

FRACTURE LINES:

**Will Canada's Water be Protected in
the Rush to Develop Shale Gas?**

**By Ben Parfitt
For the Program on Water Issues
Munk School of Global Affairs at the University of Toronto**

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About the Author

Ben Parfitt is a Victoria resident, author and award-winning magazine journalist, noted for his coverage of environmental and natural resource issues. He currently divides his time between work as a resource policy analyst with the British Columbia office of the Canadian Centre for Policy Alternatives and various freelance assignments.

About the Program on Water Issues

The Program On Water Issues (POWI) creates opportunities for members of the private, public, academic, and not-for-profit sectors to join in collaborative research, dialogue, and education. The Program is dedicated to giving voice to those who would bring transparency and breadth of knowledge to the understanding and protection of Canada's valuable water resources. Since 2001, The Program On Water Issues has provided the public with analysis, information, and opinion on a range of important and emerging water issues. Its location within the Munk School of Global Affairs at the University of Toronto provides access to rich analytic resources, state-of-the-art information technology, and international expertise. This paper can be found on the Program On Water Issues website at www.powi.ca. For more information on POWI or this paper, please contact:

Adèle M. Hurley
Director, Program On Water Issues
Munk School of Global Affairs
University of Toronto
1 Devonshire Place, South House, Room 258S
Toronto, Ontario
Canada
M5S 3K7

Tel: 416-892-8919 Fax: 416-946-8915 E-mail: hurleyut@istar.ca

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Adèle realized early on that the escalating development of “unconventional” shale gas resources in the United States would be replicated in Canada and that such developments would result in marked increases in water withdrawals from surface and groundwater sources and increased risks that such sources could become contaminated.

Having correctly anticipated the upwelling of public concern now greeting proposed unconventional gas developments from Western Canada to the Maritimes, Adèle and the Munk School asked me to prepare the following report – an opportunity for which I am most grateful. I am first and foremost indebted to Adèle for the many helpful suggestions she made during various iterations of this report, and I also owe a heartfelt thanks to those who offered to review and comment on earlier drafts including: Jim Bruce, Joanna Kidd, Andrew Miall and Tom Myers. Thanks go to Bronson Whitford and Eric Chenoix for translation and the staff at the Munk School, including Nina Boric, Todd Lane, Wilhelmina Peters, Sean Willett and Lucinda Li. Additionally, I want to thank Joanna Kidd, for also editing and designing the final report. Lastly, my thanks to Will Koop, for pointing me in the direction of many helpful documents and contacts.

BP, September 2010

1. Shale Gas: The Rush is On

In the last decade the natural gas industry has experienced a remarkable revolution that could transform the energy and political landscape of North America. Just as conventional supplies of natural gas seemed on the verge of depletion, the oil patch combined a 60-year old technology called hydraulic fracking with the technology of horizontal drilling to exploit a seemingly implacable resource: natural gas trapped inside deep and densely packed shale rock.

Hydraulic fracking, the injection of tonnes of sand, water and chemicals at high pressure, allowed industry to shatter this rock the same way a stone cracks a windshield. The resulting fractures create tiny pathways that allow small pockets of natural gas to escape from the shale. Once industry proved that fracking could release enormous volumes of gas from these ancient ocean beds, a boom in unconventional drilling erupted across the continent. In many states and provinces, companies participated in a frantic rush to secure access to mineral leases the size of small European countries. Talisman Energy, for example, acquired one million acres or roughly 2400 square miles in Quebec's St Lawrence lowlands to exploit the Utica Shale¹ while Encana Corporation purchased more than 2 million acres in British Columbia.²

Thousands of wells have now been drilled in Texas, Pennsylvania, Ohio, Alabama, Wyoming and Colorado. With 22 major shale plays (or geological formations) spread over 20 states, shale gas has grown from an insignificant source in 2000 to one that in 2010 represents a phenomenal 20 percent of all gas produced in the US.³ Canada has also witnessed its own 'shale gale' as the boom noisily expanded from its dramatic epicentre in northern British Columbia into rich shale formations in Alberta, Saskatchewan, Ontario, Quebec and New Brunswick.

Given that shale plays could provide North America with an estimated 100-year supply of a relatively "clean" fuel at low prices, both industry and government have touted the unconventional resource as "a game changer". Cambridge Energy Research Associates, for example, predicts that shale gas could replace carbon-heavy coal as the fuel of choice for power plants and become "the most significant energy innovation so far this century."⁴ Canada's Fraser Institute describes shale gas as "a reliable and affordable alternative to costly green schemes" such as wind and solar.⁵ If compressed natural gas from shale formations is used to power light vehicles, the resource might even temper the demand for heavy oil such as bitumen. Jim Mulva, chief executive of ConocoPhillips, considers shale gas "nature's gift to the people of the world."⁶ The abundance of the resource has even spawned a new lobby group: America's Natural Gas Alliance. The Alliance reports that natural gas accounts for 3.5 percent of Canadian jobs and nearly 6.7 percent of Canada's overall GDP.⁷

But every gale comes with its own storm warnings. Even supporters of the unconventional resource now admit that "water has emerged as the highest visibility environmental issue" associated with shale gas production.⁸ In fact wherever the shale industry has invaded rural communities, controversy about water use, groundwater contamination and the regulation of the industry has doggedly followed. "The largest

challenges lie in the area of water management, particularly the effective disposal of fracture fluids,” notes a 2010 MIT report on natural gas.⁹ In the United States the fracture lines are now well drawn. A series of award winning reports by the journalism group, *ProPublica*, has raised serious questions about the content of hydraulic fracturing fluids and the contamination of nearly 1,000 rural water wells by the shale gas industry. As a consequence the US Environmental Protection Agency has begun a major investigation to determine exactly what impacts hydraulic fracking might have on drinking water supplies. Plans to develop the Marcellus Shale, which is located under critical watersheds providing freshwater to major cities such as New York, have also prompted moratoriums on development. To date thousands of citizens have attended public hearings on hydraulic fracking.

Fracture lines have slowly appeared in Canada too. Exploratory drilling in the Utica Shale deposit between Montreal and Quebec City along the St Lawrence River (an area 5,000 square kilometers in size) has resulted in angry protests and calls for moratoriums.¹⁰ In New Brunswick a company abandoned plans to drill within Sackville’s town limits after town councillors raised concerns about water contamination.¹¹ Intensive drilling in northern British Columbia has resulted in unprecedented water withdrawals and even a bombing campaign directed against the Encana Corporation to protest the pace of development.¹²

Given the economic importance of the resource and growing concerns about industry’s use of and impact on water, this report examines the implications of shale gas production on Canada’s water supplies. In addition to reviewing the technological drivers of the shale gas revolution, the report also looks at the state of groundwater mapping in shale-rich regions. Lastly, it reviews the adequacy of existing regulatory frameworks to protect water resources, landowners and rural communities.

Unlike the United States where the US Congress and state regulators are fully engaged in public policy debates, neither the National Energy Board nor Environment Canada have yet raised any substantive questions about ‘the shale gale’ or its impact on water resources. The pace of the shale gas revolution demands greater scrutiny before more fracture lines appear across the country.

2. The World's Largest Frack

Shortly after 2009 rolled into 2010, workers in a remote corner of northern British Columbia began what would 111 days later become the world's largest natural gas extraction effort of its kind.

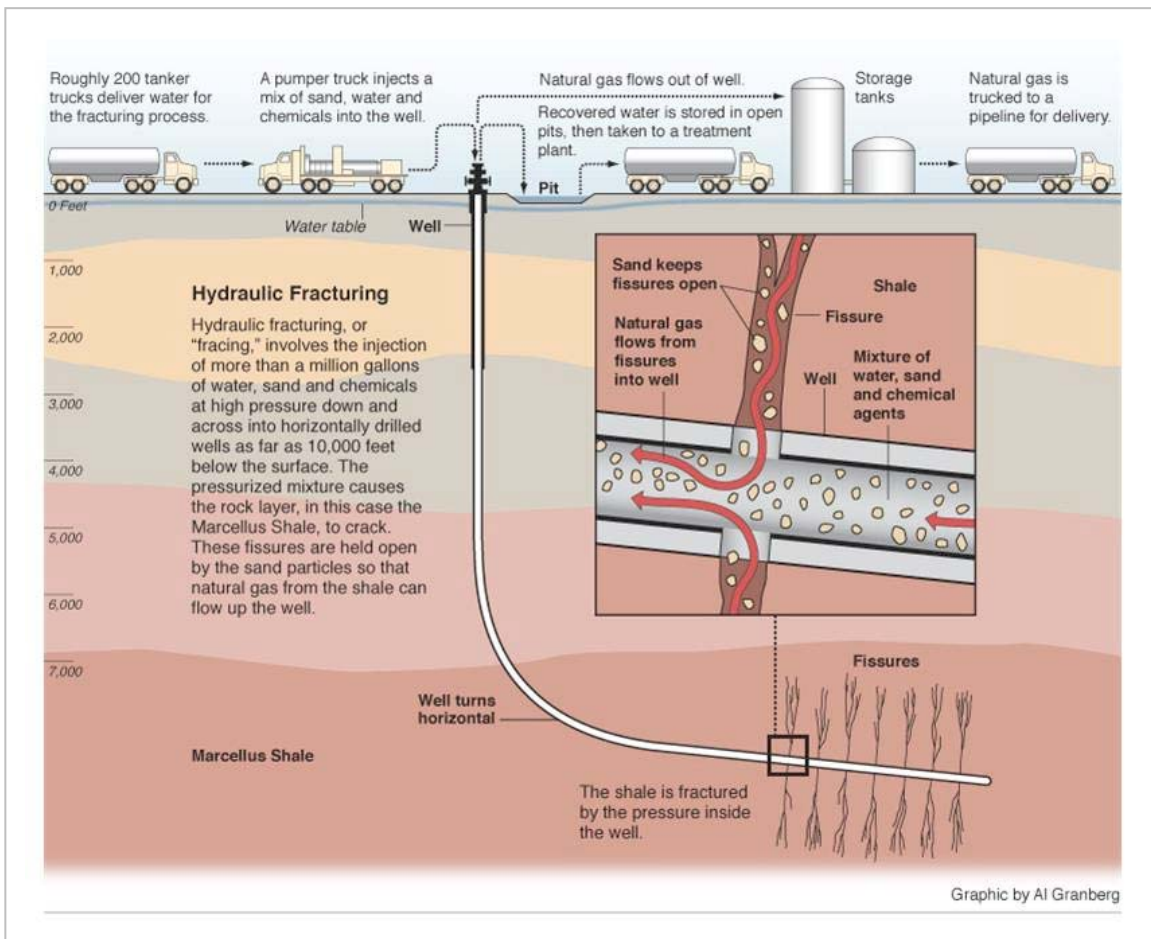
The operation began near the shoreline of a small frozen lake, about a four-and-a-half hours drive north and east of Fort Nelson, the northernmost community of any size in Canada's westernmost province. As the small army of workers moved amidst a convoy of trucks and roaring diesel-fired compressors, water was forced underground at intense pressure at one of 16 wells that had been drilled in advance of the unprecedented "hydraulic fracturing" exercise.

For three and a half months, diesel-fired compressors at the pad ran continuously and pumps sucked up water from nearby Two Island Lake. During the operation, a total of 274 consecutive "stimulations" or fracks were completed for an average of 17 fracks per well. By the time it was all over, 5.6 million barrels worth of water had been pumped underground, along with 111 million pounds of sand, and quantities of unknown chemicals. The stage was set for the beginning of what could be trillions of cubic feet of natural gas production in the region – gas that could eventually be used to heat homes and businesses, but also be destined for industrial users, including those in northern Alberta's tar sands industry. All of this and more happened largely out of sight and out of mind, in a region of Canada that, like so many others, is isolated from cities or towns of any size. Northeastern British Columbia is 79,130 square miles in size, making it larger than all but 15 of the 48 US states below the 49th parallel. So vast and remote is the region that nearly one quarter of all the lakes and rivers used by energy companies operating in the area remain, as yet, unnamed.

By 2010, obtaining natural gas from subterranean deposits was a fixture of western Canada's economy. But the events at Two Island Lake marked a major departure from what had only a few years earlier been the norm in the oil-and gas-rich provinces of Saskatchewan, Alberta and BC. Thanks to technological innovations in the United States, it was now possible to access gas reserves in sites that had previously been deemed too costly to develop, generating profits for company shareholders even in a world of low natural gas prices. This site was one of them.

The most important of those innovations – perfected in the states of Texas – was to drill not only down but also out in horizontal reaches that paralleled the earth's surface, exposing vast expanses of gas-filled rock to exploitation.

Figure 1: Horizontal Drilling and Hydraulic Fracturing



Source: Natural Gas in the Marcellus Shale Formation: New York City and Upper Delaware River Watersheds, Southern Tier of New York State. Available at: <http://www.catskillmountainkeeper.org/node/290>

But drilling horizontally through the gas-rich deposits of shale was just the start. Even after the horizontal bores were drilled, the surrounding rock was still too dense or tight to yield its trapped gases. Somehow, the shale had to be cracked open by triggering small seismic events in the surrounding rock to open tight cracks and faults already in the rock and also new pathways through it. With enough such pathways, a horizontal bore became a superhighway of sorts, directing multiple streams of gas along its length.

Hydraulic fracturing (or "fracking") became the method of choice for cracking open the shale. This involved pumping fracturing fluids (water, chemicals and additives) underground at high pressure. As the art of fracking was honed, drillers began to push the horizontal bores further and further out. Soon, multiple fracks were the order of the day, with the most distant reaches of horizontal bores (known as the toe) being fracked first, and successive fracks progressing back toward the heel, or junction of the horizontal and vertical bores.

Seen from this light, the “world’s largest” frack at Two Island Lake (as it was subsequently hailed in a May 2010 shareholder report by Houston, Texas-based Apache Corporation), was an impressive but not unexpected outcome of decades of fracking innovations. Those innovations allowed Apache and its partner in British Columbia’s shale gas-rich Horn River Basin – Encana Corporation – to do what had once seemed inconceivable. On a single pad carved out of a swath of sub-boreal forest, the companies had drilled 16 wells with horizontal reaches averaging 1.6 kilometres.¹³

The events at Two Island Lake may have been unique in setting a record for shale gas extraction, but milestone aside they were far from unusual.

Across the world, shale deposits have become the focus of increased attention by energy companies and governments. Technological advancements that make extracting the gas locked in shale formations more economically viable have led to proclamations that a new era of “clean” energy is at hand. The innovations mean that more natural gas is commercially available. For North America, that means less reliance on foreign powers for fossil fuels. And because natural gas burns clean, with fewer particulate and greenhouse gas emissions than other fossil fuels, some argue that it is the essential “transitional” fuel needed to “bridge” to the low- or zero-carbon energy sources, that the world’s leading climate scientists say must be achieved if catastrophic changes in the Earth’s climate are to be avoided.

“The future is brilliant from the point of view of the resource base,” says Robert Aguilera, an expert in the engineering required to open pathways through tight underground rock formations. From his office at the University of Calgary, he characterizes the Horn River Basin as being “on par” with the larger shale basins in the United States, and he says that other Canadian shale gas zones such as the Utica Shale in Quebec’s St. Lawrence Lowlands show similar potential.

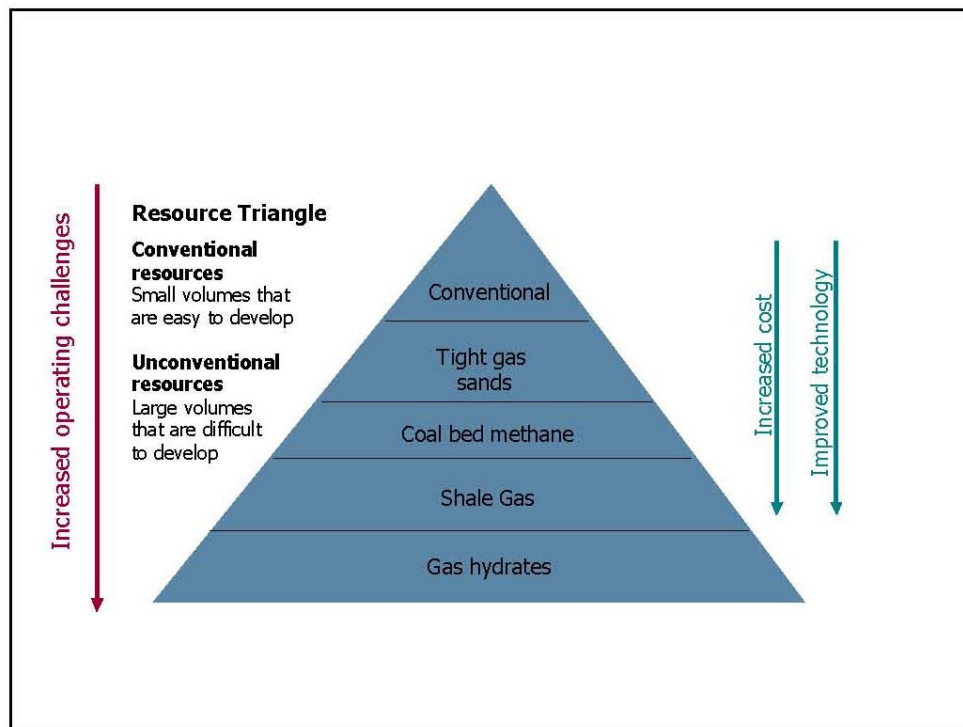
But as events in emerging shale gas plays suggest, there is mounting concern over the cumulative impacts of shale gas production on water resources and communities.

3. The Unconventional Shale Gas Revolution

Shale formations have long been known to contain gas. The first natural gas produced in the United States – in 1821 – came from a shale outcrop. Tapped by a gunsmith in Fredonia, New York, the gas was sold to a nearby inn located on a well travelled wagon route to Ohio.

As oil and gas exploitation intensified, however, gas from tight shale formations was abandoned in favor of other sources that yielded far more gas with less effort. Two drilling innovations nearly a century later would set the stage for the explosion in shale gas exploration and development that lies at the heart of this report.

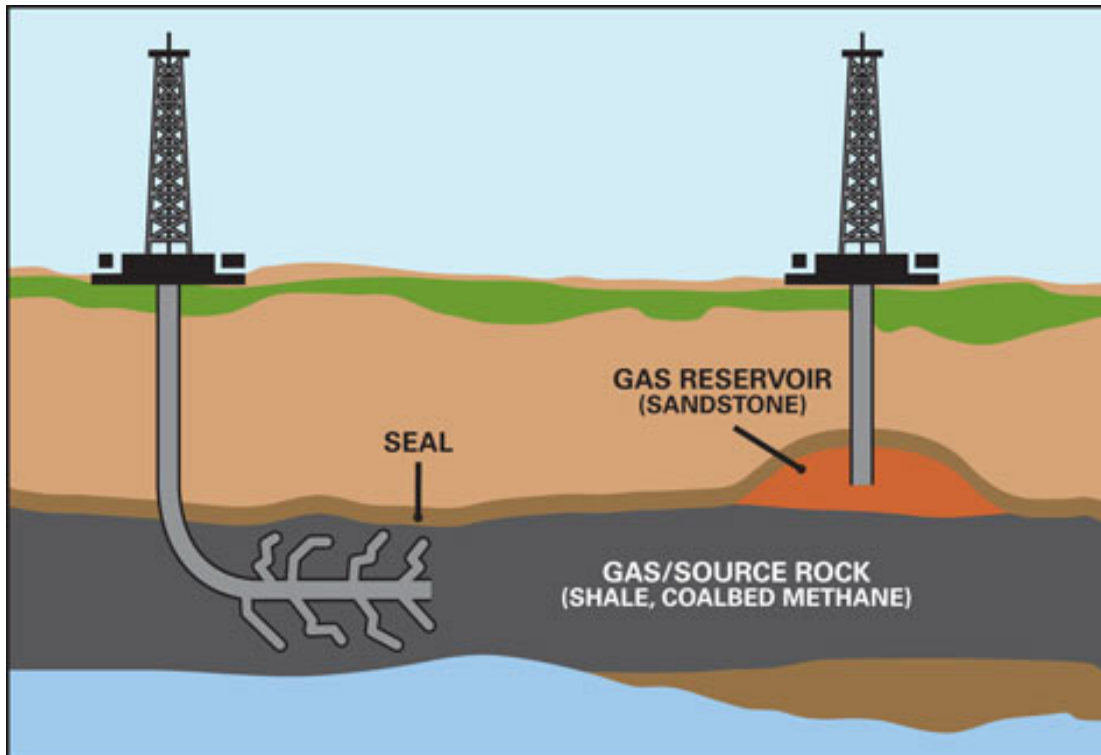
Figure 2: Conventional versus Unconventional Gas Resources



Source: Canadian Association of Petroleum Producers, 2010

The first innovation was horizontal drilling, an innovation with roots in Texas in the 1930s. While more expensive to drill, horizontal (or lateral) wellbores are advantageous because they expose far more of a gas-bearing formation to exploitation than do conventional vertical wells. While a vertical well may access 50 to 300 feet of a targeted gas-bearing formation, a lateral wellbore may expose 2,000 to 6,000 feet or more of gas-bearing shale.

Figure 3: Horizontal Drilling vs. Vertical Drilling



Source: DTE Energy, accessed at <http://www.dteenergy.com/images/gasDrilling.jpg>

The other innovation to emerge as a critical factor in the economical recovery of gas (and, increasingly oil¹⁴) from shale and other unconventional sources was fracking – a process first believed to have been used to stimulate oil and gas production either in the Hugoton field of Kansas in 1946 or near Duncan Oklahoma in 1949.¹⁵

Today, fracking is the key to unlocking commercially recoverable gas from shale. It amounts to using brute force to crack open pathways in dense rock, with water, chemicals and sand pumped at 5,000 to 15,000 pounds per square inch (psi) into wellbores using diesel compressors. With this “technology key”, a door that was previously closed or at best slightly ajar was thrust open. The combining of horizontal drilling and fracking technologies has caused global natural gas production to soar.¹⁶

Conceptually, fracking is simple, but its execution is an engineering feat. To understand what goes right with hydraulic fracturing – successfully tapping into once elusive gas reserves – and to understand what potentially can go wrong, it is instructive to understand how the industry itself describes the process.¹⁷

Oklahoma’s Oil and Natural Gas Producers and Royalty Owners and Encana Corporation have posted very similar informational videos on their websites. Both depict the technological challenges of executing a successful fracking operation, and are drawn on here to depict how the industry itself portrays its practices.

To reach the depth where the horizontal portion of a wellbore begins, a drill bit mounted on the end of a pipe grinds vertically from the surface down into the earth. This first drilling stage, both videos note, carries past the deepest fresh water zone. Surface casing or pipe is then inserted into the hole to “isolate” fresh water zones from potential contamination during the drilling process and later during gas production. In Canada, the depths at which groundwater aquifers that may be used for drinking water purposes are generally found within 100 metres of the surface.¹⁸ By comparison, the shale formations targeted for fracking may range from very shallow depths of 110 metres to up to 4,000 metres.

After the drill bit and pipe are removed, cement is pumped down the casing. When the cement reaches the bottom or shoe of the casing, it flows back up under pressure toward the surface on the outside of the pipe. The steel casing and cement “protects freshwater” from any subsequent contamination.

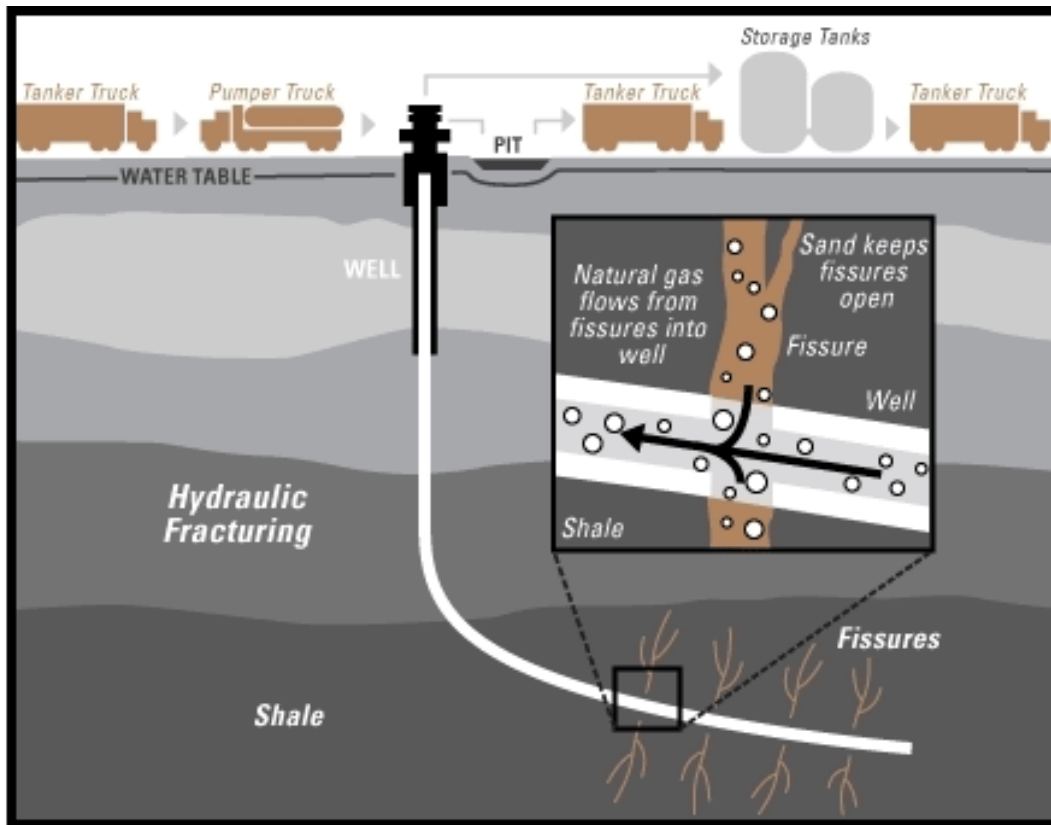
Once this is done, drilling resumes and continues down to a point about 500 feet above the targeted horizontal or lateral leg of the wellbore. At this “kickoff point”, a new drilling motor guides the drilling 300 to 450 metres in a curving arc that re-orientes the wellbore horizontally. Drilling then continues for several hundred metres paralleling the earth’s surface. Once this is done, another cementing operation fills the annulus or open space between the piping and wall of the hole.

The ensuing fracking operations take place in stages, beginning at the farthest end of the horizontal reach (the toe) and moving progressively back toward the heel or curved section. First, a perforating gun is lowered into the section of well about to be fracked. An electrical charge fires the gun, which shoots several holes through the pipe, surrounding cement and into the shale.

The perforated well section is then fracked with water, sand and additives which are pumped under high pressure underground. The pressurized mixture “causes the shale to fracture. Similar to hitting a windshield with a hammer, it shatters in all directions back to the point of origin in a controlled fashion,” Encana explains. The gas moves through these cracks into the well.

Touching only briefly upon the sensitive issue of what chemical additives it uses in its fracking fluids, Encana notes in its video that it is committed to working “collaboratively” with regulators to “develop and advance hydraulic fracturing best practices”, and that it “does not permit” the use of diesel or 2-BE (a suspected carcinogen) in its fracking fluids. (The US Congressional Committee on Energy and Commerce, which has reviewed practices in the shale gas industry, found that diesel fuel was used by several major companies in their fracking operations.)

Figure 4: Hydraulic Fracking



Source: <https://www.taipanpublishinggroup.com/images/web/taipanonline/frackingdiagram.gif>

Throughout the videos, words such as *protect*, *barrier*, *sealed*, *permanently secure* and *controlled* convey the idea that fracking follows rigid protocols that leave little room for environmental damage. The impression created is of a solid, seamless band of subterranean shale suddenly pockmarked at intervals by neat bunches of cracks that look not unlike neatly spaced root systems in a row of corn, only a mile or more underground.

4. The Non-Linear Chaos of Fracking

Every technological revolution, however, has its risks, the fracking revolution among them. While energy industry videos hint at some of those risks, they fail to depict the complexities of what goes on in the subsurface when rock at extreme depths and pressure is fractured. This is why experts like Anthony Ingraffea liken them to “cartoons”.¹⁹ Ingraffea is a professor of civil and environmental engineering at Cornell University, and a member of the Cornell Fracture Group, which creates, verifies and validates computer simulations used in the complex engineering systems where hydraulic fracturing occurs.

For years, Ingraffea developed computer models and simulation equipment for Schlumberger, one of the lead companies involved in fracking. That work included

obtaining large chunks of unearthened sandstone, drilling holes into the sandstone samples, putting production pipe into the drilled holes, filling the space between the holes and piping with concrete, using a perforating gun to shoot holes through the pipe and concrete and out into the rock, fracking the rock using water colored with red dye, and then breaking the rock open after fracking to see what had happened.

Over the years, Ingraffea learned that it is rare to find shale rock that is not already cracked. The cracks, in fact, are exactly what companies in the business of fracturing rock look for, as it takes less energy to break such rock open.

When shale formations are fracked, the pressure opens new pathways that may ultimately join and expand pre-existing pathways in the rock. The result, Ingraffea says, is “non-linear chaos”, or “more than one set” of joints. “As soon as the fluid gets through the cracks that you have created and reaches a joint system that has been there for many years, the joints open in unpredictable ways,” he says. The more joints that open and connect, the more gas that can flow out.

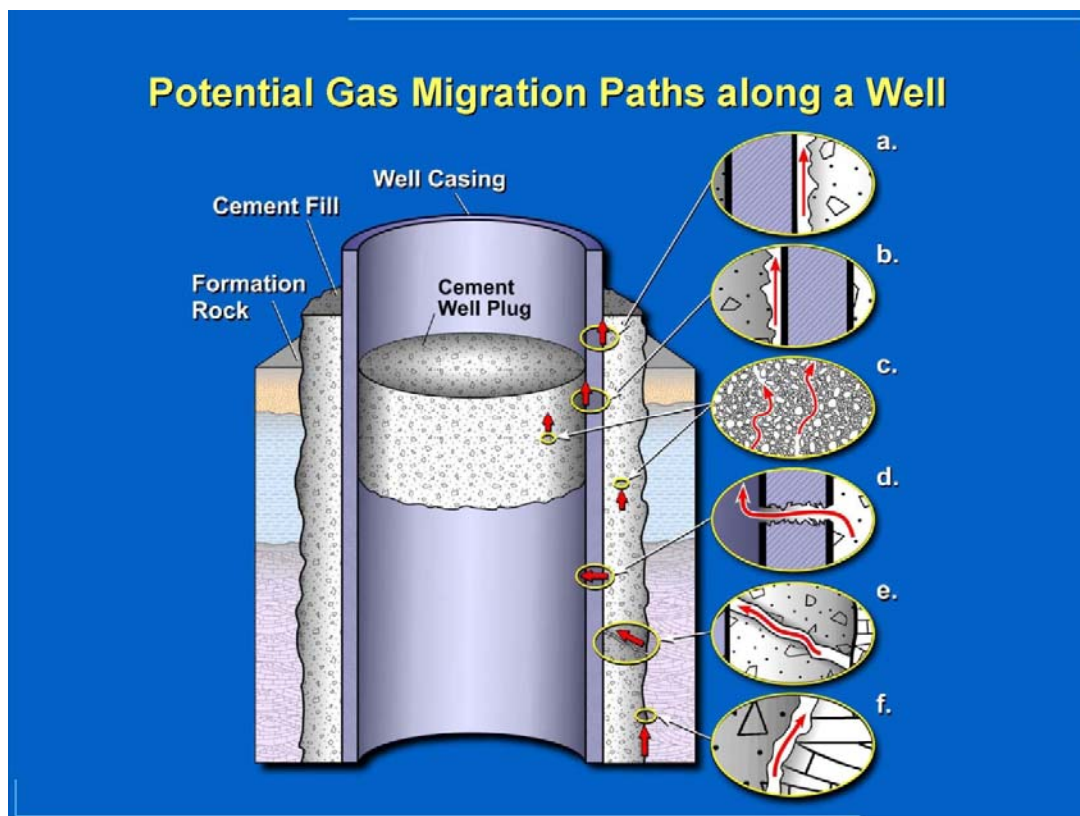
Chaos has its benefits, but it also may have its costs. In certain formations, the shale is characterized by vertical cracks. Ingraffea says that much of the Marcellus Shale that underlies portions of New York, Pennsylvania and West Virginia is composed of interlocking, blocky rock, with joints that run vertically, not horizontally. Could fracking such rock cause contaminants to migrate upwards? It is a question that Ingraffea is asked a lot.

“Since the gas shales are typically over-pressurized, and since the fracking process further increases the pressure in the rock mass for a short period of time, it is possible that the fracking process could open up a pathway upwards to freshwater,” Ingraffea says. “It is not right,” he emphasizes, “to say that thousands of feet of impermeable rock” between where the shale formation is fracked and points higher up prevents such an occurrence, a view shared by other experts.²⁰ Whether such an event is probable is another matter. How and where the fracking occurs, the density of the rock, and pre-existing faults and fractures in the rock, will all play a role in determining such an outcome. For that reason, sound geological knowledge of natural faults in the formations targeted for fracking is an essential prerequisite before any such operations occur.

Another significant issue that influences whether gas and other contaminants migrate from a wellbore is how well the annulus (the space between the well wall and the casing) is sealed. In instructional videos, the industry portrays wellbores as neat, uniform lines of a consistent thickness. But this is rarely the case, due to bulges or imperfections in wellbores that result from different rock formations, varying rock densities, and naturally occurring faults. When such an imperfect wellbore is cemented, it is conceivable that at least some of it may be improperly sealed.

Furthermore, because of the great vertical and horizontal lengths of some shale gas wells, not all wells in US gas-producing states are cemented from the top all the way to the bottom. And when lengthy wellbores are involved, there may be problems from the staging of the cementing job itself.

Figure 5: Potential Leaks from Cement-Sealed Wells



Source: Alberta Energy Utilities Board

There are many reasons why cementing of wells may be imperfect, noted a 2009 report by the three US agencies, including the Groundwater Protection Council. “In very deep wells, the circulation of cement is more difficult to accomplish. Cementing must be handled in multiple stages; which can result in a poor cement job or damage to the casing if not done properly.”²¹ Cementing imperfections increase the risk of air pockets and an imperfectly sealed annulus. The result will be faulty well infrastructure and a risk of leaks – sometimes spectacularly so. For example, in a recent letter sent to the head of British Petroleum by the US House Committee on Energy and Commerce following the explosion at the company’s offshore oil well in the Gulf of Mexico and subsequent uncontrolled release of oil and natural gas from the sea-bottom, the Committee commented on a number of apparent deficiencies in well design. This included early warning signs of an improperly cemented wellbore and failure to test the integrity of the cementing job.²²

Companies such as Schlumberger have sophisticated technology to test whether or not a wellbore’s annulus is completely sealed. But the testing costs money and is not always done, Ingraffea says.

Another concern with fracking is cumulative impacts. As noted in a recent safety memo issued in May 2010 by BC’s Oil and Gas Commission (OGC), fracking operations in

proximity to one another can – and do – result in unforeseen contamination events. The Commission’s advisory followed an event in the Montney Basin, the more southern of the province’s two major shale gas zones. During a fracking operation “a large kick” or “communication” occurred with another well 670 metres away. Sand being pumped underground during fracking at one well showed up at the other.²³

In the memo, the OGC reported that it was aware of at least 18 “fracture communication incidents” in BC and one in Western Alberta, with the distances between such communications ranging between wells spaced 50 metres to 715 metres apart.²⁴ It went on to describe a kick as:

*... An unintended entry of water, gas, oil or other formation fluid into [a] wellbore that is under control and can be circulated out. It occurs when the formation fluid is driven by a formation pressure that is greater than the pressure exerted on it by the column of drilling well in the wellbore. If the formation fluid is not controlled, a blowout may result.*²⁵

Because geological formations and groundwater aquifers are physically complex, it is difficult to know what may occur with successive fracking operations. But as the OGC advisory suggests, the outcome may be “communication events” that result in unforeseen and undesirable incidents of contamination.

The most spectacular of such events – portrayed recently in documentary films such as *Gasland* – may be drinking water so high in methane content that it can be ignited as it comes out of household taps. The footage of tap water being lit on fire packs an emotional punch that hydrologists such as Donald Siegel at Syracuse University decry because methane can come from natural near surface sources and be derived from the decay of organic matter, or it can come from deeper sources and be thermogenic in nature. It is the latter, not former, that is associated with natural gas production, Siegel says. But to the uninitiated viewer watching water from a kitchen faucet set ablaze, such distinctions may be lost. In one case in *Gasland*, it may have been methane derived from near-surface organic matter decay that flowed out of a faucet in such quantities as to become flammable.²⁶ Or then again, it might not.

In 2008, an isotopic analysis of methane in water wells in Colorado’s Garfield County found that in most cases the methane was thermogenic in origin. Geoffrey Thyne, a hydrogeologist and author of the report’s summary and conclusion, would go on to state that the test results “are interpreted as indicating petroleum-related sources, not shallow natural methane.”²⁷

Judith Jordan, who worked as Garfield County’s oil and gas liaison and whose curriculum vitae included work as a hydrologist with DuPont and a lawyer with Pennsylvania’s Department of Environmental Protection, responded to the report saying that it was “highly unlikely” such methane could have migrated along natural pathways “and coincidentally arrived in domestic wells at the same time as oil and gas development started, after having been down there for 65 million years.”²⁸ In other words, it was highly likely that the fracking caused the contamination of domestic wells with methane.

Some experts suggest that fracking can even lead to contamination of drinking water wells from shallower deposits of biogenic gas.²⁹

That there are cumulative impacts associated with fracking is clear. Yet even in Canadian jurisdictions such as British Columbia, where conventional natural gas production has occurred for decades and fracking is ramping up, regulators appear ill equipped to address and mitigate such impacts. As the province's Auditor General recently observed of British Columbia's Oil and Gas Commission:

*OGC's mandate includes an expectation that it fosters a healthy environment. We found that, while the OGC has supported the development of some tools and methodologies to assess cumulative effects, no formal provincial program is yet in place to help manage the environmental effects of developments on the land base.*³⁰

Against this backdrop, the OGC and the BC's Ministry of Environment are faced with increasing pressure from industry to develop shale gas wells. Similar pressures are soon likely to be felt by regulators in other Canadian provinces, as the industry pushes to develop a resource that it maintains provides both energy security and an environmentally friendly bridge to a low-carbon economy.

5. The Argument for Energy Security

In the United States and Canada, continental energy security is often tied to the increased use of domestic energy resources, including natural gas. Frequently, such assertions are twinned to another objective, one that might be called "green energy security."

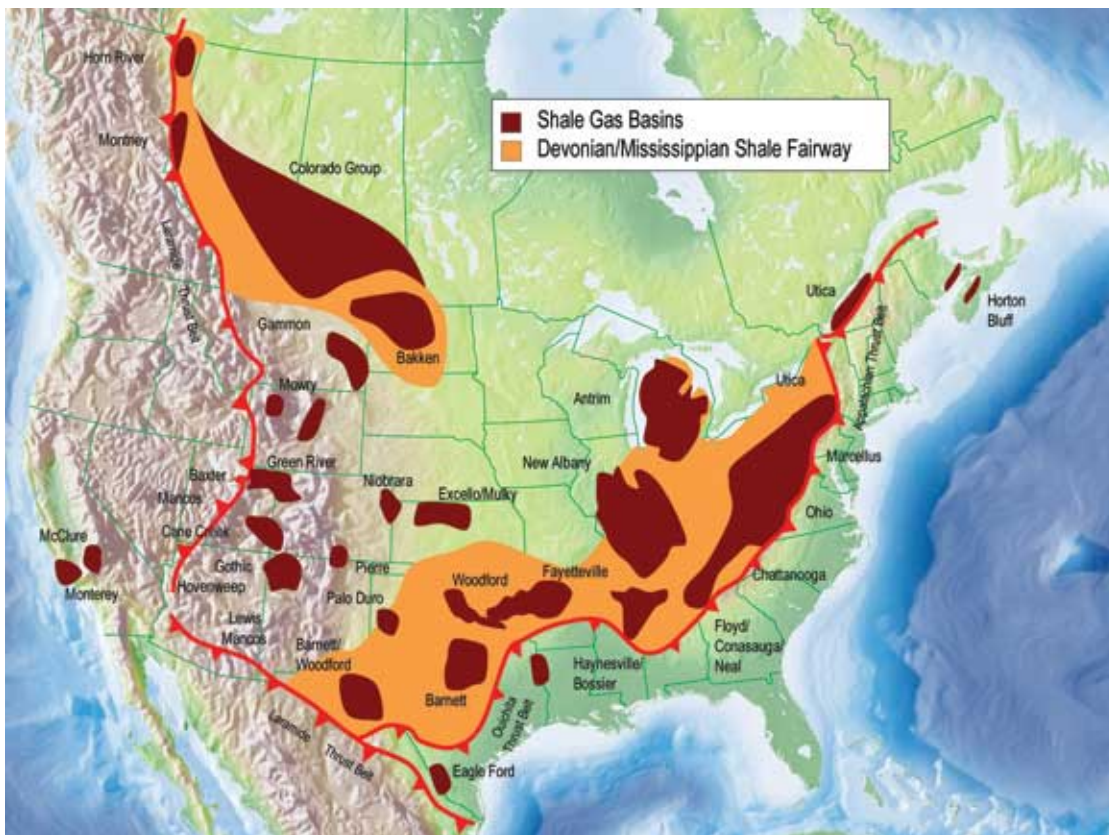
The Energy Future Coalition – whose steering committee includes former US Senators and Members of Congress, diplomats, senior members of past US presidential administrations, renowned scientists, and the heads of environmental organizations, foundations and companies – argues this point. In August 2009, it co-published a discussion paper along with the Center for American Progress promoting increased use of natural gas and other "low-carbon energy sources while providing additional protection for our climate and communities."³¹

The Coalition's arguments are enticing. They imply that there is a plentiful supply of clean or green fuel at hand and that this is an essential bridge to an even cleaner and greener future. The Coalition is by no means the first to note the apparent abundance of natural gas. In 2005 Mark Jaccard, a professor at Simon Fraser University's School of Environmental Management and a member of the Intergovernmental Panel on Climate Change, noted that the abundance of fossil fuels and natural gas in particular almost certainly meant their continued use for generations to come.

To arrive at his position, Jaccard examined both conventional and unconventional natural gas reserves and estimated total resources. (“Reserves” are essentially proven and are economically and technically feasible to extract, whereas “resources” are considered potentially available but unproven for future extraction). He estimated that global unconventional gas supplies are roughly twice those of conventional sources. He then calculated that together conventional and unconventional gas reserves total 15,000 exajoules (an exajoule or EJ is 172 million barrels of oil equivalent), and estimated gas resources total 49,500 EJ (or 3 times the amount of gas reserves). Based on such findings, Jaccard calculated that it would take 160 years at current rates of consumption to exhaust the world’s combined natural gas reserves and 520 years to exhaust their combined resources, thanks in part to shale gas.³²

Since then, experts on tight gas engineering such as the University of Calgary’s Roberto Aguilera have asserted that gas extracted from shale formations in Canada and the US will fundamentally alter the continent’s energy outlook. “The industry is finding ways to unlock the North American natural gas endowment which is, simply put, gigantic,” Aguilera said in 2009. “The addition of hydraulic fractures to these already naturally micro-fractured reservoirs lead to the monsters we are pursuing today with horizontal wells that will dominate the North American landscape for decades to come.”³³ Natural gas boosters, however, are not without critics who note that there may be nowhere near as much shale gas available as some suggest (See: *Shale Overplayed?*)

Figure 6: Major Shale Gas Plays of North America



Shale Overplayed?

While some energy analysts talk in terms of a century's supply of available gas locked up in North America's shale formations, others question such optimism. One such critic is Art Berman, a petroleum geologist who has worked with a range of industry clients including PetroChina, Total and Schlumberger. In a recent interview with the Association For the Study of Peak Oil and Gas- USA, Berman said that when all proven and probable technically recoverable natural gas resources are considered, the continent's natural gas supply is likely closer to 25 years, of which 7 might come from shale resources.³⁴

Berman suggested that the experience in the Barnett Shale in Texas is instructive, in that it is the continent's most intensely developed shale formation. During the "early rush" to develop the Barnett Shale from 2004 to 2006, hundreds of wells were drilled. But within five years of such wells being drilled, between one quarter and one third of them were already "at or below their economic limit". In other words, they no longer produced natural gas or produced so little as to be operating at a loss.³⁵

As the Barnett Shale's production wanes, investment analysts such as Middlefield Capital Corp.'s Dean Orrico echo Berman's view that while other shale plays like the Marcellus may yield considerable quantities of new gas, they will not grow enough "to offset the declines everywhere else."³⁶

Aside from the physical limitations of shale deposits, rosy natural gas estimates may not play out due to a host of geo-political factors. Much may hinge on rising energy demands in rapidly industrializing nations like China and India and will be further influenced by fuel switching in response to tightening supplies of oil.

Advocates for the increased use of natural gas use frequently focus on its far lower emissions of pollutants and greenhouse gases as compared to other fossil fuels. For example, the US Energy Information Administration calculates that bituminous coal, which is typically burned to generate electricity, emits about 205 pounds of carbon dioxide (CO₂) for every million Btu of energy. Natural gas, by comparison, emits close to half the CO₂ of bituminous coal – only 117 pounds for every million Btu.³⁷

The Coalition and the natural gas industry have understandably latched onto such numbers as proof of the environmental benefits of switching from so-called dirty energy sources such as coal and diesel fuel to clean, low-carbon energy sources such as natural gas. So too have state and provincial governments, who have announced in recent months that new gas-fired electrical plants will be built to replace old coal-fired facilities or to displace the need to build new ones.³⁸

Like the Energy Futures Coalition, Encana and other natural gas companies also champion the increased use of natural gas as a transportation fuel. The company believes that a glut of available gas sets the stage for wholesale vehicle fuel-switching, particularly in the freight and commercial trucking industries. In Italy, for example, there are currently 600,000 vehicles fueled by compressed natural gas or (CNG), whereas in all of North America there are currently just 125,000 such vehicles.³⁹

In their efforts to promote cleaner energy, organizations like the Energy Future Coalition and Center for American Progress have also championed using natural gas to stimulate renewable energy resources like wind and solar power. By coupling renewable energy with “low carbon” natural gas, they argue, renewable power’s “intermittency” problem is solved, making “firm” power available for the electricity grid. They also argue for pricing carbon to speed the shift from coal-derived energy to lower carbon fossil fuels and renewable energy sources.

6. Shale Gas: Clean, Green Energy or a Global Climate and Water Liability?

The words *natural gas* probably first entered the lexicon as a means of distinguishing it from “town gas” or the gas derived from coal, which was commonly used in lighting and later cooking in the 19th century. Today, energy companies and suppliers frequently use the words to evoke a different idea – that of a clean, and therefore environmentally beneficial fuel.

But is natural gas as green as its proponents maintain? Emerging evidence suggests not - especially when gas derived from fracking operations is considered. When one looks at the pre-combustion or “upstream” lifecycle of natural gas production (i.e., its extraction, processing, compression and transportation through pipelines) significant amounts of energy are consumed and large volumes of greenhouse gases are released to the atmosphere.

To its credit, the Energy Future Coalition acknowledges this, saying:

*It makes little sense to encourage natural gas use as a lower greenhouse gas alternative to coal or oil combustion if natural gas production yields sizeable amounts of toxic air, or global warming pollution.*⁴⁰

The Coalition goes on to say that the US Environmental Protection Agency (EPA) must “as a first step...undertake a comprehensive scientific analysis of the air, land, water and global warming impacts from natural gas production, including a lifecycle greenhouse gas analysis. It should review the effectiveness of federal and state programs at protecting people, air, land and water from gas production side effects. The EPA should also review new and emerging technologies to reduce this pollution.”⁴¹

The EPA has already noted that the natural gas industry is a significant source of methane releases, and that methane, the largest constituent of natural gas, is 20 times more damaging than CO₂ at trapping heat in the earth's atmosphere. In 2008, the EPA reported, methane emissions of more than 96 million tons CO₂ equivalent originated with the natural gas industry, making it the second-highest anthropogenic source of methane emissions in the United States.⁴²

But this only scratches the surface, says Robert Howarth, a professor of ecology and environmental biology at Cornell University. Howarth believes that a detailed study of all of the greenhouse gas emissions associated with producing and later burning natural gas from fracked shale formations will find that such emissions are on par with those associated with the dirtiest coal deposits.⁴³

Such a conclusion is confirmed by work done at Southern Methodist University's Department of Environmental and Civil Engineering by Al Armendariz. In 2009, Armendariz completed a report on emissions associated with natural gas production in the Barnett Shale underlying parts of Texas where, between 1999 and mid 2008, more than 7,700 oil and gas wells were installed. The report looked at a range of greenhouse gas emissions including those from compressor engines, condensate and oil tanks, and production activities including well drilling and hydraulic fracturing, gas processing and gas transmission. Armendariz concluded that the production of natural gas in the Barnett Shale emitted about 33,000 tons per day of CO₂ equivalent in 2009. "This is roughly equivalent to the expected greenhouse gas impact from two 750 MW coal-fired power plants," Armendariz said.⁴⁴

A related issue and one that will be of increasing importance as global demand and competition for finite fossil fuel resources intensifies, is the question of how much energy is required to bring shale gas to market. Two decades ago, Cutler Cleveland, an energy scientist at Boston University, helped develop the concept of "Energy Return On Investment" or EROI. EROI is a measurement of the amount of energy required to produce energy. In a coalmine, for example, EROI accounts for the amount of energy required to dig down into the earth, jackhammer the coal deposits, bring the coal to the surface and truck it to a thermal electrical plant. The measurement is useful in that it allows societies to assess the relative merits of different energy sources. Since the 1970s, Cleveland estimates that in the United States the EROI for domestic oil and natural gas production has steadily declined. Where once 25 units of energy were produced for every 1 unit of energy expended (25 to 1), today's average is about 15 to 1.⁴⁵

"This basic trend can be seen around the globe with many energy sources," writes Thomas Homer Dixon. "We've most likely already found and tapped the biggest, most accessible and highest EROI oil and gas fields, just as we've exploited the best rivers for hydropower. Now, as we're extracting new oil and gas in more extreme environments – in deep water far offshore, for example – and as we're turning to energy alternatives like nuclear power and converting tar sands to gasoline, we're spending steadily more on energy to get energy."⁴⁶

Cleveland is unaware of any study yet done to determine the EROI for shale gas.⁴⁷ But he has reviewed the literature on shale oil, which like shale gas requires lots of energy and water to produce. “The most reliable studies suggest that the EROI for oil shale falls between 1:1 and 2:1 when self-energy is counted as a cost,” Cleveland and Boston University colleague Peter O’Connor reported in June 2010.⁴⁸ The team also noted that for every barrel of shale oil produced, between 1 and 3 barrels of water were required. “Pumping the large volumes of water required for industrial-scale oil shale operations would be yet another energy investment negatively affecting oil shale’s already thin EROI.”⁴⁹

It is important to note that any assessment of the energy required to produce shale gas is likely to conclude that energy output and water usage are inextricably linked. In his study of the natural gas industry operating in the Barnett Shale, Armendariz concluded that fully 12 per cent of industry’s greenhouse gas emissions fell into the “well drilling and completions” category, much of which involves diesel-fired compression and pumping of water at extreme pressures. This estimate, however, likely understates the water-related energy emissions. Armendariz’s report, for example, does not address the energy consumption associated with accessing the water, trucking it to site and then dealing with the millions of cubic metres of flow-back water (wastewater) that return to the surface following fracking operations.

As discussed in the following section, shale gas production depends on water. Yet, when the full water/energy interface is considered, natural gas looks less and less clean and less desirable as a “transitional fuel” to a low-carbon future. If natural gas use is to increase in the name of bridging to a cleaner energy future, where, exactly, does that bridge lead? Howarth’s answer is to a major increase in water demand and “substantially” higher greenhouse gas emissions.⁵⁰

The risk with energy security plans linked to shale gas, then, is that there is both less climate security *and* less water security – unless great care is paid to where the industry operates and how it uses water resources.

7. Impacts on Water Quantity

The drilling and subsequent hydraulic fracturing of 16 wells on one pad in British Columbia’s Horn River Basin early in 2010 set a record for the shale gas industry. A total of 274 separate stimulations or hydraulic fracturing procedures – 17, on average, per well – were completed. This record is likely to be short-lived; in late 2010 or early 2011 Encana Corporation and Apache Canada expect to drill and hydraulically fracture another 28 wells at two new pads in the vicinity of Two Island Lake. At the new wells, the companies plan for horizontal wellbore lengths of 2,200 metres – 600 metres more on average than the previously drilled wellbores at Two Island Lake. The projected water needed to frack the longer wellbores will be an estimated 2.12 million cubic metres, an amount that will handily exceed the previous fracking record.

Where will the water come from to sustain such operations and those of other companies engaged in hydraulic fracturing activities in BC’s two big gas plays – the Horn River and Montney Basins? Such a question takes on added urgency in light of the fact that in 2010 the region experienced one of the worst droughts in recent memory, with water levels in many of the rivers currently used as water sources by the industry at their lowest recorded levels in a half century.⁵¹

Figure 7: More Shale Gas Wells, More Water: One Calculation for British Columbia’s Horn River Basin

Number of Shale Gas Wells	Water Needed for Hydraulic Fracturing
10	909,090 cubic metres
25	2,272,725 cubic metres
50	4,545,450 cubic metres
150	13,636,350 cubic metres

Source: Presentation to the Sixth Annual Shale Gas Conference in Calgary, Alberta in January 2010, by Ken Campbell, a professional geologist and senior hydrologist with Schlumberger Water Services

Greater water demand in the Horn River Basin is a certainty, as is demand throughout North America wherever shale gas resources are developed. Section 9 of this report explores the complex issues relating to water allocation in Canada now.

8. Impacts on Water Quality

With nine out of every 10 gas wells in the U.S. now fracked and with increasing fracking activities in Canada, a growing chorus of people are questioning the public health and environmental impacts of the natural gas industry’s activities. Much of the controversy surrounding fracking has come to light due to sustained investigative reporting in the U.S. by *ProPublica*, an independent, non-profit newsroom steered by print media veterans formally with *The Wall Street Journal* and *The New York Times*.⁵²

In November 2008, as part of an ongoing investigative series on the environmental threats posed by fracking activities, *ProPublica* reported on an incident in Wyoming’s Sublette County where a sampling of water from a well turned up benzene – a chemical believed to cause aplastic anemia and leukemia – in a concentration 1,500 times that considered safe for people. The well was in a part of Wyoming where 6,000 gas wells had been fracked.⁵³

“The contamination in Sublette County is significant because it is the first to be documented by a federal agency, the U.S. Bureau of Land Management,” *ProPublica*’s Abrahm Lustgarten reported. “But more than 1,000 other cases of contamination have been documented by courts and state and local governments in Colorado, New Mexico,

Alabama, Ohio and Pennsylvania. In one case, a house exploded after hydraulic fracturing created underground passageways and methane seeped into the residential water supply. In other cases, the contamination occurred not from actual drilling below ground, but on the surface, where accidental spills and leaky tanks, trucks and waste pits allowed benzene and other chemicals to leach into streams, springs and water wells.”⁵⁴

As a result of such sustained reporting, proposed shale gas developments in parts of New York State have become a flashpoint for public opposition to fracking activities, and may prove a crucial litmus test for regulatory reforms. Of particular note are key watersheds whose surface waters provide 8.2 million New York City residents with their water and that overlay portions of the Marcellus Shale, a giant shale gas formation underlying portions of New York, Pennsylvania and West Virginia.

There are three major concerns relating to the potential impact of shale gas production on water resources. These are: the specific chemicals used in fracking operations, groundwater contamination as a result of fracking activities, and water contamination resulting from the tremendous volumes of wastewater or “flow-back” water produced in fracking operations. All three have been linked to incidents of water contamination as detailed by *ProPublica*, other media outlets and environmental regulators.

Fracking Chemicals

In jurisdictions where fracking has been underway for some time, one of the most contentious issues has been the use of a range of chemical additives used in fracking fluids. In the United States, for example, fracking companies are generally exempt from publicly disclosing the chemical compounds they use in their fluids, even though some such chemicals – including benzene and diethylene glycol – are known human carcinogens.

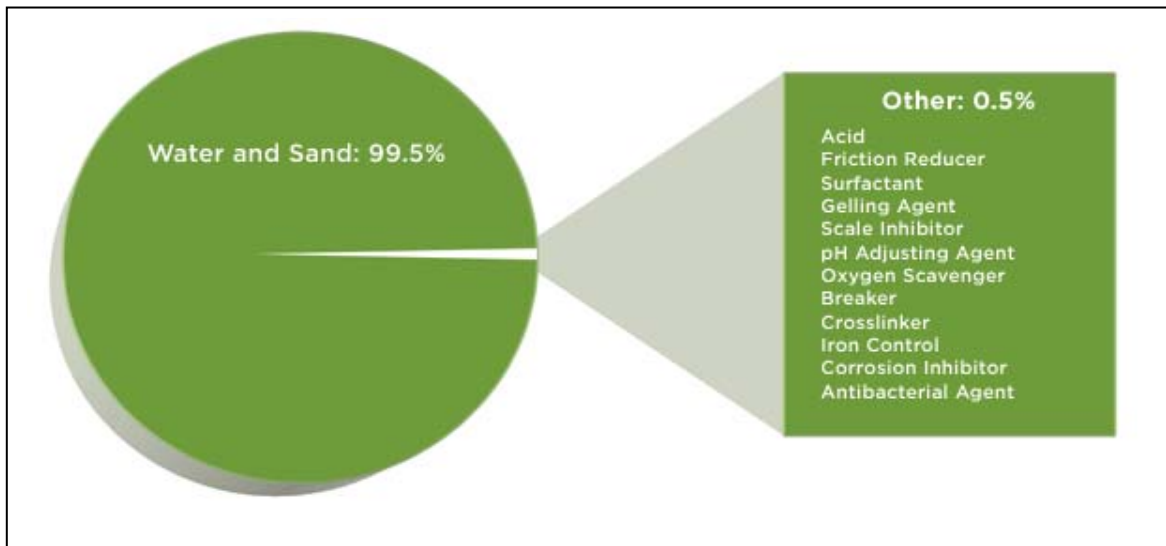
While water is by far the biggest component in the liquid stream pumped at extreme pressure underground during fracking operations, it is certainly not the only component. At various stages during fracking, large amounts of sand and unnamed “fracture fluids” or chemicals are also pumped. So-called “friction reducers” are used to lower resistance as the fluid moves down the well’s production casing. Biocides are used to prevent bacterial growth, which may inhibit the flow of gas. “Scale inhibitors” are introduced to prevent the build-up of scale within the fracture zones and wellbore. And lastly, “proppants” – fine grained sand or tiny ceramic beads – are pressure-pumped to keep the seams or cracks in the fractured rock open allowing gas to flow out more freely.⁵⁵

In the US, the Groundwater Protection Council reported in 2009 how “a small number” of potential frack additives including “benzene, ethylene glycol and naphthalene have been linked to negative health affects at certain levels.” In September 2009 – the same month that New York City’s Department of Environmental Protection voiced concerns about the impacts on state water resources of proposed shale gas developments – a massive report was also released by the New York State Department of Environmental Conservation’s Division of Mineral Resources. It listed 257 additives that may be mixed with the water injected into shale formations and provided a breakdown of the known chemicals in those additives that stretched 10 pages long.⁵⁶

To obtain its information, the Department asked six well servicing companies and 12 chemical suppliers to provide information on the composition of frack fluids. The Department would go on to say that frack fluids are typically 98% fresh water and sand, “with chemical additives comprising 2% or less of the fluid.”

The Groundwater Protection Council, citing a report by the US Environmental Protection Agency (EPA), suggested that the proportion of chemicals in fracture fluids was even less than 2%, with 98 to 99.5% of fracture fluids being water by volume.⁵⁷ However, the Council noted that a “toxicological evaluation of fracture fluid additives” was not part of the EPA study.

Figure 8: One Look at the Composition of Fracking Fluids*



Source: <http://www.hydraulicfracturing.com/Fracturing-Ingredients/Pages/information.aspx>

*** This diagram illustrates one end of the spectrum – the proportion of water and sand ranges from 98% to 99.5% and the proportion of “other” ingredients (chemical additives) ranges from 0.5% and 2%.**

To shed more light – and accountability – on the fracking industry, the US House Committee on Energy and Commerce said in February 2008 that it had asked eight well service companies – including Calgary-based Sanjel Corporation and Calfrac Well Services – to disclose the chemicals used in their frack fluids.⁵⁸ (A copy of the letter to Calfrac can be found in Appendix A.) The Committee in issuing the letters noted mounting public outcry over the potential for fracking to degrade drinking water supplies. In addition, it noted major weaknesses in US regulations saying:

In 2003, EPA entered into a voluntary memorandum of agreement (MOA) with the three largest hydraulic fracturing companies, Halliburton, BJ Services, and Schlumberger, to eliminate diesel fuel for hydraulic fracturing fluids injected into certain wells located in underground sources of drinking water. Aside from this MOA, there is virtually no federal regulation of

hydraulic fracturing. In 2005, Congress exempted the practice of hydraulic fracturing from the Safe Drinking Water Act (SDWA), except when the injected fluids contain diesel fuel. Oil and gas companies can use additives and chemicals besides diesel fuel in their hydraulic fracturing fluids, but federal regulators have no authority to limit the types and volumes of these substances. Indeed, oil and gas companies do not need to report to federal regulators what their fracturing fluids contain or where they are used.

Fracking and Contamination of Groundwater

While fracking shale formations may be relatively new in Canada, it has been used for some time in the country's most energy-rich province, Alberta, to boost production of natural gas from coal seams. With plans to frack just about any new well in a province with such a significant number of old wells – some of which are known to be improperly sealed – the fear is that the cumulative effect may lead to increased contamination of water wells.

The fear is well founded. By 2007, natural gas produced from “unconventional” coal seams was commonplace in Alberta, with close to 11,000 such wells drilled.⁵⁹ The upsurge in exploitation of the province's coal seams in the previous decade paralleled declines in Alberta's more conventional gas reserves and rising demand from the tar sands industry, which requires tremendous amounts of natural gas to separate the bitumen from the clay, sand and water that comprise the tar sands.⁶⁰

Coalbed methane, the gas extracted from coal seams, is deemed unconventional because of the added steps needed to get the gas out. Seams must often be depressurized before the gas is freed, and because the seams tend to be blocky with natural cracks that are often tightly compressed, they are also commonly fracked.

The relatively shallow depths at which many coal seams are found, has led to growing water conflicts between the gas industry and landowners.

In January 2006, Alberta's Energy and Utilities Board issued a directive in response to “the recent trend” toward fracking shallow gas reservoirs (coal seams) of less than 200 metres in depth. The directive prohibited fracking within a 200-metre radius of water wells whose depths were within 25 metres of the depths at which fracking was to occur.⁶¹ In other words, the industry needed to provide a horizontal separation of two football fields in length, and at least a 25-metre separation between a water well's lowest depth and the shallowest depth of a frack zone.

Two years later, an independent review of the EUB's directive concluded that it did not go far enough. It recommended that the EUB double the vertical separation requirement to 45 to 50 metres.⁶² This was recommended because of the geological risk that induced fractures in the coal could stretch 20 metres, a distance perilously close to the 25-metre exclusion zone. “The proposed increase therefore reflects increased safety margin,” the review concluded.

Many of the coal seams to be fracked to date in Alberta have occurred in the Horseshoe Canyon area, where the shallowest deposits are within 200 metres of the surface, meaning that fracking activities are actually occurring within freshwater aquifer zones. In a recent news report on what occurred in the aftermath of fracking at such shallow depths, Jessica Ernst, a biologist and environmental consultant to the oil and gas industry, reported drastic changes in her water and that of the nearby hamlet of Rosebud to the east of Calgary.

“I began to notice that my skin was burning in the shower. I thought it was some weird early menopause thing. Then my dogs suddenly refused to drink the water. They backed up away from it,” Ernst recalled. Subsequent tests of her water revealed abnormally high methane and ethane levels and similarly high kerosene levels in the municipal drinking water well supplying Rosebud with its water.⁶³

Such contamination supports the need for effective regulation to protect groundwater and domestic wells from the impacts of fracking. It also emphasizes the need to address cumulative effects. With conventional gas reserves dwindling there will be increased reliance on unconventional gas sources in future years. By 2015, Alberta’s Geological Survey estimates that unconventional coalbed methane production could hit 19.6 billion cubic metres – a near seven-fold increase over 2005.⁶⁴

Fracking and Contaminated Wastewater

In the United States where fracking operations are well advanced, one of the biggest environmental concerns relates to the billions of cubic metres of wastewater produced by the industry.

After gas wells are fracked, large amounts of the water, sand and chemicals pumped underground return to the surface. In 2006, it was estimated that approximately 2.16 billion cubic metres of this contaminated wastewater or flow-back water returned to the surface at fracked wells across the US.⁶⁵ How to dispose of this large volume of highly contaminated water has become a burning issue in Pennsylvania. Similarly, a demonstrated lack of capacity to properly treat and dispose contaminated flow-back water, is emerging as a potentially make-or-break issue for the shale gas industry in New York, and may yet prove a similarly decisive issue elsewhere.⁶⁶

To date, the massive volumes of contaminated wastewater from shale gas wells in the US have typically been dealt with in one of two ways – injection deep underground or treatment in municipal water treatment plants. The number of deep disposal injection sites is limited by geological constraints and regulatory requirements. Injecting wastes that are typically very salty and that may contain chemicals and heavy metals into deep disposal wells can contaminate drinking water. Municipal water treatment plants are not designed or intended to deal with the contaminated wastewater from shale gas production.

Pennsylvania’s fracking industry produces about 34,000 cubic metres of flow-back water a day. By 2011, that figure could reach nearly 72,000 cubic metres – an amount that Pennsylvania’s Department of Environmental Protection (DEP), says the state’s

waterways cannot safely absorb.⁶⁷ Worse, much of the industry's contaminated liquid waste is now trucked to municipal wastewater treatment plants that are wholly unequipped to properly process it before it is discharged into streams, rivers or lakes that may also be drinking water sources.⁶⁸

In Pennsylvania, the strains placed on municipal water treatment plants led to passage in June 2010 of regulations limiting total dissolved solids or TDS levels in treated and discharged wastewater from the shale gas industry. At the time, John Hangar, DEP Secretary said that: "The only way to protect our water resources is to implement new wastewater treatment standards for the drilling industry."⁶⁹ Hangar went on to say that TDS levels in frack wastewater had damaged equipment in other industries, led to drinking water advisories, and caused at least one massive fish kill on a local creek.

In June 2010, Hangar appeared on a National Public Radio program and had sharp words for an industry whose activities had resulted in gas migrating underground to contaminate local wells, spills of chemicals and improperly contained flow-back waters into local streams and rivers, and toxic wastewater overwhelming local municipal water treatment plants and later the rivers that the treatment plants discharged the waste to.

All of this, Hangar said, spoke to the need to more "tightly regulate" an industry that needed to "do better than it is doing right now." "Or," Hangar warned, "it's going to create a public backlash. It is in the process, in my judgment, of losing public confidence because of its inability to actually be world-class. At the end of the day, government has an essential role. It can encourage that world-class culture, or it can discourage it. But we can't actually make it [happen]. That has to come out of the top management, all the way down to the persons on the rig, who are actually the only people who are on-site 24 hours a day, seven days a week."⁷⁰

The states of Texas, Oklahoma, New York, Iowa, Virginia, Arkansas and Tennessee do not have the problem Pennsylvania does as they prohibit returning any drilling wastewater to streams.⁷¹ In these states, injecting wastewater into deep underground wells or treating it to a high enough standard so that it can be reused for fracturing purposes may be among the only options.

In Canada, by contrast, while hydraulic fracturing records are being set in BC's Horn River Basin, no senior provincial or federal regulator has come close to publicly echoing Hangar's critical assessment of industry performance. A few factors may explain why. Canadian shale gas production is as yet in its infancy. While the vast country's relatively small population is largely concentrated in pockets close to and along its very long border with the US, shale gas production to date has taken place in remote regions, far from major urban centres and political power bases. And conflicts between landowners, municipalities and fracking operators are fewer in number and generally not well publicized compared to the numerous conflicts in the US. (Yet, one such conflict in an area of intense natural gas development in northern British Columbia, where lengthy horizontal wells are routinely fracked, has generated international headlines and one of the most aggressive police investigations in Canadian history as a result of six bombings of gas pipeline infrastructure.⁷²)

But in a continent where water-intensive energy production generates significant flows of natural gas, oil and hydroelectric power from various regions of Canada to the United States, regulatory developments in one country may well influence those across the border. Further, Canada and the US share numerous lakes, rivers, streams and aquifers along a lengthy shared border, and many energy companies operating in one country also operate in the other. If water resources are to be protected in the face of expanding shale gas production, what regulatory changes need to be implemented today?

9. Shale Gas Regulation and Water Allocations in Canada

While Canada's shale gas industry is at this time only well advanced in British Columbia, the country's National Energy Board estimates that the nation could produce substantial volumes of gas in the years ahead and that there is potentially 1,000 trillion cubic feet of shale gas in the country's shale formations, of which 20 per cent could potentially be recovered – an amount that “could allow Canada to meet its own need for natural gas until well into the 21st century”.⁷³ While acknowledging that there are various environmental concerns with “water-intensive” fracking operations, the NEB generally downplays such concerns.

This section provides an overview of how water allocations are handled in BC, and in those parts of the country – Ontario, Quebec, New Brunswick, Saskatchewan and Alberta – where development of shale gas plays is in the early stages.

British Columbia

In British Columbia, the Oil and Gas Commission (OGC) regulates the fossil fuel industry. Created in the late 1990s to encourage the expansion of oil and gas exploration and development in the province, the OGC is described as a “one-stop shop” for regulatory review and approvals of energy industry projects.⁷⁴ After the creation of the OGC, the provincial government transferred responsibility for issuing short-term water use approvals from the provincial Ministry of Environment to it. With the move, the energy sector became the only industry in the province to have its own designated regulator for water approvals.

Short-term water permits apply only to surface waters in BC. The province is alone among Canadian jurisdictions in not regulating or licensing groundwater withdrawals. Longer-term surface water usage – including in the energy sector – is allocated through water licenses. MOE retains authority for reviewing, rejecting, approving and attaching conditions to all such approvals.

As of mid-2010, MOE reported that it had received a number of water license applications from energy companies interested in diverting water from reservoirs, lakes, rivers and creeks for purposes of hydraulic fracturing. Given the current lack of knowledge on some of the remote water bodies that are the subject of the applications,

the ministry said that it would likely place time limits on any new licenses, and that it was considering five-year limits.⁷⁵

Energy companies engaged in fracking operations have indicated to MOE that they hope to obtain large volumes of water under such licenses. Talisman Energy, a company also active in Quebec's St. Lawrence lowlands, has proposed diverting 2.2 million cubic metres of water per year on a "permanent" basis, from BC's largest man-made water body, Williston Reservoir. The proposal would involve building a pipeline from the reservoir to connect with the company's emerging shale gas play in the Montney Basin.⁷⁶

The OGC does not publish a readily available list of assigned or active water permits, as is the case with many other provinces where shale gas resources may soon be exploited. In August 2010, the Commission did, however, publish a report on water usage in the oil and gas sector. The document was written with the express intent of addressing the "increased" demand for water due to fracking activities.⁷⁷ While acknowledging that more water would be in use, however, the provincial energy regulator chose at several points in the document to downplay the significance of the industry's overall water demands and impacts on the environment, echoing in many of its conclusions arguments earlier voiced by the Canadian Association of Petroleum Producers.⁷⁸ At one point, for example, it stated that water usage in British Columbia's pulp and paper industry was 17 times greater than the water used by natural gas companies.⁷⁹ At another point, the OGC said that "a preliminary look" at the actual water used by energy companies in the Horn River Basin, concluded that in 2009 the companies used "less than five per cent" of what they could have used under the various water permits and licenses they held.

It is difficult, however, to conclude what this finding actually means. The OGC report provided no numbers on water volumes assigned in the Horn River, versus actual water volumes used. Furthermore, it did not indicate how extensive energy company activities were in the region in 2009 – an omission which may have something to do with the fact that in 2009, energy company activities were only a fraction of what they are anticipated to be as this new shale gas play is developed.

As part of the research for this report and as an attempt to better understand the full extent of water authorizations in the Canadian province at the forefront of shale gas development, a number of information requests were filed with the OGC, allowing a list to be compiled of all active temporary water use permits. The list provides a first-ever glimpse into what may lie ahead in more populous regions of the country such as the Montreal-Quebec City corridor. The information shows that as of April 2010 under approvals issued by the OGC, companies holding water permits could withdraw water from at least 540 points on creeks, rivers and lakes in northeastern BC Combined, the permits (which have a maximum timeframe of 12 months) allowed for daily water withdrawals of up to 274,956 cubic metres, or 60,481,864 imperial gallons. To compare, the domestic and business water consumption in the Greater Victoria area, home to nearly 336,000 residents is on average 134,282 cubic metres, or 55 percent that of the province's natural gas sector.

Information supplied by the OGC shows that some companies hold single water use permits granting them water withdrawals from numerous points on different water sources. Penn West Petroleum Ltd., for example, held one permit allowing it to withdraw water from 57 different points on numerous creeks and lakes, to a combined daily maximum of 12,975 cubic metres or more than five Olympic-size swimming pools worth of water. A single permit held by Encana gave it access to water at 71 different locations for a combined daily maximum of 16,117 cubic metres or nearly six-and-a-half Olympic swimming pools worth of water per day. Whether or not the companies actually use such water and over what timeframe is largely unknown, although most companies holding such permits are required to keep records of what they withdraw and are required to report such figures if requested to do so by the OGC.

In nearly one quarter of all cases, the assigned water rights are to “unnamed” lakes and creeks, which companies may draw on for fracking or other energy industry usages.

Typically, the permits have conditions attached to them. For example, Encana’s April 1, 2010 permit for water withdrawals at Two Island Lake grants it 9,360 cubic metres of water per day up to a maximum total volume of 200,000 cubic metres. Water withdrawals are to cease in the event that the lake level drops 0.10 metres. The company is required to keep “accurate records” of all water withdrawals and to furnish such records to the OGC if requested to do so.⁸⁰ Significantly, checks of water volumes assigned versus water volumes actually used at Two Island Lake both by Encana and Apache reveal that in 2009 and early 2010 fully all of the water volumes assigned to both companies were reported as being used, meaning that if the overall industry usage of water in the Horn River Basin is below 5 per cent as suggested by the OGC, then other companies operating in the region would have had to use virtually none of the water assigned to them under permits issued by the regulator.

While BC lacks comprehensive groundwater legislation, the OGC requires companies using groundwater for fracking and other purposes to account for such withdrawals.⁸¹

One such well in the Two Island Lake area and scheduled to be in production in August 2010, will take up to 16,000 cubic metres of water per day from the Debolt Formation, an aquifer about 900 metres underground.⁸² The highly saline water, which an Apache Canada official has described as “making ocean water look like freshwater” will then be run through a treatment plant which will remove gas, including toxic and potentially lethal hydrogen sulphide, before the water is used in nearby fracking operations. Encana estimates that the plant will supply enough water for four fracks per day, making it the “primary” but not sole source of water used in well stimulations in the region.⁸³ How this level of water use may impact deep groundwater aquifers is poorly understood.

The OGC’s main approach to regulating water usage is to limit daily and cumulative withdrawals. It also requires companies to “maintain accurate records of all water withdrawal activities throughout the term of any water approval” and to submit such records to the Commission upon request.⁸⁴ As another means of regulation, the Commission said in June 2010 that it was “moving toward industry submission” of actual

water usage.⁸⁵ Theoretically, this would allow comparisons of water volumes used in fracking operations with site-specific water withdrawals.

As recent water withdrawals at Two Island Lake suggest, however, the rigor with which the OGC monitors adherence with water permits appears somewhat lax (See: *The World's Biggest Frack: Just How Much Lake Water was Used?*)

The World's Biggest Frack: Just How Much Lake Water was Used?

Water from Two Island Lake, a small lake about a four-and-a-half hour drive north and west of the BC community of Fort Nelson was the primary water source for what was billed as "the world's largest" hydraulic frack. Permits to withdraw water from the small lake were granted by the province's Oil and Gas Commission to the two companies operating in partnership in the region – Encana Corporation and Apache Canada.

On March 22, 2010, with fracking well underway, Apache received an amended water permit allowing it to divert up to a "maximum" of 200,000 cubic metres of water from the lake.⁸⁶ Ten days later, Apache received an amended water permit granting it a 50 percent increase in withdrawals to a total of 300,000 cubic.⁸⁷

On April 15, the OGC reports, Apache "ceased" withdrawals after the water level at Two Island Lake fell to nearly 15 centimetres – the maximum allowed."⁸⁸

In response to a request for the actual water volumes removed at Two Island Lake, the OGC replied in June 2010 that it was awaiting a "revised" report from Apache. It is unclear why a revised report was needed, however, as a company hired by Apache to report on water usage at Two Island Lake had already prepared a report, dated May 20. In the report, the company noted that Apache's water withdrawals totaled precisely 200,000 cubic metres and that Apache was "in compliance" with all the terms of its water permit.⁸⁹

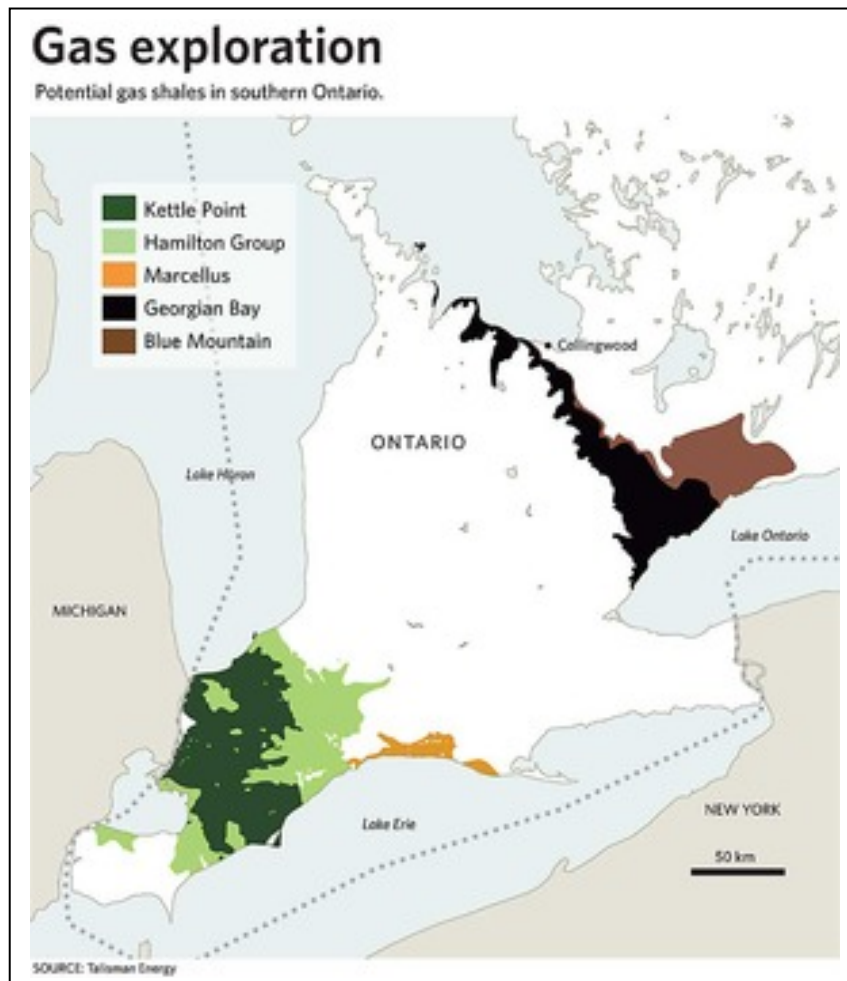
It remains to be seen why a report apparently written more than a full month after all water withdrawals had ceased would need to be revised based on new information – unless certain problems noted at the pump house operated by Encana and Apache at Two Island Lake have any bearing. At a field visit to the pump house in early June 2010, at which members of three provincial agencies – the OGC, Ministry of Environment, and Ministry of Energy, Mines and Petroleum Resources – along with members of the Fort Nelson First Nation (in whose traditional territory Two Island Lake is located) and Encana officials were present, it was noted that water pumped from the lake could be diverted past meters.⁹⁰

Ontario

While the NEB does not flag Ontario as a likely locale for significant shale gas production, a rush is already underway in Canada's most populous province to lay claim to its potential shale gas riches. Calgary-based Mooncor Oil & Gas Corp. has locked up agreements with private landowners covering 9,200 hectares in Lambton and Kent counties in the province's southwest corner.⁹¹

Although Ontario has yet to see any significant shale gas exploration, the province's Ministry of Natural Resources (MNR) and Geological Survey of Canada jointly said in 2008 that there was "significant potential" for shale gas from the Kettle Point, Marcellus and Collingwood shales – all in southwestern Ontario.⁹² Escalating land acquisitions in adjoining upstate Michigan further hint at that potential. By the summer of 2010, Encana Corporation had secured rights to 100,000 hectares of land in the state overlaying the Collingwood shale.⁹³

Figure 9: Potential Gas Shales in Southern Ontario



Source: Accessed at <http://www.sqwalk.com/q/alberta-firm-eyes-ontarios-untapped-shale-gas>

Since nearly all land overlying Ontario's shale gas formations is private land, companies wishing to explore for gas enter into lease arrangements with landowners. As lead regulator of oil and gas activities in the province, MNR does not approve such leases. All Crown land leases, however, require MNR approval.

As of August 2010, only one shale gas exploration well had been drilled in the province. Drilling requires a permit from MNR. The ministry also reviews drilling applications. It decides whether or not drilling may interfere with fresh water aquifers, and if so whether or not license applications are approved with conditions or rejected.

Terry Webster, chief geologist with MNR's Petroleum Resources Centre, hinted that such assessments may prove challenging. Ontario's shale formations are shallow, and therefore nearer to freshwater aquifers. Because they are shallow, they are also under less pressure than deeper formations and thus likely to yield less gas. "Is there enough gas to be economic to recover?" Webster asked. "Can it be recovered without interfering with people's use of groundwater?"⁹⁴ These are key questions.

Any water used in a gas well that was fracked would likely require Ministry of Environment approval. Under Ontario's *Water Resources Act* and regulations, any person taking more than 50 cubic metres of water per day must obtain a permit from MOE. Given the large volumes of water used in fracking operations, such an approval, known as a Permit to Take Water, would be required. To date, no application to use water for fracking purposes in Ontario has been made.

Quebec and New Brunswick

In Quebec, energy companies have obtained more than 400 exploration permits and leases for shale gas in a formation known as the Utica Shale, which underlies much of the lowlands to the south of the St. Lawrence River between Montreal and Quebec City.⁹⁵

In New Brunswick, the provincial government recently issued its largest ever tender for oil and gas exploration – more than one million hectares of land – to Southwestern Energy, a Texas-based firm. The company has indicated that it will spend \$47 million over the next three years exploring for shale gas in two areas, one in a large area that spans from the Northumberland Strait near Richibucto to past Fredericton, and the other area to the southeast near Cocagne. Apache Canada, meanwhile, is assessing shale formations in the Elgin area.⁹⁶

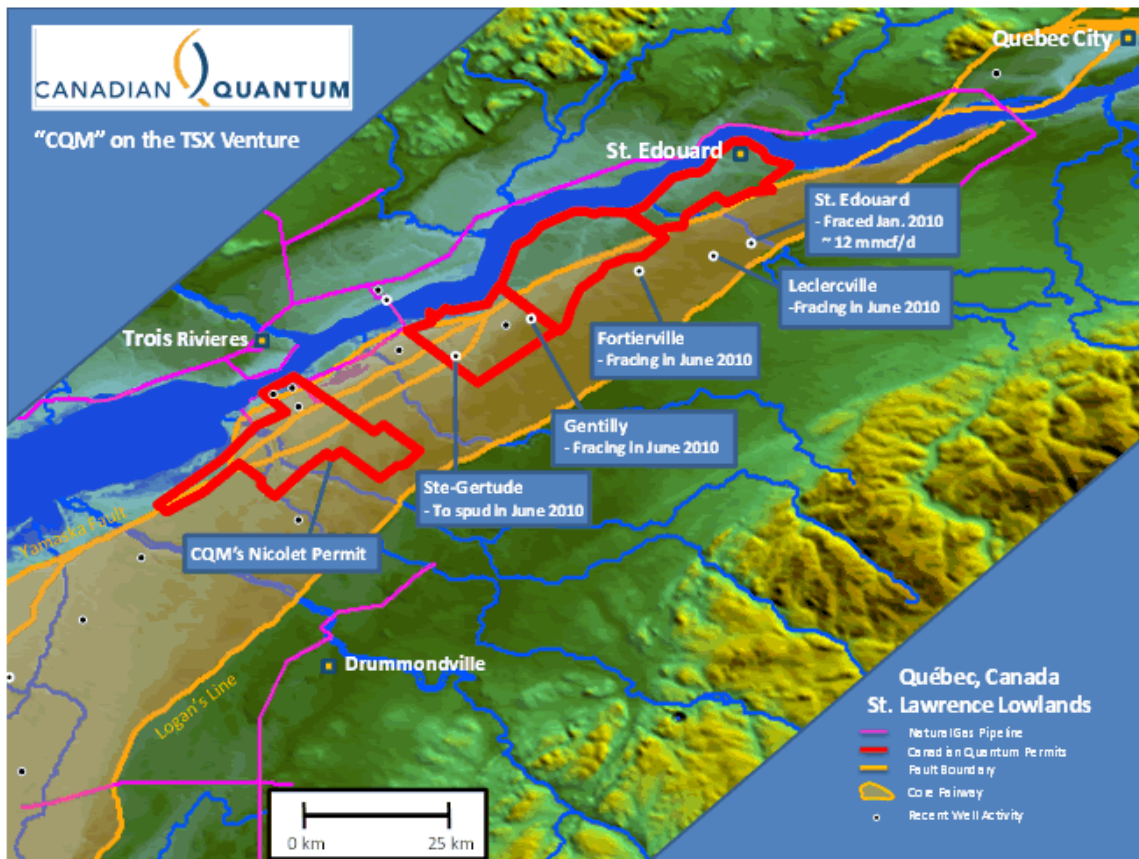
In both provinces, the environment ministries issue water approvals. This includes permits for surface water and for groundwater. In Quebec, there is a threshold for groundwater permitting. Any proposal to withdraw 75 cubic metres of water or more per day requires a permit from the province's Ministry of Sustainable Development, Environment and Parks. The Ministry is also responsible for issuing permits to dispose of wastewater and to flare natural gas.

There is intense industry interest in developing shale gas reserves in the province – the gas industry estimates that there could be up to 25 trillion cubic feet of recoverable gas in the Quebec portion of the Utica Shale.⁹⁷ In late August 2010, Quebec's Minister of

Natural Resources, Nathalie Normandeau, and the province’s Minister of Environment, Pierre Arcand, announced that the provincial government would hold a series of public meetings to address public concerns about the shale gas industry as part of what the *Globe and Mail* reported as “an aggressive schedule of environmental review and legislative overhaul that could pave the way for a new natural gas industry” in the province.⁹⁸ “We have the responsibility to exploit such potential wealth,” Normandeau said at a press conference at which several dozen protesters attempted to shout down the minister, “but we will be putting primary emphasis on the environment and on ensuring social acceptance of any development.”⁹⁹

Earlier, Normandeau had summarily dismissed concerns raised by communities in proximity to where proposed shale developments are slated to occur. After the city council of St. Marc sur Richilieu near Montreal passed a motion in May 2010 opposing all gas exploration in its territory until Quebec demonstrated that shale gas developments presented no environmental risk, Minister Normandeau responded saying: “People are asking if drilling damages the water table. The answer is no. Are the substances used in drilling polluting? The answer is no.”¹⁰⁰

Figure 10: Drilling in Quebec’s Shale Play



Source: The Market Oracle.UK. “The Utica Shale Natural Gas Play Revisited”. June 28, 2010.

On September 27, 2010 following an environmental study, the Province of Quebec announced a moratorium on exploration and development of the oil and gas potential in the St. Lawrence estuary, from Île d'Orléans to Anticosti Island, citing the “complex and fragile” nature of the environment and the dependency of coastal communities on tourism and commercial fishing. Opposition parties continued to call for a moratorium on all gas and oil development in the province until environmental studies are complete.¹⁰¹

In New Brunswick, as in Quebec, responsibility for assigning water rights rests with the Department of Environment (DOE). Any proposed water usage of more than 50 cubic metres per day – whether surface water or groundwater - triggers an Environmental Impact Assessment (EIA) under the province’s *Clean Environment Act*. In an EIA, a company proposing to make significant water withdrawals must undertake a public consultation. (Historically, such proposals have been focused on groundwater, not surface water sources.) The DOE can require that the consultation process include public meetings or hearings. Whether or not public hearings occur, project proponents must summarize all public comments and show how they will address public concerns.

In the event that a Certificate of Determination or approval to use water is granted, the Department of Environment typically sets a limit on a “maximum sustainable pumping rate per day”, a rate that might be further constrained by the hours in the day when pumping could occur, and would also include caps on how much a water source could be drawn down.¹⁰² All entities - public utilities or private companies – are subject to the 50-cubic-metre threshold and the regulations apply to all lands in the province, public and private.

Another way that water usage is regulated in New Brunswick is through Approvals to Construct. Operations where water is pumped underground require such an authorization from the DOE. Such approvals would likely require disclosure of where the water originated from and what chemicals were put in it prior to fracking procedures. Proposals to treat wastewater or produced water at any future fracking operation in New Brunswick would also trigger an EIA.

Despite these regulations, companies interested in developing the province’s shale gas resources can get around some screening by DOE by purchasing water from an existing entity that has a licensed water supply, for example, a municipality. This has occurred in British Columbia, with companies obtaining water both from municipalities and landowners – water volumes that are not captured in the industry’s water usage as reported by the OGC. Research for this paper confirmed that Apache Canada has approached at least one New Brunswick municipality – the community of Sussex – to find out how much it would cost to purchase water from it.¹⁰³

Quebec’s and New Brunswick’s decision to subject proposed water withdrawals of a certain magnitude to higher scrutiny is a concept that is embraced by Environment Canada as well, but one that is rarely applied. Under the *Canadian Environmental Assessment Act*, a comprehensive environmental assessment is required for any project proposing to withdraw 200,000 cubic metres or more of groundwater per year.¹⁰⁴

However, such assessments only apply to lands under direct federal jurisdiction, for example, First Nation reserves.

Saskatchewan

In Saskatchewan, the provincial government recently unveiled a number of financial incentives to encourage shale gas development.¹⁰⁵ Here, as in Quebec and New Brunswick, there is an authority separate from the provincial regulator of oil and gas activities (Saskatchewan Energy and Resources) that assumes responsibility for assigning water rights. The Saskatchewan Watershed Authority assigns rights to both surface water and groundwater supplies. The sole exception to this rule is water that is produced as a byproduct of oil and gas extraction activities. If a company drills for oil or gas and water comes up the wellbore as a byproduct, then that water is not subject to provincial approvals.¹⁰⁶

In addition to issuing permits to use water, the Watershed Authority also issues approvals to construct and operate facilities that draw and use water, powers similar to those held by New Brunswick's Department of Environment.¹⁰⁷

Alberta

In Alberta, the industry practice of fracking is firmly established, particularly in so-called "unconventional" formations such as coal seams. The Alberta Geological Survey (AGS) reports that there will be continued growth of coalbed methane production, and the provincial government says that other unconventional natural gas sources, in particular shale formations, will increasingly be developed.

Alberta Energy reports that "shale gas production is in very early stages", with commercial production "unlikely to occur" for some time. However, it adds that the province's shale resource "has the potential" to be significant.¹⁰⁸ On a website devoted to shale gas, Alberta Energy notes that shale gas wells are fracked, but makes no mention of the water required in such operations. The only mention of water is produced water at operating gas wells. "Produced" water refers to the water that comes to the surface with the gas, not the significant volumes of contaminated flow-back water that come back up wellbores after fracking.¹⁰⁹

In the event that shale gas development does get seriously underway in Alberta, any permit to use surface water or potable groundwater supplies would require a water license from Alberta Environment. If saline aquifers were used, permission from Alberta's Energy Resources Conservation Board would be required.

Barry Robinson, a staff lawyer with Ecojustice in Calgary, says water license holders typically must report the volumes of water used, although not all licensed withdrawals are necessarily metered. Data on specific water withdrawals may be requested of Alberta Environment, but may require a formal request under the Freedom of Information and Protection of Privacy Act to obtain, Robinson said. As for information on chemicals and additives in frack fluids, "companies are not required by Alberta Environment or the Energy Resources Conservation board to disclose any chemicals or additives" that they might use, Robinson says.

Canada

The sheer volume of water rights assigned to the energy sector by the energy regulator is one, but by no means the only cause for public concern, says Jim Bruce, who chaired the Council on Canadian Academies' Expert Panel on Groundwater from 2007 to 2009. "There has been a disturbing trend in Canada, at both the federal and provincial levels, to transfer water and environmental assessment activities for energy projects from environmental agencies to energy regulators, whose main aim appears to be promoting the energy industry," says Bruce, a former assistant deputy minister with Environment Canada and participant in various international bodies including the Intergovernmental Panel on Climate Change.¹¹⁰

No Canadian province keeps good records on actual withdrawals of groundwater, Bruce adds, yet groundwater may increasingly be a source for fracking fluids. Meanwhile, escalating use of surface waters for fracking purposes sets the table for rapid drawdown of lakes, rivers and creeks in First Nations' territories, "where protection of aquatic ecosystems is often of paramount concern."

To avoid becoming the "wild west for fracking operations", Bruce continues, it is imperative that "all jurisdictions leave regulation of water quantity and quality in the hands of water or environmental agencies responsible for protecting water for human and other uses."

10. Reporting and Oversight of Fracking Operations and Wastewater Disposal

To examine current oversight of fracking operations and wastewater disposal in Canada, we need to look at the BC situation, as this is the jurisdiction that is farthest ahead in shale gas development. The BC Oil and Gas Commission does not approve fracking operations per se, and has no specific regulations pertaining directly to fracking. The OGC does require, however, that companies drilling for natural gas apply for and receive a well authorization before any drilling and fracking occurs. The Commission says that it can also "restrict fracturing operations for safety reasons."

The OGC did not as of mid 2010 require companies engaged in hydraulic fracturing to disclose the chemicals that they used in their frack fluids, an issue that has emerged as a major source of contention in the US. In response to questions on the issue, the OGC said that such requirements are forthcoming, although when is unclear. The OGC said only that anticipated changes to the *Oil and Gas Activities Act (OGAA)*, would "require reports", including those listing fracking fluids.

As for the contaminated flow-back water that returns to the surface following fracking operations – the OGC reports that "an average of approximately 40% of the injected water remains bound in the formation" following well stimulations "and is not recovered." The 60 percent or so of contaminated wastewater that does flow back typically occurs within the first four months following fracturing. The Commission says

that some of the water – which generally is very high in mineral and salt content and may be contaminated with chemicals and heavy metals – may be temporarily diverted to storage pits before disposal.¹¹¹

What remains an outstanding question is just how large the “temporary storage” capacity will have to be as fracking operations expand in BC, particularly in more remote regions like the Horn River Basin. Assuming that just half of the chemical-laced fluids at the record-setting Two Island Lake fracking operation flowed back to the surface, it would amount to roughly 445,000 cubic metres of contaminated flow-back water – enough to bury an international soccer pitch under 15.6 metres of wastewater.

And that is just the beginning of what will be a burgeoning volume of highly toxic waste. “What we see right now is just pilot scale development in the Horn River,” says Ken Campbell, senior hydrologist with Schlumberger Water Services in Calgary. “Potentially, there will be hundreds of operations up there.”¹¹²

Currently, the “treatment” method of choice for flow-back waters in the Horn River is injecting the waste deep underground, into the saline Debolt aquifer, underlying the Horn River’s shale formations. The same aquifer is also, according to company and OGC pronouncements, a preferred source of water for future fracking operations. But it is highly unlikely that the aquifer will be able to sustain such pressure, Campbell says, noting that some parts of the aquifer may be good candidates for frack water supply and wastewater injection, while others will be poor and still others “impossible” to use for such purposes.¹¹³

In a presentation at a January shale gas conference, Campbell raised the prospect that wastewater treatment may ultimately be required. He noted that Aqua- Pure, a Calgary-based company had treated more than 2 million cubic metres of flow-back water at 50 different shale gas fracking operations in Texas, for an average of 40,000 cubic metres of wastewater treated per frack.¹¹⁴

Such treatment, however, is small in scale and will have to be ramped up significantly if the scale of contemporary fracking operations is any indication. Dave Manz, vice-president of Oasis Filter International Ltd. in Calgary suggests that the idea that such wastewater can be treated at Canadian municipal water treatment plants is “boneheaded” given the isolation of some of the country’s shale gas plays and the fact that such plants are really not equipped to handle the waste.¹¹⁵ What is needed, instead, are industrial treatment plants, centrally located near fracking operations. “This water is incredibly bad water,” Manz says, “but unequivocally it can be treated to a standard where it is reusable.”¹¹⁶

Figure 11: Current Reporting and Oversight of Fracking Operations in Canada

Province	Water Allocating Authority	Publish Water Use?	Require Disclosure of Fracking Chemicals?	Require Groundwater Mapping before Fracking Approved?
British Columbia	Energy Regulator	NO	NO*	NO
Alberta	Environment	NO	NO	NO
Saskatchewan	Environment	NO	?	NO
Ontario	Environment	NO	?	NO
Quebec	Environment	NO	POSSIBLE**	NO
New Brunswick	Environment	NO	POSSIBLE***	NO

* British Columbia’s Oil and Gas Commission has indicated that new regulations may require disclosure of fracking chemicals

** In Ontario there is no explicit requirement for disclosure of the chemicals. However, if any treatment is done on a well, a report must be submitted to the Ministry of Natural Resources providing information on the depth, type of treatment fluid and amount of proppant (sand, glass beads, etc.) used. Also, under Ontario's *Oil, Gas and Salt Resources Act*, an inspector has the authority to require a report, which could include such information.

** *New Brunswick’s Department of Environment says that under its authority to grant Approvals to Construct, a company seeking to inject water and chemicals underground in fracking operations could be required to disclose chemical contents

Wastewater treatment will cost money, on the order of \$10 to \$15 a cubic metre. But the cost must be weighed against what is gained. For starters, with wastewater treatment the industry will be able to recover half of the water it uses, meaning it will save the cost of accessing that much new water. Second, the cost of disposing of the water by trucking or piping it to disposal well sites and then pumping it back underground is saved as well. Finally, Manz says, there's the savings to the environment – a halving of water demand, whether from surface sources like rivers and lakes or from aquifers.

11. The United States: A Coming Tide of Regulation?

Several state government and federal government initiatives in the United States point to increasing regulation of the shale gas industry, including the possibility of increased “no-go” zones, or at the very least “harder-to-go-into” zones, where gas companies will have to meet a higher standard before any drilling occurs.

The US Environmental Protection Agency (EPA) announced in early 2010 that it had “serious reservations about whether gas drilling in the New York City watershed is consistent with the vision of long-term maintenance of a high quality-unfiltered water supply.”¹¹⁷ Further, in March 2010, EPA announced that it would conduct a “comprehensive research study” of the potential adverse impacts that hydraulic fracturing may have on water quality and public health.¹¹⁸

Of more immediate impact – and a potential precedent for no-go zones – is an initiative in the State of New York. In late April 2010, the state's Department of Environmental Conservation (NYDEC) announced that it would impose far stricter regulations on gas drilling in two key watersheds in the state – the Catskills, which supplies drinking water to 8.2 million residents in New York City, and the smaller Skaneateles Lake watershed, which supplies about 200,000 residents in the Syracuse area with their water.¹¹⁹ For decades, New York City has had stringent watershed protection policies in place that have enabled it to avoid investing billions of dollars in water treatment facilities. New York City officials feared that contamination from shale gas drilling and hydraulic fracturing could force the city to make such investments. Similar fears exist in Syracuse regarding the possible need to build water treatment plants.

NYDEC's decision did not ban shale drilling in the watersheds outright, as called for by some New York City regulators. But the NYDEC's new rules did require that any company wishing to drill in the watersheds would first have to conduct an environmental impact assessment for each well it proposed to drill.

Also in April, New York Democratic Congressman Maurice Hinchey asked the Delaware River Basin Commission, to conduct an environmental assessment on the cumulative impacts of natural gas extraction on water withdrawals. His call was triggered by the large number of applications to develop shale gas resources in the Upper Delaware Valley, which Hinchey said could ultimately have an impact on the 15 million residents

living in the Basin. “We have to make sure that we get this right,” Hinchey said, adding that the gas industry’s water use needed to be scrutinized in a “comprehensive” way.”¹²⁰

A month after the decision in New York State, US Secretary of the Interior Ken Salazar put the industry on notice that a higher level of planning would be required for drilling and fracking on federal lands. The new rules broadly applied to all such lands and would require a more comprehensive planning process – including expanded opportunities for public consultation before land was leased to oil and gas companies. The new rules also made it tougher for gas companies to obtain “categorical exclusions” from detailed environmental reviews. The latter decision stemmed from 77 drilling leases near the Arches and Canyonlands national parks as well as Dinosaur National Monument – leases that were hastily approved, circumventing standard review processes during the final days of the Bush administration and subsequently became the subject of a federal lawsuit.¹²¹

And a month after that, in June 2010, commissioners with the state agency in charge of regulating oil and gas developments in Wyoming voted unanimously to compel companies engaged in shale gas drilling and hydraulic fracturing to disclose the chemicals they used to assist in extracting tight gas.¹²² In doing so, Wyoming became one of the first US states to require full disclosure.

It appears that the shale gas industry itself may be reconciling to the fact that more stringent regulations are coming. In October 2009, even before the EPA announced its research study, two senior company executives – one with Chesapeake Energy, the other with Range Resources – announced their support for disclosure of the chemicals used in the hydraulic fracturing process.¹²³ They would be joined in January 2010 by the heads of ExxonMobil and XTO Energy, who announced that they would “support more disclosure” of the contents of the chemical mixes in their fracturing processes, though they remained opposed to further regulations by the EPA.¹²⁴ The opposition to further EPA regulation of shale gas production stems from fears that new regulations would add costs.

The US *Safe Drinking Water Act* regulates all waters that are used or that potentially could be used for drinking water purposes, whether above ground or below. The Act gives the EPA powers to “establish minimum standards to protect tap water and requires all owners or operators of public water systems to comply with health standards pertaining to water. The EPA is also empowered to establish minimum standards to protect underground drinking water sources from contamination, particularly from the injection of fluids. State authorities can then be delegated to enforce the standards set by the EPA. It remains to be seen whether the EPA review will result in changes to the *Safe Drinking Water Act* that impose tighter regulations on the shale gas industry.

Already, matching bills have been introduced in the US House of Representatives and Senate to close the so-called “Halliburton loophole” – a provision of the *Safe Drinking Water Act* that exempts the hydraulic fracturing industry from having to disclose the chemicals used when shale formations are fracked.¹²⁵ It is a sign, perhaps, that a tougher era of federal and potentially state regulations of the industry is at hand.

The question in Canada is whether a corresponding tide of regulation may also be at hand as fracking activities are poised to explode from coast to coast.

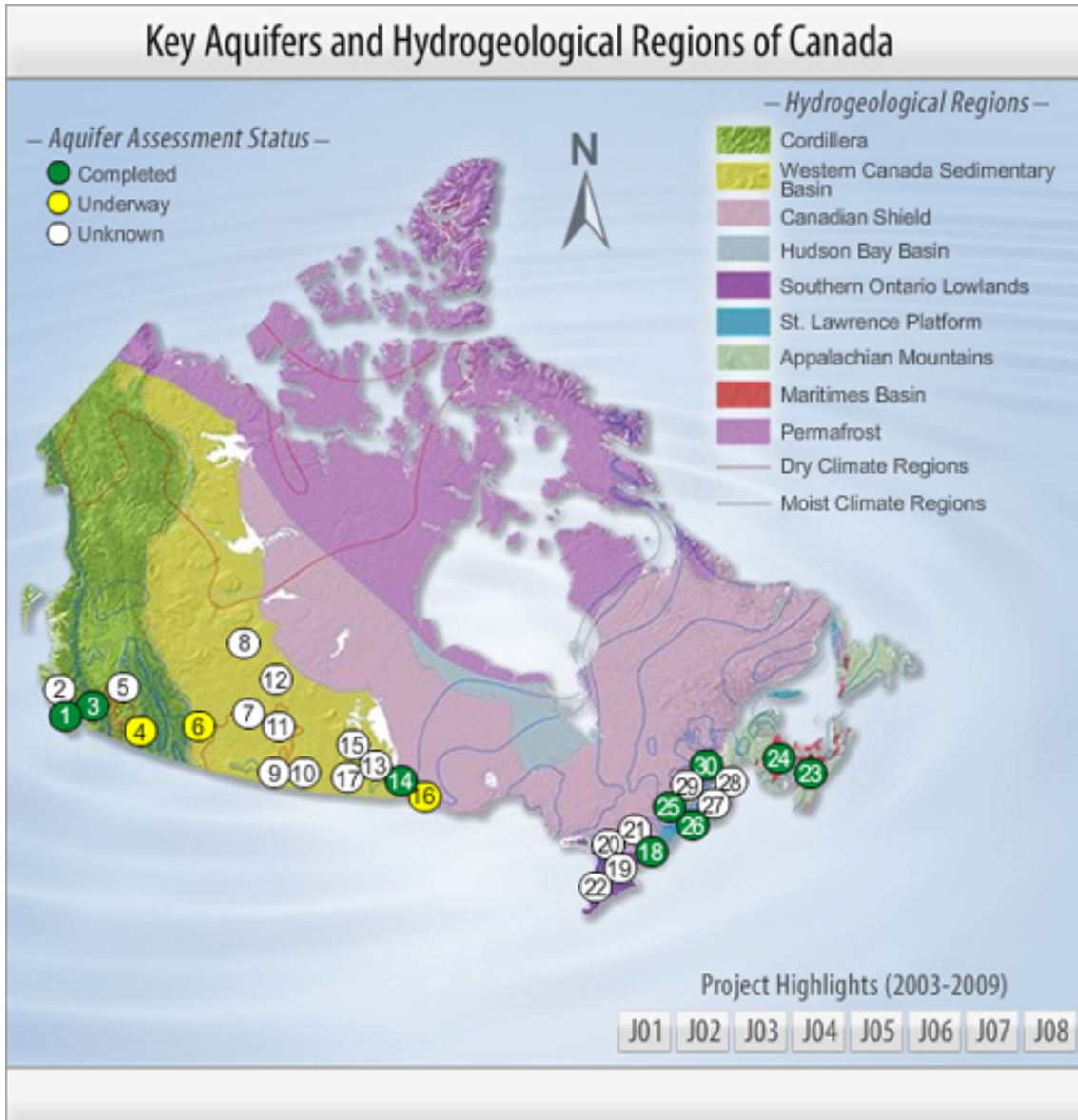
12. Water, Water Everywhere? Gaps in Understanding Canada's Water Resources

Several reports in recent years have pointed to significant gaps of knowledge in understanding Canada's water supplies, a 2009 analysis by the Council of Canadian Academies among them.

The Council's report on sustainable management of groundwater notes that the last comprehensive assessment of Canada's groundwater resources was in 1967. While efforts are underway 40-plus years later to complete a national inventory – including a commitment by the Groundwater Mapping Program of the Geological Survey of Canada to assess 30 key regional aquifers, notably in the south of the country – the pace of this critical inventory work remains glacially slow, the Council reported.¹²⁶ A similar criticism was voiced earlier in a February 2006 report on groundwater prepared for the Library of Parliament.¹²⁷

Alfonso Rivera, chief hydrogeologist of the Geological Survey of Canada and program manager of Earth Sciences Natural Resource's Canada's Earth Sciences Sector groundwater program, acknowledges that the initial surveying of the first 30 aquifers remains far from complete. To date, surveying has been completed on 12 of the 30 aquifers initially targeted for characterization and federal funding secured in 2009 should result in another seven being analyzed by 2014.¹²⁸ Rivera notes that all information gathered during the initial assessments will be turned over to municipal and provincial authorities because, "at the end of the day any allocation or management of groundwater resources is the responsibility of the provinces." A Natural Resources Canada map of the 30 key aquifers prioritized by the federal government for initial analysis, shows that some of them are located in areas of potential shale gas exploration and development. Many other aquifers to not make it onto the first priority list are in areas of potential shale gas development as well.

Figure 12: NRCAN's Aquifer Mapping Program



Source: NRCAN, accessed at http://sst-ess.nrcan-nrcan.gc.ca/gm-ces/index_e.php

While Natural Resources Canada is aware of proposed shale gas developments and their impacts on groundwater resources, this is not causing it to change its current course of inventory work. Says Rivera, it is expected that the provincial geological surveys will pick up the work – as is currently the case in the provinces of British Columbia and Alberta.

In addition to expressing concerns over the slow speed of groundwater inventorying at the national level, the Council of Academies also noted the “critical lack of data on groundwater allocations to municipal, industrial and agricultural users; on actual withdrawals of groundwater; and on volumes discharged or reused. Since groundwater

cannot be managed effectively at any scale without these data, responsible agencies should assign a high priority to their collection.”¹²⁹

The Council also touched on the issue of surface water monitoring – for the obvious reason that what happens at the surface will have an effect on how near-surface and deeper aquifers recharge over time. The Council noted, for example, that the number of active, monitored stream gauges across the country had declined over the previous 20 years by nearly 20 percent from 3,600 gauges in 1989 to 2,900 gauges by 2009.¹³⁰

Echoing the concerns of the Council of Academies, The Canadian Council of Ministers of the Environment noted in a 2010 communiqué that there are growing demands on groundwater. Among the foremost “development pressures” was increased use of water in fracking operations, the Council said.¹³¹

With that in mind, how well do regulators understand the groundwater resources underlying the Horn River Basin, where milestones are now being set for some of the longest, most intensively fracked horizontal wellbores in the world?

Efforts are underway to assess the region’s subsurface waters. But as recent publications suggest, such efforts are in their infancy. In March 2009, a group of energy companies calling itself the Horn River Basin Producers Group along with Geoscience BC – a self described industry-led, industry-focused, applied geoscience organization – announced the first phase of research to characterize groundwater reservoirs in the area. The research aimed to establish the “suitability” of such reservoirs to support exploration and development activities in the emerging shale gas industry. Core funding for the effort came from a \$5.7 million grant from the Ministry of Energy, Mines and Petroleum Resources and another \$6 million in in-kind contributions from energy companies.¹³²

In a progress report on the research effort published in 2010, the need to better understand groundwater resources is laid bare. The report notes that:

*Thousands of wells will be drilled to fully develop the HRB [Horn River Basin] shale gas play. Enormous volumes of water will be required for reservoir stimulation (fracking) and safe disposal must be ensured for equally huge volumes of produced water. Deep subsurface aquifers, carrying nonpotable water and lying far below the water table and domestic water wells, represent ideal sources and sinks for the water volumes required. Shallower aquifers, such as buried valley fills associated with Quaternary glaciation and drainage, are less desirable targets, as there is less separation from surface and well waters.*¹³³

The progress report goes on to note that while “numerous wells have been drilled in the basin margins for conventional gas reservoirs, there are relatively few wells in the basin proper, and large areas remain virtually undrilled.”¹³⁴

Similarly, a 2009 report by BC’s Ministry of Energy, Mines and Petroleum Resources written by Ministry hydrogeologist Elizabeth Johnson, noted that while “drilling has

increased rapidly” in the Horn River Basin, “geologic knowledge is still highly limited especially in the centre portion of the basin.”¹³⁵

Much work, then, remains to be done to understand just how much groundwater is available for the industry in Canada’s hottest shale gas play, let alone how the subsurface will respond as ever increasing volumes of contaminated flow-back water from fracked wells in the region are pumped back into deep aquifers.

The thrust of the current research effort is driven by the belief that the region’s creeks, rivers and lakes ought to be “rejected” as the major water supply for the industry as surface water “is not likely to sustain prolonged industry activity and poses an environmental concern.”¹³⁶ But the idea that all of the water needed by industry will be met by pumping water from deep below the surface appears to be rejected even by the energy company that is the first to tap into the deep saline aquifer underlying the Horn River Basin’s shale deposits. As Encana officials explained during a field visit to Two Island Lake – its intention is to use both surface water and groundwater to meet its hydraulic fracturing needs.

This assertion makes it even more vital to develop a comprehensive understanding of the demands for – and impacts on – the region’s poorly understood groundwater resources. And once those groundwater resources are understood and quantified, they – along with surface waters – must be adequately protected in the face of increasing shale gas development.

13. Looking Forward: Regulating Shale Gas Development in Canada

Although ‘the shale gale’ promises to increase gas reserves and government revenues, its rapid development has challenged the ability of regulators to manage the boom. In both Canada and the United States shale gas has migrated from fracking operations into aquifers and nearby drilling sites. Industry has consumed billions of gallons of public water for free and often in water scarce regions. Chemical and wastewater spills have polluted rivers and killed fish in shale gas zones. A spectacular rise in the volume of toxic waste water produced by fracking operations as well as increasing problems with gas migration in older petroleum fields near shale gas fracks has also stymied regulators.

In response the US Environmental Protection Agency, the US Congress and state governments have begun to systematically investigate claims that hydraulic fracking can impact drinking water supplies and human health. The industry’s energy intensity and rapid depletion rates are also under scrutiny. In Canada, government has notably embraced the benefits of shale production while studiously avoiding any serious discussion of its considerable environmental costs. The silence from the National Energy Board, Environment Canada and provincial energy regulators is troubling. Yet briefing notes prepared for Canada’s Natural Resource Minister Christian Paradis in August 2010

clearly warned that aggressive shale gas development could boost CO₂ emissions, destroy wildlife habitat and consume enormous volumes of freshwater.¹³⁷

Canada needs a national debate about regulatory reforms now, before the shale gas revolution affects more of the nation's watersheds as well as rural and urban communities. New regulations should not only focus on protecting ground and surface water resources, but should also reflect larger energy policy goals. They should promote more innovation and less wasteful practices in industry. Protecting groundwater and other water resources will likely require a higher degree of provincial and federal investment in water science research and ecological monitoring than is currently being practiced. In addition, regulation needs to address the cumulative ecological, financial and political risks of extensive shale gas fracking in critical watersheds.

During the rush to develop shale gas, a powerful multi-billion industry has operated within an immature and fragmented regulatory context. Nonetheless, even shale gas supporters recognize the need for greater public accountability and transparency. The cost of proactive and effective regulations needn't be onerous. A 2010 Encana report to investors disclosed that the average cost per fracking operation in the Horn River had declined from a high of \$4.3million in 2007 to an average of \$540,000 last year.¹³⁸ Kevin Smith, Encana's vice-president of Canadian Unconventional Gas Exploration notes that the company had an inventory of 600 to 1,500 gross wells in the Horn River and about 1.2 trillion cubic feet of natural gas reserves and resources. If Encana is any indication of the industry's economic health, then some of the savings achieved by lower operating costs could easily be used to meet more comprehensive and rigorous regulations that will protect water supplies and local communities. Some analysts suggest that continued industry resistance to regulations could ultimately diminish company profitability (See: *Lawyers and Would-be Investors Warn of Increasing Shareholder Liability*)

Lawyers and Would-be Investors Warn of Increasing Shareholder Liability

As members of the public, state and federal regulators and various government leaders have suggested the need for tighter regulations in the US shale gas industry, other voices - including those of legal experts steeped in environmental law and industry liability and company shareholders - are joining the chorus. Their opinions may prove instrumental in moving individual energy companies and service companies toward embracing practices that many concerned members of the public and their elected leaders are calling for, including full disclosure of the chemicals that companies use in their fracking fluids.

In May, Stephen Dvorkin and Jared Zola, two experts on law and insurance coverage and liability law, issued a report in which they warned that it did not take much imagination "to envision a future" of frack-related lawsuits.¹³⁹ Dvorkin should know: he has represented energy companies as a lawyer and served as Chief of the General Enforcement Branch of a regional EPA office. Dvorkin and Zola's report foreshadows

significant challenges for the shale gas industry in the event that lawsuits arise and insurers seek to escape and/or minimize their coverage responsibilities.

“Any internal document in which the risks of the [hydraulic fracturing] technique were considered will be pressed into service by the insurers seeking to escape coverage responsibilities,” the team reported, “and it will not stop there.”

Dvorkin’s and Zola’s warnings of potential problems with insurance coverage are being made to an industry that is indeed beginning to face a number of lawsuits, including a civil suit brought by 15 families living in Dimock, Pennsylvania. The families allege that following well drilling and hydraulic fracturing by Cabot Oil and Gas their drinking water became contaminated. They also allege that pollutants from the drilling and gas production caused them to become sick.¹⁴⁰ Similar suits from landowners alleging gas drilling-related water contamination have arisen elsewhere in Pennsylvania¹⁴¹ and states such as Texas.¹⁴²

As lawsuits escalate, ethical investment funds and investor-backed non-profit organizations are pushing for full disclosure of water and chemical use in the fracking industry. In April 2010, the Carbon Disclosure Project, an investor-backed nonprofit organization that has persuaded major corporations to disclose their greenhouse gas emissions, issued an 11-page letter to companies involved in water-intensive industries. The initiative, backed by 137 international financial institutions, called on companies to detail their water use, recycling, and discharges.”¹⁴³

Meanwhile, Green Century Capital Management, an investment advisory firm focused on environmentally responsible investing, announced a month later that it had formally called on Williams Company – the 10th largest natural gas producer in the United States – to improve its transparency. The move followed previously successful efforts by the investment advisor to convince 30 per cent each of shareholders at Cabot Oil and Gas and EOG Resources, to improve their disclosures of the risks to shareholder value associated with gas drilling and hydraulic fracturing operations.¹⁴⁴

Given the growing shale gas controversy in the United States, the lack of a coherent approach to regulation in Canada, and the incomplete status of groundwater mapping here, this report respectfully concludes that the federal government and individual provinces adopt the following recommendations:

- 1. Federal and provincial governments in collaboration with the hydraulic fracturing industry should immediately fund independent studies of all aquifers prior to shale gas exploration or sustained hydraulic fracking.*

In 2002 the Canadian Council of Ministers of the Environment pointedly recommended that baseline hydrogeological investigations be completed prior to unconventional gas drilling in order “to recognize and track groundwater

contamination.”¹⁴⁵ To date no province has honoured this critical recommendation.

2. *Full public disclosure of all chemicals used in fracturing fluids should be required before any approvals to hydraulically fracture gas wells are authorized. Before authorization, fracking companies should also be compelled to demonstrate that they have selected the least environmentally harmful fracture fluids available.*

Wyoming’s Oil and Gas Conservation Commission now requires companies to disclose the toxic chemicals in their fracking fluids. In British Columbia, the Canadian jurisdiction with the most advanced shale gas developments, the provincial regulator (OGC) has indicated that it may require that companies disclose the contents of their fracture fluids.

3. *Before hydraulic fracturing operations commence, fracking companies must conduct tests to determine the integrity of well cementing jobs and file results with regulators.*
4. *All authority to assign water rights and regulate wastewater disposal should rest with one regulatory agency whose primary responsibility is to protect vital water resources. Information on all water assignments and water withdrawals should be publicly available.*

Energy regulators have a history of sacrificing water for enhanced hydrocarbon production in Alberta and British Columbia with limited accountability. It is necessary to have an independent responsible authority to assess the multiple demands on water resources and regulate accordingly.

5. *Any proposed water withdrawals exceeding a threshold established by environmental regulators should be subject to environmental impact assessments.*

Given the extraordinary size and scale of shale gas plays in Quebec and British Columbia, government should immediately establish commissions to examine the potential and cumulative impacts on water resources, energy use, government revenues and carbon emissions.

6. *All flow-back fluids at hydraulically fractured wells should be captured, securely stored and then treated to a high enough standard that they can be re-used in subsequent fracturing operations.*

Companies must reduce water demand and waste disposal by employing different technologies to treat flow-back waters including boiling, desalination, chemical treatments, reverse osmosis and distillation. Maximum recycling of flow-back waters (which may be 70 percent of the water put down wells during hydraulic fracturing) would dramatically reduce water demand in the industry.

7. *Creative means should be found to encourage the hydraulic fracturing industry to use treated municipal waste water as the primary fracturing fluid, so as to avoid using surface or groundwater sources.*

A cooperative arrangement between Shell and the community of Dawson Creek in northern British Columbia could significantly reduce industry demands for treated drinking water. However, such arrangements will likely only work in cases where municipalities are reasonably close to fracking operations and energy costs are low enough to justify the costs of trucking or piping water to well sites.

8. *All hazardous wastes generated during and after hydraulic fracturing operations should be safely transported by licensed waste handlers and taken to approved waste treatment facilities.*

Injection of waste fluids into some deep disposal wells may make sense, but is inappropriate in many jurisdictions (e.g., New York, where only two such licensed underground injection wells are located). Government should also regulate the transportation of fracking wastes through hazardous waste regulations that require full disclosure of the materials transported.

9. *Introduce a tax on the production of shale gas, reflecting the cost savings that companies in the natural gas industry have (a) secured through more efficient production techniques, and (b) enjoyed through lower royalty rates set by governments to encourage gas developments.*

This tax should reflect a fixed percentage and be tied to the value of the gas produced. Revenues should go to an independent third-party or Crown Corporation tasked with surface and groundwater mapping in jurisdictions where there is insufficient understanding of these resources, and to environmental monitoring, forensic investigation and remediation once comprehensive mapping has been conducted.

10. *The gas industry and provincial governments should invest in a network of test wells to monitor conditions prior to, during and after hydraulic fracturing operations, with public disclosure of all test results. The tests should include isotopic analysis to determine whether gas is migrating from test wells to adjoining wells, so that liability can be tracked in cases where contamination does occur.*

A network of monitoring wells is instrumental in helping to establish appropriate well densities and ensure that groundwater resources are protected. It would also reduce prospects for “communications” between wells due to too high well densities. (“Communications” are fracking incidents that open unforeseen pathways in the underground rock formations making it possible for contaminants to move unpredictably to other well sites.)

11. Natural gas companies should be required to: 1) file electronically all water withdrawals from surface and groundwater sources, 2) where such water is subsequently used, and 3) how much toxic flow-back water is generated at each gas well site. All such reporting should be publicly accessible.

Currently, provincial regulatory agencies do not collect data on water withdrawals in a comprehensive way. Nor do they publish it, even though far more complex databases are maintained by provincial regulators and easily accessible. The lack of readily available baseline information on water approvals and water withdrawals, in particular, is of great concern. Depletion rates must be known in order for regulators to sustainably manage water resources on the public's behalf.

12. All future federal and provincial greenhouse gas inventory reporting should be revised to reflect the natural gas industry's higher greenhouse gas emissions due to energy-intensive hydraulic fracturing operations. Regulators should report the Energy Return On Investment for all unconventional gas and oil developments as well as depletion rates.

13. No-go zones should be established where hydraulic fracturing operations are banned outright or subject to more stringent reviews and approvals.

Water is more vital than natural gas. Given that most of Canada's economy depends on access to clean water, governments that fail to protect surface and groundwater resources will arguably erode the economic base if not the resilience of the nation.

The development of shale gas promises to fuel North America's energy future but with substantive environmental and energy costs. Assumptions that shale gas can be produced at low cost for over a century remain just that: faith based assumptions. In fact the revolution could dramatically slow down while costs climb dramatically.¹⁴⁶

To date Canada has not developed adequate regulations or public policy to address the scale or cumulative impact of hydraulic fracking on water resources or conventional oil and gas wells. Moreover the country has no national water policy. In the absence of public reporting on fracking chemicals, industry water withdrawals and full mapping of the nation's aquifers, rapid shale gas development could potentially threaten important water resources if not fracture the country's water security.

Appendix A

HENRY A. WAXMAN, CALIFORNIA
CHAIRMAN

JOE BARTON, TEXAS
RANKING MEMBER

ONE HUNDRED ELEVENTH CONGRESS
Congress of the United States
House of Representatives
COMMITTEE ON ENERGY AND COMMERCE
2125 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515-6115

Majority (202) 225-2927
Minority (202) 225-3641

February 18, 2010

Mr. Douglas R. Ramsay
President and Chief Executive Officer
Calfrac Well Services
411 - 8 Avenue Southwest
Calgary, Alberta T2P 1E3

Dear Mr. Ramsay:

The Subcommittee on Energy and Environment is examining the practice of hydraulic fracturing and its potential impacts. We request your cooperation in this investigation.

To help inform the Subcommittee about the chemicals used in the hydraulic fracturing process and the potential impacts on human health or the environment, please provide the Committee with the following documents:

1. Documents sufficient to show the number of wells that your company hydraulically fractured in each state, by year, between 2005 and 2009. For natural gas wells, please provide data by year and state on the number of wells fractured to produce shale gas, coalbed methane, and tight sandstone gas in the United States. Please also provide data indicating for each natural gas well whether the fracturing occurred in, near, or below an underground source of drinking water as defined by the Safe Drinking Water Act.
2. Documents sufficient to show the identity and total volume of the products, including the chemicals contained therein, that your company used in hydraulic fracturing in each state, by year, between 2005 and 2009. For natural gas wells, please provide data by year and state on the identity and total volume of the products, including the chemicals contained therein, that your company used to produce shale gas, coalbed methane, and tight sandstone gas in the United States.
3. All documents relating to the health or environmental effects of the products, including the chemicals contained therein, used by your company in hydraulic fracturing.

Appendix A

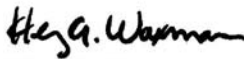
Mr. Douglas R. Ramsay
February 18, 2010
Page 2

4. All documents relating to any allegations that the products used by your company in hydraulic fracturing caused harm to human health or the environment.
5. Documents sufficient to show the percentage of hydraulic fracturing fluids your company recovered in each state, by year, between 2005 and 2009, and all documents estimating your company's fluid recovery efficiency.
6. Documents sufficient to show the volume of flowback and produced water, and the chemicals contained therein, generated from your company's hydraulic fracturing operations in each state, by year, between 2005 and 2009, and the methods by which your company disposed of this water in each state, by year, between 2005 and 2009. If you are not responsible for recovery and disposal of flowback and produced water, please provide the Committee with a list of companies that would bear such responsibility.

Please produce the requested documents by Friday, March 5, 2010. In addition, we ask that you advise the Committee by Thursday, February 25, 2010, whether you will comply with this request on a voluntary basis. Attachments to this letter provide additional information about responding to Committee document requests.

If you have any questions regarding this request, please contact Alison Cassady or Stacia Cardille with the Committee staff at (202) 226-2424.

Sincerely,



Henry A. Waxman
Chairman



Edward J. Markey
Chairman
Subcommittee on Energy
and Environment

Enclosure

cc: The Honorable Joe Barton
Ranking Member

The Honorable Fred Upton
Ranking Member
Subcommittee on Energy
and Environment

Endnotes

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- ³ IHS Cambridge Energy Resources Associations. Fueling North America’s Energy Future: The unconventional natural gas revolution and the carbon agenda. 2010. Accessed at http://www2.cera.com/docs/Executive_Summary.pdf
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- ⁷ America’s Natural Gas Alliance. “Canada Benefits”. No date. Accessed at <http://www.anga.us/learn-the-facts/economy/canada-benefits>
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- ¹⁰ CBC. “PQ calls for Shale Gas Moratorium. Sept. 2, 2010. Accessed at <http://www.cbc.ca/canada/montreal/story/2010/09/02/pq-shale-gas-moratorium.html>
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- ¹² CTV News. “RCMP to open detachment devoted to Encana bombings.” July 18, 2009.
- ¹³ Encana Corporation. Investor Day: March 16 & 18, 2010.
- ¹⁴ The American Petroleum Institute notes on its website that: “Hydraulic fracturing is a technology used in the United States to help produce more than 7 billion barrels of oil and 600 trillion cubic feet of gas. The technology has been used since the 1940s in more than 1 million wells in the United States.” For more information go to: <http://www.api.org/policy/exploration/hydraulicfracturing/>
- ¹⁵ Groundwater Protection Council, National Energy Technology Laboratory and U.S. Department of Energy Office of Fossil Energy. *State Oil and Natural Gas Regulations Designed to Protect Water Resources*. May 2009
- ¹⁵ Congress of the United States House of Representatives. Committee on Energy and Commerce. Letter to Tony Hayward, Chief Executive Officer of BP PLC. June 14, 2010.
- ¹⁶ Daniel Arthur, Brian Bohm, Mark Layne. “Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale.” Presented at the Groundwater Protection Council Annual Forum. Cincinnati. September, 2008.
- ¹⁷ To view Oklahoma’s Oil & Natural Gas Producers and Royalty Owners hydraulic fracturing video visit <http://www.oerb.com/Default.aspx?tabid=242>. To view Encana Corporation’s hydraulic fracturing video visit <http://www.encana.com/news/topics/hydraulicfracturing/>.
- ¹⁸ A helpful review of groundwater facts is published by Environment Canada and available online at: <http://www.ec.gc.ca/eau-water/default.asp?lang=En&n=300688DC-1>

¹⁹ See, for example, Anthony Ingraffea and Francois Heuze. “Finite element models for rock fracture mechanics.” *International Journal for Numerical and Analytical Methods in Geomechanics*. Vol. 4, Issue 1. Pp 25-43. January-March 1980. Or, Anthony Ingraffea, R.J. Shaffer and Francois Heuze. “FEFFLAP: A Finite Element Program for Analysis of Fluid Driven Fracture Propagation in Jointed Rock, Volume 1: Theory and Programmer’s Manual,” University of California Information Document 20368, Report to U.S. Department of Energy under Contract W – 7405 – ENG – 48, March, 1985,

²⁰ In December 2009, Tom Myers, a hydrologic consultant and Ph.D., commented on the New York State’s Department of Environmental Conservation report *Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, which was released in September, 2009. In his report prepared for Natural Resources Defense Council, Myers noted: “No vertical offset would guarantee that contaminants will not flow from the shale to the aquifers.”

²¹ Groundwater Protection Council. *op. cit.*

²² Congress of the United States House of Representatives. Committee on Energy and Commerce. Letter to Tony Hayward, Chief Executive Officer of BP PLC. June 14, 2010. The letter notes: BP’s mid-April plan review predicted cement failure, stating “Cement simulations indicated it is unlikely to be a successful cement job due to formation breakdown.” Despite this warning and Halliburton’s prediction of severe gas flow problems, BP did not run a 9- to 12-hour procedure called a cement bond log to assess the integrity of the cement seal. BP had a crew from Schlumberger on the rig on the morning of April 20 for the purpose of running a cement bond log, but they departed after BP told them their services were not needed. An independent expert consulted by the Committee called this decision “horribly negligent.”

²³ B.C. Oil and Gas Commission. “Communication During Fracture Stimulation. Safety Advisory 2010-03. May 20, 2010.

²⁴ *Ibid.* The OGC Safety Advisory goes on to describe the known “communication incidents” in B.C. and Alberta as follows:

- Five incidents of fracture stimulation resulting in communication with an adjacent well during drilling.
- Three incidents of drilling into a hydraulic fracture formed during a previous stimulation on an adjacent well and containing high pressure fluids.
- Ten incidents of fracture stimulations communicating into adjacent producing wells.
- One incident of fracture stimulation communication into an adjacent leg on the same well for a multi-lateral well.

²⁵ *ibid.*

²⁶ In a letter sent to Colorado landowner Renee McClure on April 22, 2009, the State of Colorado’s Oil & Gas Conservation Commission, noted that chemical analysis of methane gas in McClure’s water well was “typical of naturally occurring biogenic gas” from a near-surface aquifer and did not contain the “carbon compounds that would indicate a thermogenic gas [source].”

²⁷ Geoffrey Thyne. *Review of Phase II Hydrogeologic Study Prepared for Garfield County*. December 20, 2008.

²⁸ Abrahm Lustgarten. “Colorado Study Links Methane in Water to Drilling.” *ProPublica* and *Denver Post*. April 22, 2009.

²⁹ Anthony Ingraffea. “Affirming Gasland. A de-debunking document in response to specious and misleading gas industry claims against the film.” July 2010. In the document, Ingraffea, an expert on hydraulic fracturing and professor at Cornell, notes that natural gas drilling and fracking operations can lead to migration of biogenic methane. “The drilling process itself can induce

migration of biogenic gas by disturbance of previously blocked migration paths through joint sets or faults, or by puncturing pressurized biogenic gas pockets and allowing migration through an as-yet un-cemented annulus, or through a faulty cement job. The hydraulic fracturing process is less likely to cause migration of biogenic gas; however, the cumulative effect of many, closely spaced, relatively shallow laterals, each fracked (and possibly re-fracked) numerous times, could very well create rock mass disturbances that could, as noted above, open previously blocked migration paths through joint sets or faults."

³⁰ Office of the Auditor General of British Columbia. *Oil and Gas Site Contamination Risks: Improved oversight needed*. February 2010.

³¹ John Podesta and Timothy Wirth. *Natural Gas – A Bridge Fuel for the 21st Century*. Center for American Progress and Energy Future Coalition. August 10, 2009.

³² Mark Jaccard. *Sustainable Fossil Fuels: The Unusual Suspect in the Quest for Clean and Enduring Energy*. Cambridge University Press. 2005.

³³ Robert Bryce. "There Will Be Many Barnetts: A Q&A with Roberto Aguilera." *Energy Tribune*. May 21, 2009.

³⁴ Association for the Study of Peak Oil & Gas – USA. "Interview with Art Berman – part 1." July 19, 2010. <http://www.aspousa.org/index.php/2010/07/interview-with-art-berman-part-1/>

³⁵ *ibid.*

³⁶ Diane Maley. "Building a case for natural gas." *The Globe and Mail*. June 30, 2010.

³⁷ U.S. Energy Information Administration. See http://www.eia.doe.gov/ask/environment_faqs.asp

³⁸ In March 2010, Colorado Governor Bill Ritter announced that the state would retire or retrofit up to 1,200 megawatts of coal-powered electrical generation. With that single decision, Encana said, a significant amount of polluting coal technology would be retired and replaced by "clean" burning natural gas technology.

In introducing the proposed legislation that would guide that transition - the *Colorado Clean Air-Clean Jobs Act* – Governor Ritter said it would "dramatically reduce air pollution and support the growth of homegrown energy, ensuring that cleaner-burning natural gas works together with renewable energy" to build a so-called "new energy economy."

Similarly, in Canada, Encana hailed a February 2010 decision by Saskatchewan Power Corporation to purchase a guaranteed 20 years' supply of natural gas-fired electricity from the Northland Power Income Fund, calling it another significant step in the ascendance of natural gas as a cleaner alternative to coal. The agreement, Encana said, would see the construction of a new 260-megawatt combined cycle electricity plant, marking another "great win for the natural gas industry in a province that currently generates 60 per cent of its electricity from coal."

Under construction now, the plant is projected to consume 30 million cubic feet of natural gas per day. Jaccard notes that in addition to being efficient, natural gas-fired combined cycle plants "were the fastest growing electricity generation technology in industrialized countries in the 1990s." As events in Colorado and Saskatchewan attest, such growth may be expected to continue as coal-fired electrical plants age and provincial, state and federal governments enact new air quality standards or require lower greenhouse gas emissions.

³⁹ Dale Lunan. "In an effort to create markets for growing shale gas production in North America, Encana is pushing to build out our natural gas vehicle infrastructure." *Oilweek Magazine*. June 2010.

⁴⁰ Podesta and Wirth. *op. cit.*

⁴¹ *ibid.*

⁴² U.S. Environmental Protection Agency. *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008*. US EPA. April 15, 2010. As the second-highest anthropogenic source of methane emissions in the United States, natural gas trails behind that of landfills and just ahead of emissions in the coal mining industry.

⁴³ Robert Howarth. "Preliminary Assessment of the Greenhouse Gas Emissions from Natural Gas obtained by Hydraulic Fracturing." Cornell University. Department of Ecology and Evolutionary Biology. Draft Paper. March 17, 2010. Howarth bases his finding on what he admits is a "highly uncertain, but . . . likely conservative" estimate of the total emissions from natural gas obtained from underground shale deposits. Total emissions reflect both the emissions that occur when consumers burn the gas, as well as all of the emissions associated with developing and getting that gas to market. When that broader context is considered, Howarth estimates that the greenhouse gases associated with shale gas sources such as the Marcellus Shale will slightly exceed those of coal produced in energy-intensive mountain-top removal operations in nearby Appalachian states.

⁴⁴ Al Armendariz. *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*. A report submitted to Environmental Defense Fund. Austin, Texas. January 26, 2009.

⁴⁵ Thomas Homer Dixon. "The End of Ingenuity." *The New York Times*. November 29, 2006.

⁴⁶ *ibid.*

⁴⁷ Cutler Cleveland. Personal communication. August 24, 2010.

⁴⁸ Cutler Cleveland and Peter O'Connor. *An Assessment of the Energy Return on Investment (EROI) of Oil Shale*. Prepared for Western Resource Advocates. June 2010. Cleveland and O'Connor describe "self-energy" as the energy released by the oil shale conversion process that is used to power that operation.

⁴⁹ *ibid.*

⁵⁰ Howarth. *op. cit.*

⁵¹ British Columbia Ministry of Environment. Low Stream Flow Advisory – Peace Region. July 20, 2010. The advisory noted that water levels in several major rivers including the Pine, Kiskatinaw, Liard and Moberly, along with Carbon Creek, were "all at or near their lowest flows of record for this time of year." A similar advisory issued on July 22, 2010, by B.C.'s Oil and Gas Commission (Information Bulletin 2010-20) noted drought conditions in northeastern B.C. and went on to urge natural gas companies to be "diligent" in their licensed water withdrawals "and ensure withdrawals are in compliance with permit approvals."

⁵² For more information on ProPublica, go to: <http://www.propublica.org/about/>

⁵³ Abraham Lustgarten. "Buried Secrets: Is Natural Gas Drilling Endangering U.S. Water Supplies?" *ProPublica*. November 13, 2008.

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⁵⁷ U.S. Environmental Protection Agency. "Effluent Limitations Guidelines and New Source Performance Standards for the oil and Gas Extraction Point Source Category." *Federal Register*. Volume 66 No. 14. January 2001.

⁵⁸ Congress of the United States House of Representatives. Committee on Energy and Commerce. Memorandum. February 18, 2010.

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- ⁶² Taurus Reservoir Solutions Ltd. “Shallow Nitrogen Fracturing Dimensions and Groundwater Protection: Evaluation of the ERCB Directive 27.” Prepared for Alberta Energy Resources Conservation Board. October 8, 2008.
- ⁶³ Chris Wood. “Hydro-fracturing has a lucrative dirty secret: The B.C. government isn’t asking any questions about a natural gas-drilling technique involving toxic compounds.” *The Georgia Straight*. January 28, 2010.
- ⁶⁴ Alberta Geological Survey. op. cit.
- ⁶⁵ Groundwater Protection Council, National Energy Technology Laboratory and U.S. Department of Energy Office of Fossil Energy. *State Oil and Natural Gas Regulations Designed to Protect Water Resources*. May 2009.
- ⁶⁶ Joaquin Sapien and Sabrina Shankman. “Drilling Disposal Options in N.Y. Report Have Problems of Their Own.” *ProPublica*. December 29, 2009. The article notes that up to 2,500 shale gas wells could be drilled in New York State per year under optimistic drilling projections. Each well would produce up to 1.2 million gallons of wastewater, for a combined 3 billion gallons – or 5,000 Olympic swimming pools – annual production.
- ⁶⁷ Joaquin Sapien. “With Natural Gas Drilling Boom, Pennsylvania Faces an Onslaught of Wastewater.” *ProPublica*. October 4, 2009.
- ⁶⁸ *ibid.* Of primary concern, the article notes, is that the state’s municipal wastewater treatment plants – many of which accept wastewater from the shale gas industry to treat - are not capable of pulling out the oxygen-robbing Total Dissolved Solids (TDS) in the brackish industrial water. In fact, the brackish waste actually compromises the ability of the treatment plants to perform their primary task, which is to treat municipal wastewater, including human sewage, to a point where it can be safely returned to rivers that downstream users rely on for drinking water.
- ⁶⁹ Pennsylvania Department of Environmental Conservation. “Governor Rendell Praises Regulatory Panel Vote Protecting PA’s Streams, Rivers from Drilling Wastewater.” News Release. June 17, 2010.
- ⁷⁰ John Hangar. Comments made on the Diane Rehm show. National Public Radio. June 21, 2010.
- ⁷¹ *ibid.*
- ⁷² In July 2009, the Royal Canadian Mounted Police (RCMP) announced the creation of a new temporary police detachment based out of Dawson Creek devoted exclusively to investigating the six bombings of Encana gas well infrastructure that had occurred in the area since October 2008. (CTV News. “RCMP to open detachment devoted to Encana bombings.” July 18, 2009.)
- ⁷³ National Energy Board. *Understanding Canadian Shale Gas*. Energy Brief. November 2009.
- ⁷⁴ *The Vancouver Sun*. “Things are looking up for mining and that’s good for B.C.” Editorial. May 11, 2010.
- ⁷⁵ Norm Bilodeau. Regional Manager, Northern Region, Water Stewardship Division. BC Ministry of Environment. Personal communication. June 10, 2010.
- ⁷⁶ *ibid.*
- ⁷⁷ BC Oil and Gas Commission. *Oil and Gas Water Use in British Columbia*. August, 2010.
- ⁷⁸ Marc Dubord. “Update on CAPP Water Issues (Industry Perspective)”. November 17, 2009. In the presentation, the Canadian Association of Petroleum Producers notes that the “Oil and gas

sector is not a significant risk to Canada's water supply and uses relatively small volumes." It also says that: "Existing regulations and industry practices strongly protect usable water."

⁷⁹ *ibid.*

⁸⁰ Oil and Gas Commission. Approval for Short Term Water Use. Issued to Encana Corporation. OGC File: 9631494. April 1, 2010.

⁸¹ Lee Shanks. Oil and Gas Commission manager of communications. Personal communication. June 17, 2010.

⁸² Carol Howes, media relations advisor, Encana Corporation. Personal communication. June 29, 2010.

⁸³ Encana Corporation. *op. cit.*

⁸⁴ Lee Shanks. *op. cit.*

⁸⁵ *ibid.*

⁸⁶ Oil and Gas Commission. Approval for Short Term Use of Water. Issued to Apache Canada Ltd. OGC File: 9631593. March 22, 2010.

⁸⁷ Oil and Gas Commission. Approval for Short Term Use of Water. Issued to Apache Canada Ltd. OGC File: 9631593. April 1, 2010. On July 23, the Oil and Gas Commission's Lee Shanks acknowledged that OGC officials were aware that water could, indeed, be diverted past water meters, but that the Commission was satisfied the diversions only occurred at times when the company needed to temporarily bypass the meters when the meters "became frozen and required maintenance during colder temperatures. Commission inspectors have been making regular, unscheduled visits to the location. At no time was water being diverted past any metering equipment. As such, enforcement action is not being considered."

⁸⁸ Lee Shanks. Oil and Gas Commission manager of communications Personal communication. June 17, 2010.

⁸⁹ Matrix Solutions Inc. Summary of 2010 Hydrology and Water Quality Monitoring Results at Two Island Lake (Matrix 10813-522). Letter to Paul Weeks, Apache Canada Ltd. May 20, 2010

⁹⁰ On June 2, 2010, members of the Fort Nelson First Nation toured the Two Island Lake pump house operations and videotaped the proceedings in the presence of Encana Corporation, Oil and Gas Commission, B.C. Ministry of Environment and B.C. Ministry of Mining and Petroleum Resources personnel.

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⁹⁵ Henry Aubin. "Quebec makes a deal with the devil for gas profits." *The Gazette*. June 17, 2010. The article further notes that Quebec's shale gas industry, has hired the former head of Hydro-Quebec, Andre Caille, as its lobbyist. Caille says that if just 10 percent of Quebec's estimated shale gas reserves are recovered it meets the province's needs for the next century, while leaving room to export gas.

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⁹⁷ Richard Mills. "The Utica – An Emerging Canadian Shale Gas Play." *Safe Haven*. January 9, 2010.

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- ¹⁰³ Michael Cummings. Chief Administrative Officer, Town of Sussex. Personal communication. June 23, 2010.
- ¹⁰⁴ Government of Canada. Comprehensive Study List Regulations, SOR/94-638. <http://laws.justice.gc.ca/en/c-15.2/sor-94-638/index.html>
- ¹⁰⁵ Bruce Johnstone. "Sask. government introduces natural gas production incentive program." *Leader Post*. May 27, 2010. The newspaper report notes that "the [Saskatchewan] government is reducing the Crown royalty rate on horizontal gas wells to 2.5 per cent and the freehold production tax rate to zero on the first 25 million cubic metres of natural gas produced between June 1, 2010 and March 31, 2013. Currently, the combined Crown and freehold royalty rate on natural gas production averages about 5.4 per cent, according to Saskatchewan Energy and Resources (SER).
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- ¹⁰⁷ Peter Gehl. Environmental coordinator, Saskatchewan Watershed Authority. Personal communication. June 28, 2010
- ¹⁰⁸ Alberta Energy. <http://www.energy.alberta.ca/NaturalGas/944.asp>. The regulator estimates that the volume of shale gas in the Western Sedimentary Basin – which underlies Alberta and parts of neighbouring British Columbia and Saskatchewan – ranges between 86 trillion cubic feet and 1,000 trillion cubic feet.
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