Shale Gas in Canada: An Overview

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1. How much shale gas is there thought to be in Canada, and where is it located?

Estimates of Canada's shale gas resources are still very uncertain. However, the shales themselves are well mapped. A "play" is a geographic area which is being considered as a potentially economic resource for gas or oil – a shale which is "in play" in the industry. This does not necessarily mean that gas is currently being extracted – just that there is industry interest, that there could be extraction. Canada has several shale plays with varying geographic characteristics and levels of development.

Starting on the west coast: In B.C. there are four major shale plays that are thought to be possible sources of gas. The Horn River basin, in northern B.C., has been estimated to contain 448 Tcf[1] (trillion cubic feet) or 500 Tcf.[2] Of this, the National Energy Board (NEB) estimates that about 20% will be recoverable. The Montney shale/tight gas hybrid in B.C. is another potential source of natural gas; however, estimates vary widely, from 80 to 700 Tcf[3] of gas in place. There is so far no good estimate of how much of this can be recovered. The Liard basin to the west is another unmeasured prospect. Finally, the Cordova embayment to the east is estimated (by an industry advocacy group) to contain 200 Tcf[4] in place – an estimate that is likely to be on the high side.

The Colorado group occurs across southern Alberta and Saskatchewan; the NEB acknowledges that there has not been any independent analysis so far, but estimates that there could be at least 100 Tcf[5] in place, an estimate that is echoed by industry groups.

Very preliminary shale gas exploration is currently underway in southwest Manitoba.[6] Gas there is in shallow shales and is biogenic.[7] However, it remains uncertain exactly how much gas there is, and whether recovering it will be economic.

In Ontario, there are three shale plays that are considered potential natural gas sources: the Antrim/Kettle Point formation, part of the Marcellus shale, and the Blue Mountain formation. Although there has been commercial interest, not much is known about these shales yet.

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[1] By the National Energy Board, in its Ultimate Potential Report for Unconventional Gas in the Horn River Basin: http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/hrnrvr/hrnrvrm-eng.html#s3
[2] By the Oil and Gas Commission, in the Horn River Basin Status Report 09/10: http://www.bcogc.ca/document.aspx?documentID=1015&type=.pdf
[3] From the NEB document: *A Primer for Understanding Canadian Shale Gas* 14. Originally from BC Ministry of Energy, Mines and Petroleum Resources, 2006. *Regional "Shale Gas" Potential of the Triassic Doig and Montney Formations, Northeastern British Columbia*. Petroleum Geology Open File 2006-02.
[4] From an industry document: *Natural Gas in Canada: A robust resource* 19
[5] *A Primer for Understanding Canadian Shale Gas* 18
[6] http://www.manitoba.ca/iem/mrd/geo/mgstracker/swmanitoba_shale_gas_project.html
[7] Manitoba Geological Survey. "Shale gas to Three Forks" http://www.manitoba.ca/iem/mrd/geo/mgstracker/images/region6/PRES2011-1.pdf

In Quebec, the Utica shale has attracted a lot of interest. Estimates vary widely, though: One article[8] quotes industry experts as estimating that there is between 5 and 25 Tcf of gas in place, but a recent study done for Questerre has suggested that there is about 129 Tcf[9] in place in Questerre's territory alone (which does not cover the whole Utica shale), but that only 4.28 Tcf will be recoverable.

In New Brunswick, the Frederick Brook shale has been estimated to contain 67 Tcf[10] of natural gas in place, and in Nova Scotia, the Windsor shale has been estimated to contain 69 Tcf.[11]

In total, then, it is thought that there is at least 1000 Tcf of gas in Canadian shales, and possibly far more, but only a small amount of this may turn out to be recoverable. The amount that ends up being recovered depends partly on natural gas prices, which will determine whether and where shale gas drilling is economically viable. To put the above numbers in context, a 2004 NEB report[12] estimated that Canada's ultimate potential is 520 Tcf of *conventional* marketable natural gas reserves. "Ultimate potential" includes recoverable volumes that have been discovered, volumes that have already been produced, and volumes that are expected to be discovered – all minus the gas used up in processing. The same report states that Canada's remaining marketable resources of conventional gas amount to 371 Tcf. Thus if only one-fifth of shale gas in place were recoverable, it would be two-fifths of Canada's ultimate potential for conventional gas, and less than two-thirds of the remaining conventional gas.

In the context of Canadian natural gas demand: Natural Resources Canada, in its "Outlook to 2020,"[13] estimates that Canadian gas usage will rise gradually, from about 2.9 Tcf per year in 2008 to about 3.9 Tcf in 2020. This figure includes increased demand by industry and for power generation. However, Canada produces more gas than it uses, and exports the rest – mostly to the US.

The Geological Survey of Canada has done a much more thorough survey[14] of Canada's potential shale gas sites; it identifies dozens of locations across the country, and describes their geological characteristics. However, it does not make estimates of gas quantities.

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8 http://www.safehaven.com/article/15443/the-utica-an-emerging-canadian-shale-gas-play

9 http://www.questerre.com/en/investorcenter/press-releases/2009/questerre-utica-shale-discovery-assessed-at-over-4-tcf

10 In a study done by GLJ Petroleum Consultants for Corridor Resources: http://www.corridor.ca/media/2009-press-releases/20090626.html

11 *A Primer* 19; original quote from Ryder Scott Company. 2008. *Resource Potential, Horton Bluff Formation, Windsor Basin, Nova Scotia, Canada*. 43 p.

12 *Saskatchewan s Ultimate Potential for Conventional Natural Gas* Table 2.6B

13 http://www.nrcan.gc.ca/eneene/sources/natnat/revrev-2020-eng.php

14 Geological Survey of Canada. Open File 5384: The "Shale Gas" concept in Canada: a preliminary survey of possibilities.

2. Where is extraction now occurring, and at what scale?

The two major sites of active shale gas extraction in Canada are the Horn River basin and the Montney shale.

Several companies operate in the Horn River basin, and production occurs on a commercial basis. However, a 2010 NEB report states that "Currently, production data from the Horn River Basin is still confidential and estimating total shale gas production is not possible."[15] Some information is available: A B.C. Oil and Gas Commission (OGC) report[16] states that at the end of the 2009 fiscal year, there were 55 wells in the Horn River basin with production on record; the report also provides a graph of gas production, but no data. We can estimate from the graph that in the month of October 2009, production reached a peak of about 4590 million cubic feet (mmcf).

Little information for 2010 is available, except that "In 2010, the wells drilled in the HRB targeting shale gas had a production rate of 380 mmcf/day."[17]

Apache, one of the major companies drilling in the Horn River basin, provides the following information on its website: "Apache has a 50-percent interest and 210,000 net acres in the Horn River basin. During 2010, Apache reached a peak of 100 million cubic feet per day net, drilled 29 new wells and completed 30 wells. In 2011, we plan to drill 10 and complete 28 wells in the Horn River basin."[18] EnCana is another major player. It states that it owns 264 000 net acres in the Horn River Basin, in which, by the end of 2010, it had 90 wells – 43 of which were on long-term production.[19] However, EnCana does not provide production information for these wells specifically.

The Montney shale, in B.C./Alberta, has also seen a high level of production. Production as of September 2009 was 494 mmcf/d.[20]

Although there was previously a fair amount of exploratory activity in Quebec's Utica shale, all activity has stopped. On September 27, 2010,[21] the Quebec government banned oil and gas development in the St. Lawrence River area. And in March 2011, following an inquiry by BAPE (Bureau d'audiences publiques sur l'environnement), the government stated that no fracking would be authorized in Quebec from that point on, except as part of scientific investigations. This is not permanent; rather, development of

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[15] *A Primer* 16
[16] BC Oil and Gas Commission: *Horn River Basin Status Report 2010* 16
Note: mcf = thousand cubic feet; mmcf = million cubic feet
[17] OGC. Personal communication, August 26 2011.
[18] http://www.apachecorp.com/Operations/Canada/index.aspx
[19] http://www.encana.com/operations/canada/greatersierra/
[20] *A Primer* 15
[21] *Fracture Lines* 32

shale gas (and oil) has been frozen until the completion of a strategic environmental evaluation of shale gas development, which could take 18 to 30 months.

In New Brunswick, Corridor Resources has been conducting exploratory fracking on the Frederick Brook shale,[22] but extraction on a commercial basis has not begun. Apache Canada, a major partner of Corridor, recently pulled out[23] of New Brunswick due to disappointing results from exploratory wells.

3. What are the current and anticipated economic costs of extraction/production, and how do these compare to other energy sources?

A Primer for Understanding Canadian Shale Gas provides the following information on well costs across Canada (including fracking):[24]

Shale play	Cost of horizontal well (millions of $Cdn)
Horn River Basin	7 to 10
Montney Shale	5 to 8
Colorado Shale	0.35 (vertical wells)
Utica Shale	5 to 9
Horton Bluff	?

Shale gas production costs vary widely. A World Energy Council report states that "Estimates of shale gas extraction costs in North America range from US$4- 8/Mcf"[25] but that the cost of water treatment and chemical cleanup could push the minimum estimate to $6/Mcf.

The Research Triangle Energy Consortium states[26] on its website that, at a cost of $4/Mcf of natural gas, electricity costs about 4.5 cents/kWh – a number also repeated in *The Shale Gas Shock* (24). However, it is unclear whether gas prices will remain this low: MIT estimates that gas prices will rise over time, as the demand for gas increases.[27]

The US EIA, in its 2011 Annual Energy Outlook, estimated the costs of electricity from new plants opening in 2016. These are levelized costs – "the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to

[22] http://www.corridor.ca/oil-gas-exploration/new-brunswick.html
[23] http://www.nb.dailybusinessbuzz.ca/Provincial-News/2011-06-01/article-2551055/NB%3A-Apache-pulls-of-New-Brunswick-shale-gas-exploration/1
[24] *A Primer* 14 – table 1
[25] World Energy Council. *Survey of Energy Resources: Focus on Shale Gas* 14 http://www.worldenergy.org/documents/shalegasreport.pdf
[26] http://rtec-rtp.org/shale-gas/
[27] MIT. *The Future of Natural Gas* 27, Table 3.4a

remove the impact of inflation."[28] MIT also has estimates of levelized electricity costs, stated in its report on natural gas.[29]

Technology	**Cost of electricity: US cents/kWh**	
	US EIA Report	MIT Report
Gas	6.3	5.6
Coal	9.5	5.4
Hydro	8.6	
Nuclear	11.4	8.8

The EIA report operates with an estimated price of $7.07/Mcf of natural gas in 2035;[30] the MIT study uses a similar assumption, with the price continuing to rise in the decades after.[31] In both these cases, energy from natural gas compares well to other energy sources.

4. What are the primary environmental concerns associated with extraction? What do critics allege, and how do advocates respond?

High water use

Fracking a well requires a large amount of water. This has raised some concerns. Between 15% and 80% of this water is returned to the surface,[32] depending on the site, which means that a large quantity of water may be left in the ground; furthermore, this flow-back water is contaminated with various chemicals – both chemical additives and minerals picked up underground – so the water is often disposed of rather than reused. (Fracking is then a "consumptive" water use.) Thus there are questions about how sustainable this water use is. However, there are some indications that the industry in Pennsylvania is moving towards reuse of fracking wastewater:[33] Talisman Energy has stated that it recycles 100% of its flowback wastewater, and Range Resources has stated that it recycles 90% and is aiming for 100%.

It is difficult to determine the exact amount of water used in fracking. The Barnett Shale in Texas has required about 4500 cubic metres for a vertical well, and 13,000 cubic metres for a horizontal well.[34] This applies to the whole lifetime of a well, which may be

[28] US EIA: *Levelized Cost of New Generation Resources In the Annual Energy Outlook 2011* http://www.eia.gov/oiaf/aeo/electricity_generation.html
[29] *The Future of Natural Gas* 22, Table 3.1 http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf
[30] http://www.eia.gov/forecasts/aeo/chapter_executive_summary.cfm#domestic
[31] *The Future of Natural Gas* 27 Table 3.4a
[32] EPA: "science in ACTION: Hydraulic Fracturing Research Study" - http://www.epa.gov/safewater/uic/pdfs/hfresearchstudyfs.pdf
[33] http://www.pittsburghlive.com/x/pittsburghtrib/news/s_737062.html
[34] Texas Water Development Board: *Northern Trinity/Woodbine GAM Assessment of Groundwater Use in the Northern Trinity Aquifer Due To Urban Growth and Barnett Shale Development* 14

fracked in multiple stages. Since shale gas development in Canada is at an earlier stage, numbers are still rough, but one hydrologist has estimated that in the Horn River Basin, each well requires about 90,090 cubic metres.[35] There are indications that fracking in the Horn River Basin is larger than average: *Fracture Lines* (28) discusses the case of Two Island Lake, which provided 200,000 cubic metres of water for what is referred to as "The world's biggest frack." (It is unclear from *FL*'s discussion whether this was for one well or many.) Also, BAPE states that, in the Utica shale, between 12,000 and 20,000 cubic metres of water are required per well – varying with the length of the well and the number of times it is fractured.[36]

Horn River Basin wells produce 16 MMcf/d at the beginning, but decline sharply.[37] By contrast, wells in the Montney Shale produce on average 3 to 5 MMcf/d on startup, and then decline; however, they require only between 700 and 1200 cubic metres of water for fracking.[38]

In B.C., short-term water permits (for surface water) are under the jurisdiction of the Oil and Gas Commission, which in a 2010 report states that it authorized 86,535,000 cubic metres for oil and gas activity in the 2009 fiscal year, which is 1% of total authorized consumptive water use in that period.[39] Since the OGC does not publish information on *actual* water use, though, we don't know how close shale gas companies came to the maximum authorized use.

Advocates of shale gas argue that the amount of water used for fracking pales in comparison to other water uses. British Columbia's Minister of Energy, Rich Coleman, stated in *The Province* that B.C. shale gas drilling in the Horn River Basin "will only use up to 0.7 per cent of the area's annual run-off," and the OGC points out that the pulp and paper industry is granted 17 times more water than the natural gas industry.[40] But though this may be true, if shale gas production were to increase to the scale some people suggest – to become one of our primary energy sources – then the industry's water use would also grow. Recycling of flowback water would, of course, reduce this – by a lot or a little, depending on how much water is recovered from the wells in the first place.

It should also be noted that, in B.C., shale gas companies do not pay for the water they use. Rather, if they want to use surface water, they have to apply to the Oil and Gas Commission for a short-term water permit, which sets conditions on where and how

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http://rio.twdb.state.tx.us/RWPG/rpgm_rpts/0604830613_BarnetShale.pdf

[35] Ken Campbell, hydrologist at Schlumberger Water Services, at a presentation to the Sixth Annual Shale Gas Conference in Calgary, January 2010 – quoted in *Fracture Lines* 19.

[36] BAPE. *Développement durable de l'industrie du gaz de schiste au Québec* 97

[37] *A Primer* 16

[38] ibid. 15

[39] BC OGC: *Oil and Gas Water Use in British Columbia* 21

[40] ibid. 23

much water a company may use.[41] Several companies have also applied[42] for long-term water licences, which require approval from the Ministry of Environment; these are currently being considered. There is no regulation of groundwater withdrawals in B.C. Thus in none of these cases are companies constrained by the cost of the water they are using. This, of course, means that the companies have little incentive to try to minimize their water use (unless they reach the limit allowed them in their permit). A system where the companies were charged for their water use – with prices reflecting scarcity, other potential uses, contamination – would encourage companies to lower their water use and find alternatives, or ways to recycle more.

A final point to note is that not all fracking in Canada uses water. An NEB report states that "many fracs in the Montney play use CO_2 as the frac fluid,"[43] and the Colorado shale in Alberta, which has a high clay content, causing it to swell when in contact with water, is usually fracked with "nitrogen or a mixture of propane and butane." If this became more common, the impact of fracking on Canada's water resources would of course be lessened. Thus the NEB report states that "it is too early to draw conclusions on the impact of shale gas development on the use of fresh water resources in Canada."

Disposal of wastewater

Fracking fluid and flowback water; methods of disposal

A related concern is the disposal of large quantities of wastewater. The amount of fracking fluid that returns to the surface (flowback) after fracking varies between one- and two-thirds. This water contains the chemicals added to make it "slick" (to reduce friction, which allows for an increased flow rate), as well as biocides (to prevent any organisms from growing in the well), surfactants (to keep the proppant in suspension), and scale inhibitors.[44] In addition to this, the wastewater has salt content picked up underground; in some cases (depending on the local geology) it may also be radioactive.[45] There is also "produced water" – water, which had been underground, which flows up the well with natural gas – which is typically highly saline.

In most cases neither the fracking flowback nor the produced water is suitable to be directly returned to drinking water sources. It can either be injected into deep disposal wells, treated and returned to the watershed, or treated and reused for further fracking.

[41] *Fracture Lines* 26
[42] http://www.cbc.ca/news/canada/british-columbia/story/2011/07/22/bc-shale-gas-fracking-water.html
[43] *A Primer for Understanding Canadian Shale Gas* 11
[44] *The Shale Gas Shock* 19
[45] "Regulation Lax as Gas Wells Tainted Water Hits Rivers" – NYT, Feb. 26, 2011 – claims that wells can produce wastewater with up to 1000 times the federal drinking water standard for radioactive elements – although, of course, nobody drinks the wastewater.

In B.C., it is illegal to return the wastewater to surface water systems[46] (even after treatment) so it is usually injected deep underground – for example, into the Debolt aquifer, which is also a source for water for fracking.[47] In Alberta, saline water "must be returned to a similar underground environment through deep disposal wells;"[48] however, if the water is not saline, there is the possibility of "surface water discharge or reinjection into an aquifer of a similar or a lower water quality, as long as environmental impacts are addressed."[49]

In Quebec, treated wastewater may be returned to the environment, but only with prior approval from the Ministry of Sustainable Development, Environment and Parks. The Ministry has to examine whether the waste will pose any danger to the local environment or to human use of the local water supply.[50] In the case of shale drilling, this includes considering the long-term, cumulative impacts of the amounts of wastewater that would be returned to the watershed. Municipal wastewater facilities in Quebec are also allowed to treat industrial waste – but BAPE suggests that these facilities may not have the ability to properly treat fracking wastewater, so future regulations might restrict which plants can take this waste.[51] Deep underground disposal is not currently practiced in Quebec; BAPE suggests that it should not be done until a study of geological and hydrogeological risks has been done.[52]

Potential for surface-water contamination and other damage

The first concern is the possibility of spills or leaks. There have been many reported cases from Pennsylvania: spills[53] of fracturing fluid onto the ground such as from a faulty storage pit; spills of hydrochloric acid; spills of wastewater into watersheds. In Dimock, Pennsylvania, Cabot spilled about 8000 gallons of fracturing fluid into a stream[54] when a supply pipe failed, and also spilled drilling mud into other streams.[55]

These kinds of incidents occur due to faults in the storage units (pits, tanks) used to store fluid and wastewater, or due to breaks in pipes used to transport the liquids. Most incidents are cleaned up without causing permanent environmental damage, but there is some evidence that fracking fluid could be harmful if it came into contact with

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[46] BC OGC: *Oil and Gas Water Use in British Columbia* 7
http://www.bcogc.ca/document.aspx?documentID=856&type=.pdf
[47] *Fracture Lines* 35
[48] http://www.energy.alberta.ca/NaturalGas/753.asp
[49] Alberta Environment Fact Sheet: *Water and Natural Gas in Coal* -
http://www3.gov.ab.ca/env/water/Legislation/Factsheets/waterandnaturalgasincoal.pdf
[50] BAPE. *Développement durable de l'industrie des gaz de schiste au Québec* 134
[51] ibid. 135
[52] ibid. 139
[53] http://www.propublica.org/article/pas-gas-wells-booming-but-so-are-spills-127
[54] http://www.propublica.org/article/frack-fluid-spill-in-dimock-contaminates-stream-killing-fish-921
[55] http://s3.amazonaws.com/propublica/assets/natural_gas/final_cabot_co-a.pdf

surrounding wild areas. A study[56] released recently looked at the effects of fracking fluid on a forest: 303,000 litres of it were applied to 0.2 ha of the Fernow Experimental Forest in West Virginia, resulting in "severe damage and mortality of ground vegetation" immediately. "Two years after fluid application, 56% of the trees within the fluid application area were dead." The contents of the fluid were proprietary, so the scientists were not able to examine links to particular chemical contents; furthermore, the effects of the fluid would depend on the amount. But this study does at least seem to show that fluid spills could cause harm to wild plants and animals.

The second worry is that inadequately treated water might be returned to rivers and lakes that provide drinking water. Reports in the *New York Times* suggest that this has happened in Pennsylvania, where fracking waste water has been found to be highly radioactive; the water has been brought to municipal water-treatment plants which are not equipped to deal with radioactive waste.[57]

Pennsylvania's Department of Environmental Protection has discovered elevated levels of bromide in Pennsylvania rivers,[58] which it attributes to the discharge of large amounts of partially treated fracking wastewater into the rivers. Such problems could also happen in Canada in jurisdictions where it is legal to return wastewater to rivers.

Advocates, however, point out that there have not been any studies which found elevated levels of radioactivity in surface water due to contamination from fracking waste; and even if the wastewater were dangerously radioactive, it would be highly diluted if it were added to rivers and lakes, and therefore should not pose a risk. In fact, a Pennsylvania DEP study from 2010, which looked at water downstream from plants treating Marcellus shale wastewater, found that "all samples showed levels below the federal drinking water standard for Radium 226 and 228."[59] And the Pittsburgh Water and Sewer Authority, which began testing its water for radioactivity every month in response to the *NYT* article, has so far always found radioactivity levels below the federal standard.[60] Third, Pennsylvania American Water ran tests on several Pennsylvania rivers, and found "no detectable levels of radiological contaminants."[61] These cases are all discussed on the blog[62] of John Hanger – former head of the Pennsylvania DEP. Thus, while there are certainly concerns about the release of wastewater into rivers, it is unlikely that radioactivity will be a major problem.

[56] "Land application of hydrofracturing fluids damages a deciduous forest stand in West Virginia." Journal of Environmental Quality Vol. 30 No. 4 p. 1340-1344 http://www.nrs.fs.fed.us/pubs/jrnl/2011/nrs_2011_adams_001.pdf
[57] http://www.nytimes.com/2011/02/27/us/27gas.html?pagewanted=all
[58] http://johnhanger.blogspot.com/2011/04/lowering-bromide-levels-on-mon.html, http://www.post-gazette.com/pg/11109/1140412-100.stm?cmpid=news.xml
[59] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=%2016532%20&typeid=1
[60] http://www.pgh2o.com/ - "PSWA Radiological Survey"
[61] http://www.amwater.com/alerts/alert15474.html
[62] http://johnhanger.blogspot.com/2011/06/4-sets-of-test-results-prove-pa-waters.html

Potential for groundwater contamination

Groundwater contamination by fracking fluid

Third, critics argue that fracking has the potential to contaminate groundwater supplies – either with fracking fluid or with natural gas. There has been at least one case, from 1982, and reported in a recent *New York Times* article. A well belonging to James Parsons of West Virginia was contaminated by a dark gel after Kaiser Exploration and Mining Company fracked a gas well on Parsons's property.[63] The gel was not chemically tested, but EPA investigators concluded that it was fracturing fluid from the nearby gas well. This case is interesting as there was no suggestion that Kaiser's well was improperly cased; rather it is suggested that the fluid migrated up an old, abandoned well into the aquifer that Parsons's well drew from.

However, a report[64] by an industry-funded think tank, Energy In Depth, suggests a different story: A local formation, the Pittsburg sandstone, had been previously fractured before it was discovered to contain potable water sources. If Parsons's well drew water from an aquifer in, or connected to, those in the Pittsburg sandstone, then it is possible that the fracking fluid discovered came from there rather than from Kaiser's well. This would mean that the Parsons case is not evidence for groundwater contamination from *shale* drilling.

Given how long ago the events were, it is hard to determine which story is correct, so we have to investigate whether, in theory, fracking fluid could contaminate groundwater. Advocates of shale gas have two responses to the claim that groundwater could be contaminated: (1) that there is about a mile of solid, impermeable rock between drinking water aquifers and the shale, and (2) that the chemicals in fracking fluid are so diluted that they would be harmless even if they did reach aquifers.[65] I will discuss each of these claims in turn.

(1) In most cases, it is true that aquifers are separated from shales by thousands of feet of solid rock. The fractures caused by fracking tend to be mostly horizontal, and are therefore far below groundwater sources. This means that it is quite unlikely for fractures to directly reach aquifers.

However, there are some exceptions: Certain shales (such as the Colorado formation) occur closer to the surface,[66] as shallow as 300m.[67] Fracking in situations like this could lead to fractures that communicate with groundwater sources. Also, even if the rock layer

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[63] "A Tainted Water Well, And Concern There May Be More" – NYT, August 3 2011
[64] http://www.energyindepth.org/2011/08/eid-statement-on-latest-joint-effort-by-nytenvironmental-working-group-aimed-at-attacking-natural-gas/
[65] Both claims are made, for example, in *The Shale Gas Shock*
[66] "the Colorado Group is one of the shallowest potential shale gas intervals" – Geological Survey of Canada, Open File 5384. "The "Shale Gas" concept in Canada: a preliminary inventory of possibilities" 55
[67] *A Primer* 14, Table 1

between shale and aquifer is impermeable, it is still possible for contamination to occur if there are other abandoned wells nearby which the fractures could reach (as was suggested to explain the Parsons case).

A B.C. Oil and Gas Commission Safety Advisory (May 20, 2010) reported[68] that there have been 18 cases of "communication" in B.C., and one in Alberta. "Communication" refers to cases where fractures created during fracking one well connect up to an adjacent well, possibly leading to "kicks" – the transfer of fluids, sand and mud. The report states that communication has happened between wells up to 715m apart, and that "fracture propagation via large scale hydraulic fracturing operations has proven difficult to predict. Existing planes of weakness in target formations may result in fracture lengths that exceed initial design expectations." All the cases mentioned, however, were successfully controlled.

Overall, it remains true that – apart from the contested Parsons case – there have not been other verified cases of the contamination of groundwater sources by fracking fluid. The possibility certainly exists in cases where there are nearby abandoned wells, or where wells are not properly cased, but it is unlikely that fracking fluid could reach aquifers directly through fractures.

(2) While it is true that, usually, fracking fluid is mostly water, only containing other chemicals at very high dilution, this is not to say that those chemicals would therefore be harmless, were they to reach groundwater. The US Congress released a report on the chemicals in fracturing fluid, which stated:

> Some of the components used in the hydraulic fracturing products were common and generally harmless, such as salt and citric acid. Some were unexpected, such as instant coffee and walnut hulls. And some were extremely toxic, such as benzene and lead.[69]

Also, in certain cases, companies stated that some of the substances in fracking fluid were proprietary, secret even from the companies themselves: They "stated that they did not have access to proprietary information about products they purchased 'off the shelf' from chemical suppliers."[70] This means that any statements about the effects that fracking fluids would have – on people, or on the environment – are necessarily somewhat uncertain.

There are, however, some empirical cases to look at. There is at least one reported case, from Colorado, of a nurse suffering multiple organ failure after coming into contact with

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[68] http://www.bcogc.ca/document.aspx?documentID=808&type=.pdf

[69] US House of Representatives, April 2011. "Chemicals used in hydraulic fracturing" 1 http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf

[70] ibid. 4

drill stimulation fluid.[71] It should be noted, though, that the worker who was directly splashed with fluid was soon released. There is also the case, discussed in section 2, of the damage that fracking fluid caused to a forest.

In addition, after fracking, the flowback water also contains high levels of salts, benzene, and in some cases radioactive elements; all of these have the potential to be harmful if in contact with groundwater. And in cases where the main component of the fracking fluid is not water but propane, butane or some other mixture, contamination of groundwater could also be harmful.

Groundwater contamination by natural gas

There are also cases of contamination not by fracking fluid but by natural gas. In one case, a house in Ohio suffered an explosion after nearby fracking. A report by Ohio's Department of Natural Resources stated that a nearby gas well, run by Ohio Valley Energy Systems Corp., was subject to hydraulic fracturing even though there was "minimal cement behind the production casing"; gas which had accumulated in the annulus of the well finally "migrated vertically through fractures into the overlying aquifers and discharged, or exited, the aquifers through local water wells."[72]

A 2008 report from Colorado – the Garfield County Hydrogeologic Study – also supports claims that gas from wells has caused "elevated methane and chloride in groundwater wells."[73] While methane is naturally present in groundwater in certain areas, in this case the isotopic value of the methane was examined. The Phase II section of the report states:

> Two of the domestic wells sampled for gas composition and methane stable isotopes had results indicating a possible thermogenic source for the gases in the wells. Most of the domestic wells in the field area, however, have hydrocarbon gas characteristics indicative of a biogenic source.[74]

Thermogenic gas is formed deep underground in shale, while biogenic gas is created by bacteria; this result indicates that some gas has escaped from the shale or from the wells into domestic groundwater sources. The review of the study, by hydrologist Geoffrey Thyne, makes the stronger claim that "The isotopic data for the methane samples show the most of the samples with elevated methane are thermogenic in origin." There is no regulatory limit in Colorado on methane values in groundwater, and the chloride levels, while higher than normal, were below regulatory limits, so no action was taken on this issue.

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[71] http://www.propublica.org/article/buried-secrets-is-natural-gas-drilling-endangering-us-water-supplies-1113

[72] *Report on the Bainbridge Investigation* – Ohio Department of Natural Resources – 4

[73] *Review of Phase II Hydrogeologic Study* 1 - http://s3.amazonaws.com/propublica/assets/methane/thyne_review.pdf

[74] *Phase II Hydrologic Characterization of the Mamm Creek Field Area, Garfield County, Colorado,* September 2008, ES-2

The Garfield County study did not attempt to investigate the path taken by the gas. In general, it seems that the most common way that gas could escape into aquifers is via inadequately cased wells. As gas companies point out, they already have a disincentive to let gas escape this way: Any gas that leaks out is gas that could have been sold.

In Dimock, Pennsylvania, in April 2010, Cabot Oil and Gas was fined for contaminating the drinking water supplies of 14 homes. The Pennsylvania Department of Environmental Protection found[75] that groundwater was contaminated with elevated levels of methane, due to several badly cased wells. Cabot paid the fine, but denied that its drilling activities were the cause of the contamination.

Finally, a recent study[76] looked at the Marcellus and Utica shales in Pennsylvania and New York, and found "systematic evidence for methane contamination of drinking water associated with shale gas extraction." Methane levels in drinking water in areas with a gas well within 1 km were 17 times higher than in areas with no gas wells, and the chemical composition of the methane showed that it was thermogenic, and had therefore originated from the shales, not from biological sources.

Tracing contaminants

Tracing fracturing fluid could be one way to track the origin of leaks and spills, and to establish liability. Harmless chemical tracers (chemical frac tracers, CFTs) have been developed[77] to trace the quantity of fluid that flows back from each stage of fracking a well, and there seems no reason why this technology could not be used by each company to mark their fracturing fluid as their own. The tracers "do not react with each other, formation or tubulars and do not degrade with temperature or time"; they are traceable at very low concentrations, and environmentally safe.

For natural gas, isotopes are most often used as natural tracers – the isotopes of the gas that leaks into wells or taps can be compared with the isotopes of gas from the shale. This method was used in cases like the Garfield County study above.

Potential to cause seismic events

There have been some suggestions that hydraulic fracturing and/or the injection of wastewater deep underground could cause minor seismic events. In Blackpool, UK, two earthquakes occurred, with epicentres within a few kilometres of a drill site where fracking had begun. There has not been a formal investigation into this, but the British Geological Survey stated that "It is well known that injection of water or other fluids

[75] http://s3.amazonaws.com/propublica/assets/natural_gas/final_cabot_co-a.pdf
[76] "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing" - http://www.pnas.org/content/108/20/8172.abstract
[77] http://www.onepetro.org/mslib/app/Preview.do?paperNumber=00077750&societyCode=SPE

during the oil extraction and geothermal engineering, such as shale gas, processes can result in earthquake activity."[78]

The injection of gas or fluids underground – either in fracking or in waste disposal – can put pressure on faults, which may cause earthquakes. In Texas, in 2008-2009, a series of minor earthquakes occurred around the Fort Worth area – a hub of fracking in the Barnett Shale. A seismologist from Southern Methodist University stated that fracking was a "plausible cause"[79] of the earthquakes. In another case, hundreds of small to moderate earthquakes occurred in Guy, Arkansas, which is in the middle of the Fayetteville Shale. Such swarms have occurred before in the area,[80] but the Arkansas Geological Survey stated that the disposal of wastewater into disposal wells might "reduce the friction in the fault" which "may be making them happen sooner."[81] The largest earthquake was of magnitude 4.0. Similar cases have occurred in West Virginia, over the Marcellus Shale.

A primer on "induced seismicity" from the US Department of Energy states that fracking can cause microseismic events, but that it "rarely creates unwanted induced seismicity large enough to be detected on the surface."[82] Waste injection, on the other hand, can cause larger earthquakes, depending on the local geology. However, a paper by Christian Klose on human-induced seismicity[83] specifically includes "hydrocarbon production and enhanced recovery (e.g., crude oil, natural gas, steam injections)" as well as "waste water injections deep underground" as activities that can trigger earthquakes.

Air pollution

There have been some suggestions that shale gas drilling can cause air pollution. A study of Garfield, Colorado,[84] took air samples from 14 sites over a 24 month period (2004-2007) and found that "local populations may be exposed to chemicals at levels hazardous to health" – specifically, 12 of the sites showed elevated levels of benzene. Other chemicals were also found at potentially dangerous levels. However, the authors of the report state that the results are inconclusive, as sampling was so limited. Furthermore, the study does not compare levels before and after gas drilling started, so it is difficult to establish direct responsibility. Since fracking wastewater can contain high levels of benzene, and is sometimes stored in open pits where it can evaporate, it is possible that this is the cause of Garfield s air pollution, and that similar problems could happen elsewhere.

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[78] http://www.telegraph.co.uk/earth/energy/8549340/Shale-gas-drilling-suspended-after-earthquake-near-Blackpool.html
[79] http://oilprice.com/Energy/Natural-Gas/Natural-Gas-Does-Hydraulic-Fracturing-Really-Cause-Earthquakes.html
[80] http://www.nytimes.com/2011/02/06/us/06earthquake.html?_r=2
[81] http://www.watershedsentinel.ca/content/does-gas-fracking-cause-earthquakes
[82] http://esd.lbl.gov/research/projects/induced_seismicity/primer.html
[83] Klose, C.D. 2010: Human-Triggered Earthquakes and Their Impacts on Human Security 2 http://precedings.nature.com/documents/4745/version/3/files/npre20104745-3.pdf
[84] Witter et al."Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper" –September 15, 2008 http://docs.nrdc.org/health/files/hea_08091702A.pdf

On the other hand, a different study of Garfield County found that "in general, the VOC [volatile organic compound] levels detected were extremely low,"[85] although it did detect some effects from oil and gas development, including benzene and related chemicals.

5. Do concerns vary with geography or are they universal? (How applicable is US experience?)

Since shale drilling in Canada is still mostly at the exploratory stage, American shale drilling has been the primary source for information about environmental concerns. Some issues vary with geography, while others are universally applicable.

Water use

Water use for fracking varies widely. Vertical wells use far less than horizontal ones, and the length of the well also affects the amount of water needed. Use also varies with geography: while the Barnett shale is estimated to need around 13,000 cubic metres per well, the Horn River Basin shale needs about 90,000, on one estimate (noted above). Also, sometimes shale is fracked without water – with nitrogen, propane or other substances – either due to geography or to reduce water use. This is the case, for example, in the Colorado shale.

The extent to which water use is a concern also varies. If fracking is occurring in areas near urban centres (such as in New York or in Quebec), or during times of water shortage, then water use might put a strain on already stretched supplies. But if fracking happens in remote, sparsely populated areas (such as the Horn River Basin), it is less likely to use up needed resources.

Wastewater; surface-water contamination

In all cases, the water that emerges from shale-gas wells – flowback water and produced water – is contaminated and requires treatment. The extent of contamination can vary, though, depending on geography. For example, the BAPE report on shale gas in Quebec states, "the weak concentration of total dissolved solids in flowback water, which is characteristic of the Utica shale, would enable the water to be reused without the need for extensive treatment."[86] The specific kinds of contaminants also vary with geography.

In all cases, the risk of spills – of fracking fluid, other chemicals, or flowback water – or improper disposal is a concern.

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[85] Garfield County Public Health Dept. and Colorado Dept. of Public Health and Environment. "Garfield County Ambient Air Quality Monitoring Study" 2 – http://www.garfield-county.com/public-health/documents/Garfield%20County%20Ambient%20Air%20Quality%20Study%20Report.pdf
[86] BAPE: *Sustainable Development of the Shale Gas Industry in Quebec* 99

The amount of flow-back water returned from a well can also vary widely according to geography. A draft of the US SEAB Shale Gas Production Subcommittee – 90-Day Report states, "In the Eagle Ford, in Texas, there is almost no flow-back water from an operating well following hydraulic fracturing, while in the Marcellus, primarily in Ohio, New York, Pennsylvania and West Virginia, the flow-back water is between 20 and 40 percent of the injected volume."[87]

Groundwater contamination

Groundwater contamination by fracking fluid is not likely to happen in most cases; the risk increases in areas where the shale is close to drinking-water aquifers, or where there are large numbers of abandoned wells, which may not be completely plugged/cased, and which could serve as conduits for fracking fluid, flowback water, or methane to enter aquifers. It is also likely that the length and direction of fractures created vary with the type of shale: Anthony Ingraffea, quoted in *Fracture Lines* (10), states that certain shale formations tend to fracture vertically rather than horizontally, which could "open up a pathway upwards to freshwater."

Induced seismicity

The risk of causing earthquakes varies strongly with geography. The risk of seismic events increases if waste injection occurs along or near a fault line.[88] Thus the earthquake "swarms" that have occurred, e.g. in Arkansas, might or might not be repeated in Canada, depending on where fault lines are. An article published by the Canadian Centre for Policy Alternatives states that "The heart of the Utica Shale field in Quebec is bounded by two well-known earthquake fault-lines: the Yamaska Fault, and the Logan's Line Fault system" and that "the existence of these fault-lines would make Quebec's Utica Shale field a likely zone for induced earthquakes from drilling, fracking, and wastewater disposal wells."[89]

Air pollution

Air pollution varies depending on the methods used to store fracking waste and to prevent gases escaping into the air; however, it is may be less of a concern in areas which are remote and far from human habitation.

[87] http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf
[88] Klose, C.D. "Human-triggered Earthquakes and Their Impacts on Human Security" 2
[89] http://www.policyalternatives.ca/publications/monitor/big-fracking-problem

6. How do concerns about shale gas differ from those arising from the fracking used to extract coal-bed methane?

Fracking for coal-bed methane also results in large quantities of water – not, as in shale fracking, because water is injected into the well, but rather because water has to be drawn out of coal beds before they will produce gas ("produced water"). In both cases there are concerns about how the water gets disposed of – either treated and recycled, or injected underground. However, the B.C. Ministry of Energy and Mines states[90] that produced water from coal beds tends to be of good quality, and is therefore allowed to evaporate or to run off into surface water. Produced water from shale, on the other hand, tends to be in a condition that requires either underground disposal, or treatment before being allowed into surface water.

Concerns about groundwater contamination from coal-bed methane – such as in a recent Alberta lawsuit[91] claiming that EnCana contaminated a drinking-water aquifer – are also paralleled in shale gas drilling. However, it seems less likely that groundwater will be contaminated by shale drilling than by coal-bed methane drilling: Coal beds "can also contain high quality water which is able to be treated to meet drinking water standards,"[92] while shales "are typically deeper than coal bed methane formations, have not traditionally been identified as sources for supplying drinking water, [and] are not noted as containing treatable drinking water."[93] (Although certain shales, as noted above, can be shallow and close to aquifers.)

7. What mitigation measures are available, and at what cost?

Water use

The only mitigation measures for water use are (1) recycling flowback water and (2) using something other than water as fracking fluid.

Recycling flowback water has become quite common in US shale gas drilling. As noted above, some companies operating on the Marcellus shale claim that they now recycle 100% of flowback water.

In *Fracture Lines*, it is claimed that wastewater treatment will cost "on the order of $10 to $15 a cubic metre."[94] According to Range Resources, though, these costs are

[90] http://www.em.gov.bc.ca/Mining/Geoscience/Coal/CoalBC/CBM/Pages/CBMBrochure.aspx#
[91] Ernst v. EnCana Corporation
[92] ALL Consulting. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale" 3 http://www.dec.ny.gov/docs/materials_minerals_pdf/GWPCMarcellus.pdf
[93] ibid. 3
[94] *Fracture Lines* 37

outweighed by the economic benefits: It says that it "saves approximately $200,000 per well as [recycling] eliminates the cost of trucking and treating water."[95]

Wastewater disposal & surface-water contamination

The major mitigation measure for the risk of surface-water contamination is proper storage and transport of potentially dangerous materials. This can include secondary containment – to catch spilled liquids before they escape – as well as replacing the linings of storage pits as they wear out. And, of course, the more often a well site is checked, the quicker a spill is likely to be caught. Another major measure is the proper treatment of water before it is returned to streams.

Groundwater contamination

To prevent groundwater contamination – either from fracking fluid or from natural gas – the main mitigation measure is to properly case wells, making sure that there is no space between the cement and the rock for gas to migrate up. Furthermore, the area around a well site should be checked to see if it contains any old, abandoned wells, which may not be properly plugged.

It would also be possible to use tracers in fracking fluid, which would help in establishing liability if contamination were to occur.

If contamination by gas occurs, the solution is to plug the wells from which the gas is migrating into aquifers, as was done in the Dimock County case. Since there are no recent, large-scale cases of fracking fluid contaminating an aquifer, it is hard to say whether it would be possible to clean up such contamination, and how much it would cost.

Induced seismicity

The risk of causing induced seismicity increases when fluid injection happens on or near a fault line. Thus an easy way to reduce risks would be to take this into account when choosing where to drill and where to inject.

If a seismic event occurs, the damage it causes can vary – depending on where and how powerful the earthquake is. Thus the cost of mitigating the damage will also vary.

[95] "Range Answers Questions on Hydraulic Fracturing Process" - http://www.rangeresources.com/Media-Center/Featured-Stories/Range-Answers-Questions-on-Hydraulic-Fracturing-Pr.aspx

Air pollution

On July 28, 2011, the EPA proposed new regulations to control the impact of natural gas drilling on air quality.[96] It suggested "green completions"; this "separates gas and liquid hydrocarbons from the flowback that comes from the well as it is being prepared for production" and, the EPA claimed, it "reduces VOC emissions from completions and recompletions of hydraulically fractured wells by 95 percent."

New regulations were also suggested for machinery that causes emissions, and for storage tanks. The EPA also suggested that these standards, while reducing emissions, would also lead to net savings for the drilling industry, due to the sale of natural gas and condensate which is collected rather than allowed to escape into the air.

8. Who makes decisions about shale gas, and in what forums?

British Columbia

The Oil and Gas Commission (OGC), a Crown corporation, regulates the B.C. oil and gas industries. It covers "exploration, development, pipeline transportation and reclamation."[97]

The BC Ministry of Energy and Mines states that "most of the petroleum and natural gas rights in British Columbia are owned by the province, with small percentages privately-owned or held by the federal government."[98] This is because land grants usually have not included rights to the subsurface. The Ministry auctions off petroleum and natural gas (P&NG) rights every month; a company must have the rights before the OGC will give it approval to drill a well. There are three kinds of rights: permits (for exploration), drilling licenses (exclusive rights to drill in an area), and leases (exclusive drilling rights and production rights).

The process of auctioning off rights includes public input:

> An inter-agency referral and notification process is part of the disposition process. This allows provincial agencies, local governments, First Nations and the public to identify areas where access constraints may apply, and to have specific conditions included in the disposition notice.[99]

But even getting a tenure agreement (P&NG rights) is not sufficient: After this, the company applies to the OGC for approval. "Each activity, such as a geophysical survey or drilling a well, must have specific approval from the Oil and Gas Commission." The

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[96] EPA *Proposed Amendments to Air Regulations for the Oil and Natural Gas Industry* Fact Sheet http://epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf
[97] http://www.bcogc.ca/about/default.aspx
[98] http://www.empr.gov.bc.ca/Titles/OGTitles/Pages/PNGRightsinBC.aspx
[99] ibid.

commission reviews applications. In a fact sheet, the OGC describes the process in detail.[100] It includes consultation with affected First Nations groups and a “land and habitat protection evaluation.” In another fact sheet it is stated that companies *may* also “conduct public and stakeholder engagement.”[101] But holding public hearings does not seem to be required.

For fracking, companies also need to access large quantities of water. The OGC is responsible for short-term water permits, but long-term surface water licences are still under the jurisdiction of the provincial Ministry of Environment. Groundwater withdrawals are not regulated in B.C.[102]

Alberta

Alberta operates a similar tenure system to B.C. Surface rights and mineral rights are separate in the province, so most landowners do not own the mineral resources below their land. Companies lease P&NG rights from the Crown, via the Department of Energy. “The Crown owns 81 per cent of the province's mineral rights. The remaining 19 per cent are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies.”[103] Crown mineral rights are publicly auctioned off every two weeks, and in certain cases are directly sold to companies. For freehold mineral rights, the companies have to deal directly with the owner.

The Alberta Energy Resources Conservation Board (ERCB) is “an independent, quasi-judicial agency of the Government of Alberta” and is responsible for regulating fossil fuels in the province. Once a company owns the mineral rights in an area, it has to apply to the ERCB for approval of its project. The company also has to provide information “to all parties whose rights may be directly affected.”[104] Again, though, there does not seem to be provision for public hearings – either generally or for particular locations.

Alberta also has “synergy groups” across the province, composed of representatives from First Nations, local communities, government agencies, and industry,[105] which meet to share information and to discuss issues and problems related to oil and gas development in their area. These groups are overseen by Synergy Alberta.[106]

[100] http://www.bcogc.ca/documents/publications/Fact%20Sheets/Application_Process_FINAL.pdf
[101] http://www.bcogc.ca/documents/publications/Fact Sheets/Unconventional_Gas_Development_Stages_FINAL.pdf
[102] *Fracture Lines* 25
[103] http://www.energy.alberta.ca/Tenure/867.asp
[104] ERCB EnerFAQs 7 - http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_315_247_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/public_zone/enerfaqs/enerfaqs7.aspx
[105] BAPE. *Sustainable Development of the Shale Gas Industry in Quebec* 233
[106] http://www.synergyalberta.ca/

If the company needs access to private land in order to drill, it has to make an agreement with the landowner. If disputes or disagreements occur over this, the Alberta Surface Rights Board[107] is responsible for resolving them.

As for water rights, "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."[108]

Saskatchewan

In Saskatchewan, the system is similar to the previous two provinces. Most mineral rights are Crown-owned: "The Provincial Crown owns approximately 78% of all petroleum and natural gas rights in the Province of Saskatchewan. Freehold lands comprise 18.5%, Indian reserves hold 2% and the remaining 1.5% are held under Federal jurisdiction."[109] Rights are sold six times a year in auctions. Surface land owners and drilling companies have to come to agreements; they can go to the Surface Rights Board of Arbitration for dispute resolution.

Saskatchewan Energy and Resources is the provincial government ministry responsible for oil and gas regulation.

Water is regulated by the Saskatchewan Water Authority. It "assigns rights to both surface water and groundwater supplies," except for "water that is produced as a byproduct of oil and gas extraction."[110]

Manitoba

Manitoba operates a tenure system similar to that of Alberta and B.C. However, "approximately 80% of the oil and gas rights are owned by private individuals or companies (freehold), the remaining 20% are owned by the Crown in the right of Manitoba."[111] In the majority of cases, then, agreements (leases) are made directly between companies and the owners of subsurface rights. Crown rights are sold in auctions four times a year, and are of two types: exploration reservations (exclusive right to drill for 3 years) and Crown oil and gas leases (exclusive right to drill and produce oil and gas for 5 years).[112]

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[107] http://www.surfacerights.gov.ab.ca/aboutus/default.aspx
[108] *Fracture Lines 33*
[109] http://www.er.gov.sk.ca/Default.aspx?DN=3832,3402,3384,2936,Documents
[110] *Fracture Lines* 33
[111] http://www.manitoba.ca/iem/petroleum/oilfacts/index.html
[112] http://www.manitoba.ca/iem/petroleum/tenure/index.html

In Manitoba, water withdrawals above 25 cubic metres per day require a license from Manitoba Water Stewardship.[113] Industrial water users pay fees increasing with quantity.[114]

Ontario

In Ontario, shale gas is under the jurisdiction of the Ministry of Natural Resources – specifically its Petroleum Resources Centre. However, "nearly all land overlying Ontario's shale gas formations is private land,"[115] and "in southern Ontario, most mineral rights are freehold. This means the landowner, not the Crown, owns mineral rights including oil and gas."[116] Companies make arrangements directly with land/mineral rights owners. For example, Mooncor Corp. has made agreements for about 9200 hectares in Lambton and Kent counties.

The MNR is also responsible for approving applications to drill. "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."[117]

The Ministry of Environment is responsible for water use. Anyone taking more than 50 cubic metres/day needs a Permit to Take Water.

Quebec

In Quebec, shale gas drilling currently falls partly under the jurisdiction of the Ministry of Natural Resources and Wildlife (MNR), and partly under the Ministry of Sustainable Development, Environment and Parks (MSD). The MNR is responsible for gas wells, but the MSD covers water, soil and air quality (and therefore fracking) – so it only has jurisdiction on later stages of shale gas drilling. However, after the recently announced moratorium (due to the MSD) it is likely that responsibility will shift towards the latter, away from the MNR.

The moratorium holds on all shale gas drilling/fracturing in the province, except that which is directly authorized by Minister of Environment Pierre Arcand as being of scientific value; the moratorium holds until the results of a strategic environmental assessment are announced. The moratorium was enacted on the recommendation of BAPE (the Bureau d'audiences publiques sur l'environnement) in its recent report on shale gas in Quebec. BAPE does not have regulatory power; it just conducts

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[113] http://www.gov.mb.ca/waterstewardship/licensing/wlb/index.html
[114] http://www.gov.mb.ca/waterstewardship/licensing/wlb/industrial_uses.html
[115] *Fracture Lines* 30
[116] MNR Website: http://www.mnr.gov.on.ca/en/Business/OGSR/2ColumnSubPage/STEL02_167098.html
[117] *Fracture Lines* 30

investigations and makes recommendations, but M. Arcand has indicated that most of its recommendations in the report will be followed.[118]

In its report, BAPE recommends the following decision-making structure. First, a company wishing to drill for shale gas must apply to the Ministry of Sustainable Development, Environment and Parks for prior approval; then it must present its plan to the regional consultative committee that covers the area it is proposing to drill in. The committees would be composed of "company representatives, elected representatives, residents and experts," paralleling Alberta's synergy groups.[119] The committee can suggest changes to the plan, and then it submits its opinion to the Minister of Sustainable Development. At this point the Minister makes a decision: He has final say over whether the project will be authorized and under what conditions.[120]

BAPE also recommends that "shale gas projects would be subject to zoning, development and planning requirements from municipalities,"[121] so that the municipalities can "structure the development of the shale gas industry in the same way as they structure other types of industries"[122] such as the agricultural sector.

BAPE also says that "it would be premature to set up an independent agency to oversee the gas industry"[123] – a rejection of the kind of regulatory agency that exists in B.C. and Alberta. Instead, the Ministry of Sustainable Development, Environment and Parks will be responsible for applying regulations to the shale gas industry. The choice to stick with the Ministry of Sustainable Development rather than an energy regulator might point to a more hesitant attitude towards shale gas than has been adopted by the western provinces. BAPE's report also suggests that the current situation, where regulation is split between the MNR and the MSD, is inefficient, and recommends instead that potential exploration and extraction be authorized in a single certificate of authorization from the MSD. This certificate would cover all stages of gas development.[124]

However, the strategic environmental assessment is still ongoing in Quebec. All statements about Quebec's decision-making structure on shale gas are only provisional at this point – the long-term situation in the province will depend on the outcome of the assessment.

In Quebec, for surface-water withdrawals, the company has to get approval from the government, as well as providing a hydrological study assessing the potential impacts on

[118] Montreal Gazette, March 10 2011. "Quebec shale gas needs more study, government stops hydraulic fracturing"
[119] BAPE. *Sustainable Development of the Shale Gas Industry in Quebec* 233
[120] ibid. 235
[121] Lavier, Thomas. Mccarthy Tetrault. April 8 2011. "Five recommendations that will shape Quebec's shale gas industry"
[122] BAPE. *Sustainable Development of the Shale Gas Industry in Quebec* 237
[123] ibid. 243
[124] BAPE. *Sustainable Development of the Shale Gas Industry in Quebec* 240

other water users and the environment. For groundwater withdrawals, the company has to do a similar study and get approval under a different law. However, BAPE notes that, under the *Act to affirm the collective nature of water resources and provide for increased water resource protection*, the Minister of Sustainable Development will have authorization power over water withdrawals (surface- and groundwater), and also authorization power over what is done with the water after use.[125]

New Brunswick

In New Brunswick, shale drilling requires approval from both the Department of Natural Resources (DNR) and the Department of Environment (DOE).

In the province, "all oil and natural gas resources are owned by the Crown."[126] To explore or develop these resources, companies have to buy subsurface rights from the DNR. There are licenses to search ("entitles the holder to explore, drill and recover oil and natural gas from the area granted" – three years, non-renewable) and leases ("entitles the holder to the exclusive right to produce oil and natural gas from the area granted" – five years, may be extended). In addition, the companies have to make agreements with the owner of the land above which they are drilling – either the Crown or private landowners.[127] For exploration, companies also need to apply to the DNR for a Geophysical Permit, and for drilling they need a Well License.

The DOE also has to issue several permits before a well can be drilled.[128] These include an approval to construct and operate a well, and, for full-scale production, an Environmental Impact Assessment. The EIA includes input from "technical specialists from government agencies, as well as local residents and the general public"[129] – opportunities for the public to review the report and submit written comments, as well as at least one public meeting near the location of the proposed drilling.

Water usage in New Brunswick is regulated by the DOE. If a company proposes to use more than 50 cubic metres/day, of surface-water or groundwater, it has to undergo an EIA.[130] The DOE would usually set a maximum amount of water per day, and minimum levels that a water source must be above. However, *Fracture Lines* notes that companies can get around DOE screening by buying water directly from municipalities.

Nova Scotia

In Nova Scotia, hydraulic fracturing is controlled partly by the Department of Energy and partly by Nova Scotia Environment.

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[125] ibid. 114
[126] http://www.gnb.ca/0078/minerals/ONG_Introduction-e.aspx#OwnershipSurface
[127] http://www.gnb.ca/0078/minerals/ONG_Expl_Devel-e.aspx#LandAccess
[128] A list of relevant permits: http://www.gnb.ca/0009/0377/0003/index-e.asp
[129] New Brunswick DOE. "A Guide to Environmental Impact Assessment in New Brunswick."
[130] *Fracture Lines* 32

The DOE calls for exploration proposals, reviews them and chooses whether to accept or not. For fracking, companies have to apply again to the DOE, where the application is reviewed by “a committee of relevant government departments and an independent drilling engineer”; the company also has to “hold a public open house in the community and reach a lease agreement with the land owner.”[131] After this, the company has to apply to NSE for an Industrial Approval. This application has to include a fairly comprehensive range of information, including “proximity to watercourses and wells,” “location and quantity of water to be withdrawn,” “details on drilling fluids,” and “details on the handling, treatment, and disposal of wastes.”[132] The NSE can approve the project and may require public consultations and/or limits on effects on air quality.

The province, however, is currently proceeding with a review of environmental issues related to fracking; the review committee will make recommendations on regulation covering the industry.

[131] Nova Scotia – “Review of Hydraulic Fracturing in Nova Scotia” – June 2011
[132] ibid.