (60 scf/ton to 100 scf/ton). Because of the large aerial extent of the play, the OGIP is higher reaching up to 42.5 x 10^{12} m^3 (1,500 tcf).[200]

Figure 21: Stratigraphy of the Marcellus Shale

Period		Group/Unit	
Penn			Pottsville
Miss			Pocono
Devonian	Upper		Conewango
			Conneaut
			Canadaway
			West Falls
			Sonyea
			Genesee
	Middle		Tully
		Hamilton Group	Moscow
			Ludlowville
			Skaneateles
			Marcellus
			Onandaga
	Lower		Tristates
			Helderberg

Source: GWPC and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, prepared for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory (April 2009), 21.

Figure 22: Marcellus Shale



The average well spacing in the Marcellus Shale is 16 to 65 hectares (40 to 160 acres).[201] This play has not yet been fully defined, so the potential reserve estimates are still being revised, but current estimates are upwards of 7.42 x 10^{12} m^3 (262 tcf).[202]

Figure 23: Stratigraphy of the Fayetteville Shale

Period			Group/Unit
Carboniferous	Pennsylvanian		*Atoka*
			Bloyd
		Hale	*Prairie Grove*
			Cane Hill
	Mississippian		(IMO)
			Pitkin
			Fayetteville
			Batesville
			Moorefield
			Boone

Source: GWPC and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer*, prepared for the U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory (April 2009), 19.

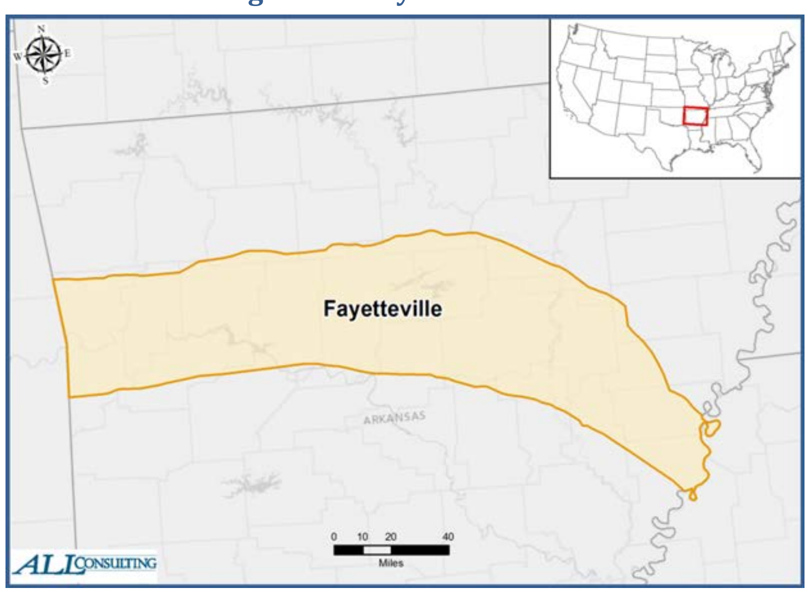
3.6 The Fayetteville Shale

The Mississippian-age Fayetteville Shale ranges from 300 m to 2,130 m in the Arkoma Basin of northern Arkansas and eastern Oklahoma.[203] The shale is bound by the Pitkin Limestone above and the Batesville Sandstone below, as depicted in the stratigraphic chart in **Figure 23**.

As successful development was proven in the Barnett Shale and operators identified parallels between it and the Fayetteville Shale, hydraulic fracturing and horizontal drilling techniques were adapted to develop the Fayetteville Shale.[204] Between 2004 and 2010 the gas production for the Fayetteville Shale increased from just over 0.28 x 10^7 m^3/yr (100 million cubic feet per year [MMcf/yr]) to approximately 22 x 10^9 m^3/yr (777 billion cubic feet per year [bcf/yr]) in 2010.[205] With over 3,700 wells in production to date, the Fayetteville Shale is currently on its way to becoming one of the most active plays in the United States.[206]

The location and extent of the Fayetteville Shale is shown in **Figure 24**. At 23,310 km^2 (9,000 square miles), the Fayetteville Shale play area is nearly double that of the Barnett Shale.[207] The average thickness of the productive shale ranges

Figure 24: Fayetteville Shale



between 6 m and 60 m with well spacing ranging from 32.4 to 64.7 hectares. The gas content for the Fayetteville Shale has been measured at 1.9 m^3/tonne to 6.9 m^3/tonne , which is less than the 9.4 m^3/tonne to 10.9 m^3/tonne gas content of the Barnett. Since the gas content of the Fayetteville Shale is less than that of the Barnett, the estimates of OGIP and technically recoverable reserves is less (1.47 x 10^{12} m^3 and 1.18 x 10^{12} m^3 [52 tcf and 41.6 tcf, respectively]).[208]

3.7 Horton Bluff

Like the Fayetteville shale, the Horton Bluff Group is an Early Mississippian group. It is located in the Canadian Maritimes Basin and ranges in depth from 1500 m to 3000 m.[209] The aerial extent of the basin is shown in **Figure 25**. The total absorbed gas content of the Horton Bluff Shale is comparable to the Barnett Shale.[210] However, unlike the Barnett, Fayetteville, or Woodford Shale plays, which are dominated by biogenic quartz or illite clay, the Horton Bluff has a high amount of quartz and clays including kaolinite and chlorite as well as significant amounts of iron carbonate (siderite).[211] Unlike the illite clays of the Barnett Shale, the kaolinite and chlorite of the Horton Bluff are sensitive to swelling.[212] The water sensitivity of these clays is expected to cause hydraulic fracturing challenges as most shale plays are fracture treated using a water-based fracturing fluid. A stratigraphic chart of the Horton Bluff Group is shown in **Figure 26.**

Figure 25: Horton Bluff/ Fredrick Brook Shale

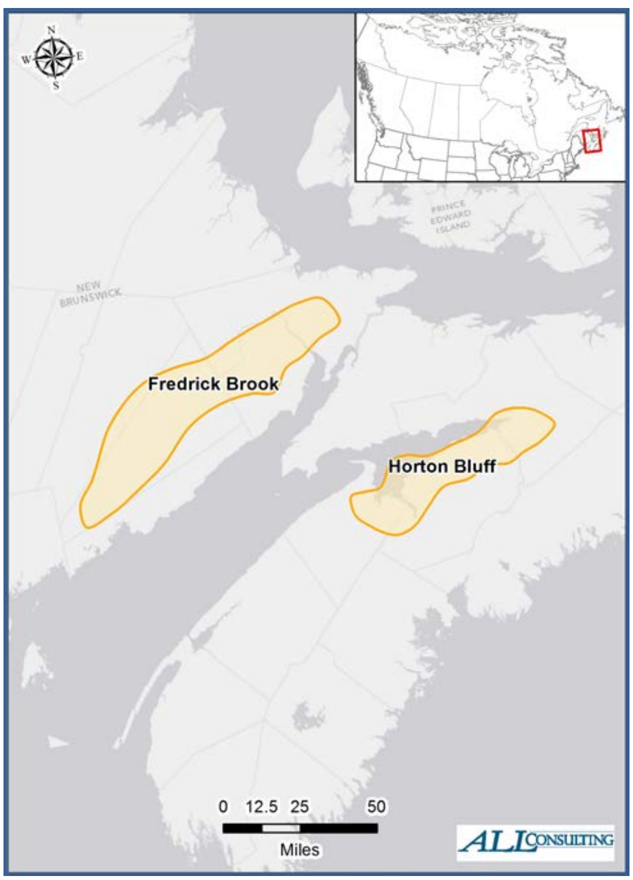


Figure 26: Stratigraphy of the Horton Bluff Group

Period		Stage	Group/Unit	
Late Carboniferous	Pennsylvanian	Stephanian	Pictou	
Late Carboniferous	Pennsylvanian	Stephanian	Pictou	Salisbury
Late Carboniferous	Pennsylvanian	Westphalian	Cumberland	Boss Point
Late Carboniferous	Pennsylvanian	Namurien	Cumberland	Boss Point
Late Carboniferous	Mississippian	Namurien	Mabou	Mabou
Early Carboniferous	Mississippian	Visean	Mabou	Mabou
Early Carboniferous	Mississippian	Visean	Windsor	Clover Hill
Early Carboniferous	Mississippian	Visean	Windsor	Cassidy Lake
Early Carboniferous	Mississippian	Visean	Windsor	Upperton
Early Carboniferous	Mississippian	Visean	Windsor	Gays River/Macumber
Early Carboniferous	Mississippian	Visean	Windsor	Hillsborough
Early Carboniferous	Mississippian	Tournaisian	Sussex	Weldon
Early Carboniferous	Mississippian	Tournaisian	Sussex	Mill Brook/Round Hill
Early Carboniferous	Mississippian	Tournaisian	Horton	Bloomfield
Early Carboniferous	Mississippian	Tournaisian	Horton	Albert: Hiram Brook
Early Carboniferous	Mississippian	Tournaisian	Horton	Albert: Frederick Brook
Early Carboniferous	Mississippian	Tournaisian	Horton	Albert: Dawson Settlement
Late Devonian		Famennian	Horton	McQuade Brook
Late Devonian		Famennian	Horton	Memramcook

Source: New Brunswick Canada, "Exploration for Natural Gas Resources," http://www2.gnb.ca/content/gnb/en/departments/natural_resources/Promo/NaturalGas/ExplorationForNaturalGasResources.html (accessed January 3, 2011).

Another challenge is that siderite yields carbon dioxide upon decomposition. Carbon dioxide (CO_2) content of the Horton Bluff Shale averages around 5%,[213] but could range from 1% to 20% of the total gas at the high levels of thermal maturity of the Horton Bluff.[214] This level of CO_2 is not unusual at high levels of thermal maturity: the Fayetteville Shale has very similar contents. To date, there has been no public discussion of a how to capture and handle the produced CO_2,[215] but this will likely become an issue as development increases.

Studies from Nova Scotia have indicated that most of the gas in the Horton Bluff is adsorbed onto clay and organic matter, making completion and production more challenging. Successful development is dependent on very effective reservoir stimulations.[216]

3.7.1 Fredrick Brook

The Fredrick Brook Shale is a member of the Albert Formation, which is a component of the Horton Group that underlies Nova Scotia and New Brunswick. The silica content of the Fredrick Brook Shale averages 38%,[217] but the clay content is high, averaging 42%.[218] The organic carbon of the Fredrick Brook member in Nova Scotia is 10%.[219] The pay zone is over 150 m thick, exceeding 1,000 m in New Brunswick.[220] The thermal maturity of the Fredrick Brook shale ranges from 0.6 to 2.4. Therefore, there is oil as well as gas in the play.[221]

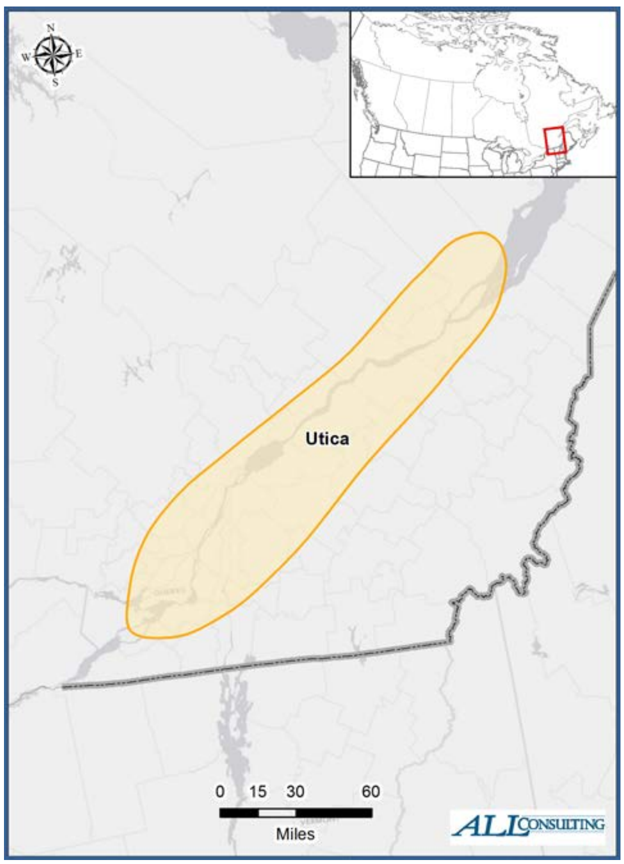
An independent analysis indicates that 1.9 x 10^{12} m^3 (67 tcf) of natural gas is in place in the Frederick Brook Shale of the Sussex/Elgin sub-basins in southern New Brunswick.[222] An additional 2.0 x 10^{12} m^3 (69 tcf) of gas in place is estimated in the Windsor Land block in Nova Scotia.[223]

The Frederick Brook Shale was put in production in early 2008.[224] Since then, several evaluation wells have been drilled and completed to evaluate the potential of the shale. Five vertical wells have been drilled in the Windsor block, which covers an area of approximately 208,800 hectares in the central portion of Nova Scotia. The wells encountered between 305 m and 1,005 m of prospective shale.[225] Based on seismic data and results of the wells that have been drilled, additional development of the resource in the future is likely."[226]

3.8 The Utica/Lorraine Shales

The Utica Shale is middle Ordovician shale located in portions of Pennsylvania, Ohio, and New York and the Province of Quebec. **Figure 27** is a depiction of the Utica shale in Canada.[227] The shale play is divided into the Utica deep, which extends from northern New York State down to Pennsylvania, and the Utica shallow, which is located in Quebec.[228] The most prospective portion of the Utica play in Canada parallels the St. Lawrence River from southeast of Montreal through Quebec City. The heart of the play sits between Logan's Line, a major thrust fault that provides separation between the unfaulted area to the Northwest and the Appalachian Thrust Belt Region to the Southeast, which is an area of high tectonic stresses that could present challenges for drilling and hydraulic fracturing operations. The Utica Shale is overlain by the Lorraine Group and

Figure 27: Utica/Lorraine Shale in Canada



underlain by the Trenton Group limestone as depicted in the stratigraphic chart in **Figure 28**.

The Utica Shale is present beneath parts of Lake Ontario, Lake Erie and part of Ontario.[229] The rock character, including the formation thickness, orientation, mineralogy, TOC, and thermal maturity vary significantly across the basin. In addition, the properties of the shale also vary vertically.[230] Coupled with the rock mechanics and structural complexity of the Appalachian Thrust Belt, there may be multiple play styles that take place throughout the area.

The composition of the Utica Shale is unlike other Canadian shale formations, as it has a higher concentration of calcite rather than silica. While calcite is a hard mineral, it does not transmit as well as silica; therefore, hydraulic fracturing may be less successful than in the shale formations with higher silica content.[231] However, the reservoir is folded and faulted, which increases the likelihood of natural fractures.

There have been no reliable independent analyses of the original gas in place in the Utica Shale. Most of the wells that have been drilled in the Utica are vertical wells. Initial rates from three horizontal wells indicated 2,800 to 22,700 m^3/d (0.1 to 0.8 MMcf/d) from medium deep shale.[232]

Figure 28: Stratigraphy of the Utica/Lorraine Shale

Period	Group/Unit	
Ordovician	Queenston	
	Lorraine	
	Utica	
	Trenton	Upper
		Deschambault
		Lower

Source: Lavoie, Denis. "The Upper Ordovician Utica and Lorraine Shales in Southern Quebec: Sedimentological and Geochemical Frameworks." www.cseg.ca/conventions/abstracts/2011/034-Upper_Ordovician_Utica_and_Lorraine_Shales.pdf (accessed January 3, 2012).

Unlike some of the other shale basins in Canada, the Utica Shale is located in a prime location for market. Its nearness to U.S. Northeast markets could allow a $1 per thousand cubic feet (mcf) premium to New York Mercantile Exchange (NYMEX) pricing,[233] a major advantage over western Canada or the United States Rockies that typically receive $1/mcf less than NYMEX.[234]

The Utica Shale is most similar to the Barnett Shale in the United States. However, with a de facto moratorium on drilling and hydraulic fracturing in Quebec, no development can currently occur. **Table 6** outlines some of the similarities between the two basins.

Table 6: Geological Comparison Between Utica Shale and Barnett Shale

Parameters	Utica Shale	Barnett Shale
Depth (m)	700-,1830	1,370 – 2,740
Thickness (m)	150	45-215
Clay Content (%)	15-26	15-30
Gas-Filled Porosity (%)	3.2-3.7	3.0-4.8
Pressure Gradient (kPa/m)	10.2 – 13.6	10.4 – 11.3

Source: Paul Kralovic, *North American Natural Gas Market Dynamics: Shale Gas Plays in North America – A Review*, Canadian Energy Research Institute, Study No. 123 (February 2011), http://www.ceri.ca/images/stories/Shale%20Gas%20Plays.pdf (accessed December 8, 2011).

Proposed well locations in the Utica extend between the two fault lines of the Appalachian thrust belt region. The faults themselves provide a risk with hydraulic fracturing due to the potential for the faults to act as conduits between the Utica Shale and shallower groundwater resources.

The Lorraine Shale is an upper Ordovician formation that overlies the Utica Shale and may also be productive. However, it is more clay-rich and may present significant challenges in hydraulic fracturing.[235] The formation can reach up to 1,980 m thick in portions of the basin.[236] While the Utica Shale formations are generally more calcerous, with averages of 59% carbonates, 24% clays, 12% quartz, and 5% feldspars, mineralogy of the Lorraine Shale are more clayey and siliceous, with approximately 52% clays, 25% quartz, 12% carbonates and 10% feldspars.[237] Since the Utica has a higher percentage of quartz and other brittle minerals such as carbonates and feldspars, the hydraulic fracturing potential is more attractive than in the less brittle Lorraine. However, the Lorraine has a higher gas in place.[238] **Table 7** shows the comparisons in reservoir properties between the Utica Shale and the overlying Lorraine Shale.

Table 7: Geological Comparison Between Utica Shale and Lorraine Shale

Parameters	Lorraine Shale	Utica Shale
Depth (m)	457-3,050	457 – 3,350
Thickness (m)	457- 1,980	300-1,000
TOC weight(%)	0.1-1.5	0.3-2.5
Ro(%)	1.1-4.0	1.1-4.0
Silica Weight (%)	30-35	12-51
Clay Weight (%)	30-38	8-66
Gas-filled Porosity (%)	1.2-3.2	2.2-3.5
Pressure Gradient (kPa/m)	13.6	13.6

Source: UBS Investment Research, "Utica & Lorraine Shales," *Q-Series®: North American Oil & Gas* (September 3, 2008), http://www.scribd.com/doc/54469681/24/Utica-Lorraine-Shales (accessed December 8, 2011).

3.9 The Colorado Group

The Colorado Group is a Middle Cretaceous unit present throughout southern Alberta and Saskatchewan (see **Figure 29)**. The group consists of shaley horizons, as well as more conventional shallow reservoirs including the Medicine Hat, Milk River, and Second White Specks shaley sandstones as shown on the stratigraphic chart in **Figure 30**. The Milk River and Medicine Hat formations have been productive for over 100 years and the Second White Specks Shale has been productive for decades.[239]

The Colorado Group is similar to the Montney formation in that it is a hybrid between a tight gas reservoir and a shale reservoir. Colorado Group gas is biogenic in nature like the Antrim Shale formation in the Michigan Basin of the United States. The shales are laterally extensive and reach up to 350 metres thick.[240] The biogenic nature signifies a low likelihood for NGLs and an underpressured reservoir, which could create challenges when hydraulic fracturing.[241]

Figure 29: Colorado Group

Figure 30: Stratigraphy of the Colorado Group

<table>
<tr><th colspan="3">Period</th><th>Group/Unit</th></tr>
<tr><td></td><td colspan="2">Tertiary</td><td>Fort Union Group</td></tr>
<tr><td rowspan="8">Mesozoic</td><td rowspan="3">Cretaceous</td><td rowspan="2">Upper</td><td>Montana Group</td></tr>
<tr><td>Colorado Group</td></tr>
<tr><td>Lower</td><td>Inyan Kara Group</td></tr>
<tr><td colspan="2" rowspan="5">Jurassic</td><td>Morrison Formation</td></tr>
<tr><td>Swift Formation</td></tr>
<tr><td>Rierdon Formation</td></tr>
<tr><td>Piper Formation</td></tr>
<tr><td>Nesson Formation</td></tr>
</table>

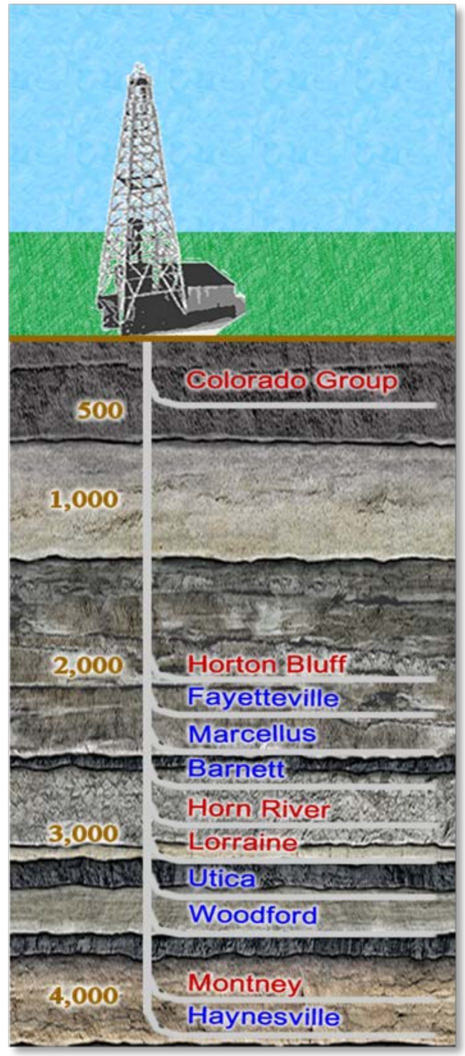
Vertical wells are anticipated to be the primary development technique for the Colorado Shales due to the poor rock conditions and the risk of wellbore caving.[242] The total gas in place is very difficult to project given the wide lateral extent and variability of the reservoir, but there could be 2.8 x 10^{12} m^3 (100 tcf) of gas in place.[243]

Contrary to the development of other shale plays, the majority of production from the Colorado Group shale plays in the Medicine Hat Field likely comes from the siltstone and sandstone intervals within the finer-grained shale as opposed to traditional shale where production originates from brittle and easily fractured intervals.[244] High-volume hydraulic fracturing operations that are becoming the norm in other Canadian and United States shale gas development are limited in the Colorado Group due to the sensitivity of the swelling clays in the shale to water.[245] As such, operators are testing nitrogen, propane, and butane fracture stimulations.

The Colorado Group shales have the advantage of existing pipeline infrastructure in place as a result of the hundreds of thousands of wells that have been drilled in the area, low drilling costs due to the shallow depths of the Colorado shale, and mostly year-round access.[246]

There are many similarities and differences between shale basins across North America. Many of these have been discussed in previous sections. **Table 8** is a more extensive comparison tool that covers the major shale basins in both Canada and the United States. **Figure 31** illustrates the depths at which the various shale formations are located.

Figure 31: Comparison of Shale Formation Depths



Source: Modified from "Canadian Unconventional Resources: Energy Security and Investment Opportunities," presentation given by Mike Dawson, President ,Canadian Society for Unconventional Resources at NAPE International Forum, Houston, Texas February 16, 2011.

Table 8: Comparison of Properties For the Gas Shales of North America

Parameters	Barnett	Fayetteville	Haynesville / Bossier	Marcellus	Antrim	New Albany	Horn River	Montney	Colorado	Utica	Lorraine	Horton Bluff
Depth (m)	1,980 – 2,590	305 – 2,130	3,200 – 4,110	1,460 – 2,590	180 – 671	500 – 2,000	1,800 – 3,000[247]	1,700 – 4,000	300	500 – 3,300	458 – 3,050	1,120 – 2,000+
Thickness (m)	30-183	6-60	60-91	15-60	36-67	15-30	15-107[248]	Up to 91	17-350	27-91	152-610	150+
Gas Filled Porosity (%)	2.5[249]	2.0 to 8.0[250]	8.0 to 15[251]	1.6 to 7.0[252]	4	5[253]	3.2 to 6.2	1.0 to 6.0	Less than 10	2.2 to 3.7	1.2-3.2[254]	2
Total Organic Carbon (%)	3.0-8.0[255]	4.0 to 9.5[256]	0.5 to 4.0[257]	1.0 to 12.0[258]	1-20	1-25[259]	1 to 8[260]	1 to 7	0.5 to 12	0.3 to 2.25	0.1-1.5[261]	10
Maturity (Ro)	1.2-2.0[262]	1.4 to > 4.0[263]	0.9 to 2.6[264]	1.5 to 3.0[265]	0.4-0.6	0.4-1.0[266]	2.2-2.8	0.8-2.5	Biogenic	1.1-4	1.1-4.0[267]	1.53-2.03
Silica (%)	35-50[268]	20 to 60[269]	N/A	20 to 50[270]	N/A	-	45-65	20-60	Sand and silt	5-25	30-35	38
Calcite or dolomite (%)	8[271]	-	-	25[272]	-	-	0-14	Up to 20%	-	30 to 70	-	Significant
Clay (%)	10-30[273]	-	25-35[274]	20-35[275]	-	-	20-40	Less than 30	High	8-40	52[276]	42
Free gas (%)	-	-	-	-	-		66	64-80	-	50-65	-	-
Adsorbed gas (%)	20-60[277]	50-70	-	-	70	40-60[278]	34	20-36	-	35-50	-	-
CO_2 (%)	Less than 2[279]	-	-	-	-	-	12	1	-	Less than 1	-	5
Play area GIP (m^3)	92.6×10^8	14.7×10^8	203×10^8	425×10^8	21.5×10^8	45.3×10^8	40.8×10^8-170×10^8	22.7×10^8-198×10^8	>28.3×10^8-	>34×10^8	-	>36.8×10^8
Horizontal well cost, including frac (Million $ Cdn)	-	-	-	-	-	-	7-10	5-8	0.35 (vertical only)	5-9	-	unknown

(-) Data not available

4 CHEMICAL USE IN HYDRAULIC FRACTURING

In an effort to identify the chemicals that may be used in the Canadian shale plays, this section contains an analysis of the chemicals used in analogous shale plays in the United States. Data has been collected through the voluntary reporting of the chemicals used by multiple U.S. operators and service companies[280] and through private communication with operators in various basins in the United States. The data was then compiled to provide a quick reference to the chemicals and their functions in hydraulic fracturing. The compilation of chemicals only includes those chemicals listed as hazardous on material safety data sheets (MSDS) and does not include non-hazardous chemical use.

Through the analysis of current drilling practices and the compilation of geologic data, analogous hydraulic fracturing practices may be identified between shale plays in Canada and the United States. In addition a review of current chemical use trends is presented.

4.1 Compiled Chemicals

The following analysis has been performed through the review of voluntary submissions by operators to the FracFocus.org website (see FracFocus.Org text box). **Figure 32** is a map of the United States shale gas basins where disclosures of chemicals were reviewed and compiled for this effort. Data was sampled on hydraulic fracturing events that have occurred since the start of 2011. This provides a current compilation of chemical- and water-use data that can be helpful in the review of similar practices being performed on the Canadian shale plays.

Figure 32 Well Sample Data Used in the Analysis of Hydraulic Fracturing Processes and Chemical Usage by Shale Play/Basin

FracFocus.Org

The FracFocus.org website is a joint effort between the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC). The GWPC and IOGCC are comprised of oil- and gas-producing states of the United States and their regulatory agencies. The FracFocus.org site was constructed to provide a resource where the public can access factual and science based information on hydraulic fracturing, and the chemicals used in hydraulic fracturing. The FracFocus.org website states:

> "The primary purpose of this site is to provide factual information concerning hydraulic fracturing and groundwater protection. It is not intended to argue either for or against the use of hydraulic fracturing as a technology. It is also not intended to provide a scientific analysis of risk associated with hydraulic fracturing."

In addition, the FracFocus.org website provides a standardized format and centralized location for the disclosure of chemicals used during hydraulic fracturing jobs performed by operators. This "Hydraulic Fracturing Chemical Registry" provides a common format for operators to disclosure the chemicals used during any job performed and transparency to the public on the chemicals used. The FracFocus.org website is one source for the analysis presented in this chapter.

The GWPC and IOGCC licensed a version of the FracFocus.org website and database to the Province of British Columbia (FracFocus.ca). British Columbia is the first province in Canada to enforce the public disclosure of ingredients used for hydraulic fracturing. As of January 1, 2012, public disclosure of hydraulic fracturing fluid is mandatory. By law, a list of ingredients used must be uploaded to the registry within 30 days of finishing completion operations - the point in time when a well is able to produce gas. The FracFocus.ca website delivers on a commitment made by Premier Christy Clark during the B.C. Oil and Gas Conference in Fort Nelson in September 2011, where she promised an online registry to increase the transparency of hydraulic fracturing in B.C.

4.2 Data Analysis

The data used in this analysis was sampled and compiled to provide a synopsis of the water and chemicals used in hydraulic fracturing processes. The data sampled was combined with confidential data obtained by ALL Consulting and analyzed for U.S. shale plays. The hydraulic fracturing disclosure data points were plotted using a Geographic Information System (GIS); fracturing jobs with sufficient reported data were included in the analysis sample. The compiled data are presented in this section along with a brief review of the statistical sample taken from the FracFocus.org website. The maps presented in **Figures 33-37** show the selected data sample locations by shale play.

As part of the analysis a data quality and completeness review was performed on the collected information. The review revealed the following statistics:

- Total number of hydraulic fracturing disclosures in the FracFocus.org database as of August 22, 2011: **3,154**
- Number of hydraulic fracturing disclosures with sufficient data to be sampled and identified through GIS for inclusion in the analysis: **746**

The selected disclosures were broken down by well type (oil or gas), because the hydraulic fracturing completion procedures and chemicals used differ depending on the type of fluid being produced. The number of hydraulic fracturing events analyzed is presented in **Table 9** by shale play and well type. The largest number of hydraulic fracturing events analyzed occurred in the Fayetteville Shale play (455) while the smallest number was in the Woodford-Caney Shale play (28). A range of the water volumes used in the observed hydraulic fracturing is also presented in **Table 9**. Based on the water use reported in personal communications with operators and a review of the FracFocus disclosures, the analysis found that, per well, water volumes increase with the increase in the number of fracturing stages performed. It is expected that the water volumes will continue to increase as lateral wellbore distances extend and the number of fracturing stages increases.

Table 10 presents a matrix of the typical hydraulic fracturing additives by type of additive, shale play, and well type (gas versus oil). The table indicates where each type of additive was most commonly used in each play. However, not all types reported are displayed (single additives used in individual wells omitted). This information is also presented on the shale play maps reviewed in this section.

A compilation of the most common chemicals observed in the hydraulic fracturing disclosures is presented in **Appendix C**. A review of the chemicals identified was conducted through the Environmental Canada Domestic Substances List (DSL),[281] the U.S. Center for Disease Control (CDC),[282] and Material Safety Data Sheets (MSDS). A map is presented in each of the following play sections showing the individual wells where information was gathered for review. The maps present the information contained in **Tables 9** and **10** that is specific to that shale play. Each section contains a table of the most common chemicals that were used in that play. This does not represent every chemical identified in use from the disclosures sampled, but those most commonly observed from the sample set. Chemicals in this table are not classified by their chemical additive purpose. A review of the chemicals on the DSL from Environment Canada is presented in the table for reference to the toxicity of the individual chemicals used. Column headings include the following:

- **Meets Government of Canada (GoC) Categorization Criteria (yes/no)**: A substance that meets the human health criteria and/or the environmental criteria for categorization as defined in Section 73 of the Canadian Environmental Protection Act (CEPA) of 1999.
- **Meets Human Health Categorization Criteria (yes/no):** A substance that has great potential for human exposure or if it is persistent and/or bioaccumulative and inherently toxic to humans.
- **Other Human Health Priorities (high/moderate/low/post 2006):** Substances that did not necessarily meet the strict criteria of the categorization exercise, but do require further attention from a human health perspective because they have potential for human exposure and/or they are inherently toxic to humans.

Table 9: Range of Water Volumes per Well Observed by Play and Number of Fracturing Job Disclosures Reviewed

U.S. Shale Play	Disclosures Reviewed	Upper Water Volume (m^3)	Lower Water Volume (m^3)
Bakken (Oil)	69	11,356	2,271
Barnett (Gas)	318	37,854	3,785
Barnett (Oil)	73	35,961	5,300
Barnett-Woodford (Gas)	45	16,277	378
Eagle Ford (Gas)	102	51,860	7,722
Eagle Ford (Oil)	112	32,176	5,300
Fayetteville (Gas)	455	36,340	5,678
Haynesville (Gas)	187	31,419	13,249
Horn River (Gas)[1]	133	81,000	34,700
Marcellus/Utica (Gas)	366	35,204	1,514
Montney (Gas)[1]	312	7,800	2,100
Woodford (Gas)	51	37,854	1,893
Woodford (Oil)	83	61,702	1,136
Woodford-Caney (Gas)	28	59,810	13,249
Total	**1889**		

[1] Source of Data, Elizabeth Johnson, "Water Issues Associated with Hydraulic Fracturing in Northeast British Columbia," Presentation give April 3, 2012 at the 6th B.C. Unconventional Gas Technical Forum, Victoria, BC, Ministry of Energy and Mines

- **Meets Environmental Criteria for Categorization (yes/no):** A substance that is inherently toxic to aquatic organisms and it is persistent and/or bioaccumulative in the environment.

Additional descriptions of the individual chemicals for each play are presented in **Appendix C**.

Table 10: Observed Most Common Hydraulic Fracturing Job Additives

Additive Type	Shale Play											
	Bakken (Oil)	Barnett (Gas)	Barnett (Oil)	Barnett-Woodford (Gas)	Eagle Ford (Gas)	Eagle Ford (Oil)	Fayetteville (Gas)	Haynesville (gas)	Marcellus/Utica (Gas)	Woodford (Gas)	Woodford (Oil)	Woodford-Caney (Gas)
Biocide	X	X	X	X	X	X	X	X	X	X	X	X
Acid		X	X	X	X	X	X	X	X	X	X	X
Buffer	X			X	X	X	X	X		X	X	
Friction Reducer		X	X	X	X	X	X	X	X	X	X	X
Gellant	X	X		X	X	X	X	X	X	X	X	X
Crosslinker	X			X	X	X	X	X		X	X	
Delayed Crosslinker	X											
Breaker	X			X	X	X	X	X	X	X	X	X
Scale Inhibitor	X	X	X		X		X	X	X	X	X	X
Corrosion Inhibitor		X		X	X	X	X	X	X	X	X	X
Iron Control		X		X	X	X	X		X	X	X	
Surfactant	X	X	X	X	X	X		X		X	X	
Clay Control	X			X	X	X	X	X	X	X	X	
Activator	X				X							
Reducing Agent					X							
Fiber/ Stabilizer					X							
Solvent				X							X	
Non Emulsifier	X	X		X		X	X	X	X	X	X	

Note: Base Carrier Fluid (typically water) and Proppant (typically sand/quartzite) exist as purposes in all Fracture Stimulations and are not listed in this table.

4.2.1 Bakken Play (Oil)

Figure 33 is a map of the Bakken shale play in the states of Montana and North Dakota and extending into Canada. The geologic analogy for the Canadian portion of the play is the U.S. portion. Typical hydraulic fracturing jobs performed in the Montana and North Dakota portions of the play are expected to maintain similar characteristics to those that may be performed in the Canadian portion of the shale. The map presents the information contained in **Tables 9** and **10** that is specific to the Bakken Shale. **Table 11** represents the list of the most commonly used chemicals identified in the Bakken oil play.

Figure 33: Bakken Shale Play
(Well sample used in study, chemical additives and water volumes)

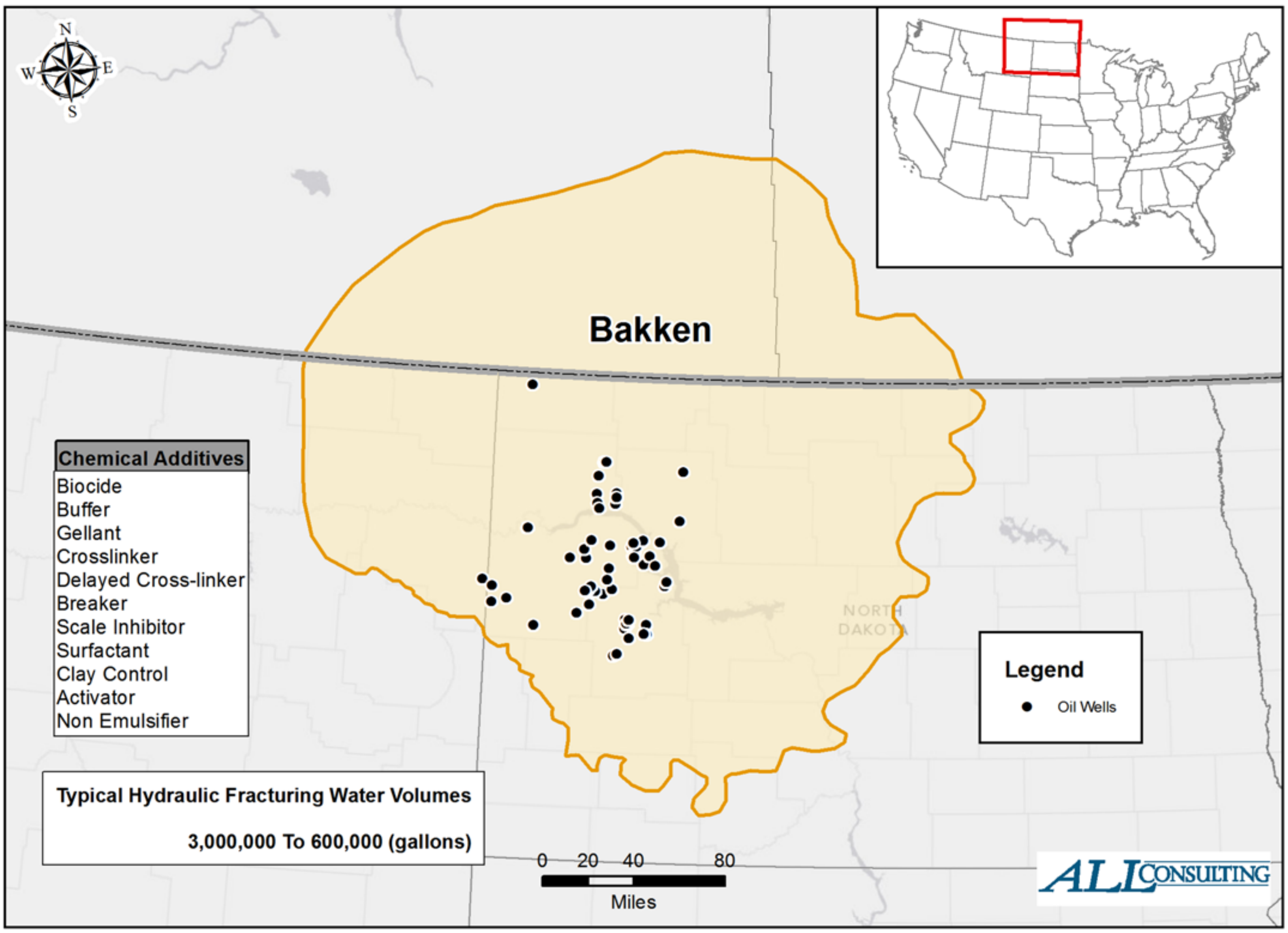


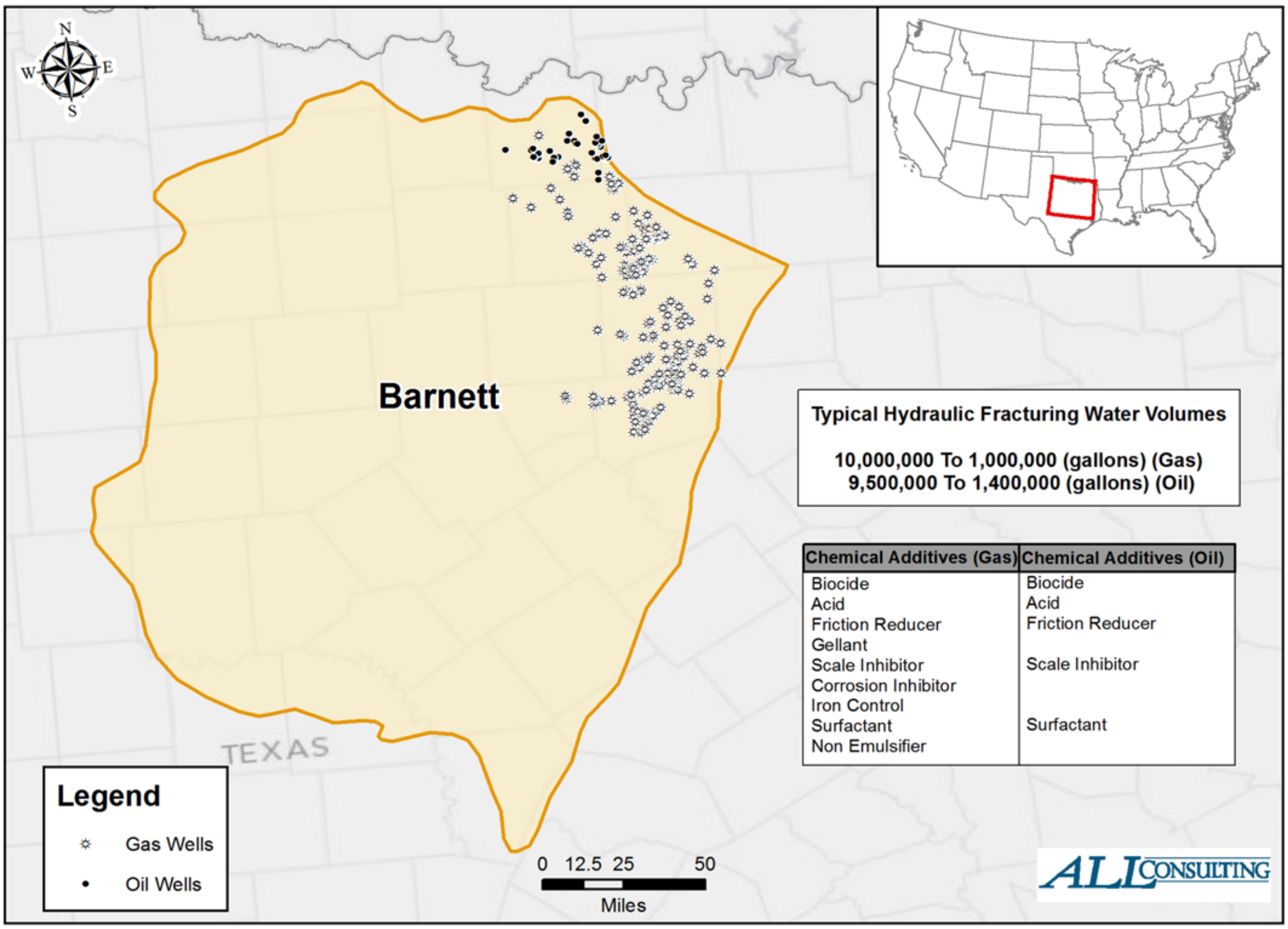
Table 11: Most Common Hydraulic Fracturing Chemicals Identified in the Bakken Oil Play					
Ingredients	**CAS**	**Meets GoC Categorization Criteria**	**Meets Human Health Categorization Criteria**	**Other Human Health Priorities**	**Meets Environmental Criteria for Categorization**
Water	7732-18-5	No	No	Low	No
Crystalline Silica (Quartz)	14808-60-7	Yes	Yes	High	No
Methanol	67-56-1	Yes	Yes	Moderate	No
Ammonium Persulfate	7727-54-0	Yes	No	Low	Yes
Oxyalkylated Alcohols	Proprietary	n/a	-	-	-
Hydrotreated light petroleum distillate	64742-47-8	Yes	Yes	Moderate	Yes
Potassium Hydroxide	1310-58-3	Yes	Yes	Moderate	No
Ethylene Glycol	107-21-1	No	No	Low	No
Guar Gum	9000-30-0	No	No	Low	No
Heavy Aromatic Petroleum Naphtha	64742-94-5	Yes	Yes	Moderate	Yes
Isopropanol	67-63-0	Yes	Yes	Moderate	No
Ethanol	64-17-5	Yes	Yes	Moderate	No
Amine Derivative	Proprietary	n/a	-	-	-
Glutaraldehyde	111-30-8	No	No	Low	No
Glycol ethers (2-Butoxyethanol)	111-76-2	No	No	Low	No
Potassium formate	590-29-4	No	No	n/a	No
Hemicellulase Enzyme Concentrate	9025-56-3	n/a	-	-	-
Nonyl Phenyl Polyethylene Glycol Ether	9016-45-9	No	No	Low	No
Tetrakis (Hydroxymethyl) Phosphorium Sulfate	55566-30-8	No	No	n/a	No

Review of chemicals performed on Environment Canada's DSL. For an expanded analysis and definition of criteria please review **Appendix C**.
GoC = Government of Canada
CBI – Confidential Business Information

4.2.2 Barnett Play (Gas)

Figure 34 is a map of the Barnett shale play in the state of Texas. The geologic analogies for the Canadian shale plays are the Horn River and Utica shale formations. Therefore, typical hydraulic fracturing jobs performed in the Barnett may have similarities to those performed in the Horn River and Utica Shale plays. The map presents the information contained in **Tables 9** and **10** that is specific to the Barnett shale oil and gas hydraulic fracturing disclosures sampled. **Table 12** represents the list of the most commonly used chemicals identified in the Barnett gas play.

Figure 34: Barnett Shale Play
(Well sample used in study, chemical additives and water volumes presented)



Chemical Additives (Gas)	Chemical Additives (Oil)
Biocide	Biocide
Acid	Acid
Friction Reducer	Friction Reducer
Gellant	
Scale Inhibitor	Scale Inhibitor
Corrosion Inhibitor	
Iron Control	
Surfactant	Surfactant
Non Emulsifier	

Table 12: Most Common Hydraulic Fracturing Chemicals Identified in the Barnett Gas Play

Ingredients	CAS	Meets GoC Categorization Criteria	Meets Human Health Categorization Criteria	Other Human Health Priorities	Meets Environmental Criteria for Categorization
Water	7732-18-5	No	No	Low	No
Crystalline Silica (Quartz)	14808-60-7	Yes	Yes	High	No
Methanol	67-56-1	Yes	Yes	Moderate	No
Hydrotreated light petroleum distillate	64742-47-8	Yes	Yes	Moderate	Yes
Hydrochloric Acid	7647-01-0	Yes	Yes	Moderate	No
Propargyl Alcohol	107-19-7	No	No	n/a	No
Nonyl Phenol Ethoxylate	127087-87-0	No	No	n/a	No
Propargyl alcohol	64743-02-8	No	No	Low	No
Polyoxyalkylenes	68951-67-7	Yes	Yes	Moderate	No
Modified thiourea polymer	68527-49-1	No	No	n/a	No
Copolymer of Acrylamide and Sodium Acrylate	25987-30-8	Yes	Yes	Moderate	Yes
Sorbitan Monooleate	1338-43-8	No	No	Low	No
Phosphonate Salt	Proprietary	n/a			
Glutaraldehyde	111-30-8	No	No	Low	No
Oxydiethylene Bis (Akyl*Dimethyl Ammonium Chloride)	68607-28-3	No	No	Low	No
Sodium Hydroxide	1310-73-2	Yes	Yes	Moderate	No
Dazomet	533-74-4	No	No	n/a	No
Trisodium Nitrilotriacetate	5064-31-3	Yes	Yes	Moderate	No
Sodium Sulfate	7757-82-6	No	No	Low	No

Review of chemicals performed on Environment Canada's DSL. For an expanded analysis and definition of criteria please review **Appendix C**.

4.2.3 Eagle Ford Play (Oil)

Figure 35 is a map of the Eagle Ford shale play in the state of Texas. The identified geologic analogy for the Canadian shale play is the Utica shale formation. Typical hydraulic fracturing jobs performed in the Eagle Ford are expected to maintain similar characteristics to those that may be performed in the Utica Shale. The map presents the information contained in **Tables 9** and **10** that is specific to the Eagle Ford shale oil and gas hydraulic fracturing disclosures sampled. **Table 13** represents the list of the most commonly used chemicals identified in the Eagle Ford oil play.

Figure 35: Eagle Ford Shale Play
(Well sample used in study, chemical additives and water volumes presented)

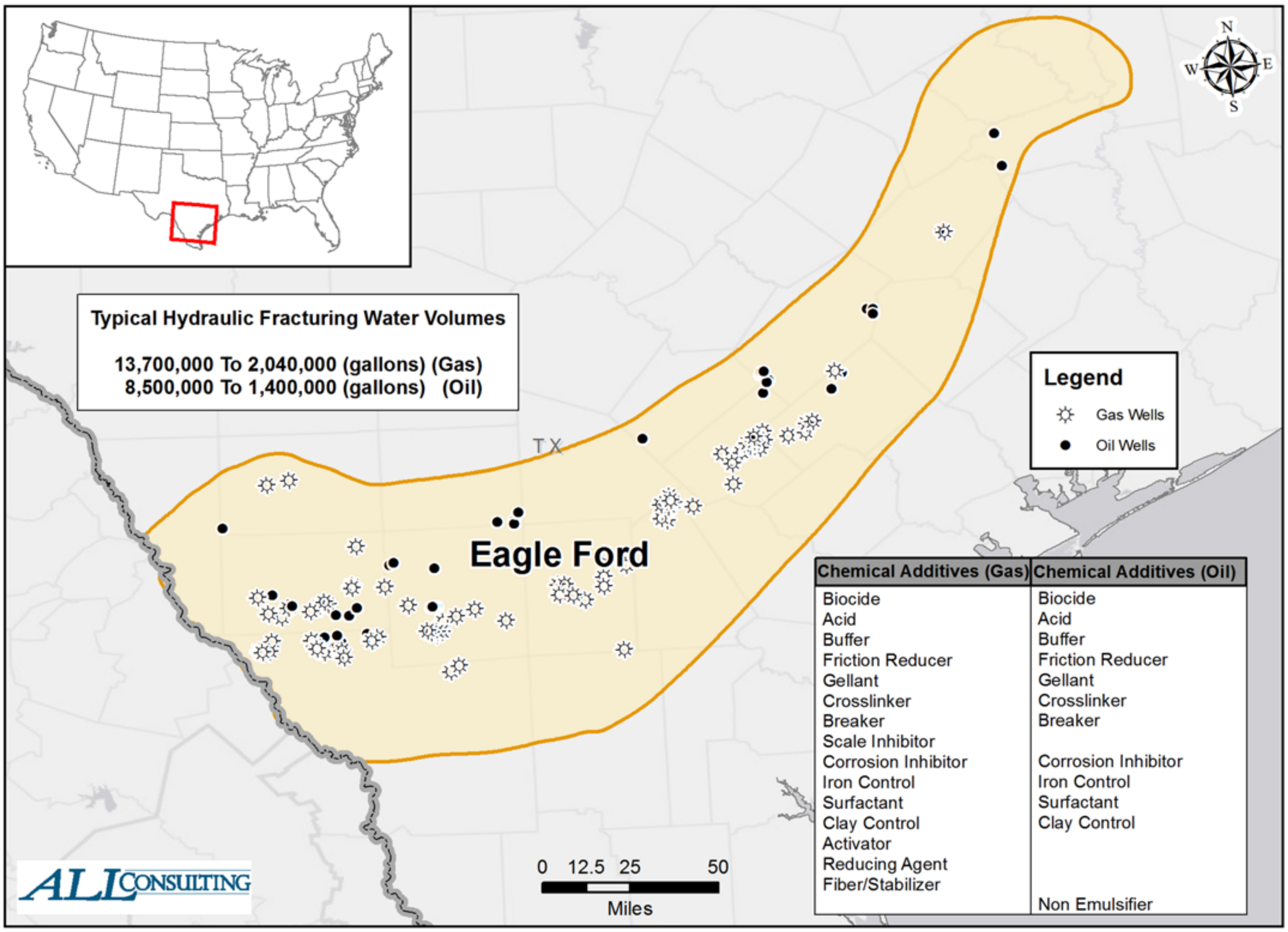


Table 13: Most Common Hydraulic Fracturing Chemicals Identified in the Eagle Ford Oil Play

Ingredients	CAS	Meets GoC Categorization Criteria	Meets Human Health Categorization Criteria	Other Human Health Priorities	Meets Environmental Criteria for Categorization
Water	7732-18-5	No	No	Low	No
Crystalline Silica (Quartz)	14808-60-7	Yes	Yes	High	No
Potassium Hydroxide	1310-58-3	Yes	Yes	Moderate	No
Methanol	67-56-1	Yes	Yes	Moderate	No
Hydrotreated light petroleum distillate	64742-47-8	Yes	Yes	Moderate	Yes
Sodium Hydroxide	1310-73-2	Yes	Yes	Moderate	No
Ethylene Glycol	107-21-1	No	No	Low	No
Sodium Chloride	7647-14-5	No	No	Low	No
Hydrochloric Acid	7647-01-0	Yes	Yes	Moderate	No
2,2-dibromo-3-nitrilopropionamide	10222-01-2	n/a	-	-	-
Petroleum Distillate	Proprietary	Uncertain	-	-	-
Polyethylene glycol	25322-68-3	Yes	Yes	Moderate	No
Sodium Chlorite	7758-19-2	No	No	n/a	No
Isopropanol	67-63-0	Yes	Yes	Moderate	No
Ammonium Persulfate	7727-54-0	Yes	No	Low	Yes
Potassium Carbonate	584-08-7	No	No	Low	No
Potassium Chloride	7447-40-7	No	No	Low	No
Boric Acid	10043-35-3	Yes	Yes	Moderate	No
Citric Acid	77-92-9	No	No	Low	No
Acetic acid	64-19-7	Yes	Yes	Moderate	No
Hydrocarbon distillate	68476-34-6	Yes	Yes	High	Yes
N, N-Dimethyl Formamide	68-12-2	No	No	Low	No

Review of chemicals performed on Environment Canada's DSL. For an expanded analysis and definition of criteria please review **Appendix C**.

4.2.4 Fayetteville Play (Gas)

Figure 36 is a map of the Fayetteville shale play in the state of Arkansas. The geologic analogies for the Canadian shale plays are the Horn River and Utica shale formations. Typical hydraulic fracturing jobs performed in the Fayetteville may have similarities to those that may be performed in the Horn River and Utica Shale plays. The map presents the information contained in **Tables 9** and **10** that is specific to the Fayetteville shale gas hydraulic fracturing disclosures sampled. **Table 14** represents the list of the most commonly used chemicals identified in the Fayetteville gas play.

Figure 36: Fayetteville Shale Play
(Well sample used in study, chemical additives and water volumes presented)

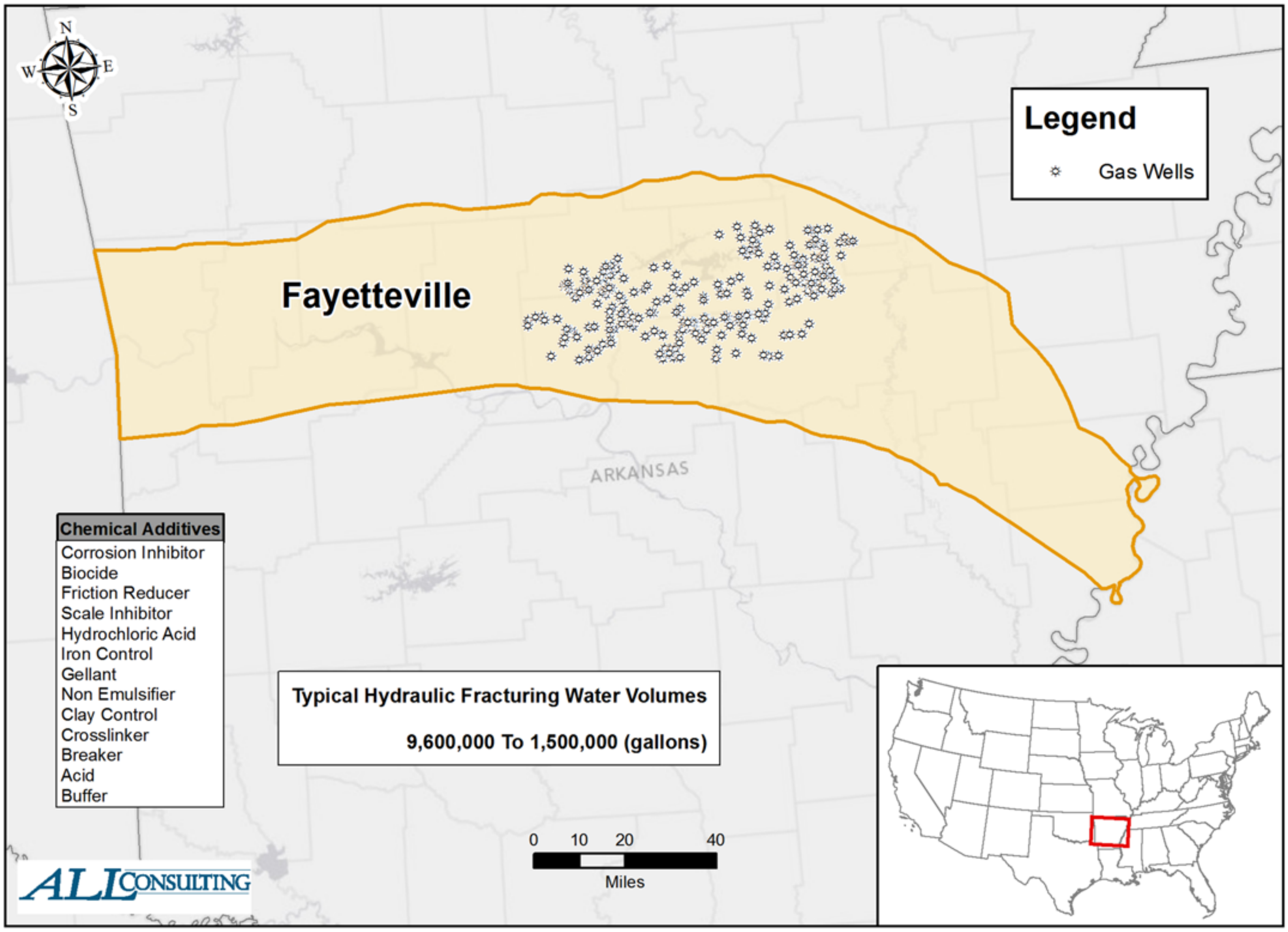


Table 14: Most Common Hydraulic Fracturing Chemicals Identified in the Fayetteville Gas Play

Ingredients	CAS	Meets GoC Categorization Criteria	Meets Human Health Categorization Criteria	Other Human Health Priorities	Meets Environmental Criteria for Categorization
Water	7732-18-5	No	No	Low	No
Crystalline Silica (Quartz)	14808-60-7	Yes	Yes	High	No
Methanol	67-56-1	Yes	Yes	Moderate	No
Hydrochloric Acid	7647-01-0	Yes	Yes	Moderate	No
Glutaraldehyde	111-30-8	No	No	Low	No
Hydrotreated light petroleum distillate	64742-47-8	Yes	Yes	Moderate	Yes
Isopropanol	67-63-0	Yes	Yes	Moderate	No
Propargyl Alcohol	107-19-7	No	No	n/a	No
Ethanol	64-17-5	Yes	Yes	Moderate	No
Quaternary ammonium compound	68424-85-1	Yes	No	Low	Yes
Aliphatic acids	Proprietary	n/a	-	-	-
Aliphatic alcohol glycol ether	Proprietary	n/a	-	-	-
Sodium erythorbate	6381-77-7	No	No	n/a	No

Review of chemicals performed on Environment Canada’s DSL. For an expanded analysis and definition of criteria please review **Appendix C**.

4.2.5 Marcellus/Utica Play (Gas)

Figure 37 is a map of the Marcellus/Utica shale play in the States of New York, Pennsylvania, Ohio, and West Virginia. The geologic analogy for the Canadian shale play is the Utica Shale and where portions of the Marcellus Shale may be present. Typical hydraulic fracturing jobs performed in the Marcellus/Utica are expected to maintain similar characteristics to those performed in the Utica Shale in Canada when completing the well for gas. The map presents the information contained in **Tables 9** and **10** that is specific to the Marcellus/Utica shale gas hydraulic fracturing disclosures sampled. **Table 15** represents the list of the most commonly used chemicals identified in the Marcellus/Utica gas play.

Figure 37: Marcellus/Utica Shale Play
(Well sample used in study, chemical additives and water volumes presented)

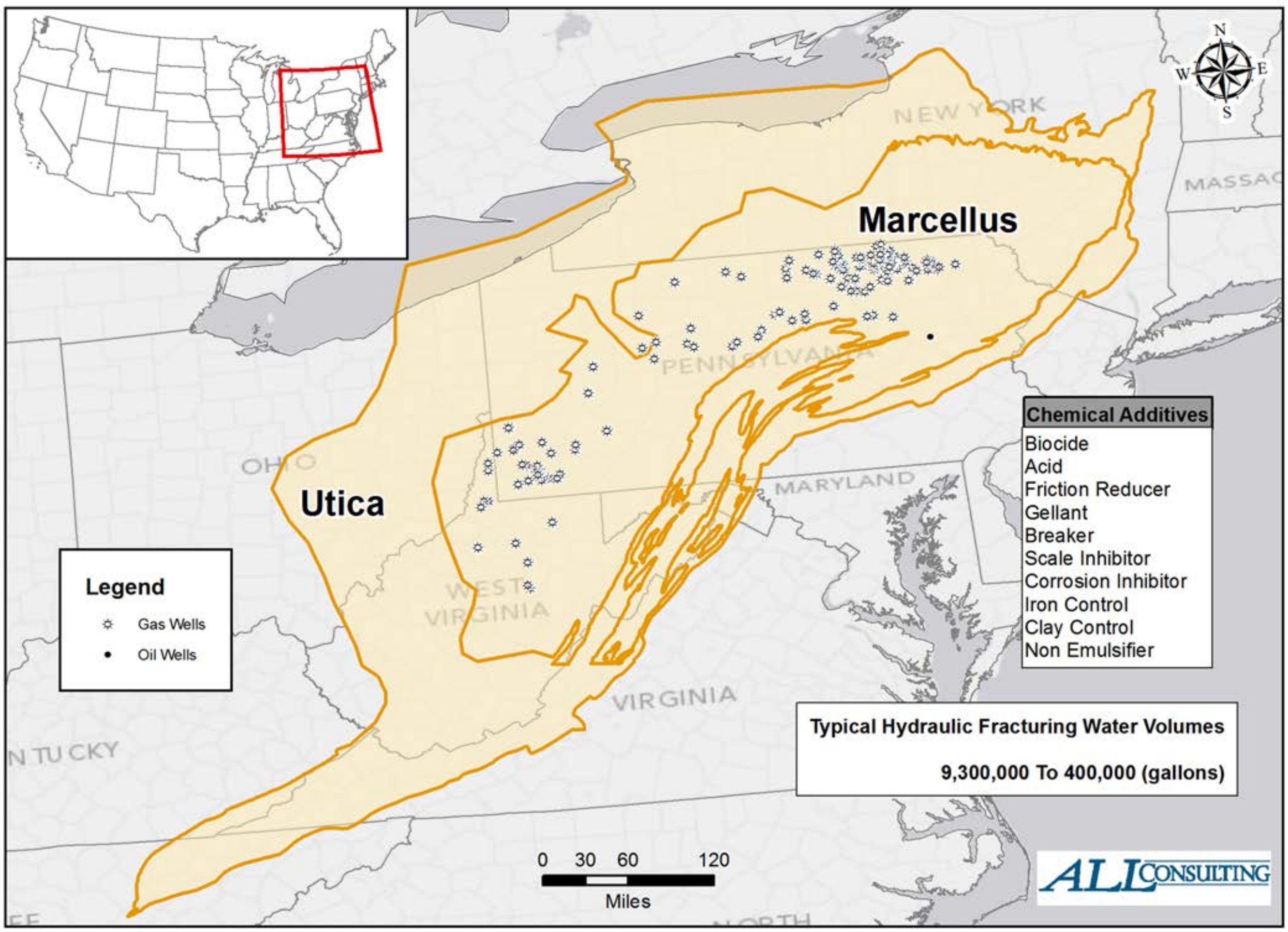


Table 15: Most Common Hydraulic Fracturing Chemicals Identified in the Marcellus/Utica Gas Play					
Ingredients	**CAS**	**Meets GoC Categorization Criteria**	**Meets Human Health Categorization Criteria**	**Other Human Health Priorities**	**Meets Environmental Criteria for Categorization**
Water	7732-18-5	No	No	Low	No
Crystalline Silica (Quartz)	14808-60-7	Yes	Yes	High	No
Methanol	67-56-1	Yes	Yes	Moderate	No
Hydrochloric Acid	7647-01-0	Yes	Yes	Moderate	No
Hydrotreated light petroleum distillate	64742-47-8	Yes	Yes	Moderate	Yes
Propargyl Alcohol	107-19-7	No	No	n/a	No
Glutaraldehyde	111-30-8	No	No	Low	No
Ethylene Glycol	107-21-1	No	No	Low	No
Ethanol	64-17-5	Yes	Yes	Moderate	No
Quaternary ammonium compound	68424-85-1	Yes	No	Low	Yes
Isopropanol	67-63-0	Yes	Yes	Moderate	No
Didecyl dimethyl ammonium chloride	7173-51-5	No	No	n/a	No
Citric Acid	77-92-9	No	No	Low	No
Diethylene Glycol	111-46-6	Yes	Yes	Moderate	No
Review of chemicals performed on Environment Canada's DSL. For an expanded analysis and definition of criteria please review **Appendix C**.					

4.3 Chemical Use Trends

The current observed trends for chemical use in hydraulically fractured wells are driven by a number of factors that influence the types and amounts of chemical used. These factors include environmental pressures, costs, toxicity, and improved understanding about the impacts of the types and amounts of chemicals on the effectiveness of the hydraulic fracturing jobs. These pressures have led to the reduction of the number of chemicals used in hydraulic fracturing jobs.

The Pennsylvania Department of Environmental Protection compiled and published a list of the chemicals used during the performance of hydraulic fracturing jobs. The list of chemicals initially include all chemicals used on well sites and was not limited the list to those actually being injected during fracturing. That list has since been revised to show only the chemicals used as part of the fracturing process.[283,284]

Also significant is that certain operators, have voluntarily limited the numbers of chemicals considered hazardous during their hydraulic fracturing operations.[285] In the Barnett Shale slickwater hydraulic fracturing fluids contained as many as 18 additives for a single well.[286] However, today in the Marcellus Shale operators have found that they can perform a fracture with as little as 5 additives.[287] As this is a comparison between two basins, it is not clear that this is a trend.

In addition to reducing the number of chemicals used in fracturing, operators are increasingly utilizing "Green" chemicals. "Green" chemicals are difficult to define because of the variables that have to be accounted for when considering effectiveness and their significant dilution during hydraulic fracturing. There are tradeoffs to be considered when using less effective "green" chemical substitutes, which may be more environmentally benign per volume of chemical but require greater volumes than a traditional chemical that is highly diluted. These factors are weighed by the hydraulic fracturing design team when selecting chemicals for use. More discussion of green chemicals can be found in Section 2.5 of this report.

Consideration of toxicity is affecting the selection of chemicals as well. Provinces and States are beginning to review the selection of chemicals relative to their toxicity to aquatic life and water resources. Examples of this regulation change are the revision of New York's Storm Water permit application rules and regulations[288] and the Canadian DSL.[289] The New York guidelines provide operators with an outline on how to effectively choose which "Green" chemicals to use during high volume hydraulic fracturing operations. The DSL has a sub-list of toxic substances that provides suggested control actions for the substance's life cycle from the research and development stage through manufacture, use, storage, transport, and ultimate disposal or recycling.

In addition to substituting more environmentally benign chemicals for their more traditional counterparts, companies are developing methods that eliminate the need for certain chemicals altogether. For example, UV light treatment has been used to replace biocides, as has been described in previous sections, and uncemented multistage stimulation systems such as the ones developed by Schlumberger result in higher fracture rates with lower pump pressures, reducing chemical volumes and eliminating certain acid sub-stages. Additionally, some wells are being completed with the use of other carrier fluids for transporting proppant, like LPG or CO_2. Use of other carrier fluids decreases water consumption and disposal of produced fluids when returned to the surface. These alternatives may prove to be less toxic in the long run but their expense and/or availability could delay or limit their widespread use.

Many U.S. states and the Province of British Columbia are requiring disclosure of the chemicals used during hydraulic fracturing through both laws and regulations. A listing of States that have required or are developing public reporting of chemicals used in hydraulic fracturing includes Arkansas, Colorado, Idaho, Louisiana, Montana, New Mexico, North Dakota, Pennsylvania, Texas, West Virginia, and Wyoming. Many others are considering similar requirements. In Canada, only British Columbia mandates the reporting of chemicals used to hydraulically fracture a well. However, it is expected that other Provinces will follow. Some states are requiring more than just the disclosure of the hazardous chemicals listed on MSDS and are beginning to require the disclosure of all chemicals used during fracturing. These reporting requirements are influencing the chemicals being used and how those are being reported as companies try to use both the correct chemical for the job and ones that can be fully disclosed without having to claim confidential business information.

"Range Resources, which uses contractor Frac Tech for its fracing work, says its frac fluid additives are chosen from a list of only nine compounds — hydrochloric acid, methanol propargyl, polyacrylamide, glutaraldehyde, ethanol, ethylene glycol, alcohol and sodium hydroxide."

Source: Anya Litvak, "DEP Releases New List of Frac Chemicals; Used in Marcellus, Other Pa. Operations," *Pittsburgh Business Times* (June 30, 2010), http://www.bizjournals.com/pittsburgh/stories/2010/06/28/daily40.html?page=2 (accessed December 22, 2011).)

5 BEST MANAGEMENT PRACTICES

Best Management Practices (BMPs) describe a suite of technologies, methods, and procedures that are site-specific, economically feasible, generally voluntary, and usable for guidance or help in achieving a desired outcome. They are proactive in nature and are most effective when incorporated into a development project during the early stages. For any given situation there may be multiple BMPs available and use of particular practices will depend on many factors that are specific to the location, geology, hydrology, climate, surface conditions, and demographic features associated with a shale gas project. Thus the use of the word "best" in BMPs does not imply that a given practice is best everywhere. Each situation must be analyzed and a combination of practices must be chosen to address those circumstances effectively. The use of BMPs can reduce and mitigate the risks associated with oil and gas development including the practice of hydraulic fracturing. Most of the commonly used BMPs identified for hydraulic fracturing and oilfield operations address issues at the surface. These include reducing impacts to noise, visual, and air resources, fracture fluid handling, additive storage, spill containment, traffic reduction, and impacts to water sources, wildlife, and wildlife habitats. Several BMPs that have been adopted by industry are also being integrated into regulatory practices. There are also several BMPs that can be used to mitigate the risks associated with the subsurface environment:

- Review of Baseline Conditions,
- Appropriate Wellbore Construction,
- Use of Green Fracturing Chemicals,
- Reduction of Chemical Usage,
- Cement Integrity Logging,
- Well Integrity Testing,
- Fracturing Treatment Design,
- Pre-Fracturing Treatment and Analysis,
- Monitoring During Hydraulic Fracturing,
- Post-Fracture Modeling, and
- Information Exchange.

BMPs for the above topics are described below. Additional BMPs for the surface domain can be found in other resources and can be applied to mitigate the impacts associated with surface development issues.

5.1 Review of Baseline Conditions

Generally, before a well is hydraulically fractured, operators look at the conditions surrounding the proposed wellbore location to identify any potential problems that could occur as part of the fracturing process. The elements of the review vary based on local conditions and can include evaluations of offset oil and gas wells, water wells, and geologic conditions.

National Petroleum Council Recommendation:

"Natural gas and oil companies should establish regionally focused council(s) of excellence in effective environmental, health, and safety practices. These councils should be forums in which companies could identify and disseminate effective environmental, health, and safety practices and technologies that are appropriate to the particular region. These may include operational risk management approaches, better environmental management techniques, and methods for measuring environmental performance. The governance structures, participation processes, and transparency should be designed to: promote engagement of industry and other interested parties; and enhance the credibility of a council's products and the likelihood they can be relied upon by regulators at the state and federal level."

National Petroleum Council, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," September 15, 2011, NPC, Executive Summary Section II.A.1.

5.1.1 Baseline Local Conditions

The history of nearby wells can be evaluated to identify issues that might be of concern in the well and that may require mitigation before hydraulic fracturing can commence. For example, operators evaluate nearby wells for cementing problems such as lost returns, irregular hole erosion, poor hole cleaning, poor cement displacement, etc. The casing setting depths and design can also be reviewed to ensure that there is adequate protection in place to prevent the migration of fluids. If a problem is identified, the conditions of the well are reviewed and analyzed to determine whether additional well design and/or remedial operations are necessary to address the identified issues before commencing hydraulic fracturing operations.

5.1.2 Baseline Water Testing

Some operators and regulatory authorities have recognized the benefit of collecting baseline water samples in areas where hydraulic fracturing is being conducted. Water sampling of nearby wells, rivers, creeks, and water wells can provide the well operator, regulatory agency, and landowners with baseline water quality information.[290] This information can serve to identify pre-development water quality issues that may exist as well as water quality impacts that can be attributed to development activities.

5.1.3 Baseline Geologic Conditions

The geologic conditions of the reservoir being developed are also considered in relation to hydraulic fracturing. The identification of geologic hazards is an integral BMP for the design, completion, and stimulation of a well. As an example, jointing in a hydrocarbon reservoir can be beneficial for production purposes, but a fault that may connect to overlying formations or that may allow non-hydrocarbon fluids to migrate into a production reservoir can result in undesired situations, including production of large volumes of water, which inhibits hydrocarbon production. Faults can be identified from seismic data or during drilling operations through evaluation of drilling breaks, gas shows, and lost circulation.[291]

CAPP – Hydraulic Fracturing Operating Practice:

BASELINE GROUNDWATER TESTING

CAPP and its member companies are committed to protecting fresh groundwater sources. This practice outlines the requirement for companies to test domestic water wells within 250 metres of shale or tight gas development, and to participate in longer term regional groundwater monitoring programs. The purpose of these programs is to establish baseline characteristics of the groundwater predevelopment, and to analyze whether there have been changes over time.

The testing process includes two aspects: domestic water well testing, where companies will develop programs to test existing camp wells, domestic wells and natural springs with landowner consent; and regional groundwater monitoring, where industry will work with government and regulators to design and implement regional groundwater monitoring programs.

Purpose: To describe minimum requirements for baseline testing of fresh (non-saline) groundwater in shale and tight gas development areas.

Objective: To enable and demonstrate conformance with the CAPP Guiding Principles for Hydraulic Fracturing:

We will safeguard the quality and quantity of regional surface and groundwater resources, through sound wellbore construction practices, sourcing fresh water alternatives where appropriate, and recycling water for reuse as much as practical.

We will continue to advance, collaborate on and communicate technologies and best practices that reduce the potential environmental risks of hydraulic fracturing.

Under this Operating Practice, companies will undertake domestic water well sampling programs and participate in regional groundwater monitoring programs. These programs include:

- Testing water wells within 250 metres, or as specified by regulation, of a wellhead before drilling shale or tight gas wells.
- Establishing processes to address and track stakeholder concerns that pertain to water well performance, including notifying the appropriate regulator.
- Collaborating with government and other industry operators in nearby regions to broadly understand regional groundwater quality and quantity through monitoring programs or studies that reflect good judgment and sound science.

Isolating potential problem-areas caused by faults can reduce the risk of groundwater contamination, reduce the need to produce fluids from non-hydrocarbon producing formations, and increase the success of hydraulic fracturing stimulations in the production reservoir. If the faulted area in the well is not isolated, the acid pad used to prep the area around the wellbore for fracturing and other fluids can enter the faulted zone breaking it down in the early phases of hydraulic fracturing. This can allow subsequent pumped fluids to travel into the fault, leaving the rest of the productive zones in the wellbore un-fractured. One BMP approach to isolating faults in horizontal wells is the use of open-hole packers to block certain areas of the wellbore and prevent fluid migration in that area.

5.2 Wellbore Construction

The design and construction of the wellbore is a crucial part of mitigating the impacts associated with hydraulic fracturing. While there are regulatory requirements that well casing must be able to withstand the compressive, tensional, and bending forces it will be subjected to during the well's productive life, the casing must also be situated to prevent the migration of fluids through the wellbore. The American Petroleum Institute (API) has specifications and recommended practices for the design, manufacturing, testing, and transportation of casing that should be considered during well design and casing installation. Furthermore, Provincial oil and gas regulations, prescribe the minimum casing requirements to provide sufficient protection of groundwater resources. However, it is possible that in some cases localized groundwater aquifers or specific local geologic and reservoir factors may influence casing design such that an operator ops for a wellbore design beyond what is required). In these instances, operators are encouraged to use BMPs to address concerns and ensure that casing and cement isolate production fluids and groundwater from other fluids encountered in the wellbore.

Upon drilling a well the strategic placement of cement during well construction can be a BMP when that placement goes beyond requirements to prevent the migration of fluids, including hydraulic fracturing fluids, from one zone to another and to protect shallow zones that may contain water that is suitable for domestic or agricultural consumption. Placement of cement with the properly engineered characteristics can isolate zones, which can cause unwanted migration of fluids into or out of the wellbore, protecting resources above the production reservoir and ensuring hydrocarbons are produced to the surface.

5.3 Fracture Evaluation

For over three decades, wireline tracer surveys have been used to determine the height of fractures created during hydraulic stimulation procedures. This technology tags different stages of a fracture operation with multiple radioactive tracers, providing the capability to discern between created and propped fracture heights in one or more zones of interest. A wireline instrumentation and data analysis system is used to identify and separate the individual yields from multiple radioactive tracers. An additional feature determines whether the tracer material is inside of the borehole or distributed throughout the created fracture zone. A single post-fracture pass of the logging instrument is used to accumulate gamma ray spectra at set intervals along the borehole. A weighted algorithm calculates the radioactive intensities as a function of depth, while the peak-to-Compton down-scatter ratio determines the proximity of the tracer material to the wellbore. The effectiveness of the system to evaluation multistage fracture operations has been proven time and again.

5.4 Green Chemicals

Public scrutiny over the use of chemical additives in hydraulic fracturing has led to chemical suppliers developing less toxic "green chemicals" for use in hydraulic fracturing operations. Use of these chemicals is a BMP to reduce the risk of impacts to water resources. Service companies that supply chemicals for hydraulic fracturing first developed "green chemicals" for use in European off-shore resources.[292] These companies are now developing green chemicals to market in North America for use in on-shore hydraulic fracturing projects.[293] Green chemicals are designed to achieve results similar to their non-green counterparts, but the green chemicals are formulated with non-toxic substances or are designed to break down into non-toxic substances in the environment after they have performed their intended task. The use of green chemicals can reduce hazards associated with surface spills and in the subsurface if the fluids migrate to groundwater resources.

Green product usage is not limited to the chemical additives used during a fracture treatment. Green tracers are used to identify proppant coverage and fracture geometry. Data from tracers is used to ensure that the stimulation has been effective and to identify areas that may need additional stimulation treatments.[294] Some operators are now using non-radioactive traceable proppants to replace radioactive materials that have been used in the past. The chemical markers are incorporated into the design of the proppants during manufacturing. These new proppants, first developed to identify failures in offshore wells,[295] eliminate the danger, difficulties, and potential environmental hazards that can result from using radioactive materials. These proppants also do not require special disposal when returned to the surface with the flowback water.[296]

5.5 Reduction of Chemical Usage

The number of chemical additives that are used in any given hydraulic fracturing operation has been decreasing over the last several years. As a BMP to reduce the overall risk of chemical usage, operators are more closely reviewing the effectiveness and necessity of each chemical additive to decide which to use for their fracturing jobs. In addition, several alternative

Chemical Classification:

There is minimal consistency for classifications of hazardous materials throughout the world. Most countries have laws and regulations in place relative to hazardous materials. However, the variations between the different countries and regulators are significant enough that there are different labels or data sheets for the same product in different countries. However, the Globally Harmonized System (GHS) of Classification and Labeling of Chemicals is a universal identification process that is being implemented for chemicals throughout the world. GHS provides a single system to measure the hazards associated with the handling and use of various chemicals. The GHS includes labels and safety data sheets and a basis for harmonization of rules and regulations of chemicals at a national, regional, and worldwide level. The program has three main purposes:

- Define hazards of chemicals relative to human health and environment;
- Create a classification process for chemicals with comparisons of defined hazard criteria; and
- Communicate hazards and protective measures as they appear on labels and Safety Data Sheets.[2]

Both Canada and the United States have advocated their intent to implement GHS. Having a consistent language about hazard identification could minimize risks associated with the chemicals that are used in hydraulic fracturing.

[1]United Nations Economic Commission for Europe, "Globally Harmonized System of Classification and Labelling of Chemicals (GHS)" (2003), http://www.unece.org/trans/danger/publi/ghs/ghs_rev00/00files_e.html (accessed April 25, 2012).

[2]United States Department of Labor, Occupational Safety and Health Administration, "A Guide to the Globally Harmonized System of Classification and Labelling of Chemicals (GHS)" (n.d.), http://www.osha.gov/dsg/hazcom/ghs.html (accessed November 5, 2011).

techniques are being employed by operators to eliminate or reduce chemical usage in hydraulic fracturing.

One example is the use of ultraviolet (UV) light, which has been used to effectively treat both aerobic and anaerobic bacteria in other water treatment applications, to reduce usage of biocide chemicals. Bacterial growth in hydraulic fracturing fluids that use fresh water is a concern in many shale basins as bacteria can result in the corrosion of iron and steel casing, tubing, and associated infrastructure as well as the generation of hydrogen sulfide (H_2S) gas. As a result, biocides have been used in most fracture stimulations to control bacterial growth. UV light can be used as a replacement for biocides at the surface to kill bacteria in the source water of a fracturing fluid. With the use of UV light at the surface, biocides can be used in reduced quantities to treat downhole bacteria growth. For example, in a 19-million-litre fracture stimulation, the volume of biocide used in a UV-treated operation would be 1,900 litres, while without the use of UV light, the treatment would use 19,000 litres. That is a 90% reduction.[297] **Figure 38**is an example of the UV light tool that is used during a hydraulic fracture treatment. The bacteria absorb the energy from the UV light, which damages their DNA structure and hinders their ability to produce proteins or replicate.[298] This is a substitution of a mechanical process for a chemical one.[299]

Figure 38 Tool that Uses Ultraviolet Light to Act as a Control for Bacteria

Source: Halliburton Energy Services, Inc., "Well Stimulation Technology" (January 2011), unpublished.

Other products that can reduce the volume of chemicals used in fracturing are lightweight proppants, as described in section 2.4.1. Since the lightweight proppant weighs less than traditional proppants, a lower-viscosity fluid can be used to transport the proppants into the formation. Therefore, a smaller volume of gelling additives is needed for the treatment. In addition, flowback of proppant after the fracture treatment is complete is virtually eliminated as the lightweight proppant is more easily carried into the fractured formation and is retained in the created fracture system when the pressure is released.[300]

Measuring and monitoring the effectiveness and success of hydraulic fracturing operations also helps to reduce chemical use. As operators become more familiar with localized reservoir properties and wellbore conditions, some chemicals may be deemed unnecessary and thus be reduced or eliminated. Defining and refining the treatment process is an ongoing effort and focus towards the reduction of chemical usage has become a commonly used BMP.

5.6 Cement Integrity Logging

Another BMP for well construction is evaluating and confirming the cement integrity, i.e., whether the cement has formed a competent seal between the casing and the surrounding rock to prevent the flow of fluids behind the casing. Confirmation of cement integrity is a requirement in many regulatory programs and considered a standard industry practice but where it is not required it should be considered a BMP. In order to assess the placement of cement, operators can use integrity logging methods. Logging is often performed on wells to aid evaluation of the cement bond to the casing. The logs measure the presence of cement and the quality of the cement bond or seal between the formation and the casing. A cement bond log (CBL) uses the variations in amplitude of an acoustic signal traveling down the casing wall between a transmitter and receiver to determine if there are voids in the bond on the exterior casing wall. The fundamental principle is that the acoustic signal will be more attenuated in the presence of cement than if the casing were uncemented. Running a log can help identify issues with wellbore construction prior to hydraulic fracturing. Information from a log is often analyzed together with drilling reports, laboratory reports, modeling, simulations, and mechanical integrity tests to get the entire picture of the cement job quality.

Cement bonding tools can help identify issues with cementing that may need to be addressed prior to performing a stimulation treatment. A Variable Density Log (VDL) is a tool that can be used to evaluate the cement job. The VDL is generally used to assess the cement to formation bond and to help identify channels or gas intrusion in the cement. When a VDL is run in conjunction with a CBL, an experienced engineer can draw conclusions about the cement job, however all interpretations are subjective. .

5.7 Well Integrity Testing

Testing of the integrity of a well assures that the well has been sufficiently constructed so that it will not leak or fail during stimulation and during the life of the well. After casing is installed and cemented into place, a casing pressure test pressurizes the well to ensure that the casing integrity is adequate to meet the hydraulic fracturing design objectives planned for the well. During the pressure test, the maximum anticipated pressure is applied for a set period of time (typically 30 minutes). Generally, the test is considered successful if the well does not lose more than 10% of the pressure over the testing period. If the casing pressure test fails, remedial corrective actions are conducted prior to proceeding with operations.

In addition to the casing pressure test, a shoe test or leak-off test may be performed after drilling out the casing strings. During a leak-off test, the well is shut in and fluid is pumped into the wellbore to increase the pressure on the formation just drilled.[301] At some point, fluid will begin to enter the formation, or “leak off,” by moving into the rock matrix. The results of the test indicate the maximum pressure that can safely be applied to the well during subsequent drilling operations. This is performed as the well is being drilled and prior to final completion of the wellbore.

A formation integrity test (FIT), which tests the isolation between the zones where hydraulic fracturing will occur during the completion of the well after drilling, can also be conducted. The well is pressured up and a pressure recording device monitors any pressure losses, which could indicate defective casing, cement, or formation conditions. The pressure that is exerted on the well is a predetermined value that is less than the fracture pressure.

Many Provinces and territories recognize the importance of wellbore integrity testing and have implemented rules and regulations that require operators to conduct one or more of these tests. Even with the rules and regulations in place, many operators use BMPs that consist of integrity testing above the regulatory standards to help assure the safe and successful treatment and operation of the well.

5.8 Fracturing Treatment Design

Another practical BMP is the use of information collected during the drilling and construction of the well to design and model the fracturing treatment using site-specific conditions. Site-specific data are gathered during construction and logging of the well prior to stimulation. This targeted information provides the completions engineer and service company the information needed to design a successful hydraulic fracturing job specific to that well. This was discussed in more detail in section 2.2. Post-treatment Analysis, also previously discussed in section 2.6, completes the BMP to evaluate the success of a new treatment design.

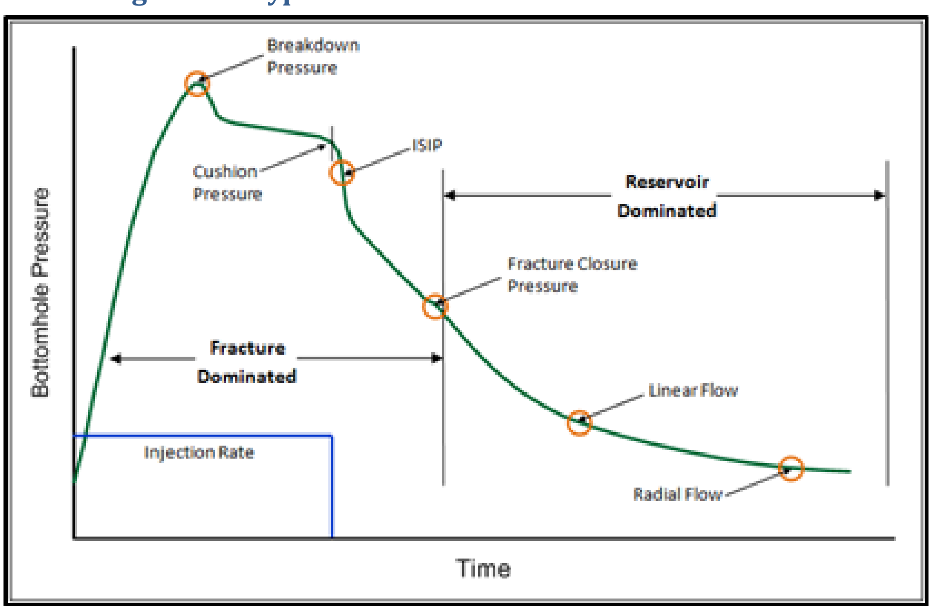
5.9 Pre-Fracturing Treatment and Analysis

One of the most frequently applied pre-fracturing treatment BMPs is a test that allows an operator to determine the breakdown pressure of the formation. This mini-frac test, which is performed prior to initiating a full-scale hydraulic fracture treatment, is used to develop site-specific details of the formation being treated and includes information on the closure of the fracture system after pumping to obtain fracture efficiency, closure pressure, fracture dimensions, fracture gradient, fluid efficiency, formation permeability, reservoir pressure and leak off coefficients (see **Figure 39**).[302,303] Each of these properties can be identified by evaluating pressure versus time curves as shown in **Figure 39.** This process is used to refine treatment parameters and procedures, increasing the success of the fracture stimulation.

5.10 Monitoring During Hydraulic Fracturing

Monitoring and adjusting designs as necessary during a stimulation treatment is a prudent BMP. Real-time monitoring and control of treatment progression and fracturing geometry can identify potential problems with the hydraulic fracture stimulation and allow operators to stop them before they cause harm. Surface injection pressure, slurry rate, proppant concentration, fluid rates, and sand or proppant rates are all continuously monitored and compared to anticipated conditions.[304] Any unexplained deviations from the anticipated design conditions can be immediately analyzed, the cause can be determined, and corrections can be made before continuing operations. This

Figure 39: Typical Pressure Behavior of Mini-Frac Tests



Source: Fekete Associates, Inc.

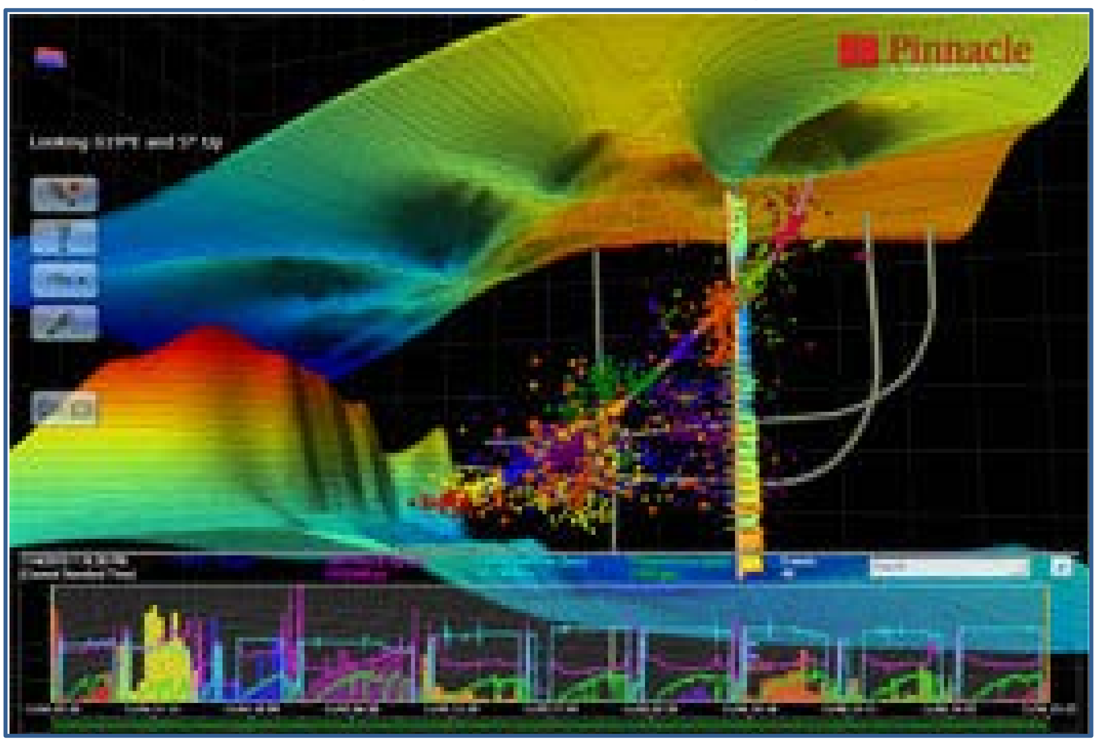
BMP was discussed in more detail in section 2.3.

Models and simulations can be used to assist in the monitoring of bottom-hole pressure versus time curves to analyze fracture height, fracture widths, and fracture half-lengths. In addition, microseismic monitors and tiltmeters can be used to provide information on fracture positions in the wellbore. An array of tiltmeters is placed either on the surface or in adjacent wellbores. The tiltmeters measure the tilt or deformation that is produced by the hydraulic fracture at each location, giving the operator real-time data on the fracture distributions, orientations, and sizes.[305] Microseismic mapping can provide an image of the fracture network by monitoring the microseismic events that are triggered during a hydraulic fracture. An engineer can look at the three dimensional outputs, such as the one shown in **Figure 40**, to identify where fracturing was successful and where the events didn't perform as planned.

Microseismic fracture mapping delivers a representation of the fractures by identifying micro-earthquakes that are produced by shear slippage on bedding planes or natural fractures next to the hydraulic fracture. The position of the microseismic events is gained using a downhole receiver array that is placed at the depth of the fracture in an offset wellbore. This technology can be used to ensure that fracture propagation remains in the target zone and that the entire zone is effectively stimulated.[306] This technology can help boost production and reduce the number of wells and fractures required. Results from microseismic fracture mapping can also be used to "calibrate" fracture growth models.

The data obtained from the various monitoring can supply information on fracture complexity, conductivity, height growth, barrier effectiveness, well-to-well and frac-to-frac interference, water entry points and general

Figure 40: Microseismic Mapping



Source: Halliburton, "Microseismic Monitoring," http://www.halliburton.com/ps/default.aspx?navid=2455&pageid=4249&prodgrpid=PRG%3a%3aL03O4I15 (accessed December 13, 2011).

fracturing execution.[307] Field data sets can have their issues and are rarely complete, therefore having multiple sources and an understanding of the type of data available and the level of accuracy is very useful. The information sources may include:

- 3-D Seismic can be combined with overlays of microseismic, micro-losses of mud and frac breakdown pressures to identify natural fracture locations.
- Pumping records documenting pumping behavior can provide insight to frac initiation, frac extension and overall frac growth.
- Microseismic is commonly used to describe the stimulated reservoir volume in shales. Microseismic with pressure, rate and proppant loading combined with the event time creates useful data for tracking shear fracturing events. These shear events are frequent in several shale fractures where natural fractures open and form conduits and the broad fracture-to-formation contact areas necessary for shale development.
- Proppant marked with low-level gamma energy tracer provides many uses including conformation of fracture initiation points, verification of fracture diversion, configuration of near wellbore isolation between fractures in multi-frac wells, and realization of proppant interference from frac-to-frac and even well-to-well in moderately closely spaced wells.
- Chemical tracers in the flow back water from both fractured wells and offset wells have been used for identifying water return from individual stages, polymer clean-up, well-to-well frac interference, and helping to verify intricate fracture growth.
- Production logging can provide valuable data on production from each frac stage; however, horizontal wells have complex flow and the correct application of this technology is necessary to identify and quantify the fluid entry and exit points.

5.11 Post Fracturing Modeling

An operator can use the information that is collected from a hydraulic fracture treatment to make improvements and changes in future stimulation design. The information gathered from post-fracture diagnostics, three-dimensional modeling, tracers, and simulations can provide an engineer with information that cannot be obtained otherwise. Each time the information is analyzed from hydraulic fracture treatments, future designs are refined to make the next fracture stimulation more successful.

International Offshore Petroleum Environmental Regulators' Group

The IOPER was established in 2008 as a network of offshore petroleum regulators to support, to advise, and to promote global environmental exchange. The Group is comprised of Canada, Australia, the United States, the United Kingdom, and Norway. Information exchanged among regulators through IOPER includes the following:

- Offshore environmental trends;
- Petroleum industry environmental performance;
- Lessons from environmental incidents;
- Industry best environmental practice;
- Environmental regulatory initiatives; and
- Measuring the effectiveness of regulatory activities.

[1]Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), *2010/2011 Annual Report: Leading Through Efficient Fair and Competent Regulation,* http://www.cnsopb.ns.ca/pdfs/SNSOPB_2011_AnnRept_Eng.pdf (accessed August 12, 2011).

5.12 Information Exchange

The free exchange of information between the operators, public, and regulators is a BMP that should be considered when developing a resource and especially when developing in a new area. Proactively providing information to the community will go a long way in easing tensions that can occur when bringing a new industry to an area. In addition, there is a desire by operators, the public, and regulators to remove the mystery that surrounds the process of hydraulic fracturing. By providing clear, scientific information on the process and responding sincerely to public concerns, fear of the unknown can be removed and cooperation can be promoted. Various efforts are being made by operators and regulators to provide for exchanging data (e.g., recommendations to develop data portals and websites like FracFocus [see Section 6.0, Chemical Use in Hydraulic Fracturing] and the International Offshore Petroleum Environmental Regulators' Group).

Remote locations such as the Horn River will require technological advances, such as multiple wells on a single pad to achieve economic success. (Picture Courtesy of Nexen, 2010)

6 HYDRAULIC FRACTURING REGULATIONS

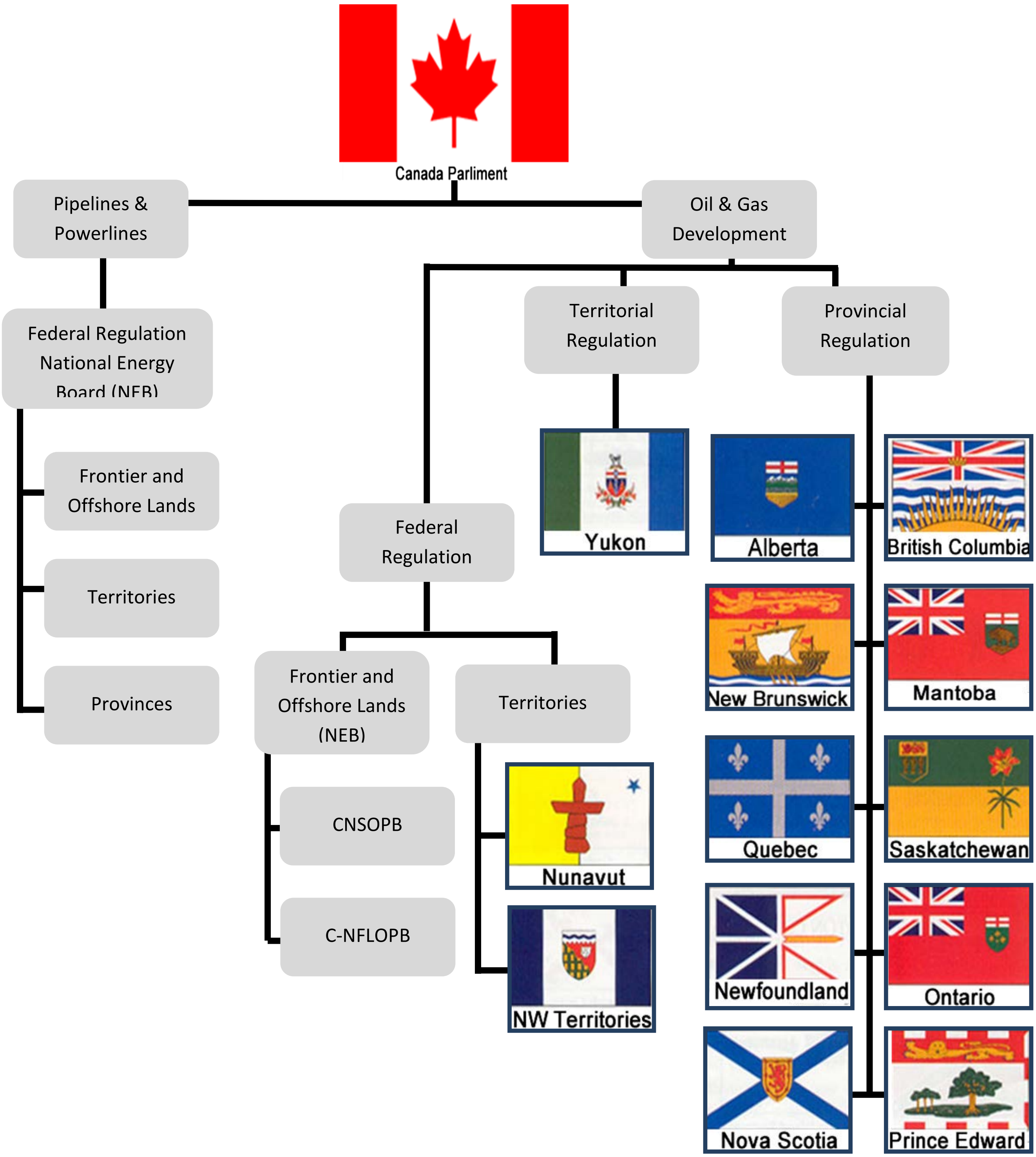
Under the Canadian Constitution, the Federal government has the exclusive jurisdiction over Canada as a whole, including international and interprovincial trade of oil and gas resources.[308] There are ten provinces and three territories in Canada (see map in **Figure 41**). The Federal government has the responsibility of regulating the Yukon, Nunavut, and Northwest Territories (NWT) and oil and gas development in certain lands set aside for First Nations people and offshore areas not under provincial control. Provinces have the exclusive authority to make laws regarding the exploration for and development, conservation, and management of non-renewable natural resources.

Figure 42 shows the breakdown of oil and gas regulation in Canada. The Federal government regulates pipelines, power lines, and all aspects of trade in the country, regardless of who regulates oil and gas development. Oil and gas development activities within the ten Provinces are regulated by the Provincial governments. Nanavut and the NWT are regulated by the Federal government. The Yukon is self-regulated. Offshore and frontier land development are also under federal regulation.

Figure 41: Provinces and Territories of Canada

Source: ALL Consulting, 2012

Figure 42: Organization of Canadian Oil and Gas Regulations



Source: ALL Consulting, 2012

Prior to the early 1900s, surface rights and mineral rights both came with the purchase of land, depending on the jurisdiction. However, since then, mineral rights have been retained by the government and cannot be purchased. Canadian Provincial law states that the mineral resources that lie under privately owned property in Canada are regarded as property of the Crown.[309] This information is outlined in the Mineral Resources Act of every province. As a result, over 90% of the mineral rights in Canada are currently under ownership of the government. The remaining mineral rights that were acquired prior to implementing the Canadian Provincial law are “freehold,” or privately owned. The mineral rights owners for these “freehold” lands may be a factor in the leasing and acquisition of the oil and gas resources, but do not come into play with regards to well construction or resource production.

The following sections discuss the divisions of government that regulate oil and gas in Canada. Included in each section is a discussion of the regulatory acts that provide authority to the governmental entity responsible for the regulation.

6.1 Federal Regulation

The Federal government regulates oil and gas activities on frontier, certain offshore and territorial lands in Canada, and on those lands set aside for the First Nations people. Frontier lands and offshore in Canada are defined as the territorial sea (12 nautical miles beyond the low-water mark of the outer coastline) and the continental shelf (beyond the territorial sea). The Frontier lands are comprised of a majority of the Yukon, Nunavut, and NWT in addition to land offshore within Canada’s jurisdiction, including the east, west, and north coast offshore areas, the offshore areas surrounding the high Arctic Islands, and the Hudson Bay offshore areas.[310] The frontier lands in Canada are shown in **Figure 43**. There are four principle Acts that govern oil and gas activities in frontier Canada:

- The Canada Oil and Gas Operations Act (National Energy Board [NEB])
- Canadian Environmental Assessment Act (CEAA)
- Canada-Newfoundland Atlantic Accord Implementation Act (Canada-Newfoundland and Labrador Offshore Petroleum Board [C-NLOPB])
- Petroleum Resources Accord Implementation Act (Canada-Nova Scotia Offshore Petroleum Board [CNSOPB])

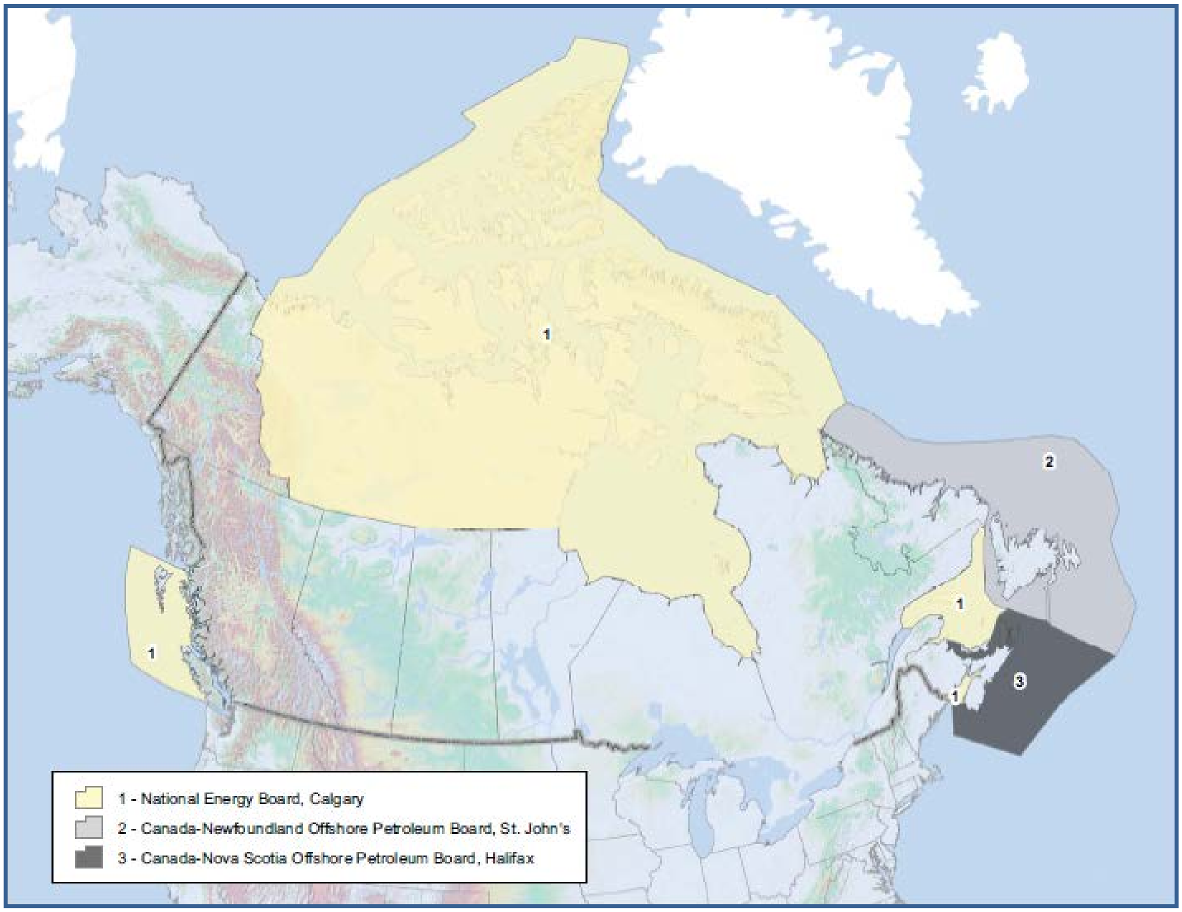
Each of these acts is discussed below.

6.1.1 Canada Oil and Gas Operations Act

The manner in which oil and gas is explored, produced, and transported on frontier lands is regulated under the Canada Oil and Gas Operations Act (COGOA). The COGOA, along with the National Energy Board Act, the Canadian Environmental Assessment Act, the Northern Pipeline Act, and certain provisions under the Canada Petroleum Resources Act, assigns certain responsibilities to the National Energy Board (NEB). The NEB is an independent Federal agency that is responsible for regulating international and interprovincial aspects of the oil and gas industry.[311] It is also responsible for regulating Frontier lands and offshore areas not covered by provincial or federal management agreements.[312] The primary regulatory responsibilities of the NEB include the following:

- Interprovincial and international powerlines and pipelines;
- Imports and exports of natural gas and oil;
- Energy studies and advisory functions; and
- Frontier oil and gas.

Figure 43: Canada Frontier Lands



Source: ALL Consulting, 2011

6.1.2 Canadian Environmental Assessment Act

The Canadian Environmental Assessment Act (CEAA) requires that all projects where a Federal department or agency has a decision making authority undergo an environmental assessment (EA).[313] The federal decision-making authority is responsible for carrying out the EA process, including scoping, public consultation, assessment, and evaluation of the significance of the environmental effects and mitigations.

There are four types of EAs that exist under the CEAA: screenings, comprehensive studies, panel reviews, and mediations. Screenings and comprehensive studies are self-directed and must be completed by the responsible authority or delegated to a third party. Panel reviews and mediations are done by an unbiased mediator or independent review panel.

Screenings are the systematic analysis of potential environmental effects associated with proposed project activities. The responsible authority is tasked with determining whether there is a need to mitigate the potential adverse impacts associated with the project, modify the project plan, or further assess the project through either mediation or a panel review. A screening can range from a simple analysis of the available information to a full background study. Screenings account for 99% of all EAs conducted in Canada and include a wide range of projects, from small-scale projects such as grazing permits to large-scale projects such as mining developments.[314] Screening can be accepted as is or the information provided can be used to initiate a mediation or panel review if situations warrant a higher level of review.

Comprehensive studies are typically required for larger projects where the potential for significant adverse environmental effects and public health concerns are at stake. Large-scale oil and natural gas developments usually require a comprehensive study. A comprehensive study assesses the actions of the proposed project and their potential impacts, proposes alternative means of carrying out the project that are economically and technically feasible, evaluates the need for any follow-up programs in respect to the project impacts, and measures the capacity of renewable resources that are likely to be significantly affected by the project to meet the needs of present and future generations. This review process is more stringent than a screening and requires public participation.[315]

A panel review is an impartial and objective review of a project that will likely have adverse environmental impacts. This type of review can also be done when the public concerns warrant a higher review process than would normally be covered under a screening or comprehensive study. A panel of independent experts is appointed to conduct the panel review. The panel acts as an advisory committee to the Minister and responsible authority, or the agency responsible for issuing the permits or approval, but the responsible authority makes the decision about whether to take action on the project in whole, in part, or not at all.

Mediation is a voluntary process where two parties use an independent and impartial mediator to resolve their issues. The Minister of the Environment appoints the mediator. This process can be used to address all issues that arise in the EA process, or it can be used for only specific questions. Mediations can be used to prevent a panel assessment, which can be costly and time consuming. Although shale gas extraction is regulated primarily at the provincial and territorial level, the Environment Minister, the elected head of Environment Canada, has requested the Council of Canadian Academics to conduct an independent expert panel review of the current scientific knowledge

CAPP – Hydraulic Fracturing Operating Practice:

WELLBORE CONSTRUCTION AND QUALITY ASSURANCE

CAPP and its member companies recognize that sound wellbore design and construction is fundamental to protecting groundwater resources and to responsible shale gas development. Industry is committed to excellence in the design, installation and maintenance of wellbores. Each wellbore has steel casing that is cemented to prevent any fluids from migrating into groundwater. Wellbore design is strictly controlled by individual Provincial regulators, and companies have procedures in place to ensure wellbore integrity prior to initiating hydraulic fracturing operations.

Purpose: To describe minimum requirements for wellbore construction and quality assurance in shale gas and tight gas hydraulic fracturing operations.

Objective: To enable and demonstrate conformance with the CAPP Guiding Principles for Hydraulic Fracturing:

We will safeguard the quality and quantity of regional surface and groundwater resources, through sound wellbore construction practices, sourcing fresh water alternatives where appropriate, and recycling water for reuse as much as practical.

We will continue to advance, collaborate on and communicate technologies and best practices that reduce the potential environmental risks of hydraulic fracturing.

Under this Operating Practice, companies will demonstrate that processes are in place to ensure proper design and installation of the wellbore, and to ensure the integrity of the wellbore prior to initiation of hydraulic fracturing. These processes include:

- Complying with applicable regulatory requirements and using good engineering practices for wellbore design.
- Installing and cementing surface casing to surface to create a continuous cement barrier, which is assessed to ensure integrity of the wellbore.
- Designing wellbore casing to withstand minimum and maximum loads anticipated during hydraulic fracturing, confirming wellbore integrity with a pressure test where possible.
- Determining the cause and developing appropriate remedial plans to restore wellbore integrity in the unlikely event that it is compromised, such as surface casing vent flow or gas migration.

associated with the environmental implications of hydraulic fracturing. In addition, he has also asked Environment Canada to conduct a similar in-house study. These reviews are being conducted pursuant to the CEAA.[316]

6.1.3 Canada-Newfoundland Atlantic Accord Implementation Act

There are currently no shale gas prospects in the offshore areas of Newfoundland. However, if shale gas resources are discovered in the future, the Canada-Newfoundland Atlantic Accord Implement Act (Atlantic Accord) regulations would initially be used to cover the development of the resource, and specific modifications could be implemented to address the resource development.

The Atlantic Accord is an agreement between the Government of Canada and the Government of Newfoundland and Labrador on the management of oil and gas resources and revenue sharing for offshore reserves.[317] The Atlantic Accord outlines the requirements that must be met for offshore development projects. Under the agreement, neither governmental agency can amend the policy without approval of the other party.

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) is comprised of seven members: three from the Federal government, three from the Provincial government, and one non-governmental member elected by the other six members as the Chief Executive Officer (CEO). The Board oversees legislative and regulatory compliance related to safety, environmental protection, resource management, and industrial benefits within the offshore areas covered under the agreement.[318] The Board is also authorized to establish spacing units and well production rates and has the power to perform "any duties necessary for the management and control of petroleum production."[319]

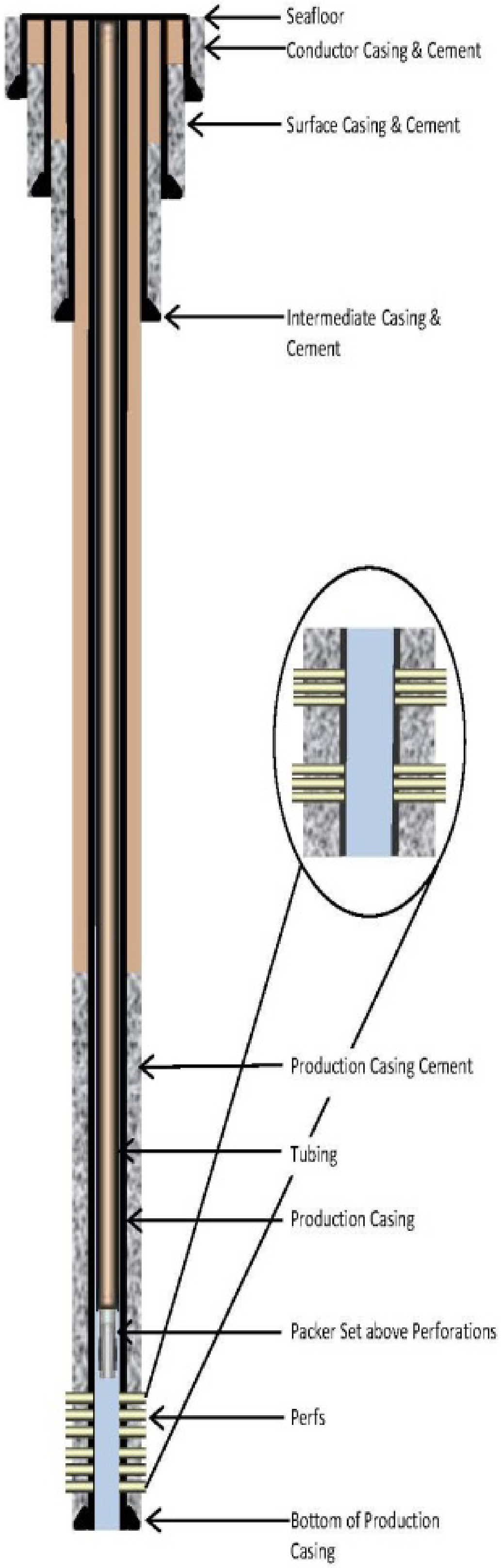
Casing and cement are the primary means for protecting groundwater during construction, completion (including hydraulic fracturing) and production of a well. The C-NLOPB has regulatory standards in place in various sections of the Drilling and Production Regulations that contain minimum casing and cementing requirements. In addition to the regulations, a set of guidelines are available to provide assistance in understanding how the requirements of the regulations can be met.[320] The wellbore diagram in **Figure 44** shows an example of an offshore well.

A project specific EA and an Environmental Protection Plan (EPP) are required for well operations. The project specific EA is required under both the Atlantic Accord and the CEAA and is comprised of a technical report that investigates the impacts on the environment and also the impacts the environment has on the operations. A requirement of the EA is public consultation of potentially impacted parties.

The second component of a well approval process is an Approval to Drill a Well (ADW).[321] An application must be submitted for each well to be drilled and approved by the C-NLOPB prior to initiating operations. The ADW must contain detailed information regarding the well design, equipment specifications, and geological prognosis. Casing and cementing program specifications, testing programs, drilling fluid programs, and other information are also required. Standards are in place for the placement and pressure testing of casing and cement:

- The well casings must be designed to withstand the pressures of drilling and completion, including hydraulic fracturing pressures, and protect groundwater zones from contamination. The required depth of the surface casing is not mandated in the regulations. However, it must be

Figure 44: Offshore Well Construction



adequate kick tolerances and well control operations.

- The casings must be cemented to prevent formation fluids from moving through the casing annulus and must protect petroleum and water zones.[322] Surface casing should be cemented to the seafloor or to a depth at least 25 m above the base of the conductor casing, if installed.[323] Cement should also rise to a minimum of 150 m above the permafrost layer, if applicable. A minimum compressive strength of 3,450 kilopascals (kPa) should be met.[324]
- The procedure for the selection, evaluation, and use of chemical substances that are proposed for the project, including process chemicals and drilling fluid ingredients, must be submitted in the EPP.[325] Approval for the hydraulic fracture stimulation must be granted through an Approval to Alter the Condition of a Well (ACW).[326] In addition, an outline of the equipment that will be used and the estimated duration of the operation must be submitted on a Notification to Complete (NOC) prior to initiating operations.
- The volume of fluid that is produced or injected must be measured and recorded. The composition of the fluid that is used must be submitted on a revised NOC after the hydraulic fracture stimulation is done. In addition, the stimulation details must be submitted on a Final Well Report.

6.1.4 Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act

There are currently no shale gas prospects in the offshore areas of Nova Scotia. However, if shale gas resources are discovered in the future, the Canada-Nova Scotia Offshore Petroleum Accord Implementation Acts would initially be used to cover the development of the resource, and specific modifications may be implemented in the future to address the resource.

Oil and gas activities in the Nova Scotia Offshore Areas are regulated by the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), an independent joint agency of the governments of Canada and Nova Scotia established in 1990 pursuant to the Canada-Nova Scotia Offshore Petroleum Accord Implementation Acts.[327] The CNSOPB is a Federal Authority under the CEAA and follows the requirements outlined in the act.[328] As such, all operators are required to submit an EA prior to the authorization of any proposed offshore petroleum work or activity. The operator must also submit an EPP and a spill response plan. The EA and EPP must contain commitments to follow the Offshore Chemical Selection Guidelines (see below).

The drilling and production guidance document for C-NLOPB is also used for operations covering offshore activity regulated by the CNSOPB. As such, many of the following requirements are duplicates of the list in the previous section:

- The well casings must be designed to withstand the anticipated pressures, including hydraulic fracturing pressures, and protect groundwater zones from contamination. The required depth of the surface casing is not mandated in the regulations. However, it must be installed deep enough to provide adequate kick tolerances and well control operations.
- The casings must be cemented to prevent formation fluids from moving through the casing annulus and must protect petroleum and water zones.[329] Surface casing should be cemented to the seafloor or to a depth at least 25 m above the base of the conductor casing, if installed.[330] Cement should also rise to a minimum of 150 m above the permafrost layer, if applicable. A minimum compressive strength of 3,450 kPa should be met.[331]
- The volume of fluid that is produced or injected must be measured and recorded. The composition of the fluid that is used must be submitted on a revised NOC after the hydraulic fracture stimulation is done. In addition, the stimulation details must be submitted on a Well History Report. The stimulation records must be submitted as an appendix to the report.[332]

Offshore Chemical Selection Guidelines (OGSC)

The OCSG were prepared jointly by the NEB, the C-NLOPB, and the C-NSOPB and a public/government/industry comprised working group for all areas under the jurisdiction of the NEB, the C-NLOPB and the C-NSOPB. The OCSG provides the framework for minimizing potential impacts associated with the chemicals used in offshore drilling and production. In each of the areas, an operator must meet the minimum expectations outlined in the OCSG as part of the authorization for any work or activity related to oil and gas exploration and production. The following items are required as part of the OCSG:

- The quantity of each chemical used and its ultimate fate, including storage, discharge, and waste brought to shore, injected downhole or left in the well, or consumed by chemical reaction.
- Biocides must be registered with the Pest Management Regulatory Agency (PMRA).
- All chemicals must be on the Domestic Substances List (DSL) of approved substances pursuant to the Canadian Environmental Protection Act (CEPA) or go through a New Substances Notification process to identify any restrictions.
- Chemicals on the Non-Domestic Substance Lists (NDSL) appearing in volumes less than 1,000 kg/year and all other chemical appearing in volumes less than 100 kg/year do not require chemical registration.

6.2 Territorial Regulations

The following presents the regulatory differences between the territories. Note that each territory has specific regulations that are either proposed or pending.

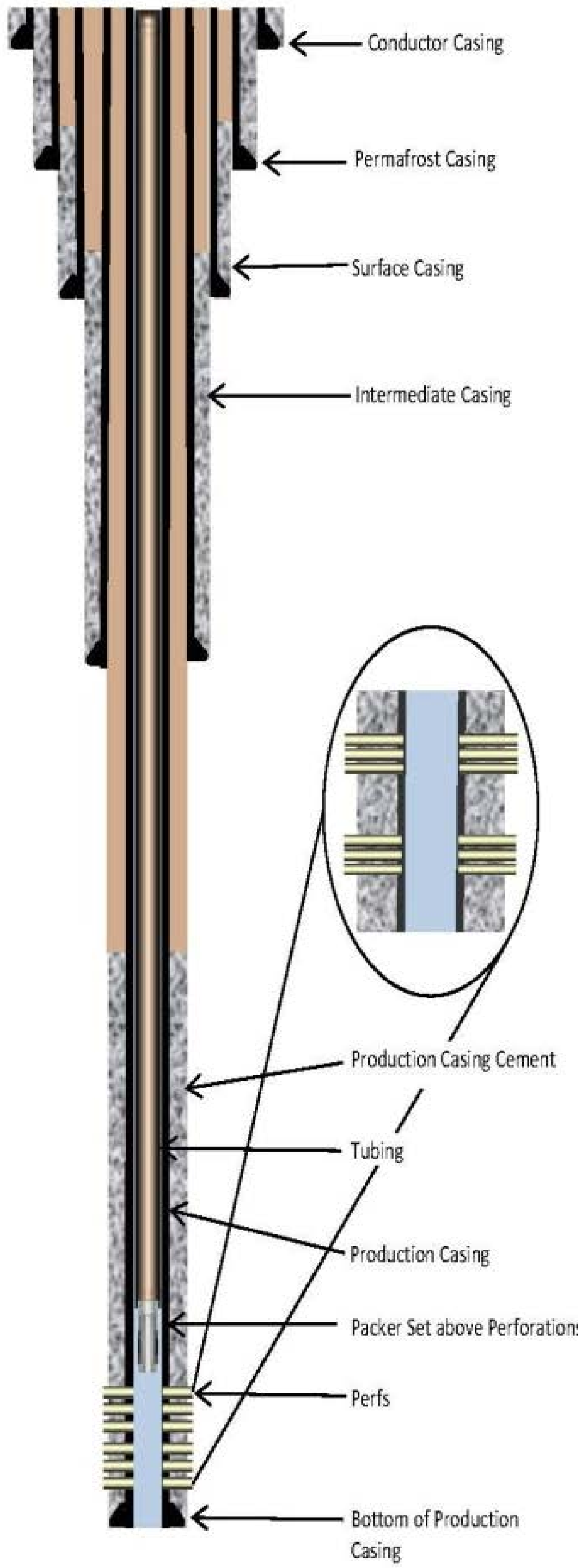
6.2.1 Yukon

The government of the Yukon Territory has powers similar to those of a provincial government. The territory underwent the process of negotiated devolution, which transferred the responsibility for management of onshore oil and gas resources from the Federal government to the territory, in November 1998.[333] The Oil and Gas Resources (OGR) section within the territory's Department of Energy, Mines and Resources (EMR) is responsible for managing oil and gas resources, activity, and development within the Yukon Territory pursuant to the Yukon Oil and Gas Act. Although there are currently no prospective shale gas targets in the Yukon Territory, the following regulations would initially be used to cover the development of the resource, if development were to occur, and specific modifications might be implemented in the future.

Protection of groundwater during hydraulic fracturing is primarily done through proper installation of casing and cement. The EMR has regulatory standards in place, via various sections of the Yukon Oil and Gas Act, relative to wellbore construction. Standards for the placement and pressure testing of casing and cement in the Yukon Territory include the following:

- Conductor casing must be set to a minimum depth of 20 m. Surface casing must be set in a competent formation at a depth at least 150 m and not more than four times the setting depth of the conductor pipe or casing or 500 m, whichever is greater. Intermediate casing must be set as required to protect the well against anticipated pressure or difficult wellbore conditions (see **Figure 45**).

Figure 45: Yukon Territorial Well Construction



- When permafrost occurs (see **Figure 46**) at a depth greater than 150 m, another casing string called permafrost casing must be set to a depth of 150 m below ground level. In this situation, surface casing must be set at least 100 m – but not more than 300 m – below the base of the permafrost. When permafrost casing is used, the surface casing annulus must be sealed at the surface and suitable devices must be installed to monitor and relieve any pressure that may accumulate under the seal.[334]
- Surface and permafrost casing must be cemented to the surface, or at least 25 m above the base of the previous casing string. Intermediate casing must be cemented a minimum of 300 m above the intermediate casing shoe or 150 m above the base of the permafrost and rise to a minimum of 25 m above the shoe of the previous casing, if practicable.[335]
- Cement is to cure for a minimum of 12 hours and must attain a compressive strength of 3,500 kPa before any drilling can recommence.

Hydraulic fracture stimulation must be done in a safe manner that allows the operators to gather information about the formation and production capabilities.[336] If the anticipated stimulation treatment pressure exceeds 75% of the minimum internal yield pressure of the production casing, the stimulation must be done through tubing with a packer seated as near to the production formation as possible. This will allow the stimulation interval to be isolated and provide another protection barrier during the stimulation.

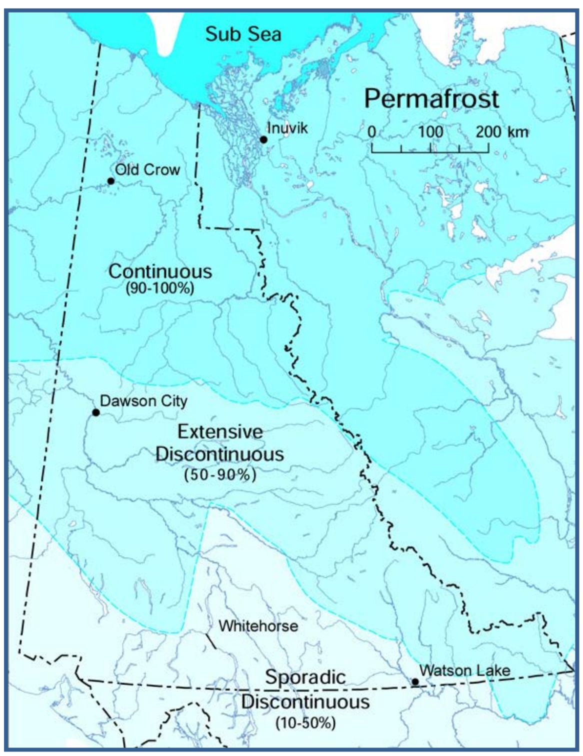
6.2.2 Northwest Territories and Nunavut

Oil and gas resource management on Crown Lands in the Northwest Territories, Nunavut, and the northern offshore areas are regulated under the following two Federal statutes: the Canada Petroleum Resources Ace (CPRA) and the COGOA.[337] Pursuant to the COGOA, the Canada Oil and Gas Drilling and Production Regulations were implemented, which outline operation requirements on Federal lands. The Mineral and Petroleum Resources Directorate has the responsibility for disposition and administration of oil and gas resources in the Northwest Territories.[338] There are no current shale gas prospects in the Northwest Territories and Nunavut, but there are regulations in place that would cover initial development.

The following regulatory standards that protect aquifers from hydraulic fracturing are in place for casing and cementing (see **Figure 45**). These standards are found in various sections of the Canada Oil and Gas Drilling and Production Regulations:

- The casing must be installed at a depth

Figure 46: Yukon Territory Permafrost Distribution (Yukon Government)



Source: Yukon Government, "Glaciers, Permafrost and River Ice" (updated May 3, 2011), http://yukonwater.ca/Understanding YukonWater/WaterFacts/Glaciers.aspx (accessed December 1, 2011).

that provides for adequate kick tolerances and safe, constant bottom-hole pressures.

- Surface casing must be cemented to the surface and allowed to set for at least 12 hours under pressure before drilling can commence.[339]
- Production and intermediate casing must be cemented to a height that is sufficient to ensure isolation of the productive zones, allowed to set for at least 24 hours, and pressure tested before the cement plug is drilled.

The Canada Oil and Gas Drilling and Production Regulations state that all reasonable precautions must be taken when hydraulically fracturing or chemically treating to ensure that no irreparable damage is done and to ensure there is no ingress of water into productive oil and gas zones.[340] Before conducting hydraulic fracturing, the following steps must be taken:

- An application for well approval is required for all workovers, completions, and recompletions, including hydraulic fracturing operations. A detailed description of the proposed work or activity and the rationale for conducting it must be included on the application.
- Any application for authorization also requires the submission of an EPP. One component of the EPP is a description of the procedures for the selection, evaluation, and use of chemical substances, including process chemicals and drilling fluid ingredients.[341]

Once hydraulic fracturing has been complete, the following information must be submitted to the Mineral and Petroleum Resources Directorate:

- A daily report that identifies the operations that have been carried out, including items such as hydraulic fracturing
- A report that outlines the particulars of the results obtained from a hydraulic fracture stimulation
- A report of the rate of flow and volume of the fluid that is produced from each well, fluid that is injected into each well, and any produced fluid that enters or leaves, or is used, flared, vented, burned or otherwise disposed of[342]
- A Well Operations Report (submitted within 30 days after the end of a well operation) that includes:
    - A summary of the well operation, including any problems encountered;
    - A description of the completion fluid properties; and
    - Details of any impact of the well operation on the performance of the well, including any effect on recovery.

6.3 Provincial Regulation

The following presents the regulatory overview of each of the provincial regions. Each province's specific regulations for casing and cement programs relevant to hydraulic fracturing and groundwater protection are discussed.

6.3.1 Alberta

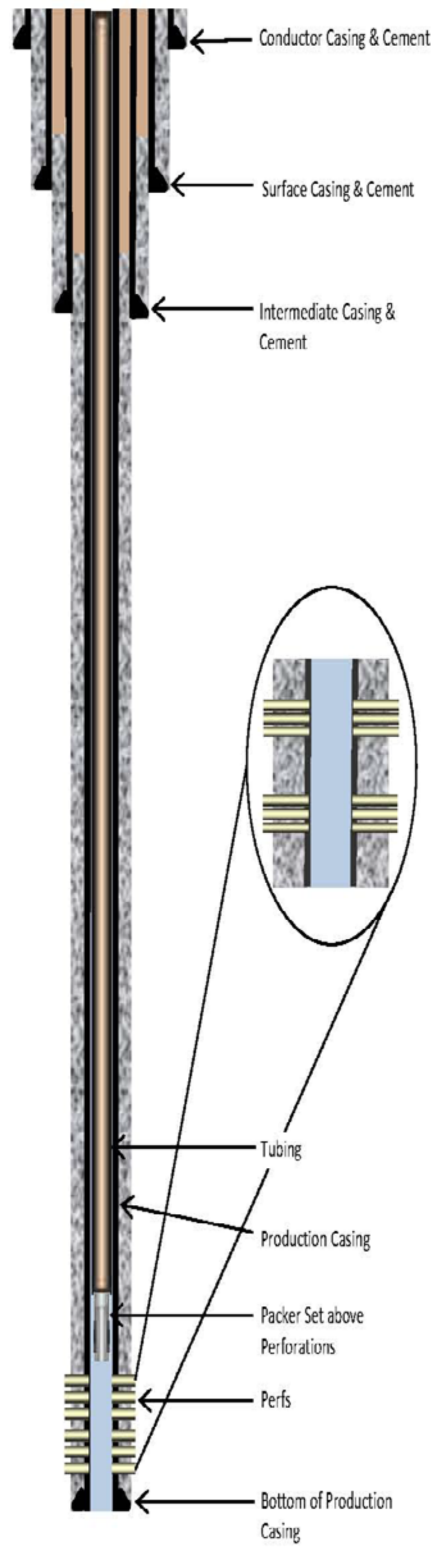
Oil and gas development in Alberta is regulated by the Energy Resources Conservation Board (ERCB) pursuant to the Energy Resources Conservation Act. The Oil and Gas Conservation Act establishes the regulatory regime for approvals administered by the ERCB and thus the development of oil and gas resources in the Province.[343]

Alberta has extensive regulatory standards for casing and cementing to protect aquifers during hydraulic fracturing (see **Figure 47**). These standards are found in various sections of the Oil and Gas Conservation Act and include the following:

- Conductor casing, when required for well control, must be set between 20 and 30 m into a competent zone. Conductor casing must be used when a search within 1 kilometre (km) indicates water flows, or when there are springs and/or flowing seismic shot holes within 1 km. Surface casing must be set at a calculated depth that takes into consideration local water well depths and pressure measurements from adjacent wells. These procedures are contained in **Appendix A**.
- Conductor casing and surface casing must be cemented to surface. When surface casing setting depth is either less than 180 m below the surface or 25 m below any aquifer that is a source of usable water, the casing string next to the surface casing must be cemented to surface. When less than 180 m of surface casing has been run or the casing is less than 25 m below an aquifer with usable water, intermediate or production casing must be cemented to the surface. For situations when more than 180 m of surface casing has been set at least 25 m below an aquifer with usable water, an operator must consult the map in **Appendix B** to determine the required top of cement.

In August 2009, the ERCB issued Directive 27 for Shallow Fracturing Operations. Under this directive, hydraulic fracturing cannot occur within 50 m of the vertical depth of any water well within a 200-metre radius. Hydraulic fracturing at depths less than 200 m requires a full assessment of potential impacts prior to initiating a fracturing program. The assessment must include the following information:

Figure 47: Provincial Well Construction for Nova Scotia, Prince Edward, Manitoba, Newfoundland, and Alberta



- The fracture program design, including proposed pumping rates, volumes, pressures and fluids;
- A determination of the maximum propagation expected for all fracture treatments to be conducted;
- Identification and depth of offset oilfield and water wells within 200 m of the proposed shallow fracturing operations;
- Verification of cement integrity through available public data of all oilfield wells within a 200-metre radius of the well to be fractured;
- Landholder notification when active water wells are within 200 m of the proposed fracturing operations.

Fracturing is also prohibited within 50 m of bedrock surface, even if the depth exceeds 200 m. The depth of bedrock for all wells where shallow fracturing has occurred must be determined through water well drilling reports, bedrock topography maps, or another acceptable method and maintained in operator files.

In addition to the above requirements, Directive 27 requires the use of only non-toxic fracture fluids above the base of groundwater protection. Also, an operator must provide the ERCB with the composition of the fracture fluids upon request for all shallow hydraulic fracturing operations. Fracture treatments must be designed to prevent contamination of non-saline water zones.

6.3.2 British Columbia

In October 2010, the legal regime for oil and gas activities in the Province was changed when the British Columbia (B.C.) Oil and Gas Commission Act, the B.C. Pipeline Act, and the regulatory provisions in the B.C. Petroleum and Natural Gas Act were repealed and the B.C. Oil and Gas Activities Act (OGAA) was implemented.[344] The OGAA updated and consolidated the regulatory provisions in each of the previous acts and furthered the authority of the Commission with respect to oil and gas activities under other provincial legislation such as the Environmental Management Act, Land Act, Water Act, Heritage Conservation Act, Forest Act, and Forest Practices Code of B.C. Act.[345] The B.C. Oil and Gas Commission continues to regulate the Province's oil and gas operations, including hydraulic fracturing, under the OGAA. However, both the Commission and the Provincial Cabinet have the ability to craft regulatory enhancements.

The Provincial Cabinet introduced the OGAA General Regulation, Environmental Protection and Management Regulation and the Drilling and Production Regulation (DPR) to protect public safety. Standards addressing safety, environmental impacts, and resource development are found in various sections of the regulations. The DPR includes standards for casing and cementing that, among other benefits, prevent groundwater contamination during hydraulic fracturing (see **Figure 48**):

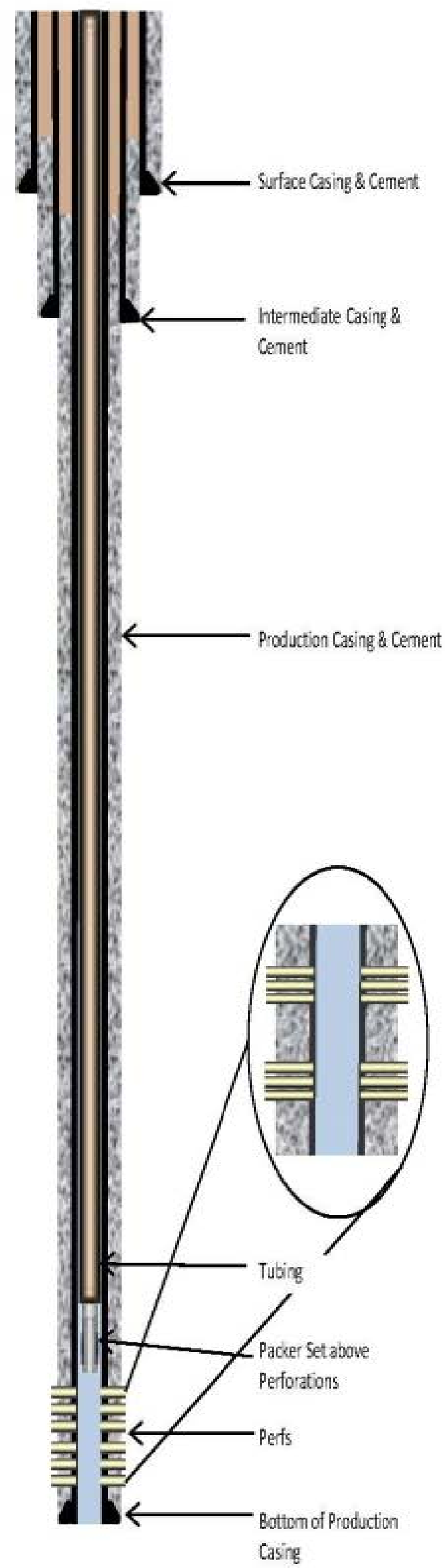
- Casing must be designed so that it will not fail if subjected to the maximum loads and service conditions that can reasonably be anticipated during the expected service life of the well.
- Surface casing must be set in a competent formation at a depth sufficient to provide a competent anchor for blowout prevention equipment and to ensure control of anticipated well pressures.
- Surface casing must be cemented to the surface.
- If the surface casing is not set below the base of all porous strata that contain usable groundwater or a minimum depth of 600 m, the next casing string must be cemented to surface.

- Surface casing cement must not be drilled out until sufficient compressive strength has been reached to allow the safe conduct of drilling operations.
- Intermediate and production casing should be cemented to the surface or at least 200 m above the shoe of the previous casing string. Additionally, the cement is not to be drilled out until sufficient compressive strength has been reached to allow the safe conduct of drilling operations
- If there is any reason to doubt the effectiveness of casing cementation, a survey must be made to evaluate the cement integrity and any necessary remedial measures must be taken.
- If a casing leak or failure is detected, the well permit holder must notify the commission about the leak or failure without delay, and repair the leak without unreasonable delay.
- The well must be configured such that the surface and intermediate casing annulus can freely vent, excessive pressure cannot occur at the surface casing shoe, and the surface casing must be equipped with an open valve.

Hydraulic fracturing operations are prohibited at a depth of less than 600 m below ground level without approval. The following information must be included in any application where fracturing is proposed at less than 600 m:

- The fracture program design including proposed pumping rates, volumes, pressures, and fracturing fluids;
- Estimation of the maximum fracture propagation;
- Assessment of groundwater resources in the area;

Figure 48: Provincial Well Construction for New Brunswick, Quebec, Saskatchewan, British Columbia, and Ontario



- Identification and depth of all wells within 200 m of the proposed shallow fracturing operations;
- Verification of cement integrity through available public data of all wells under the Commission's jurisdiction within a 200 m radius of the well to be fractured;
- Notification of water well owners within 200 m of the proposed fracturing operations;
- Pre-fracture and post-fracture sampling of water wells within 200 m of the proposed fracturing operations where agreed to by water well owners;
- Bedrock depth; and
- Assessment of the suitability of the candidate well for the proposed fracturing operations including casing and cement integrity.[346]

The operator must submit a Completion/ Workover Report for each separate operation on a well within 30 days of completing the stimulation. The report must state the purpose of the operation; include a chronological summary of work done; indicate the completion type and activity; state which stimulation type achieved breakdown; provide total volume and maximum pressure used; include a flow summary along with final gas flow rate, final flow pressure and final flow date; indicate whether radioactive material was used; discuss the outcome of the operation; and include a downhole schematic diagram. In addition, detailed reports of the completion/workover must also be submitted.

Starting in January 2012, B.C. has required companies to disclose hydraulic fracturing fluid ingredients (e.g. chemicals and additives).[347] To facilitate disclosure, the Province established a publically accessible online registry called FracFocus.ca through a partnership with the U.S. site FracFocus.org.[348] The FracFocus.ca database provides greater transparency into where hydraulic fracturing has taken place within the Province and on the additives being used.

6.3.3 Manitoba

The Petroleum Branch of Innovation, Energy and Mines is the regulatory authority responsible for the exploration, development, and production of oil and gas resources under the Oil and Gas Act and the Oil and Gas Production Tax Act.[349] While immediate development of Manitoba shale resources is not proposed, there are several shale targets that may be developed in the future, including the Carlile, Favel, and Ashville formations.[350]

Proper casing and cementing is key to groundwater protection during hydraulic fracturing operations. The details of the casing and cementing operations must be submitted as part of the Well License Application that is reviewed and approved prior to initiating drilling operations (see **Figure 47**).

The following requirements must be met in Manitoba:

- Surface casing must be installed to a depth of 25 m below the top of the bedrock, 10% of the true vertical depth of the well, 100 m below ground surface, or a depth required by the director, whichever is greatest.[351]
- Surface casing must be cemented by the pump and plug method with sufficient cement to circulate to the surface. Intermediate or production casing must be cemented by the pump and plug method to a depth at least 150 m above the top of the Swan River Formation, a groundwater zone that services many residents of Manitoba.
- Surface casing cement must be allowed to cure for at least 8 hours and pressure tested to 7,000 kPa. Intermediate or

production casing cement must be allowed to cure for 24 hours for production casing and 12 hours for intermediate casing. Production casing and intermediate casing must also be pressure tested to 7,000 kPa.

Within 30 days after hydraulic fracture stimulation, the operator must submit a report that identifies the fluid and tools used and the treatment pressures and volumes in a report acceptable to the director.[352] In addition, any chemical treatment in the wellbore must also be reported within the 30-day timeframe.

6.3.4 New Brunswick

The Oil and Natural Gas Act gives the Minister of Natural Resources of New Brunswick the regulatory authority to manage all facets of oil and gas development, including hydraulic fracturing. Energy and environmental officials in the Province are developing a natural gas action plan to govern shale gas development, and hope to have the process complete by the end of Spring 2012.[353] New Brunswick has not issued a moratorium on development while developing the plan.

Although new regulations have been implemented, the government of New Brunswick is continuing to develop its regulatory framework through a Natural Gas Steering committee comprised of ministers and deputy ministers of the Departments of Environment, Energy and Natural Resources.[354] Steering committee officials are weighing ideas, including one presented by a company teamed with an environmental group. SWN Resources Canada, has entered into a unique collaboration with environmentalists. Its parent company, Southwestern Energy of Houston, has been working with the Environmental Defense Fund (EDF) on a set of model standards for safe drilling that they have suggested be considered by the government of New Brunswick to decide whether a new energy business can be developed while protecting the landscape.[355]

The model regulations used some U.S. state requirements and industry BMPs to identify casing and cementing requirements for groundwater protection. In addition, the model rules would require hydraulic fracturing chemical disclosure.

Oil and gas operators in New Brunswick must register their projects with the Project Assessment and Approval Branch of the Department of the Environment to comply with the Environmental Impact Assessment Regulation and must conduct a Phased Environmental Impact Assessment (EIA) review.[356] The Phased EIA review must be initiated prior to well pad construction and must include construction details, drilling details, waste management details, and any past, current or future projects or activities in the area whose effects may interact with the proposed project. Public consultation is required as part of the entire process.

In addition to conducting an EIA, oil and gas operators must obtain Approvals to Construct and Operate, which require the submission of the following:

- A Chemical and Waste Management Plan that outlines storage methods, handling and disposal for all chemicals, and waste and waste water identification;
- A Water Management Plan that describes the water source, withdrawal rate, transfer method, and disposal of flowback water for hydraulic fracturing;
- A Private Well Water Sampling and Analysis Program that requires testing of private water wells near the proposed site prior to any activities; and
- A Quarterly Environmental Report, which includes flare volumes, combustion gas volumes, summary report of waste, spills, and/or leaks, an

outline of proposed activities for upcoming quarter, and updated maps.[357]

While the action plan is being developed and research is being conducted, new regulations have been implemented by the committee. Oil and gas operators are now required to conduct baseline testing on all potable water wells within 500 m of drilling operations.[358] Operators are also required to establish a security bond to protect property owners from individual accidents resulting in the loss or contamination of drinking water.

Companies are required to adhere to the draft General Regulation under the Oil and Natural Gas act for casing and cementing requirements, as well as follow good development practices to protect groundwater sources during hydraulic fracturing.[359] Casing and cementing details must be provided on the Application for Well Authorization Form and the required Drilling Program Submission that must accompany the application.

The following regulations for casing and cementing are still in draft form and are not publically available, and may change when the regulations become final (see **Figure 48**):

- Surface casing setting depth must adhere to Directive 008 "Surface Casing Depth Requirements" for Alberta (see Appendix A for calculation).
- Surface casing must be cemented to surface as depicted in the wellbore diagram in **Figure 48**.[360]
- A minimum of 6 hours must pass after cementing operations before drilling can recommence unless an operator can confirm, using acceptable testing equipment and procedures, that the cement has attained a compressive strength of 3,500 kPa.

Pursuant to General Regulation under the Oil and Natural Gas Act, an operator must report hydraulic fracturing activities on a daily basis and include the type, quantity, and size of propping agents; type and volume of carrier, additives, and plugging agents; feed rates; and pressures.[361] In addition, under the new regulations that were implemented in June 2011, the operators are now also required to provide full disclosure of all proposed and actual contents of all fluids and chemicals used in the hydraulic fracturing process.[362]

6.3.5 Newfoundland and Labrador

Onshore oil and gas resources in Newfoundland and Labrador are regulated under the Petroleum and Natural Gas Act. Development of shale resources in Newfoundland and Labrador is not planned for the immediate future. However, there have been some indications that the shallow shales of the Green Point Formation may be prospective for oil.[363]

Proper casing and cementing are the primary means of protecting groundwater during hydraulic fracturing operations. The Petroleum and Natural Gas Act requires that the proposed casing and cementing record be provided in the Application for Authority to Drill a Well. The Final Well Report must include more specific information, including

- Size, weight, grade, number of joints, type of thread/connection, depth of shoe, and make and type of casing hangers and seals for each casing string;
- Location of centralizers and scratchers, sacks of cement, type and amount of cement additives, and the intervals cemented or top of cement behind each casing string; and
- Basis for estimated top of cement,(i.e. calculations or cement bond log).

If shale resources are developed in the future, the following casing and cementing regulations would initially be used to protect groundwater during hydraulic fracturing (see **Figure 47**) and specific modifications may be implemented in the future:

- Under normal pressure conditions, the surface casing must be set in a competent formation at a depth of at least 150 m and not more than 4 times the depth of the conductor casing or 500 m, whichever is greater. Intermediate casing must be set at a depth to ensure at least 25% of the hole is cased during all drilling operations below the surface casing. Under abnormal pressure conditions, the operator must install additional casing to that required under normal conditions.
- The conductor casing must be cemented from the casing shoe to the surface, where practical. Surface casing must also be cemented to the surface or to a depth that is at least 25 m above the base of the conductor casing. Intermediate casing must be cemented with sufficient cement to isolate all hydrocarbon or potable water zones, isolate abnormally pressured intervals from normally pressured intervals, and rise to a minimum of 300 m above the casing shoe.
- After cementing each casing string, the cement must be allowed to set for at least 12 hours unless the operator can determine that the compressive strength of the cement is at least 3,500 kPa after a minimum of 6 hours.

The maximum injection pressure used during a well stimulation must not exceed the burst pressure resistance of the weakest joint in the casing or tubing used or the rated working pressure of the wellhead, whichever is less.[364]

A Final Well Report that includes details of the completion operations must be submitted within 90 days of the rig release date for exploratory wells or within 45 days of the rig release date of a development well. The Well Report must include the following stimulation specific criteria:

- Date of stimulation;
- Interval;
- Method;
- Contractor;
- Type and quantities of stimulations; and
- Results of formation stimulation.

6.3.6 Nova Scotia

Onshore oil and gas activities are administered by the Nova Scotia Department of Energy. The Petroleum Resources Act and Regulations provide the regulatory framework for the management and allocation of petroleum rights.[365]

The Horton Bluff formation is still in the early phase of development. Five wells have been drilled in Nova Scotia and three of those wells have undergone hydraulic fracturing.[366] These three wells are the only wells that have been hydraulically fractured in the Province. Vertical wells in the McCully gas field and analogous basins in New Brunswick are currently being produced and evaluated.

Proper casing and cementing represent the primary means of protecting groundwater during hydraulic fracturing. The Petroleum Resources Act requires every operator to conduct the drilling and completion of a well in accordance with current petroleum standards and good petroleum drilling practices while maintaining full control of the well at all times. In Nova Scotia, regulations require any well that is drilled to be cased in steel to prevent fluids from traveling to formations where it is not intended (see **Figure 47**). The casing must also be cemented for additional aquifer protection.[367] The details of the casing and cementing program must be submitted on the ADW and are approved at the discretion of the Department of Energy.

The review and approval process for hydraulic fracturing onshore initiates when the Department of Energy issues a call for exploration proposals.[368] If and when the proposal is successful, the government can enter into a lease agreement. A separate application must be made for hydraulic fracturing. The relevant government departments and an independent engineer review the application and the operator is required to hold a public open house and obtain landowner approval if the proposed activity is to occur on private land.

In addition, an application for Industrial Approval must be submitted to Nova Scotia Environment that contains the following information:

- Proximity to water courses;
- Details on fluids, including handling and disposal;
- Fluid Monitoring Plan;
- Emergency Response Plan; and
- List of all chemicals to be used.

Project-specific terms and conditions can be imposed by Nova Scotia Environment to address potential concerns.

The operator must also file an application for an Authority to Complete at least 24 hours prior to the well completion. The application must include the well completion program that is consistent with good petroleum drilling practice and provides for the isolation of each completed interval from any other porous or permeable interval penetrated by the well and efficient testing and production of any completed reservoir interval. A well history report that contains a copy of any report that concerns well stimulation must also be submitted upon completion of an onshore well.[369]

In light of concerns over drinking water protection, the Government of Nova Scotia began examining the potential environmental issues associated with the hydraulic fracturing process in April 2011. The review team, comprised of officials from the Departments of Energy and Environment, will look at and review other jurisdictions across Canada and the United States and take into consideration the opinions and expertise of outside experts. The final product of the review process will be a set of recommendations that will be submitted to the Government of Nova Scotia to improve current Provincial regulations.[370] The scope of the project includes the following:

- Effects on groundwater;
- Use and effects on surface water;
- Impacts on land, such as potential soil contamination;
- Waste management, including surface ponds or produced waters;
- Management of additives in hydraulic fracturing fluids;
- Site restoration; and
- Financial security/insurance.[371]

The review is anticipated to be complete in early 2012.

6.3.7 Ontario

Oil and gas wells in Ontario are regulated pursuant to the Oil, Gas and Salt Resources Act (OGSRA), which became effective June 27, 1997.[372] The Ministry of Natural Resources (MNR) is responsible for maintaining safe and sustainable development of hydrocarbon resources. There are currently no shale gas prospects being actively pursued in Ontario. However, there is potential for development in the future. The Antrim Shale of Michigan extends northward into Ontario and is known as the Kettle Point Formation. The Utica Shale, which is known as the Collingwood/Blue Mountain formation, and the Marcellus Shale are also present in the Province. The Marcellus is located primarily under Lake Erie and will require special techniques to extract but this is nothing new as companies have had drilling rigs in the lake for nearly 100 years.[373] Development of resources in the Province is possible in the future and hydraulic fracturing would be regulated under the existing framework.

The Provincial Operating Standards in Ontario outline the casing and cementing requirements that protect groundwater during hydraulic fracturing operations. The casing and cementing must be installed to protect all water zones and all potential oil-bearing or gas-bearing formations encountered during drilling operations. The casing and cement must prevent the migration of oil, gas, or water from one horizon to another.[374]

The proposed design program must be outlined in the Application for a Well License. The potential formation pressures that may be encountered during drilling operations and during production, injection, or stimulation operations must be considered in the casing design. The following requirements must be followed (see **Figure 48**):

- Surface casing must be installed to isolate and protect potable water sources from other formations permanently, to prevent cross flow contamination, to prevent sloughing of unconsolidated material into the wellbore, and to be capable of anchoring the well control equipment.[375] The surface hole must be drilled below the lowest potable water zones. Intermediate casing is installed to protect equipment and shallower formations from excessive pressures, to prevent fluid migration between formations, to prevent shales and unconsolidated material from falling into the open hole, and to control the maximum anticipated target zone pressure.
- The cement must prevent fluid migration between formations and protect all potable water formations, potential hydrocarbon-bearing zones, and casings from all fluid-bearing formations. Surface casing must be cemented to surface unless an exception is met for cable tool operations. Intermediate casing must be cemented by circulation method with sufficient cement volume to theoretically reach to at least 25 m above the casing seat of the previous casing string. In many areas of Ontario, multiple aquifers may be encountered in the intermediate hole. When aquifers are present in the intermediate hole, the operator has to cement the next string of casing in place as well. Production casing must be cemented inside the previous intermediate casing string at least 25 m above the intermediate casing seat, but not less than 100 m above the highest potential pay zone.[376]
- The operator must collect cement samples and use them to determine sufficient wait on cement time. Drilling operations may not recommence for six hours or until the casing cement samples confirm a compressive strength of 3,600 kPa as determined by cement tables and visual examination.[377]

All hydraulic fracture stimulation descriptions must be revealed on the Daily Record, which is a report of all the events that are performed during a given day.[378] In addition, on the Drilling and Completion Report, the following details regarding stimulation activities are required:[379]

- Treatment Date;
- Treatment Number;
- Treatment Type;
- Top Depth;
- Base Depth;
- Formation;
- Treatment Fluid;
- Treatment Amount;
- Treatment Pressure;
- Fracture Pressure;
- Proppant Type; and
- Proppant Amount.

Stimulation fluids recovered from a well must be kept separate from oilfield fluid and disposed of in accordance with the Environmental Protection Act.

6.3.8 Prince Edward Island

Oil and gas development on Prince Edward Island (PEI) is regulated pursuant to the Provincial Oil and Natural Gas Act. While exploratory activities on the island have identified potential reservoirs, only 20 exploratory wells and 1 reentry well have been drilled on and around the Province.[380] Nine exploration wells drilled from the 1950s to 1978 revealed substantial oil and gas shows (observation of hydrocarbons on cuttings or increased gas readings) in two wells, but there were no commercial discoveries as a result of the exploratory program.[381] However, as a result of the one of the shows, a follow-up well was drilled in 1997. The results indicated 50m of potential gas pay (portion of the reservoir that contains economically producible hydrocarbons) but did not identify commercial capabilities. Shale gas development on the island is not currently planned; however, regulations are in place to protect aquifers if hydraulic fracturing is used in the future (see **Figure 47**):

- Conductor casing must be set to at least 30 m[1] below the mudline of the water body and cemented to surface in areas that are permanently covered by water. Surface casing must be set to a minimum depth of 305 m and at least 15 m into a competent formation by an approved method.[382]
- Surface casing must be cemented to the surface. Intermediate and production casing must be cemented through all porous zones and to a minimum of 305 m above the casing shoe.
- Surface casing cement must set for at least 12 hours and until a minimum compressive strength of 3450 kPa is achieved before the cement plug can be drilled out of the casing. Production and intermediate casing cement shall be allowed to set for at least 24 hours before the cement plug can be drilled out. Prior to drilling out any cement, the casing must be pressure tested to a minimum of 6,900 kPa.

Hydraulic fracturing proposals must undergo a thorough environmental assessment and public consultation prior to approval. The Province's Environmental Minister has stated that the analysis and studies being conducted in adjacent provinces will be taken into consideration before a permit authorizing hydraulic fracturing operations to commence is issued.[383]

Hydraulic fracturing events must be reported within 30 days after the well completion and must include a signed well completion report and include any formation test service reports

[1] Prince Edward Island regulations are written in Standard Oilfield Units.

and pressure charts. If the well is a new well, a new well report must also be submitted.

6.3.9 Quebec

The oil and gas industry in Quebec is regulated under the Mining Act and the Environmental Quality Act. Hydraulic fracturing in Quebec has been placed on hold until it is proven safe by an independent study. The Quebec Environmental Minister promised that no new shale gas projects would be approved until a Strategic Environmental Assessment (SEA) was completed, unless they were necessary for SEA study purposes.[384] Eleven experts have been tasked with undertaking the SEA that is anticipated to take between two and three years to complete,[385] In the interim, a new set of regulations to govern shale gas development has been implemented.[386]

Pursuant to the regulations, casing and cement have to be installed in all the encountered geological horizons that contain water, oil, or gas. The casing and cement must also be of sufficient strength to prevent any migration of oil, gas, or water from one geological horizon to another, and must be able to withstand any bursting, crushing, tension, or other physical stresses to which it will be subjected.[387] The details of the proposed surface and casing program are required on the ADW.

- Surface casing must be set at a depth equal to or greater than 10% of the maximum depth of the well.
- Each casing string must be cemented to the surface, with certain exceptions. When casing cannot be cemented to the surface, or in the case of intermediate casing where technical conditions do not warrant cementing to surface, cement must be completed by perforation or injection into the annular space and must meet the following conditions:
    - Surface Casing/Cement column above the shoe must be at least 50% the length of the casing;
    - Cement column up to the surface must be at least 5 m under the ground level; or where the well intersects potable water zones, at least 25 m under the potable water zone. **Figure 48** depicts a well diagram based on the regulations for well construction in Quebec.
- Secondary Casing (Intermediate or Production) must be cemented as follows:
    - Cement column must be at least 150 m above the shoe;
    - Cement column must be present at the level of any porous and permeable zone and at the level of the 100 m above that zone; or
    - Cement column in the annular space of the preceding casing must be at least 50 m above the shoe (see **Figure 48**).[388]

The casing and cementing details must be submitted on the daily drilling report, the Application for a Well Completion License, and the completion report.

The new regulations require companies to obtain a certificate of authorization for all exploratory drilling of oil or natural gas in shale as well as any fracturing operation throughout the province. As part of the certificate of authorization applicants are required to notify and consult the public via local newspapers and a website, in addition to disclosing the science and techniques of the drilling and fracturing methods.[389] Chemical compositions of the fracturing fluids must be disclosed as well. In addition, companies must disclose geology and water tables and detail air pollution measures and disposal plans. In the interim, hydraulic fracturing will only be allowed on the 18 shale gas wells that have already been fractured in the Province, and the 13 wells that have been drilled but not yet fractured under the new regulations.[390] The de facto moratorium has halted any additional hydraulic fracturing until the study is complete.

An application for a well completion must be submitted prior to completing an oil and gas well. The well completion license limits the stimulation pressure to a pressure less than 75% of its normal bursting strength of the casing.[391] In addition, the well completion license application must identify the stimulation program, but no specific requirements are outlined in the application.

6.3.10 Saskatchewan

Saskatchewan's oil production is second only to Alberta's among the Provinces.[392] The number of oil wells drilled in Saskatchewan increased by 70% from 2009 to 2010[393] and it is anticipated that activity will continue to increase in the future. Eight economic forecasters have predicted that Saskatchewan will have the fastest growing economy in Canada in 2011, which is a direct benefit of the oil and gas industry.[394] Fueling this driver is the 2011 Global Petroleum Survey, which identified Saskatchewan as the best place in Canada for oil and gas investment.[395] Furthermore, the survey identified the Province as the 11th (out of 136) best place in the world to invest in oil and gas,[396] a fact expected to drive the oil and gas industry well into the future.

Oil and gas development in Saskatchewan is governed by the Oil and Gas Conservation Act and the Oil and Gas Conservation Regulations, which were updated November 2010.[397] They require the following:

- Surface casing is required to be run to a minimum depth of 20 m below the base of the glacial drift, 10% of the projected total depth of the well, or 75 m below ground surface, whichever is deepest.

  Figure 48 provides a well diagram based on the regulations for well construction in Saskatchewan.[398]

- Surface casing cement must be pumped until cement is recovered at the surface and allowed to set under pressure for at least 8 hours before drilling can recommence. Production casing must be cemented and allowed to set for at least 24 hours and properly tested by the pressure method before the plug can be drilled out or before the well can be perforated.

Details of formation fracturing must be submitted on a Finished Drilling Report certified by the owner of the well within 30 days after completion of any workover job, including hydraulic fracturing. However, there are no specific requirements outlined on the form. Upon the request of the Minister, service companies shall submit reports and records of hydraulic fracturing. Daily records showing the oil, gas, and water produced from the well must be maintained. Operators are required to submit a "Form A-2: Notification of Flowback Fluid and Fracture Sand Disposal" no later than 48 hours after the disposal of the flowback fluid and/or fracture sand.[399]

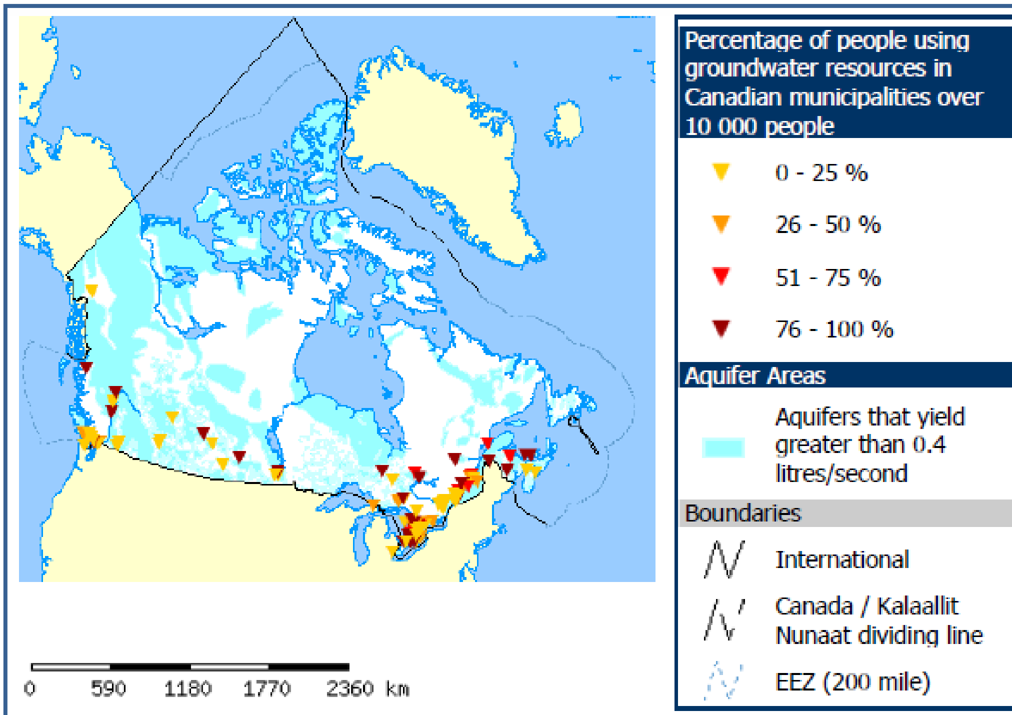
In October 2000, the Saskatchewan Energy and Mines Petroleum Development Branch issued Information Guideline GL 2000-01 entitled "Saskatchewan Hydraulic Fracturing Fluids and Propping Agents Containment and Disposal Guidelines."[400] While the guidelines focus on the disposition and surface management of fracturing fluids, which is beyond the scope of this document, it does state that "selecting environmentally friendly additives, using no-leak containment devices, minimizing the volume of fracturing fluids used, re-using and recycling sands, and selecting the best disposal option should be an integral part of well stimulation programs."[401]

6.4 Regulatory Comparisons

Regulation of hydraulic fracturing has been done for decades under existing Federal, Provincial, and Territorial regulations in Canada. Although specific regulatory language has not necessarily used the term "hydraulic fracturing regulation," requirements for surface casing, cementing, groundwater protection, and pressure testing have been prevalent in most regulatory regimes, all of which are directly applicable to the minimization of risks associated with hydraulic fracturing.

Groundwater is an integral natural resource in Canada. Approximately 8 million Canadians rely on groundwater for domestic, agricultural and industrial uses,[402] so protection of groundwater is a priority for the regulatory agencies, citizens, and oil and gas operators alike. **Figure 49** identifies the percentage of people using groundwater in cities greater than 10,000 in population. High concentration of arsenic is found in different parts of Canada, as are dissolved organic material, iron, manganese, ammonium, and high salt levels. In order to decipher between naturally occurring groundwater contaminants and potential contamination from hydraulic fracturing, operators may adopt baseline water testing as a BMP, a prudent measure that is supported by CAPP member companies. Currently, only Alberta and New Brunswick have baseline sampling requirements but many operators sample nearby domestic water wells prior to drilling. Subsequent testing could identify changes and allow the operator to compare the groundwater constituents to those in the stimulation and to determine whether changes have occurred and possibly what sources may have caused the changes.

Figure 49: Groundwater Use Distribution in Canada



Location of Aquifers in Canada and Proportions of People Relying on Groundwater;
http://atlas.nrcan.gc.ca/site/english/maps/freshwater/distribution/groundwater

Source: Natural Resources Canada. "The Atlas of Canada." Updated March 14, 2003. http://atlas.nrcan.gc.ca/site/english/maps/freshwater/distribution/groundwater (accessed December 1, 2011).

Surface casing is installed to protect groundwater resources and for pressure control of subsequent drilling operations. Since freshwater protection is a primary consideration when designing surface casing, drilling through groundwater zones with air, freshwater, or freshwater-based drilling fluid is an appropriate precaution and is a requirement in most provinces. In addition, setting surface casing at least 30 m below the deepest drinking water source provides a consistent standard of protection.[403] Most of the Canadian regulations specify the importance of surface casing and while many do not directly refer to the base of fresh water in the regulations, the regulations appear adequate to protect fresh water as evidenced by the lack of groundwater contamination incidents associated with hydraulic fracturing.[404, 405, 406] In addition, most regulations give the directors discretion for modifying casing setting depths. Some provinces like Alberta, with extensive oil and gas development, have extremely comprehensive surface casing setting guidelines that fully consider regional variances in groundwater. Most provinces and territories in Canada require cement to be circulated to the surface, which is important for completely isolating groundwater aquifers. **Table 16** identifies which mitigation measures are outlined in Federal and Provincial regulations in Canada.

After cement is set and before drilling or completion operations commence, it is important to evaluate the compressive strength of the cement surrounding the casing shoe. This is not a consistent requirement across the regulatory regimes in Canada. API Guidance recommends that the cement have a compressive strength of at least 3,450 kPa and achieve 8,275 kPa in 48 hours at bottom-hole conditions.[407] Many regulatory regimes also specify a wait on cement (WOC) time that must be met. This is not consistent throughout Canada.

A surface casing pressure test that will determine if the casing integrity is adequate to

CAPP – Hydraulic Fracturing Operating Practice:

FRACTURING FLUID ADDITIVE RISK ASSESSMENT & MANAGEMENT

CAPP and its member companies are committed to reducing the environmental risks associated with the additives in fracturing fluids. Hydraulic fracturing fluids are primarily comprised of water, sand and a very small amount of chemical additives. This practice outlines the requirements for companies to better identify and manage the potential health and environmental risks associated with these additives; where possible, fracturing fluids with lower risk profiles can be selected.

Purpose: To describe minimum requirements for the risk-based assessment and management of fracturing fluid additives used in the development of shale gas and tight gas resources.

Objective: To enable and demonstrate conformance with the CAPP Guiding Principles for Hydraulic Fracturing:

We will support the development of fracturing fluid additives with the least environmental risks.

We will continue to advance, collaborate on and communicate technologies and best practices that reduce the potential environmental risks of hydraulic fracturing.

Under this Operating Practice, companies will assess the potential risks of fracturing fluid additives and create risk management plans to effectively manage the additives, and make the process used to develop specific plans publicly available. This assessment includes:

- Identifying chemical ingredients and characteristics of each additive.
- Assessing potential health and environmental risks of each additive.
- Defining operational practices and controls for the identified risks.
- Incorporating risk management plans for each well fractured.

Table 16: Regulatory Comparisons for Canadian Territories and Provinces

“**G**” – Generally addressed in Regulations “**S**” – Specifically addressed in Regulations “**F**” – Covered by Federal Regulation		**Federal Regulation**					**Provincial Regulation**									
		Newfoundland & Labrador Offshore	Nova Scotia Offshore	Northwest Territories	Nunavut Territory	Yukon Territories	Alberta	British Columbia	Manitoba	New Brunswick	Newfoundland & Labrador	Nova Scotia	Ontario	Prince Edward Island	Quebec	Saskatchewan
Groundwater Protection	Surface Casing Requirement	**G**	**G**	**G**	**G**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**
	Surface Casing Groundwater Protection Setting	**G**	**G**	**G**	**G**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**
	Pressure Testing of Casing	**G**	**G**	**G**	**G**	**G**	**S**	**G**	**G**	**G**	**F**	**F**	**G**	**G**	**G**	**G**
	Baseline Water Sampling	**G**	**G**	**G**	**G**	**G**	**S**	**S**	**F**	**S**	**F**	**F**	**F**	**F**	**F**	**F**
	Vertical Depth Restrictions	**G**	**G**	**G**	**G**	**G**	**S**	**S**	**F**	**F**	**F**	**F**	**F**	**F**	**F**	**F**
	Water Well Setbacks	**G**	**G**	**G**	**G**	**G**	**S**	**S**	**F**	**F**	**F**	**F**	**F**	**F**	**F**	**F**
Hydraulic Fracturing Operations	Regulatory Notification	**S**	**S**	**G**	**G**	**G**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**
	Fracturing Plan	**S**	**G**	**G**	**G**	**G**	**S**	**G**	**G**	**S**	**G**	**S**	**G**	**G**	**S**	**G**
	Public Notification	**G**	**G**	**G**	**G**	**G**	**S**	**S**	**F**	**F**	**F**	**S**	**F**	**F**	**F**	**S**
	Reporting	**S**	**S**	**G**	**G**	**G**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**	**S**
	Fracture Fluid Chemical Disclosure	**S**	**S**	**G**	**G**	**G**	**S**	**S**	**S**	**S**	**G**	**G**	**G**	**G**	**S**	**S**

Regulatory Notification – Federal wells typically requires an Approval to Drill a Well (ADW) application submitted for each well.
Fracturing Plan – Federal approval for hydraulic fracture stimulation requires an Application to Alter the Condition of a Well (ACW) as well as a Notification to Complete (NOC) describing the fracturing equipment and duration.
Reporting – The composition of the fracture fluid is required to be submitted on a revised NOC, in addition the stimulation details must be submitted on a Final Well Report, Well History Report, or Well Operations Report.
Fracture Fluid Disclosure – Federal offshore wells follow the Offshore Chemical Selections Guidelines (OGSC) and subsequence reporting requirements.

meet the well design and construction conducted prior to drilling out the plug at a pressure objectives is a prudent BMP. After drilling out the surface casing plus a small interval of new formation, performing a formation pressure integrity test (shoe test or leak-off test) is appropriate to ensure safety. This is a requirement in most of the Provinces and Territories in Canada.

7 MAJOR PATHWAYS OF FLUID MIGRATION

This section focuses on the defined pathways of contamination that could potentially allow fluid migration to pose a risk to a current or prospective source of drinking water or fresh water. The scenarios considered in this report are limited to those that could occur during the injection phase of a hydraulic fracturing operation, and are limited to those events that occur in the subsurface. Five potential pathways are addressed in this report:

- Vertical fractures created by hydraulic fracturing
- Existing conduits (e.g., natural vertical fractures or old abandoned wellbores) providing a pathway for injected fluid to reach a fresh water zone
- Intrusion into a fresh water zone during hydraulic fracturing based on poor construction of the well being fractured
- Operating practices performed during well injection
- Migration of hydraulic fracturing fluids from the fracture zone to a fresh water zone

Potential pathways to contamination other than those caused by subsurface injection are not considered in this analysis. This includes other pathways that could occur during a hydraulic fracturing operation, including those that occur on the land surface, such as equipment failure and accidental spillage. The following sections discuss each of the subsurface pathways.

7.1 Vertical Fractures Created by Hydraulic Fracturing

The probability that hydraulic fracturing could create fractures that extend from the hydrocarbon resource-producing zone to a fresh water zone is extremely low to nonexistent.[408] The pressures, fluid volumes, and duration of fracturing stimulation currently used make it highly unlikely that a vertical fracture could extend from the fractured shale to a fresh water zone.[409] Without calculating the required pressures, fluid volumes or stimulation duration one can surmise that creating a fracture over a kilometer in distance would necessitate a large volume of fluid at a sustained pressure for an extended duration. An actual calculation of this scenario would require numerous variables and result in a theoretical fracture that is not possible. In addition, all hydraulic fracture treatment jobs are closely monitored and designed for optimal fracture propagation. Operations are monitored to assure that fractures do not extend out of the target zone. Fracturing outside of the geologic formation that contains oil or gas would be ineffective and costly and is not in the interest of the producing company. There are many factors that need to be considered when assessing this risk scenario:

- What is the distance from the zone being fractured to the fresh water zone?
- What is the volume of hydraulic fracturing fluid being pumped and what is the size of the fracture being created?
- What are the geologic barriers to be overcome by the creation of vertical fractures?
- What are the intervening hydrostatic conditions of the formations between the fracture zone and the fresh water zone?
- What is the direction and orientation of the fracture being created?

7.1.1 Distance bet ween Zones

According to the Interstate Oil and Gas Compact Commission (IOGCC), not one case has been documented of the fracturing process creating a fracture leading to communication of hydraulic fracturing fluid with a fresh water zone.[410] Some news articles have asserted that the act of hydraulic fracturing has the potential to create a pathway between natural gas- and oil-producing zones and groundwater aquifers,[411] but that is highly improbable.[412] The probability that a fracture could be created to extend to a fresh water zone is higher in plays where the producing formation and the fresh-water zone are in closer vertical proximity. However, most shale plays are several thousand metres below any fresh water zones; as a result, fractures would have to travel through several thousand metres of confining layers of rock. A review of compiled data from hydraulic fracturing jobs performed by a major hydraulic fracturing service company discloses the comparison between the fracture height and the intervening distance between the fractures and fresh water zones for over 2,300 separate fracture stages.[413] **Figure 50** is an example of this compilation for the Barnett Shale. From the graph, one can see that the vertical fractures are several thousand metres below the freshwater aquifers in the Barnett. In addition to the natural protection of groundwater provided by the distance between producing shale gas or oil formation and potentially usable groundwater source, there are protection factors built into Territorial- and Provincial-required well completion procedures.

7.1.2 Additional Barriers and Intervening Geology

The geology of the formations in between the productive shale zones and the fresh water zones provide additional protections against the vertical growth of fractures. The rock formations found between the producing shale and groundwater aquifers tend to act as natural barriers to vertical fractures because there are natural variations in the properties of these rocks.[414] These geologic differences can form boundaries above and below a target shale zone, preventing fracture growth outside of the shale formation. Additional layering is also present in the thousands of metres of rock formations between the productive shale zones and groundwater aquifers. If two materials are sufficiently dissimilar at the interface of two different formations, the potential for the fracture to change course from a vertical to horizontal fracture is increased considerably.[415]

7.1.3 Hydraulic Conditions of Intervening Geology

For a fracture to reach from the oil- or gas-producing zone to a fresh water zone, enough of the fluids being pumped must be maintained in the fracture to propagate that fracture. Fluids that have leaked off into the formation being fractured are often trapped in those formations. This is seen in most basins from the low volumes of fracture fluid that are recovered after the fracture treatments are stopped and the flow of fluids is reversed. The intervening formations between the target zone and fresh water zones contain lower pressure than is required to fracture the rock. Therefore, if a fracture were to propagate into those zones, fracturing fluid would leak off into the intervening zones. [416] This is what typically causes a fracture to "Screen Out" or stop propagating in the productive zone. This leak-off from the fracture being created into the intervening formations is another factor that reduces the probability that a vertical fracture would extend from the productive zone to a fresh water zone.

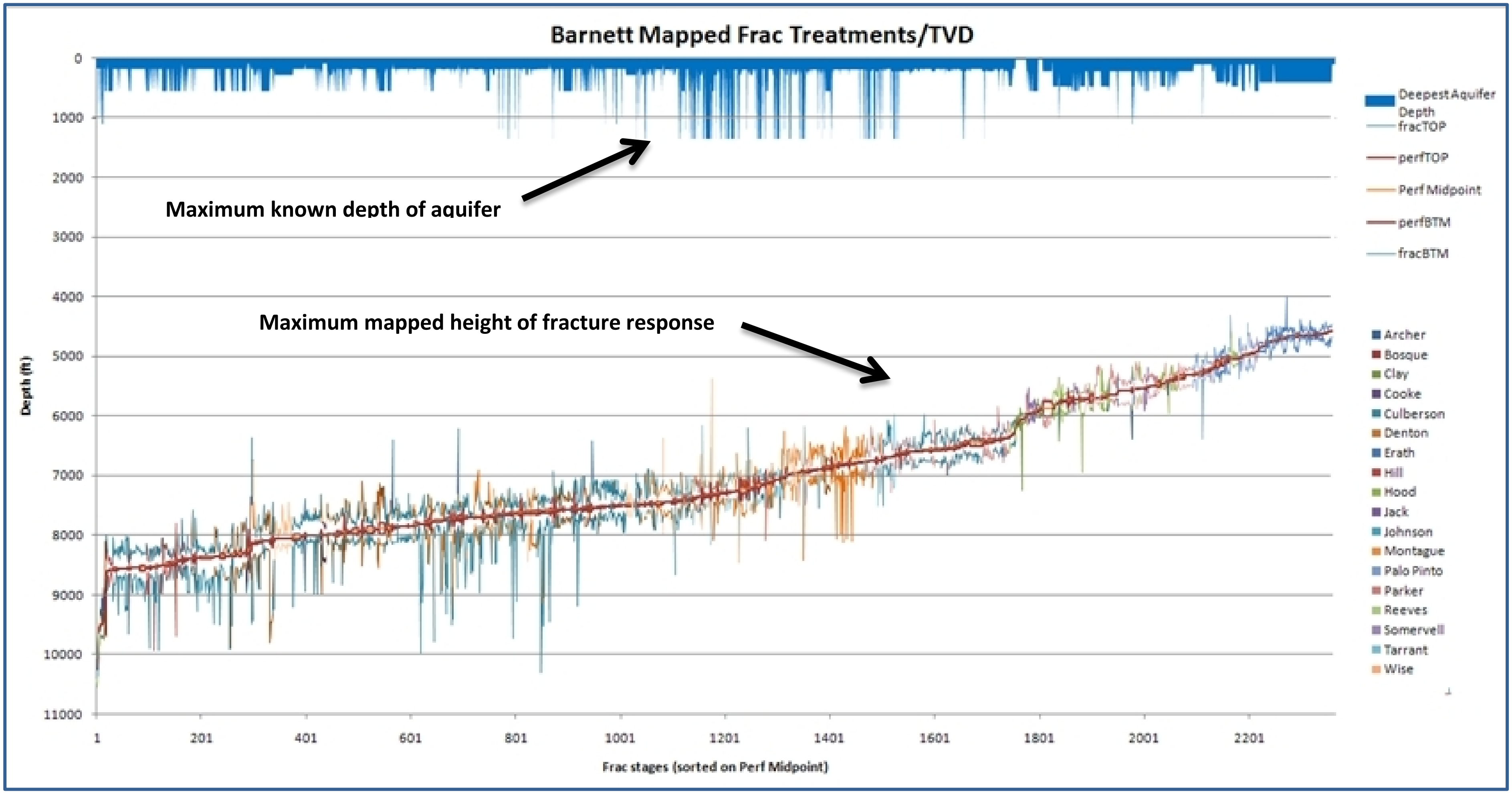
7.1.4 Direction and Orientation of Fractures

The fracture orientation created varies based on the depth of the formation and the plane of least resistance to fracturing. Please review **Section 2.0** (Overview of Hydraulic Fracturing) and **Figure 7** for additional discussion on fracturing and fracture orientation. For shallower wells the fracturing plane of least resistance typically causes horizontal fractures to be created. Vertical fractures in shallower zones are less likely to be created, because the direction of least principal stress causes horizontal fractures (i.e., parallel to the ground surface) rather than vertical fractures.[417] Such fractures will not reach a fresh water zone because they will not grow in the direction of the fresh water zone. Furthermore, the movement of high pressure fluids in horizontally layered rock formations would be horizontal rather than vertical. The permeability properties of the rock causes pressurized fluids to spread out along the layered fractures rather than upward.[418]

7.1.5 Volume and Size of Hydraulic Fracturing Job

Hydraulic fracture operations are engineered, designed, and modeled before any fluid is injected. The design of each job, including the volumes of fluid and the pressures to be used, limits the distance the fluid can travel and therefore the length and height of the fracture created.

Figure 50: Fracture Height Determination – Microseismic



Source: Kevin Fisher, "Data Confirm Safety of Well Fracturing," *The American Oil & Gas Reporter* (July 2010).

For a fracture to extend the thousands of metres between the productive zone and a fresh-water drinking zone, the fracture stimulation would need to be much larger than those typically designed for oil and gas development. Basically, the volumes that would be necessary to cause a fracture to reach the groundwater zone are not used in fracturing of shale formations. Fracture jobs are specifically engineered to fracture for an optimum width and length and to be contained within the gas- or oil-producing zone. If a fracture were to travel beyond the productive zone, the job would not be effective, and could potentially destroy the productivity of the well. The resulting excessive cost of the fracturing job and the loss of potential revenue from the well would result in an economic loss to the owner of the well.

7.2 An Existing Conduit Providing a Pathway to Fresh Water Zone

Another pathway considered for groundwater contamination is through existing conduits, such as faults, existing fractures, abandoned wellbores, or other available conduits that are connected to drinking water sources. For this scenario to occur, the hydraulic fracturing stimulation must push hydraulic fracturing fluids, natural gas, or the existing brine from deeper formations into the drinking water sources through an available transmissive flowpath. For fracturing fluid to travel through an existing conduit, the following conditions must exist:

- A flowpath exists that would allow for fluid movement;
- Existing conditions have not allowed flow prior to the fracturing event;
- The fracture treatment would continue even after encountering the flowpath; and
- Pressure is sufficient to raise the fluid to a height that would overcome the hydraulic head in the fresh water zone.

The theory used in this potential flowpath considers only the pressure differences between the production and fresh water zones.

Real-world considerations such as friction loss, barriers resistance, or sustained flow rates were not considered when determining the potential for vertical migration to the fresh water zone in the hypothetical case presented. Thus, this represents an idealized situation. Without these parameters a conservative analysis is performed thus providing a built-in safety factor. This however does not truly represent the real-world conditions present during a hydraulic fracturing job. In order to calculate if a fluid can travel through an existing conduit to a fresh water zone, the pressure required to lift a fluid column must be calculated.

The following equation is used to determine the pressure required to lift a fluid column based on head:

Where:

Head = Metres of Fluid Column, m

Water Gradient = 9.795 kPa/metre

Specific Gravity of Fluid = Density of Fluid/Density of Water

Using the above equation, the head difference between two columns of fluids can be calculated for both the fresh water zone and the producing reservoir. In addition, the difference between the heads when fracturing is taking place can be determined and, if the

$$\boldsymbol{Pressure = Head \times Water\ Gradient \times Specific\ Gravity\ of\ Fluid}$$

pressure to lift the fluid column is known, it can also be determined if fluid can migrate through an available pathway. The hypothetical hydraulic and reservoir parameters given in **Table 17** and in the radius of influence calculation above were assumed simply to show the calculations involved. Using these, one can determine the pressure that would be sufficient for a proppant-laden fluid to overcome the head in a fresh water zone and migrate into that fresh water zone.

Table 17: Reservoir Parameters

Parameter	Value
Base of Fresh Water	150 m
Water Head	60 m
Specific Gravity of Reservoir Fluid	1.1
Existing Head Reservoir	900 m
Head Fresh Water Above Reservoir Head	810 m
Specific Gravity of Fracture Fluid	1.5

In this hypothetical calculation, the head in the reservoir would have to be increased by 810 m or 8,727 kPa for the in-situ fluid in the reservoir to have the potential to affect the groundwater used for drinking. Performing the same calculation for the fracture fluid with a 1.5 Specific Gravity would mean that the pressure in the reservoir would have to be increased by 11,901 kPa. Continued injection would have to occur to maintain this pressure increase in the reservoir to sustain flow. Once fracturing ends, injection also ends and the pressure begins to decrease in the reservoir, stopping any hypothetical flow out of the reservoir.

The most likely case in which an artificial penetration could provide a flowpath for hydraulic fracturing fluids is through the well itself. There are many barriers of protection in a properly constructed wellbore. In order for a well to fail, the protections provided by the casing and cement would have to fail. The following presents an analysis of the protection provided by casing and cement *when they are properly installed* and the probability that these protections will fail through corrosion.

This type of analysis was presented in an API series of reports in the 1980s.[419,420] These reports evaluated corrosion levels in injection wells associated with oil and natural gas production, mainly those that injected salt water (brine) brought to the surface in the process of producing oil or gas. This research developed a method for calculating the probability (i.e., risk) that fluids injected in this manner could impact a source of groundwater used for drinking.[421,422] This research effort evaluated data for oil- and gas-producing basins to determine which ones contained natural formation waters that were reported to cause corrosion of well casings. The researchers divided the United States into 50 basins, and they ranked each basin by its potential to have a casing leak resulting from such corrosion.[423]

The API study analyzed 19 U.S. basins in which casing corrosion was a possibility. Through risk-probability analysis, an upper bound for the probability of the fracturing fluids reaching a source of groundwater used for drinking was developed. Using the API analysis and then assuming a modern horizontal well completion in which 100% of the groundwater used for drinking is protected by properly installed surface casings (and for geologic basins with a reasonable likelihood of corrosion), the authors calculated that the probability that fluids injected at depth could impact a source of groundwater used for drinking would be between one well in 200,000 (2×10^{-5}) and one well in 200,000,000 (2×10^{-8}) if these wells were operated as injection wells, which routinely inject at disposal pressure, compared to an oil or gas well where the stimulation only happens for minutes over a period of months.[424] These values do not account for the differences between the operation of a producing gas shale well, which serves as a pressure sink, and the operation of an injection well that is a pressure source. A producing gas well would be less likely to experience a casing leak for the following reasons:

- It is operated at a reduced pressure compared to an injection well;
- It would be exposed to lesser volumes of potentially corrosive water flowing through the production tubing; and
- It would only be exposed to the pumping of fluids into the well during fracture stimulations, which only last from one day to a few days.[425]

The API study analyzed wells that had been in operation for many years. An important conclusion in the API report was:

> …for injected water to reach a underground source of drinking water in the 19 identified basins of concern, a number of independent events must occur at the same time and go *undetected* [emphasis added] [by the operator and regulators]. These events include simultaneous leaks in the [production] tubing, production casing, [intermediate casing], and the surface casing coupled with the unlikely occurrence of water moving long distances up the borehole past salt water aquifers to reach a underground source of drinking water.[426]

The API analysis places an upper bound on the probability of contamination through such a pathway. Because of the historical nature of the study, it does not account for advances that have occurred in equipment, applied technologies, and changes to regulations.[427] When considering a modern shale gas well, there would be an even lower probability for groundwater contamination, perhaps by as much as two to three orders of magnitude, because of the construction of the well and the fluid dynamics in the wells. The probability for a groundwater source used as drinking water to be impacted by the pumping of fluids during hydraulic fracture treatments in a properly constructed well using the latest regulations on well construction and permit requirements and when a high level of monitoring is performed would be even less than the one well in 200,000,000 (2×10^{-8}) estimated in the study.[428]

7.3 Poor Well Construction

Improper well construction is the most likely reason for the migration of fluids from a wellbore to a groundwater source. Maintaining wellbore integrity is essential to isolate the wellbore from the surface and subsurface environment and to contain the injected fluid and produced fluid within the wellbore.[429] Regulatory programs in both Canada and the United States place a strong emphasis on casing design and protection of fresh groundwater resources. Current well construction requirements consist of installing multiple layers of protective steel casing and cement that are specifically designed and installed to protect fresh water aquifers and to ensure that the producing zone is isolated from overlying formations. The regulatory review section in this report details current well construction requirements. These requirements have proven more than adequate to contain a well during hydraulic fracturing operations as demonstrated by the lack of documented contamination incidents associated with the practice.[430,431,432]

Surface casing, cemented into place, is a protective measure that shields potable groundwater and maintains stability in the well. Standards for cement ensure that requirements for strength and chemical composition are met. Standards for surface casing assure that it is capable of withstanding designed pressures, including the pressures that are experienced during hydraulic fracturing operations, when cemented. While different regulatory agencies have different requirements for surface casing and cementing criteria based on varying geologic conditions, the criteria are all designed to provide the same protection. Although the specific language varies, the rules generally state that surface casing must be set to a depth below the deepest potable fresh water zone in a manner to prevent the migration of fluids, both water and hydrocarbons, from one formation to another.

During the fracturing treatment, water and proppant are pumped down the well at treatment pressure to fracture the formation. This may be the only time during the life of a well that the casing is subjected to elevated internal pressure. When the well's casing is used as the "frac-string," it and the cement used to maintain integrity are designed specifically to withstand the pressures and flexing of the casing seen only during fracturing. Depending on site conditions and production economic, it may be decided in the design phase to minimize the impact on the casing through the use of an additional "frac-string" of pipe. This "frac-string" may be run into the well to protect the casing during the fracturing process. This "frac-string" is designed to withstand the specific treatment pressures and is removed after the job is complete. In these cases the well casing and the cement may be designed for typical well operations and not bolstered to serve as a "frac-string." Therefore, the well bore cement is not impacted by any flexing of the casing during the fracture treatment.

It is essential that producing and fresh water zones are isolated in the wellbore. In order to make certain that this is occurring, a variety of checks are used. Operators may ensure that the cement has properly bonded to the casing by using checks such as acoustic cement bond logs. Additionally, oil and gas regulatory agencies often specify the required depth of protective casings and regulate the time that is required for cement to set prior to additional drilling. These requirements are often based on regional conditions.

Following the required well construction regulations and BMPs in an area will greatly limit any potential for the injected hydraulic fracturing fluids to have a pathway to migrate

CAPP – Hydraulic Fracturing Operating Practice:

WATER SOURCING, MEASUREMENT, AND REUSE

CAPP and its member companies recognize that water is a resource we all share. We put great emphasis on the need to use and manage water responsibly in our operations. For shale gas and tight gas developments, water is typically only required for well drilling and completion and not for the actual production of the gas. Some of the water injected during fracturing operations is recovered with the gas, and is either recycled for reuse in another operation or disposed of according to regulations. This practice requires companies to evaluate available water supply sources, measure water use and reuse water as much as practical in hydraulic fracturing operations.

Purpose: To describe minimum requirements for safeguarding water quantity through assessment and measurement of water sources, including recycled water, in shale gas and tight gas hydraulic fracturing operations.

Objective: To enable and demonstrate conformance with the CAPP Guiding Principles for Hydraulic Fracturing:

We will safeguard the quality and quantity of regional surface and groundwater resources, through sound wellbore construction practices, sourcing fresh water alternatives where appropriate, and recycling water for reuse as much as practical.

We will measure and disclose our water use with the goal of continuing to reduce our effect on the environment.

We will continue to advance, collaborate on and communicate technologies and best practices that reduce the potential environmental risks of hydraulic fracturing.

Under this Operating Practice, companies will safeguard water quantity through assessment and measurement of water sources (including recycled water). As with all industrial operations, the volume of water that can be withdrawn is approved by the Provincial regulator to ensure sustainability of the resource. These practices include:

- Complying with withdrawal limits and reporting requirements of water licences/permits. Also, collecting and reporting water use data through CAPP's Responsible Canadian Energy™ Program.
- Implementing a decision-making framework to evaluate and understand available water sources.
- Monitoring surface water and groundwater quantity data, as required to demonstrate sustainability of the water source; and collaborating with other companies on best practices.

to a fresh water source. Statistics from past fracturing events do not provide any evidence of fresh water contamination from injection during hydraulic fracturing. The impact from the hydraulic fracturing process on properly constructed wells is negligible. Regulations are in place to ensure the proper construction of wells and responsible operators and drillers ensure that these practices are followed. Regulatory requirements are not the only reason for an operator to have a properly constructed well: poor wellbore construction can allow fluids to migrate outside of the production zone, causing potential revenue loss and possible well failure.

7.4 Operating Practices during Injection

Design and modeling cannot anticipate every event that can occur during the performance of a hydraulic fracturing job, such as natural over pressuring of the formation or unanticipated formation subsidence. The monitoring of a hydraulic fracturing job is continuous and when any operating variable diverges from what is expected, the job may be immediately stopped to address the situation. This continuous monitoring of pressures and volumes during a hydraulic fracturing job ensures a high probability of a successful job and consequently provides protection to the fresh water source.

Other practices have also been put into place to ensure that a hydraulic fracturing job is successful. This includes cement designs that incorporate additives that can overcome unforeseen events, such as the presence of flowing gas or crude oil.[433] Depending on the design requirements of the well, a cement sheath that can react in the event of a failure and repair itself automatically, sealing the flow pathways before intervention would be necessary, and has been developed. This may only be warranted in special circumstances specific to a well's location, geology, and expected treatment options. The auto-repair ability is not limited to a single incident: the technology will self-repair on multiple, independent occasions.[434]

7.5 Migration of Fluids from Fracture Zone to a Shallow Groundwater Zone

This section analyzes the potential for flow of fluids through the rock, rather than through a fracture or artificial conduit like in section 7.2. During the injection period of a hydraulic fracturing job, the migration of the injected fluids away from the injection zone would only occur if there were a pressure sink, area of low pressure that the fluid would flow toward. This would mean that existing fluids in the reservoir would already be flowing toward that pressure sink. If fluids flowed toward a pressure sink that contained fresh water, it would be occurring due to natural pressure gradients, and the fresh water zone would not exist, because it would have received fluids thus mixing with the fresh water. Therefore the probability that injected fluids would migrate based solely on existing reservoir dynamics is negligible. The following presents a theoretical overview of reservoir pressure dynamics that addresses this issue.

In order for fluid to flow within a reservoir, a pressure differential must exist. For example, for fluid (i.e., oil, gas, and/or water) to move into the wellbore and be produced, the wellbore and the area immediately surrounding the wellbore must have a lower pressure than the parts of the reservoir that are farther away, yet still in communication with the wellbore through pathways in the rock matrix.

Darcy's Law defines the relationship between the flow of fluids through porous media and the reservoir properties through the generalized form of the equation:[435]

$$Q = \frac{ckA(P_1 - P_2)}{\mu L}$$

Where:

Q = Flow Rate

c = Unit Conversion Factor

k = Formation Permeability

A = Area

P = Pressure

μ = Fluid Viscosity

L = Length[436]

The relationship between the reservoir parameters can be used to explore the effects in the reservoir of a hydraulic fracturing operation, production, or hypothesized migration of fluid either in the reservoir or surrounding formations. The ability of fluid to flow in a porous media is impacted by the dynamics of pressure in the reservoir. These dynamics must be considered when evaluating what happens to the fluid used during a hydraulic fracturing operation in a post-fracture environment. It can be assumed that fluid from a hydraulic injection event is in communication with the wellbore since that fluid was emplaced through the use of the wellbore.

It is more difficult for fluid from a hydraulic fracturing job to flow up and down than side to side in a shale bed. This is because the permeability properties that govern the flow of pressurized fluid within and between the rock layers cause the fluid to spread out horizontally rather than vertically. Vertical and horizontal directions of permeability are measured to determine the ability of the fluid to flow in those directions. As an example, shale subsurface rock that is deposited in layers, has typically more restrictive permeabilities that are vertical than horizontal (assuming flat-lying shale beds).

The following analysis examines a worst-case scenario for vertical migration of fluid from the fractured reservoir to a fresh water zone. The assumptions for this scenario are

- A reservoir condition is introduced that allows the fluid to migrate beyond the barrier that originally trapped the hydrocarbon in place;
- The wellbore is non-productive;
- The well is abandoned after the hydraulic fracture treatment is finished, initial flow back leaves some fracture fluid in the reservoir, and that fluid is able to move;
- There are no barriers that would prevent the natural migration of fluids from the reservoir to the fresh water zone;
- The pressure in the reservoir is sufficient to raise the in-situ reservoir fluid to the level of the fresh water zone);
- There are no sink zones or over-pressured zones between the reservoir and the fresh water zone; and
- There are no fractures or faults connecting the reservoir with the fresh water zone, so that the fluid must travel through the rock matrix.

Using these assumptions, the potential of a fluid to migrate through the geologic formations located between the Horn River Shale in British Columbia and a shallow freshwater aquifer can be estimated. Additionally, the velocity of the fluid traveling through the intervening geologic formations to fresh water zones can be calculated using reservoir pressure dynamics. The following represents a derivation of Darcy's law for fluid velocity relative to vertical movement of fluid through porous media:[437]

$$v = \frac{c k_{avg} \rho g h}{\mu L}$$

Where:

v = velocity = Q/A

k_{avg} = average permeability

c = unit conversion factor

ρ = density

h = head, length

μ = viscosity

L = distance fluid travels, length

g = constant for acceleration of gravity

The permeability used in the previous equation must be an average permeability representing the permeability of the layers that are being considered. For the case being considered in this analysis, an average permeability calculation accounts for the fact that the fluid has to travel through each layer before reaching the next. The equation for this permeability averaging is

$$k_{avg} = \frac{L}{\sum {L_f}/{k_f}}$$

Where:

k = permeability

L = Length[440]

Calculations using the above theory on velocity and knowledge of the travel distance can determine the time it would take for fluid to migrate from the Horn River Shale to a fresh water zone above the Cretaceous Shale. In order to make these calculations, the fluid parameters of water can be used for simplicity as well as the reservoir parameters identified in **Table 18**.

Using the numbers in **Table 18** for each formation, the average permeability calculated is approximately 0.0119 millidarcies (md). Imputing this permeability value into the Darcy's law equation, a pressure differential head, as presented, yields approximately 400 thousand years for fluid to migrate from the Horn River Shale to the groundwater source used for drinking in the area.

Based on the time for fluid to flow and the required conditions for this activity to occur it is highly improbable that migration from the production zone to a fresh water source will occur through the rock matrix of the intervening layers.

Table 18: Hypothetical Reservoir Parameters for Calculations

Formation	Head at Base, m.	Top, m.	Bottom, m.	Vertical Permeability, md*
Fresh Water Zone	200	0	600+	--
Cretaceous Shale	--	600	700	0.01
Debolt/Rundle	--	700	1000	25
Mississippian Shale	--	1000	1700	0.01
Upper Devonian Shale	--	1700	2500	0.01
Horn River Shale	2100^	2500	--	--

Fluid Viscosity 0.85 cp

Fluid Density 1.0

* A general rule of thumb for vertical permeability is considered to be 10% of horizontal permeability. Permeability assumed to be maximum from range presented for lithology type.[438]

\+ Based on regulation requirements for Surface Casing in British Columbia.[439]

^ Assumed sufficient to reach 200 m into Fresh Water Zone

8 PAST INCIDENTS OCCURRING DURING HYDRAULIC FRACTURING

Numerous reports of environmental contamination across North America have been attributed to hydraulic fracturing in the mainstream media. In fact, none of these incidents has been documented to be caused by the process of hydraulic fracturing: some have been shown to be the result of poor execution of other parts of the drilling, development, and production process, such as methane migration due to casing leaks or poor cement jobs; some have been caused by accidents such as surface spills or by past practices that are no longer allowed, such as leaving wastes in old reserve or production pits; some were the results of contaminants that existed in drinking water aquifers before any drilling activity was begun; some have causes yet to be determined and await further testing and research.

Environmental contamination can result from a multitude of activities that are part of the oil and gas exploration and production process: road and well pad construction, freshwater withdrawals, changes in land use, improper cementing of wells, inadequate number of well casings, naturally over-pressurized wells, poor chemical handling practices, inappropriate chemical storage, natural gas migration, inability of municipal wastewater treatment plants to treat produced water, disposal of brine, erosion and sedimentation, introduction of invasive species, increased truck traffic, emissions from drilling, fracturing, compression equipment, and spills and accidental releases. All of these activities are distinct from the process of hydraulic fracturing as described in this report. Yet, contamination of ground water and drinking water is frequently attributed to hydraulic fracturing.

A recent study by the Energy Institute at the University of Texas at Austin analyzed numerous reported environmental incidents associated with oil and gas development.[441]

CAPP – Hydraulic Fracturing Operating Practice:

FLUID TRANSPORT, HANDLING, STORAGE, AND DISPOSAL

CAPP and its member companies are committed to reducing the risk of potential spills of fracturing fluids, produced water, flowback water and fracturing fluid wastes associated with the hydraulic fracturing process. This practice requires companies to transport, handle, store and dispose of all fluids in a manner that is safe and environmentally responsible.

Purpose: To describe minimum requirements for fluid transport, handling, storage and disposal in shale gas and tight gas hydraulic fracturing operations.

Objective: To enable and demonstrate conformance with the CAPP Guiding Principles for Hydraulic Fracturing:

We will continue to advance, collaborate on and communicate technologies and best practices that reduce the potential environmental risks of hydraulic fracturing.

Under this Operating Practice, companies will implement practices and procedures to: identify, evaluate and mitigate potential risks related to fluid transport, handling, storage and disposal; and respond quickly and effectively to an accidental spill of fluids (including remediation of the spill site). These practices and procedures include:

- Following applicable federal, Provincial and municipal regulations for fluid transport, including Transportation of Dangerous Goods (TDG) regulations.
- Implementing maintenance and safety protocols to address the risks associated with fluid transport by road, rail or pipeline.
- Reducing fluid transport by road in large-scale development projects where possible.
- Constructing and operating pipelines that transport fluids in accordance with applicable regulations.
- Removing natural gas from fluids prior to storage.
- Following applicable regulatory requirements for fluid storage.
- Restricting wildlife access to fluid storage sites.
- Safely disposing of fluids that are no longer needed at approved waste management facilities, including disposal wells.

After considering the possible avenues of contamination and performing an analysis of media coverage, the report states:

> However, there is at present little or no evidence of groundwater contamination from hydraulic fracturing of shales at normal depths. No evidence of chemicals from hydraulic fracturing fluid has been found in aquifers as a result of fracturing operations.[442]

The authors go on to say that surface spills of chemicals present a greater risk than fracturing operations.

The term "hydraulic fracturing" is often confused, purposefully or inadvertently, with the entire development lifecycle. As a result of this confusion, there are many reported incidents of contamination falsely attributed to hydraulic fracturing in the mass media and in reports and articles from environmental NGOs. **Table 19** contains a list of many of the most prominently discussed incidents, in chronological order. Included in the table is the type of release along with the exposure pathway for any contaminants. In each case, the table shows that the cause was not hydraulic fracturing, or notes that further study is needed to document the cause with reasonable certainty.

Several incidents have become especially widely discussed and attributed to hydraulic fracturing in the media. These are described in more detail in **Appendix E.** These descriptions are illustrative of the analysis that is required to determine the true causes of contamination.

While hydraulic fracturing has not been shown to cause contamination of ground water or surface water, more study of the potential risks is needed to inform the debate on this process. Perhaps the most prominent current study is that being performed by the USEPA on the relationship between hydraulic fracturing and potential impacts on drinking water resources.[443] The study is examining the conditions and risk pathways that may be associated with the potential contamination of drinking water resources to identify the factors that may lead to human exposure and risks. The scope of the proposed research includes the full lifecycle of water in hydraulic fracturing, from water acquisition through the mixing of chemicals and the fracturing process to the post-fracturing stage, including the management of returned and produced water and its ultimate treatment and/or disposal. To better understand potential human health effects, USEPA plans to summarize the available data on the toxicity of chemicals used in or released by hydraulic fracturing, and to identify and prioritize data gaps for further investigation. USEPA is also including several case studies, both retrospective and prospective, as part of the research. Initial results from this effort are expected to be released in late 2012, with the final report anticipated for release in 2014.

Table 19: Literary Review of Groundwater Contamination Claims

Location/Field	Date of Incident	Type of Release/Reported Effect	Primary Contaminant Reported as Released	Risk Exposure Pathway from Release	Cause
Garfield Field, Colorado	May 2001	Methane in drinking water well, well blow-out – Possibly old inadequately plugged wells	Methane	Inhalation, Explosion, Asphyxiation	Abandoned Wells
Alabama, Black Warrior Basin	June 2004	Methane in shallow drinking water wells	Methane	Inhalation, Explosion, Asphyxiation	Poorly constructed, sealed, or cemented wells
Cannon Land Field, Colorado	October 2005	Valve break, approx. 200 gallons of fracturing fluids sprayed in air; 15-20 gallons entered irrigation ditch (dry)	Potassium Chloride, ethoxylated nonylphenol, trimethylbenzene light aromatic naphtha, oxyalkylated phenolic resin, ethylbenzene, xylene, and isobutyl alcohol	Inhalation, Dermal Contact, Ingestion	Equipment Failure
Barrett Field, Colorado	2005- 2006	Condensate and flowback products in air	Benzene, Xylene, acetone, toluene and ethylbenzene	Inhalation	Air emissions
Farmington, New Mexico	June 2006	Spill of (Halliburton) HF chemicals caused a "cloud"	"acidizing composition"	Inhalation, Ingestion, Dermal Contact	Surface release
Clark, Wyoming	August 2006	Gas well blowout possible groundwater contamination	Petroleum Hydrocarbons	Ingestion	Blowout/overpressured formation
McKean County, Pennsylvania	September 2007	Natural gas leak through abandoned wells caused by over-pressured wells	Methane	Ingestion, Inhalation	Abandoned wells
Bainbridge Township, Ohio	December 2007	Methane build-up within a home causing an explosion	Methane	Inhalation, Explosion, Asphyxiation	Methane migration
Huerfano County, Colorado	2008	Possible methane in 20 drinking water wells	Methane	Inhalation, Explosion, Asphyxiation, Dermal Contact	Poorly constructed, sealed, or cemented wells
Parachute Creek, Colorado	January 2008	Storage pit leak and discharge into Parachute Creek	Fracturing Fluid	Inhalation, Ingestion, Dermal Contact	Pit leak
Garfield County, Colorado	May 2008	Leaking waste pit resulting in nearby spring contamination	Benzene	Inhalation, Ingestion, Dermal Contact	Pit leak
Monongahela River	October 2008	Total dissolved solids (TDS) exceeded state and Federal levels	TDS	Ingestion, Dermal Contact, Plant Receptors	Water treatment
Dish, Texas	2009	Air emissions of benzene in excess of short-term levels	Benzene, Xylene, Toluene and Ethylbenzene	Inhalation	Air emissions

Location/Field	**Date of Incident**	**Type of Release/Reported Effect**	**Primary Contaminant Reported as Released**	**Risk Exposure Pathway from Release**	**Cause**
Dimock, Pennsylvania	January 2009	Methane gas migration to the surface; drinking water well explosion; elevated methane levels in adjacent wells	Methane	Inhalation, Explosion, Asphyxiation, Dermal Contact	Methane migration
McKean County, Pennsylvania	April 2009	Drilling activities impacted at least seven drinking water supplies	Methane, iron and manganese above PADEP MCLs.	Ingestion, Inhalation	Poorly constructed, sealed, or cemented wells
Caddo Parish, Louisiana	April 2009	Fluid and chemical release from vessels and piping connections into an adjacent field; 17 head cattle dead	Milky White Substance	Ingestion, Dermal Contact	Equipment failure
Lycoming County, Pennsylvania	July 2009	Natural gas leak through the well casing and methane in drinking water wells	Methane	Inhalation, Dermal Contact, Explosion, Asphyxiation	Casing/Cement Failure
Pavillon, Wyoming,	August 009	Fracturing chemicals reported in drinking water wells in Pavillon, Wyoming; USEPA to study; no cause-and-effect determination	2-BE, metals	Ingestion	Under study
Dimock, Pennsylvania	September 2009	Two liquid gel spills that caused polluted a wetland and caused a fish kill in Stevens Creek	Lubricant Gel	Ingestion, Inhalation, Dermal Contact	Surface spill
Hopewell Township, Pennsylvania	October 2009	Spill of diluted hydraulic fracturing fluids; a broken joint in a transmission line caused leak and flow into an unnamed tributary of Brush Run, causing fish kill	Diluted Hydraulic Fracturing Fluids	Inhalation, Ingestion, Dermal Contact	Equipment failure
Hopewell Township, Pennsylvania	December 2009	Overflow from a wastewater pit and contaminating a high-quality watershed	Hydraulic Fracturing Fluids	Inhalation, Ingestion, Dermal Contact	Surface release
Washington County, Pennsylvania	January 2010	Failed to implement proper erosion and sedimentation control measures, which led to surface releases	Turbid discharges, and discharged diesel fuel and hydraulic fracturing production fluids	Inhalation, Ingestion, Dermal Contact	Surface release
East of Calgary, Alberta	January 2010	Methane in drinking water from public water supply wells in Rosebud, Alberta	Methane	Inhalation, Explosion, Asphyxiation, dermal contact	Alberta Research Council report concluded it was naturally occurring
Troy, Pennsylvania	February 2010	Discharged production fluids into a drainage ditch and through a vegetated area, eventually reaching a tributary of Sugar Creek	Produced Water	Inhalation, Ingestion, Dermal Contact	Surface release

Location/Field	Date of Incident	Type of Release/ Reported Effect	Primary Contaminant Reported as Released	Risk Exposure Pathway from Release	Cause
Doddridge County, West Virginia	June 2010	Discharge into a tributary of Buckeye Creek contaminating a 3-mile segment	Petroleum-based Material	Inhalation, Ingestion, Dermal Contact	Surface release
North Dakota	September 2010	Casing and cementing failure in casing near surface	Salt Water	Ingestion	Casing/Cement failure
Dimock, Pennsylvania	November 2010	Vibrations, spills on location, plant and animal loss, drinking water contains lead	TDS and Chlorides	Dermal contact, ingestion, inhalation, noise, and biological receptors	Surface release
Swan Lake, B.C.	May 2011	Sour gas leak	Natural Gas with H_2S	Inhalation, dermal contact	Equipment failure
Jackson County, West Virginia	August 2011	Fracturing fluid migration into drinking water well	Dark and Light Gelatinous Materials and White Fibers	Ingestion	Abandoned wells
Alberta, Canada Innisfall	January 2012	An existing oil producing well within a km of an on-going fracture stimulation erupted fluids on the ground; no groundwater contamination	Oil	Inhalation, Ingestion, Dermal Contact	Under Study

9 SUMMARY

This Primer focuses on the subsurface injection of fluids during hydraulic fracturing operations and highlights the following important points:

- The regulatory framework in Canada maintained by the Federal, Territorial, and Provincial authorities is protective of groundwater and responsibly regulates the construction and stimulation treatment of oil and gas wells. Some areas in Canada have a rich and diverse history of oil and gas development and as such the regulations in those areas have a greater complexity.
- The shale gas industry is adequately regulated with the current framework of regulations nationwide, but enhanced regulatory definition and requirements may ease some of the public's and industry's uncertainty about development of the resource in newly discovered plays, especially if those plays are not in historic oil and gas areas.
- A review of past contamination or exposure incidents attributed to hydraulic fracturing did not identify any events where a cause-and-effect relationship exists with the process of injection of hydraulic fracturing fluids.
- Numerous best management practices exist to help mitigate exposure and contamination risks from hydraulic fracturing and related activities. Following best management practices provides better environmental protection and control during the development of the natural gas and oil resource.
- A review of the geologic conditions of Canadian shale plays in comparison to those in the United States may provide analogies to development processes and techniques currently being used to develop the resources in the United States.
- Reviewing the chemicals and volumes used during the process of hydraulic fracturing in shale plays in the United States provides information on expected chemical use in Canadian shale plays. It also highlights the highly dilute nature of those chemicals during the injection process.
- The probability of contamination of ground water during the injection process of hydraulic fracturing in a properly constructed well is very low to negligible.

These points, taken together with the advanced technologies and practices developed by industry to develop the shale gas resources, serve to protect human health and reduce environmental impacts.

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Glossary

ABNORMAL PRESSURE. A subsurface condition in which the pore pressure of a formation exceeds or is less than the expected, or normal formation pressure

ADDITIVE. Any substance or combination of substances comprised of chemical ingredients found in a hydraulic fracturing fluid, including a proppant, which is added to a base fluid in the context of a hydraulic fracturing treatment. Each additive performs a certain function and is selected depending on the properties required.

ANNULUS (Annular Space). The space surround one cylindrical object placed inside another, such as the space in between the casing and the wellbore, or between the casing and tubing, where fluid can flow.

AQUIFER. A body of rock that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

AREA OF REVIEW. An engineering study of all the wells, producing, plugged, and abandoned, as well as other potential concerns within a pre-defined area around a wellbore.

BASE FLUID. The base fluid type, such as water or nitrogen foam, used in a particular hydraulic fracturing treatment. Water includes fresh water, brackish or saline water, recycled water or produced water.

BASIN. A closed geologic structure in which the beds dip toward a central location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

BEDROCK. Solid rock either exposed at the surface or situated below surface soil, unconsolidated sediments and weathered rock.

BIOCIDE: An additive that kills bacteria.

BLENDER. The equipment used to prepare the slurries and gels used in stimulation treatments.

BLOW OUT PREVENTER. A large valve at the top of the well that may be closed if the drilling crew loses control of formation fluids.

BRINE. Water containing salts in solution, such as sodium, calcium or bromides.

CASING STRING. Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geologic formations.

CASING SHOE. The bottom of the casing string, including the cement around it, or the equipment run at the bottom of the casing string.

CEMENT BOND LOG. A log that uses the variations in amplitude of an acoustic signal traveling down the casing wall to determine the quality of cement bond on the exterior casing wall.

CEMENT EVALUATION LOG. A representation of the integrity of the cement job, especially whether the cement is adhering solidly to the outside of the casing.

CEMENT JOB. The application of a liquid slurry of cement and water to various points inside or outside the casing.

CENTRALIZER. A device that is used to keep the casing or liner in the center of the wellbore to ensure efficient placement of a cement sheath around the casing string.

CHEMICAL ABSTRACTS SERVICE (CAS): The chemical registry that is the authoritative collection of disclosed chemical substance information.

CHEMICAL ABSTRACTS SERVICE REGISTRY NUMBER (CAS NUMBER). The unique identification number assigned by the Chemical Abstracts Service to a chemical constituent.

CHEMICAL INGREDIENT. A discrete chemical constituent with its own specific name or identity, such as a CAS number, that is contained in an additive.

CIRCULATE. To pump through the whole active fluid system, including the borehole and all the surface tanks that constitute the primary system.

CLAY STABALIZER. A chemical additive used to stimulation treatments to prevent the migration or swelling or clay particles in reaction to water based fluid.

COMMUNICATION: The flow of fluids from one part of a reservoir to another or from the reservoir to the wellbore.

COMPETENT INDIVIDUAL. A competent individual is a person who is trained and experienced to perform the required duties.

COMPLETION. The activities and methods to prepare a well for production and following drilling. Includes installation of equipment for production from a gas well.

CORROSION INHIBITOR. A chemical additive used to protect iron and steel components in the wellbore and treating equipment from the corrosive treating fluid.

DISPOSAL WELL. A well which injects produced water into an underground formation for disposal.

DOMESTIC WATER WELL. An opening in the ground, whether drilled or altered from its natural state, for the production of groundwater used for drinking, cooking, washing, yard or livestock use.

DUCTILE. A rock's ability to deform under tensile stress.

EXPLORATION. The process of identifying a potential subsurface geologic target formation and the active drilling of a borehole designed to assess the natural gas or oil.

FLOW BACK. The process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.

FORMATION (GEOLOGIC). A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

FORMATION FLUIDS. Any fluid that occurs in the pores of a rock.

FRACTURE GRADIENT. The pressure gradient at which a specific formation interval breaks down and accepts fluid.

FRACTURE NETWORKS. Patterns in multiple fractures that intersect each other.

FRACTURE PUMP. A high pressure, high-volume pump using in hydraulic fracturing treatments.

FRACTURING FLUIDS. The fluid used to hydraulically induce cracks in the target formation and includes the applicable base fluid and all additives.

FREE NATURAL GAS. Free gas is defined as gas that readily comes out of solution at atmospheric pressure and ambient temperature.

FRESH (NON-SALINE) GROUNDWATER. Groundwater that has a total dissolved solids (TDS) content less than or equal to 4,000 mg/L or as defined by the jurisdiction.

GAS MIGRATION. A flow of gas that is detectable at surface outside of the outermost casing string. It refers to all possible routes for annular gas entry and propagation through and around the cement sheath.

GREEN CHEMICAL. The Oslo and Paris Commission is a group of experts who advise North Sea countries on environmental policy and legislation. OSPAR has been influential in establishing North Sea legislation on drilling fluids that has served as the model for other operating areas. OSPAR has published lists of environmentally acceptable and unacceptable products, referred to as the "green," "grey" and "black" lists. The Green list consists of products posing relatively little harm to the environment (specifically the marine environment). Examples include inert minerals such as bentonite, inorganic salts that are common constituents of seawater such as sodium and potassium chloride, and simple organic products such as starch and carboxymethylcellulose (CMC). The Grey List consists of products 'requiring strong regulatory control' and includes heavy metals such as zinc, lead and chromium. The Black list covers products considered unsuitable for discharge and includes mercury, cadmium and 'persistent oils and hydrocarbons of a petroleum origin.' The inclusion of hydrocarbons in the black list has been the driving force behind the reduction of oil discharges in the North Sea and elsewhere and has serious implications for the use of oil and synthetic fluids.

GROUND WATER. Subsurface water that is in the zone of saturation; source of water for wells, seepage, and springs. The top surface of the groundwater is the “water table.”

HORIZONTAL DRILLING. A drilling procedure in which the wellbore is drilled vertically to a kick-off depth above the target formation and then angled through a wide 90 degree arc such that the producing portion of the well extends horizontally through the target formation.

HYDRAULIC FRACTURING. Injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock thus inducing a network of fractures through which oil or natural gas can flow to the wellbore.

HYDRAULIC FRACTURE MONITORING. A technique to track the propagation of a hydraulic fracture as it advances through a formation.

HYDROSTATIC PRESSURE. The pressure exerted by a fluid at rest due to its inherent physical properties and the amount of pressure being exerted on it from outside forces.

INJECTION PRESSURE. The pressure at which a treatment fluid can be injected into the formation without causing a fracture of the rock matrix.

INJECTION WELL. A well used to inject fluids into an underground formation either for enhanced recovery or disposal.

INTERMEDIATE CASING. A casing string that is generally set in place after the surface casing and before the production casing to provide protection against caving of weak or abnormally pressured formations.

KEROGEN. The naturally occurring, solid, insoluble organic matter that occurs in source rocks and can yield oil upon heating. Kerogens have a high molecular weight relative to bitumen, or soluble organic matter. Bitumen forms from kerogen during petroleum generation. Kerogens are described as Type I, consisting of mainly algal and amorphous (but presumably algal) kerogen and highly likely to generate oil; Type II, mixed terrestrial and marine source material that can generate waxy oil; and Type III, woody terrestrial source material that typically generates gas.

KICK TOLERANCE. The maximum volume of gas kick that can be circulated out of the hole when the well is shut in without breaking formation strength at shoe depth or overcoming the weakest anticipated fracture pressure in wellbore.

LITHOLOGY. The macroscopic nature of the mineral content, grain size, texture and color of rocks.

MATERIAL SAFETY DATA SHEET (MSDS). A document, as required by the Controlled

Products Regulations under the federal Hazardous Products Act, that contains information on the potential hazards (health, fire, reactivity and environmental) of an additive and its components.

MINERALOGY. The physical and chemical structures of minerals, including their distribution, identification, and properties.

MINI-FRAC. A small fracturing treatment performed before the main hydraulic fracturing treatment to acquire critical job design and execution data and confirm the predicted response of the treatment interval.

MINIMUM INTERNAL YIELD PRESSURE. The lowest internal pressure at which a pipe failure will take place.

NON-DARCY FLOW: Fluid flow that deviates from Darcy's law, which assumes laminar flow in the formation. Non-Darcy flow is typically observed in high-rate gas wells when the flow converging to the wellbore reaches flow velocities resulting in turbulent flow.

NON-GOVERNMENTAL ORGANIZATION (NGO). A constituted organization that operates independently of any government.

ORIGINAL GAS- IN- PLACE. The entire volume of gas contained in the reservoir, regardless of the ability to produce it.

OVERPRESSURE. The pressure regime in a stratigraphic unit that exhibits higher-than-hydrostatic pressure in its pore structure. This phenomenon is the primary cause of "oil gushers".

PAD. A fluid used to initiate hydraulic fracturing that does not contain proppant.

PAY. A reservoir or portion of a reservoir that contains economically producible hydrocarbons. The term derives from the fact that it is capable of "paying" an income. Pay is also called pay sand or pay zone.

PERMAFROST. The permanently frozen subsoil that lies below the upper layer (the upper several inches to feet) of soil in arctic regions.

PERMEABILITY. A rock's capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.

pH. Hydrogen ion potential, which is the $\log_{10}$ of the reciprocal of hydrogen ion, H^+, concentration.

PLAY. A conceptual model for a style of hydrocarbon accumulation used by explorationists to develop prospects in a basin, region or trend and used by development personnel to continue exploiting a given trend. A play (or a group of interrelated plays) generally occurs in a single petroleum system.

POROSITY. The percentage of pore volume or void space or that volume within rock that can contain fluids.

PRODUCED WATER. Water naturally present in the reservoir or injected into the reservoir to enhance production, produced as a co-product when gas or oil is produced.

PRODUCING ZONE. The zone or formation from which natural gas is produced.

PRODUCTION CASING. A casing string that is set across the reservoir interval and within which the primary completion components are installed.

PROPPING AGENTS/PROPPANT. Synthetic or natural non-compressible grains such as coated sand or sintered bauxite ceramics pumped into a formation during a hydraulic fracturing operation to hold fractures open around the wellbore and to enhance fluid extraction after hydraulic fracturing pressures are removed.

RECOVERABLE RESOURCES. The volume of resource that is technically or economically feasible to extract.

RECYCLE. The process of treating flowback or produced water to allow it to be reused either for hydraulic fracturing or for another purpose.

REUSE. The process of using water multiple times for similar purposes.

RESISTIVITY. The ability of a material to resist electrical conduction.

RIG-UP. To make ready for use. Equipment must typically be moved onto the pad, assembled and connected to power sources or pressurized piping systems.

SAFETY STANDDOWN. Safety Standdown promotes knowledge-based training along with personal discipline and responsibility as essential elements of oil and gas field professionalism and safety.

SALINE GROUNDWATER. Groundwater that has a total dissolved solids (TDS) content more than 4,000 mg/L or as defined by the jurisdiction.

SCREEN OUT. A condition that occurs when the solids carried in a treatment fluid, such as proppant in a fracturing fluid, create a bridge across the perforations or similar restricted flow area. This creates a sudden and significant restriction to fluid flow that causes a rapid rise in pump pressure.

SERVICE COMPANY. A company that performs hydraulic fracturing treatments for an operator.

SHALE FORMATION RESOURCE PLAYS. An area in which hydrocarbon accumulations or prospects of a given type occur in continuous shale formations. For example, the shale gas plays in North America include the Barnett, Eagle Ford, Fayetteville, Haynesville, Horn River, Marcellus, Montney, and Woodford, among many others. Outside North America, shale gas potential is being pursued in many parts of Europe, Africa, Asia, and South America. Typical trapping mechanisms, as seen in more conventional play types, may not be present for a shale formation resource play to exist.

SHALE GAS. Natural gas produced from low permeability shale formations.

SHOW. A surface observation of hydrocarbons, usually observed as florescent liquid on cuttings when viewed with an ultraviolet or black light (oil show) or increased gas readings from the mud logger's gas-detection equipment (gas show).

SLICKWATER. A water based fluid mixed with friction reducing agents, commonly potassium chloride.

STIMULATION. Any of several processes used to enhance near wellbore permeability and reservoir permeability. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near-wellbore area. Stimulation in shale gas reservoirs typically takes the form of hydraulic fracturing treatments

SURFACE CASING. A large diameter, relatively low pressure pipe string set in shallow yet competent formations to protect fresh water aquifers onshore, provide minimum pressure integrity, and enables a diverter or blow out preventer to be attached to the top of the string. It also provides structural strength so that the remaining casing may be suspended at the top and inside the casing.

SURFACE WATER. Water collecting on the ground or in a stream, river, lake, sea or ocean, as opposed to groundwater.

SURFACTANT. A chemical that preferentially absorbs at an interface, lowering the surface tension or interfacial tension between fluids or between fluid and solids.

TECHNICALLY RECOVERABLE RESOURCES. The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.

TIGHT GAS. Natural gas trapped in a hardrock, sandstone or limestone formation that is relatively impermeable.

TORTUOSITY. Any unwanted deviation from the planned well or fracture trajectory. It can lead to resistance on fluids as the flow through a diverted path.

TOTAL ORGANIC CARBON. The concentration of organic material in source rocks as represented by the weight percent of organic carbon. A value of 2% is considered the minimum for shale gas reservoirs.

TRADE NAME. The name under which an additive is sold or marketed.

TRADE SECRET. Any confidential formula, pattern, process, device, information, or compilation of information entitled to protection as a trade secret under the applicable law which is used in a business and which gives the business an opportunity to obtain an advantage over competitors that do not know or use it.

TRANSPORTATION OF DANGEROUS GOODS (TDG) REGULATIONS. The Transportation of Dangerous Goods Act, administered by Transport Canada, contains regulations designed to promote public safety when handling or transporting dangerous goods via road, rail, air and marine.

TREATMENT. See Stimulation

UNCONVENTIONAL. Oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs.

WAIT ON CEMENT (WOC). To suspend drilling operations while allowing cement slurries to solidify, harden and develop compressive strength.

WASTEWATER. Spent or used water with dissolved or suspended solids, discharged from homes, commercial establishments, farms and industries.

WATER DELIVERABILITY TEST. A field test to estimate the flow capacity of the water well under existing conditions (e.g., using the landowner's pump). Water is withdrawn from the well for a fixed duration (usually 1 hour) before the pump is turned off and the water level is allowed to recover.

WELLBORE: A wellbore is the open hole that is drilled prior to the installation of casing and cement.

WELL COMPLETION. See **Completion**.

WORKOVER. To perform one or more remedial operations on a producing or injection well to increase production. Deepening, plugging back, pulling, and resetting the liner are examples of workover operations