GEOLOGICAL SURVEY OF CANADA
OPEN FILE 7096

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# SUMMARY

The combination of new technologies, such as advances in horizontal drilling and the development of efficient hydraulic fracturing techniques along the horizontal laterals, as well as the relatively rapid increase in the price of natural gas and associated liquid hydrocarbons (from shale oil), have made shale gas exploration and production increasingly appealing over the last decade.

Recognizing the importance of this major resource for the Canadian economy, the Geological Survey of Canada (GSC) organized a workshop in November 2012, in Calgary. Two major geoscientific issues, identified at a previous meeting in May 2012, were addressed: 1) the need for a scientifically sound methodology to evaluate the "in-place" and "producible" gas resource in the shales and 2) the need for improving geoscientific knowledge about groundwater management and protection given the injection of large quantities of water and chemicals required for hydraulic fracturing operations. Fifty-six participants from various provincial/territorial and federal governments, as well as universities attended this 2-day workshop. Twenty-six of them participated in the groundwater resources theme.

Two keynote speakers, one for the shale gas resources theme (Mr. Mike Johnson, from the National Energy Board), and one for the groundwater resources theme (Mr. Daniel J. Soeder, from the U.S. Department of Energy), gave enlightening presentations at the beginning of each day. On the groundwater side, informative presentations were given by five provincial representatives on the first day, followed by round-table discussions held over the 2-day period in order to efficiently tackle several key topics. Participants were invited to alternately take part in five different discussion groups that had for sub-themes: water quantity, wastewater management, migration mechanisms, data gaps and monitoring methodology.

This Open File presents a review of the presentations and discussions that took place on the groundwater resources side. Its counterpart for the shale gas resources theme is Open File 7088. The main conclusions of the groundwater resources theme group can be summarized as follows:

- Research must be developed to reduce water consumption for slickwater hydraulic fracking.
- The use of saline or brackish water, which is not in conflict with other water demands, should be fostered, along with the use of "green" additives.
- Baseline studies should be carried out to ensure that groundwater is characterized prior to exploration.
- Monitoring plans must be developed based on the site characteristics for water, gas and well casings before, during and after fracking and production.
- Research studies must be carried out since little is known on potential migration pathways of fluids and gas from the casing or shale formation towards surficial aquifers.
- Findings from this research should support the development of regulations and policies that must be well adapted to activities related to this new unconventional energy resource.
- Data from all sources need to be made available and integrated into a common database.
- The public, who is concerned by hydraulic fracturing and aquifer contamination, needs to be better informed with scientific facts. Research will help fill many of the existing data gaps.

- Collaboration is essential (between federal and provincial/territorial departments, among federal departments and agencies, among provinces and territories, as well as with other countries such as the U.S.) for the protection of groundwater resources.
- The industry should also be part of research studies, to share their data and contribute financially.

# DISCLAIMER

This document is an informal discussion paper based on the personal views, ideas and concepts of participants attending the shale gas workshop, and in some cases, the views of their organization. The observations and recommendations contained herein do not necessarily reflect the opinion of Natural Resources Canada or the Government of Canada, or those of the other departments and organizations identified in the document. Notes from the round-table discussions have not been reviewed by the agencies represented at the workshop, however, the workshop participants were aware the notes would be published. This document is a working draft for discussion purposes.

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# INTRODUCTION

## Background

Improved production techniques are unlocking huge volumes of natural gas from shale deposits in North America. In Canada, production is increasing rapidly, mainly in British Columbia, however almost all provincial jurisdictions have shale targets currently being explored and evaluated. Technical success has been highly variable and concerns over associated environmental issues have been raised.

A Natural Resources Canada (NRCan) workshop was held in Ottawa in May 2011 regarding current work on shale gas and the identification of critical knowledge gaps. Two major geoscience issues were identified at the workshop: 1) the need for a scientifically sound methodology to evaluate the in-place and producible gas resource in the shales and 2) the need for geoscience knowledge to improve groundwater management and protection.

Recognizing the importance of this major resource for the Canadian economy, the Earth Science Sector of NRCan has initiated a review of its potential role in this area of research, including mechanisms for collaboration between the Geological Survey of Canada (GSC) and the provinces/territories on addressing these concerns. For this purpose, the GSC, which is leading the NRCan activities on resources and groundwater assessment, organized a geoscience workshop to discuss these two major issues on November 24-25, 2011. This Open File presents a review of discussions related to the groundwater resources theme, while Open File 7088 focuses on the shale gas resources theme.

## Context

Natural gas is used extensively in residential, commercial, industrial and power generation applications. Natural gas is a combination of hydrocarbon gases consisting primarily of methane ($CH_4$), and, to a lesser extent, ethane, butane, propane and other gases. Conventional hydrocarbon systems include five key elements: a source rock rich in organic material, thermal maturation, a reservoir rock, a migration pathway and a caprock that acts as a seal. In general, economic gas reserves occur where organic rich shale is deeply buried (between 1 and 3 km). Shale gas, in contrast, is an unconventional system in which the source rock and the reservoir rock are found in a single geologic unit. Artificial stimulation techniques that increase gas flow to commercially viable rates are required to produce gas from very low permeability rock. This stimulation technique is called hydraulic fracturing, fracking or a frac.

Natural gas from hydrocarbon-rich shale formations, known as “shale gas”, is an abundant Canadian resource that will probably play an important role to meet future energy demands. Natural gas has the lowest $CO_2$ emissions per unit energy of any fossil fuel, and is thus, neglecting any potential leaks of methane during production or transport, a relatively ‘clean’ hydrocarbon energy supply that could provide a critical “bridge” energy resource to help the transition to a lower $CO_2$ economy. Greenhouse gas (GHG) emissions from the combustion of natural gas are less than those from oil and much less than those from coal (http://www.nrcan.gc.ca/energy/sources/natural-gas/1349). However, the extraction process for shale gas requires higher emissions than those from conventional natural gas wells (due to the fracking operations). Furthermore, recent publications in the U.S. have questioned whether shale gas is as clean as once thought, since one has to take into account shale gas wells that may be leaking or venting more methane than expected (see Section 2.3).

In 2009, fossil fuels accounted for the greatest share of Canadian energy production, with crude oil representing 36.8%; natural gas, 37.7% (about 95% was from conventional sources, and the last 5% is from unconventional sources such as coal bed methane and shale gas); and coal, 8.2% (NRCan website: http://www.nrcan.gc.ca/energy/sources/natural-gas/1349). The remainder comes from renewable energy sources, including hydroelectricity (7.9%); wood (3.4%); emerging forms (e.g. wind, tidal and solar for 0.1%), and nuclear energy (5.9%). The proportion of shale gas versus conventional gas is expected to increase over the coming years. Three main factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling; 2) advances in hydraulic fracturing, and 3) increasing natural gas prices over the last decade as a result of significant supply and demand pressures (Nash, 2010), although prices have been generally falling over the past 1-2 years.

The release of hydrocarbons from shale requires high-pressure injection of large volumes of fluid (slurry), typically composed of water with added sand (or other proppants) and chemicals to fracture the rock. These induced fractures allow flow of released gas into the wellbore. Environmental concerns with hydraulic fracturing include excessive water consumption, potential contamination of drinking water wells (by methane and injection fluids), surface water contamination from both drilling activities and fracturing fluid storage and disposal, as well as risks to air quality from the migration of gases and chemicals to the surface, surface water contamination from the potential mishandling of waste, and the health effects associated with these. The fact that some shales may also be located under populated areas (e.g. Utica Shale, QC) and below key Canadian aquifers has contributed to increase these concerns. In addition, shale gas resources may be located in regions where no conventional oil and gas activities have yet taken place. This explains why some communities are reluctant and highly concerned by potential environmental risks. Furthermore, problems and perceptions experienced in the U.S. have exacerbated fears and, therefore, the NIMBY “not in my backyard” syndrome has taken hold. However, it is not yet known whether shale gas development could impact shallow aquifers.

As a result of these concerns, shale gas activities have been banned in France and Bulgaria, and a moratorium has been put in place in the province of Quebec and the State of New York, pending an environmental review. As development of natural gas wells has increased in the U.S. since the year 2000, there have been increasing concerns about contamination by private well owners, and the U.S. Environmental Protection Agency (EPA), among others, has been mandated by the U.S. Congress to initiate exhaustive studies on the topic (http://www.epa.gov/hfstudy/).

Hydraulic fracturing has been used to stimulate production in conventional oil and gas reservoirs (mostly in vertical wells) in North America for more than 60 years. However, recent fracturing in horizontal wells uses greater amounts of water and chemicals, as well as higher pressure, and a much larger volume of rock is involved than in conventional techniques. Moreover, as new technologies develop, these two issues intensify since lateral wells are becoming longer and can be hydraulically fractured more often before being abandoned, and more wells can be drilled on the same pad.

Although shale gas development is a relatively mature industry in the United States (with more than 40,000 producing wells), shale gas is still in its nascent stages in Canada (http://www.nrcan.gc.ca/energy/sources/natural-gas/1349). Most of the current drilling and production activities are in northeast British Columbia. Northern BC has active sites (Horn River and Montney), while Alberta, Saskatchewan and New Brunswick are near the production level. The Alberta government is examining water allocation to support this gas development. Exploration and production figures in terms of wells for each province are provided in Table 1. The provinces and territories not included in the table have none.

Table 1: Number of drilled, exploration (with hydraulic fracturing) and production wells dedicated to shale gas

| No wells | BC* | AB | SK | ON | QC | NB | NS |
|---|---|---|---|---|---|---|---|
| Drilled | 1873 | 190 | 85** | 1*** | 29 | 4 | 5 |
| Fracturing | ~1873 | 178 | ~ 42 | - | 18 | 3**** | 3 |
| Production | 1354 | 114 | 35 | - | - | 1**** | - |

* Numbers for BC correspond to minimums, since only wells from the Horn River Basin and Montney Trend have been considered for this estimate.
** Around 35 of these wells were drilled for commingled production, i.e. with both the shales and the sands of the Colorado Group as the targets.
*** The government also drilled 3 other wells for research purposes.
**** In addition to shale gas wells, 46 tight-sand gas wells have been fracked and are currently producing.

Based on these issues and concerns, the GSC organized a geoscientific workshop to initiate provincial-federal discussions on this topic and address concerns raised about several aspects, including casings, contaminant migration mechanisms, as well as water management. The GSC intended this workshop to be a discussion forum on existing knowledge, to identify key methodologies and data gaps, as well as to identify priority research needs to provide guidance for upcoming research programs within the federal government.

## Objectives

The main objective of this workshop was to discuss and exchange ideas on two broad themes: 1) the need for a scientifically sound methodology to evaluate the in-place and producible gas resource in the shale and 2) the need for geoscience knowledge to improve groundwater management and protection. An Open File for each broad theme was planned to serve as a reference for establishing strategic directions for geoscientific research in support of sustainable development of this emerging energy resource. Results from this research are expected to eventually contribute to the development of regulations and policies.

## Attendance

This workshop gathered representatives (hydrogeologists, scientists and managers) from provincial departments of Environment and the federal governments, as well as university professors. In total, 56 persons from 9 provinces and two territories participated in this workshop, 27 of whom participated in the groundwater resources theme. These participants are listed in Table 2. They provided interesting and fruitful discussions. They also raised questions for which answers do not always exist. Most attendees participated in more than one round-table discussion over this two-day workshop and thus, had a chance to share his/her opinions on different subjects.

Table 2: Participants in the groundwater resources theme

| Province | Name | Organisation |
|---|---|---|
| **Alberta** | Anita Gue | Environment Canada |
| | Cathy Ryan | University of Calgary |
| | Karlis Muehlenbachs | University of Alberta |
| | Rod Smith | GSC – Calgary |
| | Steve Grasby | GSC – Calgary |
| | Tony Lemay | Alberta Geological Survey |
| **British Columbia** | Elizabeth Johnson | BC Resource Develop. & Geoscience Branch, Ministry of Energy and Mines |
| **Manitoba** | Bob Betcher | Manitoba Water Stewardship |
| **New Brunswick** | Annie Daigle | Natural Gas Group, NB Executive Council Office |
| **Newfoundland and Labrador** | Dorothea Hanchar | Water Resources Management Division, NL Environment and Conservation |
| **Nova Scotia** | John Drage | Water & Wastewater Branch, Nova Scotia Environment |
| **Northwest Territories** | Francis Jackson | Aboriginal Affairs and Northern Development Canada |
| | Todd Paget | Department of Environment and Natural Resources, Gov. of the NWT |
| **Ontario** | Baolin Wang | GSC – Ottawa |
| | Dale Van Stempvoort | Environment Canada |
| | Francois Bregha | Council of Canadian Academies |
| | Laura Cervoni | GSC – Ottawa |
| | Mélissa Desforges | NRCan / CANMET |
| | Stewart Hamilton (presentation via Skype) | Ontario Geological Survey |
| **Prince Edward Island** | Qing Li | Environment, Energy and Forestry, Prince Edward Island |
| **Québec** | Alfonso Rivera | GSC – Quebec |
| | Bernard Vigneault | GSC – Ottawa |
| | Christine Rivard | GSC |
| | John Molson | Université Laval |
| **Saskatchewan** | Cas Rogal | Saskatchewan Watershed Authority |
| | Jim Hendry | University of Saskatchewan |
| **USA** | Daniel J. Soeder | National Energy Technology Laboratory, U.S. Department of Energy |

This Open File is divided into two main parts: 1) notes taken during the oral presentations of five provincial representatives; 2) summaries of the round-table discussions on five themes related to groundwater resources, namely water quantity, wastewater management, migration mechanisms, data gaps and monitoring methodology.

# 1. GROUNDWATER RESOURCES PRESENTATIONS

Five short presentations were given by representatives from different provinces on the first day (November 24) to set the stage for thematic discussions. The notes taken during these presentations are presented below.

A keynote presentation was given by Mr. Daniel Soeder from the U.S. Department of Energy (National Energy Technology Laboratory) on the second day. The presentation was about environmental issues related to shale gas exploration and production that the U.S. has had to deal with over the last decade and outlined improvements they have made in management practices.

Files in PDF format of all the Power Point presentations (6) are provided in the appendices.

### Ontario

*Stewart Hamilton, Ph.D., Senior Geologist, Ontario Geological Survey*

Dr. Stewart Hamilton discussed geochemistry in Ontario. The Ontario Geological Survey (OGS) has conducted an ambient groundwater chemistry project, and its results are of particular interest to the shale gas sector of the oil and gas industry. Dr. Hamilton's presentation addressed why groundwater is studied, the relationship between lithology and chemistry, biogenic methane in water wells, and the Niagara Peninsula's geochemical anomaly.

The Ambient Groundwater Geochemistry Program (AGGP) of the OGS characterizes the natural state of water quality and chemistry throughout Ontario. The AGGP delineates the natural state of groundwater in the province and the controls on its chemistry.

Groundwater is sampled at a consistent sample density and is accessed by a variety of means including springs and monitoring wells, but the majority of samples come from domestic and farm wells. "We simply knock on people's doors and ask if we can sample their wells, and they normally say yes," he said.

The AGGP began five years ago and has mapped approximately 40,000 km$^2$. Dr. Hamilton noted the groundwater geochemistry technical objectives:

- Characterize baseline groundwater geochemistry of the major rock and overburden units province-wide, subject to accessibility.
- Relate the water chemistry to the aquifer chemistry.
- Gain an understanding of where groundwater flows from and to, and what the transport conditions are like within Ontario.

Dr. Hamilton said, "Although there are 3 million people in Ontario that rely on groundwater, we don't even know where even a small proportion of that groundwater originates."

The AGGP analyzes groundwater samples for field parameters such as pH, redox state, temperature, conductivity, field alkalinity, major ions, dissolved gases (including methane) measured in the field, trace metals in the lab, and trace anions. "We probably have one of the best iodide datasets in the world. It is important to differentiate brine sources because we can tell where brines come from with a really good iodide dataset. We can tell whether they're coming from anthropogenic sources or otherwise."

Four types of water quality problems with water wells were plotted from the MOE water well database: sulphurous water, salty water, water containing gas, and mineralized water. The data source for these problems was not sophisticated, but derived mostly from generations of drillers tasting the water and checking boxes on forms. New data sources will provide better quality data, said Dr. Hamilton.

He highlighted selected results that demonstrated a lithological association with water chemistry. Methane in bedrock well water was particularly associated with Devonian Shales. He discussed the associations demonstrated by the presence of various minerals.

Natural gas that we observed in well water is a natural occurrence, and not an anthropogenic signal, said Dr. Hamilton. “This is people’s well water; people actually drink this water, and it’s natural.” He said that while methane is not toxic to humans, the problem is that it can make houses blow up.

The data showed a high amount of methane at the interface between bedrock and overburden. Dr. Hamilton cited the pickled shale hypothesis used in the Antrim extension; biogenic gas or microbial gas-play locations are related to the original position of glaciers. In this area, where glaciers sat on top of the strata, they provided an enormous hydrostatic head, which pushed all the original salt water out of the formation and replaced it with fresh water. This allowed organisms that use dissolved inorganic carbon, such as bicarbonate or dissolved $CO_2$, as an electron acceptor, started eating primary organic matter, producing methane as a waste product.

There is an inverse correlation between the presence of hydrogen sulphide and the presence of natural gas. Where sulphate is present, organisms use sulphate to produce hydrogen sulphide rather than using inorganic carbon and producing natural gas. Dr. Hamilton said it was unusual to see hydrogen sulphide and significant methane concentrations in the same water.

Heavy rare earth elements (HREEs) in bedrock well water on the Niagara Peninsula suggest water is flushing up these elements presumably through thousands of abandoned gas wells in the area, and reaching the subsurface. In one surface water body, an ecosystem exists based on hydrogen sulphide that is inferred to be related to a nearby abandoned gas well.

This study provides a benchmark for future changes in water composition, demonstrates strong correlations between water chemistry and rock type, and shows high potential for the presence of natural gas (methane) in domestic well water. Study results showed extensive areas of karst conditions that control local groundwater flow characteristics. One karst area is on the Niagara Peninsula anomaly, and may be enhancing regional flow of anthropogenically impacted groundwater.

In answer to a question about exploration for shale gas using horizontal drilling in southern Ontario, Dr. Hamilton said he was not aware of active exploration for shale gas in the province. The Devonian deposits are so shallow, they may be difficult to exploit, he said. However, the Utica Shale that extends under Lake Erie could possibly be a target.

## Nova Scotia

*John Drage, Hydrogeologist, Nova Scotia Environment*

John Drage said this workshop is timely for Nova Scotia since, along with other jurisdictions, it is currently reviewing potential environmental impacts of shale gas and hydraulic fracturing. As the province has only had a few shale gas exploration wells, Drage said he would speak more broadly about onshore gas in Nova Scotia, current activity and challenges, groundwater regulations, and the current hydraulic fracturing review.

In 2007/2008, hydraulic fracturing was done on three shale gas exploration wells in Nova Scotia. Drage said that one of the biggest challenges is managing the produced water recovered from these exploration wells.

Drage said all Nova Scotia onshore hydrocarbon exploration targets the Carboniferous sedimentary basin, which includes shales, sandstones, coal beds, and carbonates in three key formations. Onshore locations cover about one-third of the province. The Horton Group is the primary target for shale gas in Nova Scotia.

While there are currently no applications for hydraulic fracturing in Nova Scotia, there are a number of petroleum agreements in place for blocks of leased land where companies can potentially explore — eight conventional agreements and three for coal bed methane.

Nova Scotia requires three main approvals before drilling:

- An exploration agreement from the Nova Scotia Department of Energy
- An authority to drill approval from the Nova Scotia Department of Energy
- Industrial approval (i.e., environmental approval) from Nova Scotia Environment

Some of the key terms and conditions that have been used in approvals to protect groundwater include, but are not limited to: baseline and post-operational water well surveys to characterize water quality within 1,000 metres of drill sites; casing and cement integrity checks; lining and berming of drill pads; and secondary containment for liquid wastes.

The province is currently carrying out a technical review of potential environmental issues associated with hydraulic fracturing. The review will focus on the protection of water. The scope includes, but is not limited to: the management of additives to hydraulic fracturing fluids, particularly the issue of disclosure of frac fluid additives; wastewater management; site restoration; frac design; and financial security and insurance requirements.

**New Brunswick**

*Annie Daigle, Hydrogeologist, New Brunswick Department of Environment*

Annie Daigle addressed the status of natural gas and oil drilling in New Brunswick. She outlined New Brunswick's oil and gas exploration history, noting that the province was among the first jurisdictions in North America to develop oil and gas. Since the 1990s, there has been more exploration in tight sands, and quasi-unconventional gas development. New Brunswick features two active fields, the McCully Gas Field and the field at Stoney Creek.

Daigle said New Brunswick's case is unique in that major infrastructure is already in place as the nearby Maritimes & Northeast pipeline crosses the province from Sable Island offshore to market.

While an estimated 80 TCF of gas in place (GIP) exists in New Brunswick's known and proven basins, Daigle said other basins exist in the province, but the government does not know the GIP estimate for those structures. The geology of the area leads the government to believe that shale is there, and likely shale gas. Approximately 1.4 million hectares of land is currently leased or licensed for oil and gas exploration. Recent geochemical surveys show promising results for the presence of unconventional tight sand, as well as oil in that area.

New Brunswick's regulatory position is based on known resource estimates. "If all we ever develop are our current known resources, the regulations we have in place today are adequate. If we find oil or gas elsewhere, that becomes a game changer for the province" said Daigle.

New Brunswick's oil and gas geologic setting is in the Frederick Brook formation, very deep at 2.5 kilometres, as well as a thick shale formation measured between 500 metres to over 1 kilometre. Considering GIP, the superficial footprint is small, but it is a great potential resource in terms of thickness.

Daigle showed a schematic of one of three horizontal shale gas wells drilled to date. Of the two wells that have been hydraulically fractured, one was unsuccessful; however, Corridor Resources is still actively pursuing the resource. Liquid propane was used instead of slickwater to hydraulically fracture the wells, which has been proven very successful, although costlier than a frac done with water. They have the only producing shale gas well in New Brunswick fractured with gas.

New Brunswick's government has committed to exploring this resource in a responsible manner. The government does not consider a frac moratorium necessary, since the earliest timeline for production in the province, if these wells prove economically viable, would be five to six years. The results of stimulating these wells must be examined to gain a better understanding.

The government's response to public concerns over natural gas development was to develop the Natural Gas Group, a multi-departmental body. The Natural Gas Group developed an environmental protection plan (EPP) and is working on plans for communications, economic benefits, resource development, a community development approach, and a regulatory framework. The group adopted a holistic approach to community and resource development to get the maximum benefit from the resource while protecting the environment.

Oil and Gas Resource regulation in New Brunswick is not new—the *Oil and Natural Gas Act* was enacted in the province in 1976—but the current regulations were not intended to address the level of development New Brunswick could see if a full-scale shale gas industry develops. If a technically and economically viable shale gas resource is discovered, the scope of the regulations will have to be broadened.

Environmental Impact Assessment (EIA) regulations fall under the *Clean Environment Act*. Changes made to the regulations in January 2011 now mandate a phased EIA for oil and gas exploration. A company enters the EIA process as soon as it proposes to drill a well. A 60-person technical review committee, comprising representatives from multiple federal and provincial departments, reviews new oil and gas drilling activities under the auspices of the New Brunswick Department of Environment.

Phased EIAs ensure public consultation. Previously, the only EIA trigger was commercial production or constructing a pipeline. Since most environmental damages in terms of land use happens when building the pad, "we want people to have a say in where the industry is going to set up."

The government identified three key tasks that needed to be done before completion of the EPP:

- Water quality baseline testing: All potable water wells within 200 metres of seismic testing, and 500 metres from oil or natural gas well pads, will be tested from the edge of the pad, not from the wellbore itself.
- Full disclosure of chemical additives: Companies must be prepared to disclose hydraulic fracture chemical additives. So as not to exclude companies doing leading-edge research,

the government gets the recipe and the public gets the ingredients. This information will be posted on the prominent shale gas section of the New Brunswick government website.

- Security bond: The burden of proof rests on the oil and gas company for environmental damage. Within a specific distance of an oil and gas well, if something goes wrong with a private well, the company must prove they did not do it. All companies must pay into a cash security bond, and if the company is not willing to remediate the situation, the government will draw on the cash bond to do the work.

Daigle said the government is committed to a profit-sharing formula so landowners and communities can share in the financial benefits of oil and gas production on their land, beyond the fees associated with leasing the land for well pad access.

The EPP is nearly complete and a public consultation is planned once details are finalized. The EPP is designed to ensure responsible development by addressing key issues:

- Sharing information
- Reducing financial exposure to taxpayers
- Protecting landowner rights
- Addressing potential impacts of geophysical activity and seismic activities
- Ensuring contaminants do not escape from the wellbore or from hydraulically fractured geological formations
- Monitoring to protect water quality
- Addressing water quantity
- Managing wastes
- Verifying geological containment outside the wellbore

Daigle discussed water supply management, noting that the wise use of water is a government priority. She talked about treatment and discharge as part of the wastewater management strategy. In New Brunswick, all wastewater is currently collected and stored in enclosed tanks with secondary containment and sent to approved facilities for treatment and discharge in Debert, Nova Scotia.

Should shale gas prove to be commercially viable, other options will be explored, such as dedicated treatment facilities or recycling and reuse technologies. Stronger requirements are currently proposed to take a cradle-to-grave approach to water management for the oil and natural gas industry.

Deep well injection is not an option for New Brunswick. Daigle said, “We don’t feel we have appropriate containment to allow deep well injection. We lack pore space. The cap rock is questionable, and the government is opposed to deep well injection in New Brunswick, so companies will be going the more expensive route. But we are keeping an eye out for new technologies.” Natural gas opportunities are substantial and there is potential for significant economic benefits—royalties, jobs, and opportunities for provincial companies.

Daigle highlighted some challenges with natural gas development:

- Public acceptance
- Potential environmental, economic, and social impacts

- Quality and quantity of water issues
- Air emissions
- Land use changes
- Financial challenges of road usage

A participant asked why deep well injection was “ruled out right off the bat? Is there an underlying public concern?” Daigle said there is public concern. New Brunswick has never had a true conventional natural gas production field; it is unconventional tight sand.

In answer to which jurisdiction was used a model for the EPP, Daigle said New Brunswick’s current regulations are based on the Alberta model, but the province is building on that. “A cross-jurisdictional survey by our entire team will leave no regulatory stone unturned,” she said.

Considering the potentially large environmental impact of water treatment, a participant asked if there is a balance between water treatment and the perceived impact of injection. Daigle said this issue is part of the province’s long-term planning. There will be additional consultation on GHGs, she said, related to the Climate Change Action Plan.

One participant asked if including landowners in the royalty equation would affect land values and result in rampant land speculation. Daigle said New Brunswick has the reverse problem in terms of public perception. “We don’t have a lot of agriculture left in the province; the potato belt is not in the shale gas play areas. The biggest problem we have for agriculture is the land is all being turned into residential development.”

She said oil and gas exploration has allowed some farmers to stay viable. They can stay on their land by leasing a well pad area to natural gas companies. People are more concerned the value of their land will go down, and their houses will loose value.

Daigle was asked about provincial regulations where a company is assumed responsible for well contamination. The participant wondered how to avoid spurious claims of contamination by landowners. Daigle said baseline testing is necessary. Testing includes organics, non-organics, and gas analyses. “We do have biogenic and thermogenic methane in the province.” It is important to type it as thermogenic or biogenic to get a good understanding of water quality.

In answer to the question about who pays for the baseline, Daigle said companies pay. Companies operating in the province are doing it anyway, and they are willing to do the testing since it is new territory. She said companies’ main issue around the reverse onus is the wording, but they do not have a problem with the concept.

### British Columbia

*Elizabeth Johnson, Ph.D., Hydrogeologist, British Columbia Ministry of Energy and Mines*

Dr. Elizabeth Johnson discussed water issues associated with hydraulic fracturing in northeast British Columbia. Over 28,000 wells have been drilled in British Columbia since 1950, and hydraulic fracturing is not new. In the 1970s, horizontal drilling improved directional control. Technological developments are driven by economics. Accelerated development is occurring in the Montney tight gas shales using "foam" (sometimes called "energized") frac techniques (with gas and water, see Section 2 for a description) and slickwater in the Horn River Basin shales.

Dr. Johnson said the fracking approach and subsequent water use varies with geography. An order of magnitude difference exists between foam and slickwater fracs; foam fracs in siltstone or shale formations use around 200 $m^3$ of water, while siliceous shale slickwater fracs require 2,500–5,000 $m^3$. This difference highlights the importance of knowing which type of fracking is being used, particularly when discussing extensive drilling programs.

Dr. Johnson's study looked at multi-stage wells for approximately 500 wells in seven formations and five different basins. The study covered wells with multiple stages of hydraulic fracturing, looked at hydraulic fracturing treatment types, and compared hydraulic fracturing in the Montney versus Horn River Basins.

Evolving fracturing technology allows companies to stagger vertical and horizontal well placement, to use dual and triple laterals, and to increase the number of frac stages per well. Since the water per frac stage has been increasing over time, the impact on water use should be monitored.

Longer horizontal laterals are now being used. Earlier wells were about 1 kilometre long and are now pushing out to 3 kilometres. Closer spacing between fracs can now be accomplished, from widely spaced fracs of about 400 metres in 2007 down to 150 metres in 2010, and now even 50 metres is possible.

Water use varies geographically, from company to company, and usage is higher for slickwater fracturing. The Horn River Basin has the highest average, using approximately 20 times that of the Montney, and about 10 times the amount in Montney North. Even though more wells are drilled in the Montney, the cumulative water usage does not match the cumulative water usage of the Horn River Basin.

Water sourcing is a key issue for hydraulic fracturing in BC. Dr. Johnson said saline water is available in the Debolt Formation underlying the Horn River basins. The Debolt water is saline with $H_2S$ and gas, but is usable for fracking. Encana built a scrubbing plant to remove the $H_2S$ and uses the water for fracking. Not all companies have access to Debolt water, as it is not uniformly available to all well sites.

While it is possible to get water back to reuse, recycling water has a feasibility and timing issue for a number of reasons:

- Water returns at a slower rate;
- Handling and storage constitute problems in the middle of winter;
- It is a remote location (harder to share between sites, less infrastructure);
- It is logistically difficult to contain the volumes required for the next season of fracking.

The return water volume varies from 15 to 70%. In some locations, it is difficult to collect sufficient water for a high-volume fracking program. In the Montney, between 50 and 100% of water is returned, and is a combination of produced and flowback water. The vast majority of water is disposed of downhole.

Saline or flowback water can be conditioned to make it usable by adding chemicals or electrical current, and various other ways. Dr. Johnson recently learned that water at 25,000 ppm could be directly used for fracturing. Friction reducers can be used between 25,000 and 50,000 ppm. The trade-off is that the cost rises considerably after 50,000 ppm. High saline water up to 100,000 ppm can be used only with expensive specialty friction reducers.

Other recycling options that Dr. Johnson mentioned include chemical conditioning, blending, filtering, flocculation/coagulation, reverse osmosis, mechanical vapour recompression, and electrical coagulation.

A participant asked whether companies are starting to talk about water co-operative groups and alternative saline water uses like pulling out geothermal energy. Dr. Johnson said geothermal energy is a challenging discussion in British Columbia. Some areas are being innovative in using community water, including reconditioning municipal wastewater to use for fracking.

In answer to a question regarding the timing of water use and whether the 20,000 $m^3$ water is needed initially or is spread out over time, Dr. Johnson said, “With fracking, you can think of your water as a capital cost, so you put all the water in the well initially when you create the fractures, then you start to produce. After you frac a well, it may run for 20 years, five years, or 40 years. Production drops off on a decline curve, so when production is no longer economic, you may choose to refrac.”

In response to another question, she said water well complaints go through British Columbia’s Oil and Gas Commission, not to the Ministry of Energy and Mines, where she works. “My understanding is that with respect to shale gas, there haven’t been any complaints,” she said.

Dr. Johnson said there is a much greater population and more intensive agricultural usage in the Montney, but no population centres in the Horn River Basin.

In response to a question about whether anyone was monitoring the recharge capacity of the Debolt water source, Dr. Johnson said, “No, there’s an environmental waiver from the environmental assessment office on the Debolt for that particular project.” There are requirements that the groundwater above and around must be monitored. Since Debolt water is saline and not considered useful for the general population, industry needs to conserve and manage that saline water as its resource. The province has not moved in a regulatory fashion.

A participant asked whether Dr. Johnson had noticed any difference in well integrity between the two kinds of fracking - for example, more surface vent flows in slick water versus foam. Dr. Johnson said they had not looked at this area, but she said it was an interesting idea.

In answer to a question about approvals for water use when companies drill their own wells, Dr. Johnson said the Oil and Gas Commission has dispensation to issue temporary permits for water to use for any oil and gas activity. It is a one-stop shop for temporary permits for surface water, groundwater, and source water.

## Quebec

*John Molson, Ph.D., Assistant Professor, Department of Geology and Geological Engineering, Université Laval*

Dr. John Molson presented a review of the Quebec situation with respect to the shale gas industry. He described the environmental challenges faced by the shale gas industry in a sensitive agricultural area, with concerned farmers, and competing demands for limited water.

Shale gas is a completely new industry in Quebec: only twenty-nine wells have been drilled and less than half of those have been fractured. In the fall of 2010, the provincial government began a series of public consultations (through the Bureau d’audiences publiques sur l’environnement [BAPE] commission), and invited the public to forums held over several months. Public forums like this one are unique to Quebec, and are invoked for a range of environmental issues including hydroelectric dams and power plants.

One of the recommendations arising from the BAPE forums was to form a strategic environmental committee. Dr. Molson is a committee member, along with 10 representatives from universities, government ministries, industry, municipalities, and the environment sector. The committee comprises a range of expertise. “We have three years to finish our work, to identify risks and if possible to propose a plan to go forward safely, and in a sustainable manner,” he said.

Quebec sees itself as a relatively "green" province with an abundance of hydroelectric power. It is a sensitive issue to move to developing petroleum resources. Managing this issue is new for Quebec. The committee is also looking beyond groundwater issues to public security, public health, and social issues, even economics and energy policy. “We currently import about 10% of our energy resources in the form of natural gas, all from Alberta. It’s not an insignificant amount, so there’s a payback if we cut that off and have our own source. For example, we could cut the amount of $CO_2$ emissions from transport,” said Dr. Molson.

Groundwater issues are very important. The target area falls between the Logan Line and the Yamaska Fault on the south shore of the St Lawrence River. There is concern about migration paths along the faults and fractures. The area has already been claimed by various companies. Currently, there is a moratorium on drilling in the St. Lawrence River and marine permits located between Quebec City and Anticosti Island have been revoked.

The committee is also looking at the well itself, the casing, and construction methods. There is a real concern over contamination of shallow aquifers, especially from leaks along the wellbore or from the wellhead. “We need more data and modelling, for example, to determine if the Lorraine Formation is a sufficient cap rock, and what groundwater travel times might be. We are looking at issues of flow systems. Really, we have only limited data on what’s happening hydrogeologically deep underground.”

Another Quebec government program is funding watershed scale studies on aquifer characterization, which will cover the next series of projects that are targeting shale gas from Montreal to Quebec City.

“We want to look at what flow systems might look like, between shallow aquifers and deeper bedrock, and how much water might be contacting these units. We will look at density issues and temperature and what’s going on in the natural, undisturbed case, and then post-fracturing,” said Dr. Molson.

He said the province is concerned about the impact on agriculture and is trying to balance the potential for a cleaner source of energy. He said Quebec wants to learn from other jurisdictions’ experiences.

A participant asked if Quebec had instigated a baseline study for gas concentrations in water. Dr. Molson said a baseline geochemistry and gas concentration survey is being implemented. He said separating the different types of gases will be studied in the future and developing a baseline will be a key component.

With target depths of between one and two kilometres, a participant said Quebec is assuming the same type of geology, with two vertical models of flow. “If it is really that shallow, if you add those natural fractures there, it could be catastrophic,” said a participant. Dr. Molson said, “We are proposing studies to see what influence those fractures would have on flowpaths for gas or contaminants. We know where the faults are. These plans are very conceptual.” He said the government wants to work on understanding the local scale flowpaths as well through a series of watershed-scale hydrogeological studies (known as PACES projects).

A participant asked if the committee’s work will end up as a series of regulatory proposals or changes to the law. He asked how a company would make a proposal. Dr. Molson said regulation is part of the committee's mandate, to establish a regulatory framework. Companies can make applications to the Ministry of the Environment for exploratory drilling. "There's no moratorium on drilling. They can be allowed to drill if they can make a case for providing important new data." Companies cannot do advanced exploitation or production.

## 2. GROUNDWATER RESOURCES DISCUSSIONS

The goal of these round tables was to discuss the different issues related to the exploration and production of shale gas resources. The groundwater resource theme was divided into five sub-themes, so that many key aspects of potential impacts of shale gas activity could be tackled in the two days available. Discussions were targeted at examining what should be done to make sure that fresh groundwater aquifers are safe, before large-production shale gas activities start. Indeed, only BC has production wells for the moment, and they are located in remote, northern areas. Interesting examples are provided throughout the text to better understand the Canadian situation. Since slickwater is the most common technique used in the industry throughout the world due to its low cost and effectiveness, and that this workshop focused on groundwater, most information and comments are related to this technique, although fracking may also be performed using other fluids, as described below.

Depending on the shale characteristics, three types of fluids may indeed be used for fracturing: 1) water ("slickwater" and gels), 2) gas (e.g. carbon dioxide, nitrogen and more recently propane and butane), and 3) foams. The advantages of gas fracturing include easier cleanup and less formation damage. Disadvantages include a much higher cost, less effectiveness at initiating the fracture, difficulty entraining and transporting the proppant, and a greater difficulty in controlling the growth of the fracture (Soeder, 2012). Foam fracs are a variation of a gas frac, where pressurized gas, usually nitrogen, is mixed with a liquid surfactant to create a high pressure foam-like material capable of cracking the rock and carrying proppant into a fracture. The foam is designed to break down when the pressure is released, leaving a residual amount of the surfactant material behind and allowing the nitrogen to escape from the well. Foam fracs are expensive and used only in special circumstances: they work best in softer, more ductile rocks such as siltstone or shale with clay or carbonate rocks and under-pressured horizons. However, at great depths, foams loose their ability to transport proppant because the fluids are less able to generate bubbles; therefore, slickwater treatments may be more appropriate even in these environments (Johnson and Johnson, 2012). If an environment is equally conducive to both slickwater and foam fracs, slickwater fracturing will generate a higher stimulated reservoir volume and better production at a lower cost (Romanson et al., 2010).

Other types of fracturing techniques also exist, but they are not commonly utilized. Oil frac is not efficient in shale formations and cryogenic fracs, a compromise between hydraulic and gas fracs, remains to be better adapted to in situ conditions. The idea of cryogenic fracs is to use the gas in liquid form as a hydraulic fluid to crack the rock and carry the proppant into the fractures. However, cryogenic liquid gases are tremendously expensive, and introducing intensely cold fluids downhole causes all sorts of problems (Soeder, 2012). Energy fracturing uses chemical explosives to pressurize the rock. It is the oldest type of well stimulation technology. Energy fracs were originally done by merely dropping a lit stick of dynamite down a well. High explosives transmit too much energy too quickly, and were thus not very effective, often causing more formation damage than stimulation (Soeder, 2012). There are, however, promising new energy frac techniques in development (e.g. tailored pulse loading), which use a slower release explosive.

For this Open File, the authors have tried to place comments and information heard at the workshop in the appropriate sub-theme section. However, all subjects are clearly interconnected and overlapping. Some background information is presented at the beginning of each sub-section that will allow non-expert readers to better follow the discussions. Informed readers may choose to skip this part. In this document, fracturing, fracking and frac are used synonymously.

## 2.1 Water quantity

### Background

Technological advancements have allowed rigs to be able to progressively deviate from the initial vertical section and continue horizontally through the target rock unit (see Figure 1). The horizontal part of the well, called a “lateral”, is typically from 1 to 3 km long. After drilling is completed, fracturing is performed: a fluid (slurry) is injected under high pressure using powerful pumps to fracture (crack) the shale, to increase its permeability and ease the flow of natural gas. Among all the frac techniques described above, slickwater hydraulic fracturing is the one that uses more water. It is, however, the least expensive and has proven to be very effective, especially in brittle rocks with higher silica content and lower clay content (Johnson and Johnson, 2012). Slickwater fracturing is the most common technique used.

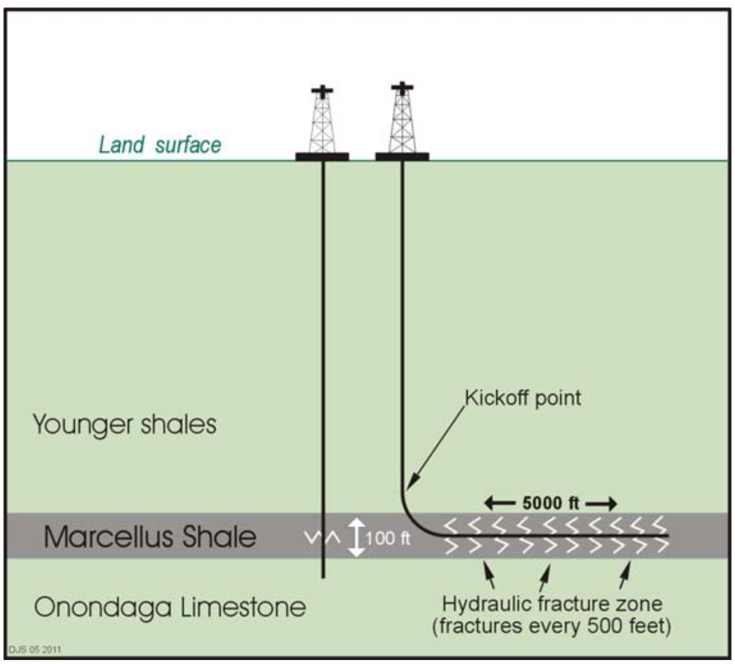


Figure 1: Illustration of the combination of horizontal drilling and hydraulic fracturing technology used for gas production from the Marcellus Shale in the Appalachian Basin. Horizontal wells have a much greater contact area with the shale than vertical wells, which are limited by the formation thickness (modified from Soeder and Kappel, 2009). Not to scale.

The fluid for slickwater fracturing is a mixture of water (>97-98%), proppants (usually sands) and chemical additives (see Section 2.2) that is injected at high pressure. Water can either be taken from surface water (streams, lakes), municipal water plants or groundwater (which can sometimes be brackish or even saline). After the hydraulic fracturing, the horizontal and vertical sections of the well bore act as a conduit for the gas. The wells need to have vents at the top of the well for gas migration. These operations represent a well-coordinated effort that may include 100 to 150 trucks if water must be transported and a dozen people at all time on the site for 4-8 weeks. More common now, however, is to use a central impoundment, and transport the water to individual sites via a temporary, overland pipeline: this requires far fewer trucks. Because of scheduling difficulties, drilling companies will have a frac service company come out and frac up to a dozen wells one after another. Figures 2 and 3 illustrate this type of operation in the Marcellus Shale Formation, Pennsylvania (U.S.).

Figure 2: Drillpad for a Marcellus Shale well near the town of Waynesburg, Pennsylvania (U.S). This is a minimal pad for a horizontal Marcellus gas well; another, older pad nearby was available to stage much of the equipment, allowing this one to be somewhat smaller than the standard 5-acre (20,000 $m^2$) size. Trucks and trailers give a sense of scale. Photographed in 2010 by Daniel J. Soeder.

These shale formations are usually a few tens to hundreds of meters thick. Long laterals allow the wellbore to be in contact with the producing shale interval over significantly longer distances compared to a vertical hole. The challenge is indeed to be as specific as possible to target the most prolific zones. Because laterals are very long, it is not possible to maintain a downhole pressure to frac the entire length in a single stimulation event (Ground Water Protection Council, 2009). Hydraulic fracturing is therefore performed in stages, 150 to 300 meters in length starting at the farthest end of the horizontal borehole, called the toe, and moving back towards the vertical portion of the well, called the heel, until the horizontal section of the well has been completely fractured. For each stage of a fracture treatment, a series (8-15) of different volumes of fracture fluids, called sub-stages, with specific additives and proppant concentrations and particle size, are injected sequentially (Ground Water Protection Council, 2009).


Figure 3: A hydraulic fracturing operation in progress on two parallel Marcellus Shale wells in Pennsylvania. Water supply is in an impoundment behind the photographer. Sand is in the tank with the two men standing on top. Pump trucks are to the right of the two massive wellheads. Photographed in 2011 by Daniel J. Soeder.

There are two types of techniques for well completion and fracking. The first one involves cementing the production casing in the horizontal wellbore and then using perforating guns to puncture the casing and thus, create access to the formation for hydraulic fracturing (Kimmitt, 2011). This is called “plug and perf”. The perforating gun works like a real gun, shooting explosive charges into the tubing wall and punching holes through it. Modern perf guns use shaped explosive charges rather than lead slugs to punch holes in the casing. The charges consist of military or industrial-grade high explosives. The imparted pressure is in the range of 10 to 15 million psi. This creates holes in the casing between 0.6 and 0.2 cm (¼ and ¾ inch) in diameter, with a depth into the rock from 15 cm (six inches) to as much as a few meters (Soeder, 2012). The other method uses an open case, and packers are mechanically set in order to isolate sections of the laterals. The isolated intervals are fracked one after the other, from toe to heel. This method is called “open hole multi-stage system (OHMS) completion”; it has recently been developed to save time and money and has proven to be very efficient. Morover, OHMS reduces the time that fracture fluid is in contact with the rock, thereby reducing the risk of formation damage (Johnson and Johnson, 2012).

During a frac, the pressure on the fluid is increased until the formation strength is exceeded and the rock cracks. This is called breakdown. Because water is virtually incompressible, as soon as the fractures are created and water begins flowing into them, more water must be added at the surface to maintain the pressure. The initial part of the fracturing is performed with slickwater only. Afterwards, as the fractures open up, proppants (usually sand with increasing particle sizes) and gels (to carry the latter) are added to the water, since the high-pressure environment of the rock formation would naturally cause fractures to close after the treatment is completed and pressure is released (Johnson and Johnson, 2012). Proppants therefore bare their name because they “prop open” the walls of the fractures. The proppant is pumped away into the formation and pressures are maintained until the hydraulic fractures extend outward up to about 300 m from the well (Soeder, 2012). When the first stage of hydraulic fracturing is finished, the pressure is released and this interval is sealed (plugged), to allow the next interval to be fracked. The process is repeated until the heel (upper end of the lateral) is reached. Depending on the size of the perforated zones and the length of the lateral, as many as 5 to 10 (or even more) staged hydrofracs can be performed on a single lateral (Soeder, 2012). The entire perforating and hydraulic fracturing process can take about a week for an average-length lateral.

The volume of water used in shale gas fracturing is two to four times higher than in conventional production (Soeder, 2012). One of the largest massive hydraulic fracture experiments ever attempted in a vertical well was performed in the Cotton Valley Limestone in Texas by Mitchell Energy in 1978. Approximately 900,000 gallons (3,400 $m^3$) of water and 1.27 million kg of sand were pumped into the target formation to create a fracture estimated to extend 825 m from the well bore in two directions (Ahmed et al., 1979). The U.S. literature reports that drilling and hydraulic fracturing on shale gas wells together typically use from 2 to 4 million gallons (7,500 to 15,000 $m^3$) of water. Each stage of a hydraulic fracture can use 300,000 to 500,000 gallons (1,130 to 1,900 $m^3$) of water, with an average of about 3 million gallons (11,400 $m^3$) total for hydraulic fracturing per well (Ground Water Protection Council, 2009). Volumes, however, vary widely depending of the geological formations and characteristics of the well. In BC, volumes of water range from 2,000 $m^3$ to over 70 000 $m^3$ whereas in Saskatchewan, they are only in the order of 200 to 400 $m^3$. In Nova Scotia, volumes for the two wells that have been fracked so far were of 5,900 and 6,800 $m^3$, while in NB, volumes varied between 2,000 and 20,000 $m^3$. It is difficult to estimate how much water will be required for each well until test drills have been done. Quantities of fluids depend mainly on the geology, i.e. the lithology and petrophysical qualities of the rock and hence, the pressure necessary to fracture the shale, the shale depth, length of laterals, the frac technique used, the number of fracture stages per well and anticipated water returns (Johnson and Johnson, 2012). In addition, in order to maximize efficiencies and minimize footprints, well pads are designed for many wells, which may be fractured consecutively, thereby increasing water needs over a short period. Typically in BC, there are currently six or eight wells per drilling pad, but this number can go up to 20 or even 30 wells on each pad.

When compared to other fossil fuel production needs, natural gas appears to be quite “green”. Table 3 presents average water consumption for different fossil fuels found in Mielke et al. (2010).

Table 3: Water consumption related to energy resources activities by MMBtu ($10^6$ Btu)

| **Fossil fuel** | **Water consumption** (in gal/MMBtu) |
|---|---|
| Oil (primary) | 1.4 |
| Oil (secondary and Enhanced Oil Recovery) | 62- 65 |
| Oil sands | 13-33 |
| Conventional natural gas | ~0 |
| Shale gas | 0.6-1.8 |

Most flowback water is recovered within a few days after the injection. However, the amounts are highly variable, depending on the shale formation and technology used. As little as 10-20% or more than 70% of the injected water may be recovered at the surface. As a general rule, it is expected that 30% will be recovered.

**Discussions**

Participants opened discussions by saying that the quantity of water needed for the shale gas industry varies widely, and may become an increasingly relevant issue, based on the specific activity and the region in which the shale gas is located. The quantity of water needed is mainly dependent on the geology, as the composition of the shale may control the type of fracturing performed and the pressure needed to induce fractures. A participant added that the amount of water also seems to depend on the company and the technology used. Water supply issues may occur in certain areas of Canada, where precipitation is less abundant (e.g. southern parts of Alberta and Saskatchewan).

The water used per frac and depth of fracturing appears to be relatively well-known, since the industry must report these values. However, only the total consumption is sometimes reported so the amount of groundwater used may be unknown. However, BC's Oil and Gas commission issues permits for surface water and source water wells. They issue quarterly reports of the amount of surface water requested and the actual amount used. Nonetheless, a participant noticed that these quantities are approximations, and they are probably only accurate within a factor of 2 or 3. So far, surface water (fresh or even potable water) has mainly been used for drilling and fracking. Also, the number of fracking jobs that the well will undergo before being abandoned cannot be estimated. This will be driven by gas prices, market forces, and the number of production wells. Therefore, in some areas, even if water quantity may not be an important issue now, it could become one, with the increasing number of wells and the number of fracking processes per well. A participant noted that the amount of water used per well is increasing fast. Another participant agreed, saying that this increase has been documented in the Horn River (BC). In summary, the most important factors that determine water quantity is geology and depth, as well as the economics, since shale gas activities are highly dependant on the market price.

A participant made the observation that the quantity of water used for fracking, compared to other industries such as agriculture, is actually quite small, although because it is expressed in gallons or in litres, two relatively small units of measurement, the public may perceive the amount to be large. Others replied that water amounts used for fracking cannot be compared to the amount of water taken for agriculture because even if some water is recovered, the water footprint is considerable since a lot of water is lost to the hydrological cycle (for a couple of centuries at least) and therefore to future use and/or it becomes highly chemically-charged. The group then decided to compare the average amount of water necessary to frac a well (typically 15,000 to 20,000 $m^3$ for the major shale plays in North America) to the consumption of each Canadian (1,420 $m^3$ per year, all categories, OECD, 2005 or 120 $m^3$ per year per person, Environment Canada website: http://www.ec.gc.ca/eau-water/default.asp?lang=En&n=3788622E-1), to find that it represents the typical annual consumption of 11 to 14 Canadians, or from 125 to 167 residents when considering only home consumption. This amount was also put in perspective by comparing it to the amount of water required to feed a dairy cow (245 $m^3/y$) or beef cow (145 $m^3/y$): it would take 60 dairy cows or 100 beef cows to attain 15,000 $m^3$. Some participants thought this represented a large amount while others considered this a relatively small quantity and should not be an issue. One participant argued that when you multiply these amounts by the number of wells and fracking jobs performed in each of them, they add up to make a huge volume that must be taken into consideration, especially when water resources are limited. A participant noted that there have been similar quantity issues with bottled water. Although amounts may not be so large, it represents a public issue to which the government is sensitive.

In cases where water quantity does not appear to be an issue on an annual basis (based on a preliminary water budget), water shortages and therefore conflicts between users could appear on a seasonal basis. In certain regions, increasing demands and climate change could also increase the actual water stress, such as in southern Alberta close to the Saskatchewan border, where Encana found a huge reserve of natural gas in the Colorado shales. These activities could create challenges for regulators to effectively manage with multiple water demands in regions of limited supply.

Recycling and re-use was then discussed. It is now possible to recycle the water that flows back to the surface, which has a moderately to high TDS content (total dissolved solids content, a measure of all inorganic species dissolved in the water). The industry is now able to use saline to hyper-saline (from 25,000 mg/L or even 100,000 mg/L) water for fracking. The petroleum industry (e.g. in Saskatchewan) is still, nonetheless, looking for fresh water, because the higher the TDS, the less efficient the fracking (more friction reducers must be used, see Section 3.2). Furthermore, the equipment must be modified to tolerate this highly saline fluid. For the moment, most companies are not equipped for the use of saline water. It is believed that the highest level of water salinity that could be re-used could be further increased in the future, likely above 100,000 ppm (mg/L).

There was an agreement among participants that reduction in freshwater usage is a key issue for the acceptance by the population and for the protection of the environment. It would indeed ensure that there is less competition among water users, that water is not lost to the hydrologic cycle, and that less processed water must be stored, treated or injected. It is also in the best interests of industry to reduce water needed for fracking in order to lower treatment and disposal costs. Doing this was said to be a "triple win", i.e. for the public, the industry, and the environment. Increasing water recovery rates for-re-use was also discussed. Participants wondered if there could be circumstances where the government could impose (or not) a certain amount of recycled water for hydraulic fracking. The group was not sure, but noted that it would probably have to be on a case-by-case level since recovery rates are very different from one site to another, based on the geology and equipment/technology used. New technologies may indeed allow more recovery. Participants all agreed that governments must at least encourage recycling, if not impose percentages. A participant noted that using recycled water, however, only postpones the issue of disposal.

A participant related BC's experience: since there is not much surface water other than bogs and wetlands, nor groundwater in northern BC, companies must store water and re-use or re-inject it. They must therefore truck the recovered water from one well to the next. Companies apparently found it economically feasible. A water pipeline is under evaluation, as a possible alternative method of transporting recycled water, which would reduce fuel for trucking and reduce environmental footprints from transportation by large vehicles, as well as reducing risks of spills. Another participant shared that the procedure commonly in use for the Marcellus Shale is a central impoundment to store the needed water, taken during times of high streamflow.

Temporary overland pipelines are used to get the water to the various wellsites, and recovered flowback is stored in tanks, which are trucked to the next location to be used as source water for the next frac. The participant noted that this was primarily driven by costs: disposal costs for high TDS water in Pennsylvania increased fivefold between 2009 and 2011.

The answer to water reduction might be water pricing: if the oil and gas industry needs water, they would have to buy it. Elevated costs for fresh water would probably be a good incentive to promote innovation to reduce water consumption. Costs could be established according to quantity (the more you use, the more you pay) and quality (fresh water would cost more than brackish or saline water). A participant noted that for the moment, companies can use surface water for free or very little money, so why would they pay for an expensive well to get saline water? In some provinces, companies must already pay for water (BC, Saskatchewan, Manitoba, Nova Scotia, Québec). However, the group was uncertain if a permit was needed to take brackish or saline water, or if this requirement applied only to freshwater resources. Water allocation in each province is made through established priorities: drinking water, agriculture, wildlife habitat, recreation, industrial, etc. In Quebec, regulations for water pricing could make a big difference, because areas where shale gas may be exploited are fairly populated and water resources are limited. The group identified the need for provinces to reconsider how they allocate those water licenses through a management debate on priorities, considering specific conditions at each site and taking into perspective water value for a Canadian citizen over time and the provincial and national best interest on a long-term perspective. A participant added that because aquifers provide freshwater for life, this should be considered a higher priority over energy resources, including shale gas.

Water pricing, however, raised some objections, since this may open up the door to a secondary market and to water under the North American Free Trade Agreement (NAFTA) as a saleable commodity, and might override provincial water regulations on export and lead to Canada losing control of the resource. Another problem would be related to productivity: if water is on the market, the industry will not be able to compete with the economic values for petroleum production. In addition, many people are very concerned and reluctant to put a price on water. Freshwater limits for regions with low recharge rates were suggested as an alternative. In theory, if water is not available, permits[1] should not be issued for this use. Perception was identified as a major issue. It was noted that perception will be defined locally by the density of the population (e.g. in northern British Columbia with sparse population, versus populated areas such as in southern Alberta or Quebec), as well as by local competition for the water resource, including drinking water and agriculture. For example, in Prince Edward Island, the priority is drinking water, then the ecosystem, followed by agriculture, and then by industrial needs. A water market for the industry was also suggested by a participant, which would work similarly to the greenhouse gas market. However, it was noted that different climatic conditions, as well as variable geologic settings, come into play in this case.

The group emphasized the need for regulation and recognized that one of the government's roles is to encourage economic development, while protecting its natural resources. Therefore, they suggested that governments should regulate the use of fresh water, so as to push the industry to develop new technologies that would reduce water consumption and to modify their additives when recognized as potentially harmful to health and/or to the environment. Several provinces are trying to get ahead of the curve and develop a management plan for water resources. Many

[1] A water permit system exists in nine out of ten provinces. A pumping permit is typically good for one to two years.

provinces have set up commissions, including Nova Scotia, New Brunswick and Quebec. New Brunswick is anticipating an increase in drilling and hydraulic fracturing intensity over the next few years, so they are trying to get ahead while the intensity of activity is still low. A participant underlined the fact that the industry is currently experimenting, since this industry is in its initial stage and that it was the same situation for governments (regarding regulations). Collaboration with other countries and between provinces was thus strongly recommended.

A few participants raised the question on the environmental value of water in various areas. They all agreed that water has a value, but it has not been quantified yet and questionned the process of doing so. A participant noted that water pricing will (should?) probably be integrated into regular water management plans in future years. The price of water has been established in a few countries (e.g. France, Switzerland, Belgium, Mexico, Brazil), since all users must pay to use this resource. However, water budgets are not known at the local scale across Canada, which is the scale of interest to industry. As a first trial, it was suggested that maps of shale formation targets (Horn River, Liard, Utica, etc.) could be superposed with known surficial and bedrock aquifers (in preparation at the GSC). A participant noted water is a necessity and people don’t always recognize it, partly because it is free, but governments should acknowledge it.

Other subjects such as water sources and remote areas were tackled. The group discussed the potential use of seawater for slickwater hydraulic fracturing. As some participants reported, new technologies and research now allow fracking to be performed with high salinity levels although more chemicals (including friction reducers) must be used. Unanimously, the group said that under no circumstances should municipal potable water be used in fracking. They also thought that the industry should report their consumption using different categories, such as fresh surface water, fresh groundwater, as well as seawater and brackish and saline groundwater. A few participants said that the governments should start thinking about the fact that regions above the $55^{th}$ parallel (e.g. Horn River area, BC) are at or above the discontinuous permafrost line, with related issues such as the unfeasibility of digging ponds during the winter, access problems, limited amounts of water and water transport.

## 2.2 Wastewater management

### Background

A typical slickwater fracking job will use low percentages of between 3 to 12 chemical additives, depending on the characteristics of the water and the shale formation (Nash, 2010). Proppants and chemical additives in most slickwaters constitute less than 2 - 3% of the overall composition. About half of the added chemicals consist of a polyacrylamide friction reducer that makes the water “slick” to allow fluids to go further downhole. The friction reducers (surfactants such as industrial detergents and glycols that reduce the surface tension) play two roles: to help the frac fluid reach the target formation without excessive pressure loss from the surface, and to help the fluid penetrate existing natural fractures in the formation to open them up. Petroleum distillates must be added to serve as "carriers" for these friction reducer compounds. The remaining chemicals include stabilizers to prevent pipe corrosion, acids (e.g. HCl) to clean the perforations (often called “perfs”), a scale inhibitor like phosphoric acid, and biocides to prevent micro-organism growth. The fluid starts out thin so it can penetrate natural fractures and open them up. However, as the frac fluid is injected, it has to carry proppants (e.g. sand) into the fractures, so the viscosity has to be increased using different kinds of gels. These gels also contain a breaker compound, which activates after a certain time interval and breaks down the structure of the gel, reducing the viscosity to ease the flowback recovery after the frac is completed (Soeder, 2012). Breakers may contain BTEX (benzene, toluene, ethylene, xylene) compounds. Many of these additives are common chemicals which people regularly encounter in everyday life, such as swimming pool products, bleaching agents, glass cleaners, makeup removers, and antifreeze (Nash, 2010). A U.S. study reported that of the 750 compounds used in hydraulic fracturing products, more than 650 contained chemicals that are known to be possible human carcinogens, and that between 2005 and 2009, 279 products had at least one component listed as "proprietary" or "trade secret" (U.S. House of Representatives, 2011).

In the U.S., there exists a hydraulic fracturing chemical registry: fracfocus.org. This website provides information related to chemical additives, methods of fracking and regulations by state. This is a joint project of the U.S. Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. The province of British Colombia has recently implemented a parallel site: http://fracfocus.ca.

Fracking can be summarized as follows: slickwater is injected at high pressure in a well into shale gas formations that are typically located more than 1 km below the ground surface, to induce fractures and thus increase the shale permeability. A caprock (rock with a very low permeability) with a thickness of a few hundreds of meters should be located above it. Hydraulic fracturing is designed so as to only frack the shale formation, not the caprock. Radial fractures generated by the hydraulic fracturing are generally no more than 300 m long (see Section 2.1).

When this water is pumped back to the surface (thereafter called wastewater or flowback water), it also has a moderate to high TDS content. Flowback water typically has a TDS content ranging from 10,000 mg/L to 100,000 mg/L. The longer its residence time within deep geological formations, the higher its salinity (or TDS content). Flowback water is usually stored in surface ponds or tanks, before being either treated on site or off-site in a specialized treatment plant, re-used to frac another well, or re-injected in a deep saline formation. Saline water is now more and more being used for fracking (such as in the Horn River Basin, BC). This represents a great advance, since this eliminates user conflicts for basic usages such as agriculture and drinking water. However, saline water is less efficient and more expensive chemicals, including friction reducers, must be added to the fracking fluid.

This flowback water, with a high content of total dissolved solids (TDS) and other contaminants, thus represents a major management challenge. However in BC, unlike in the U.S. where flowback is sometimes treated before being discharged to surface waters, all wastewater is re-used or re-injected into deep saline aquifers (often where it had initially been withdrawn). Moreover, flowback water in BC may only be stored in surface tanks or ponds for less than 3 months. Other issues often raised in discussions about hydraulic fracturing pertain to 1) the fate of the fracturing fluid in the subsurface environment (often > 70% of the total amount injected) and 2) the need for more additives, namely friction reducers, to the recovered water due to the high salt content it acquires during its passage through deep geological formations.

A 2011 MIT report stated that there has been no evidence that hydraulic fracturing has penetrated and contaminated shallow freshwater aquifers; however, they considered that there were major environmental challenges in the area of water management, particularly the effective disposal of fracturing fluids (MIT, 2011). Some of the wastewater disposal issues are similar to those in the conventional oil industry (where injection is performed to increase the oil recovery) or in carbon capture (where $CO_2$ is injected at high pressure in deep saline formations). However, volumes of wastewater are much greater in shale gas operations. Wastewater disposal will hopefully become a less important issue, as industry will likely be increasingly recycling and treating its wastewater in future years.

Air emissions related to shale gas wells can result from two activities: drilling and fracking, and production. Well drilling and fracturing can produce particulate matter, nitrogen oxides, sulfur oxides, carbon dioxide and carbon monoxide (all related to the engines used to power the drill and pumps), as well as other gases linked with natural gas itself that can escape during the drilling phase. Emissions related to the wells themselves or to the flowback water retention basins include methane, ethane, liquid condensate, and volatile organic compounds (VOCs) such as benzene, toluene, ethylbenzene and xylene (BTEX) that are especially toxic. Therefore, it is critical to get baseline data on air emissions, analogous to baseline groundwater quality, because there can be numerous sources of these emissions. For instance, every vehicle with a tank of gasoline emits BTEX and other VOCs. As a result, using air quality data to identify VOCs from shale gas wells may be problematic.

Potential problems associated with hydraulic fracturing, wastewater management, as well as wellhead and casing leaks have been summarized in Howarth et al. (2011a). This schematic is presented in Figure 4.

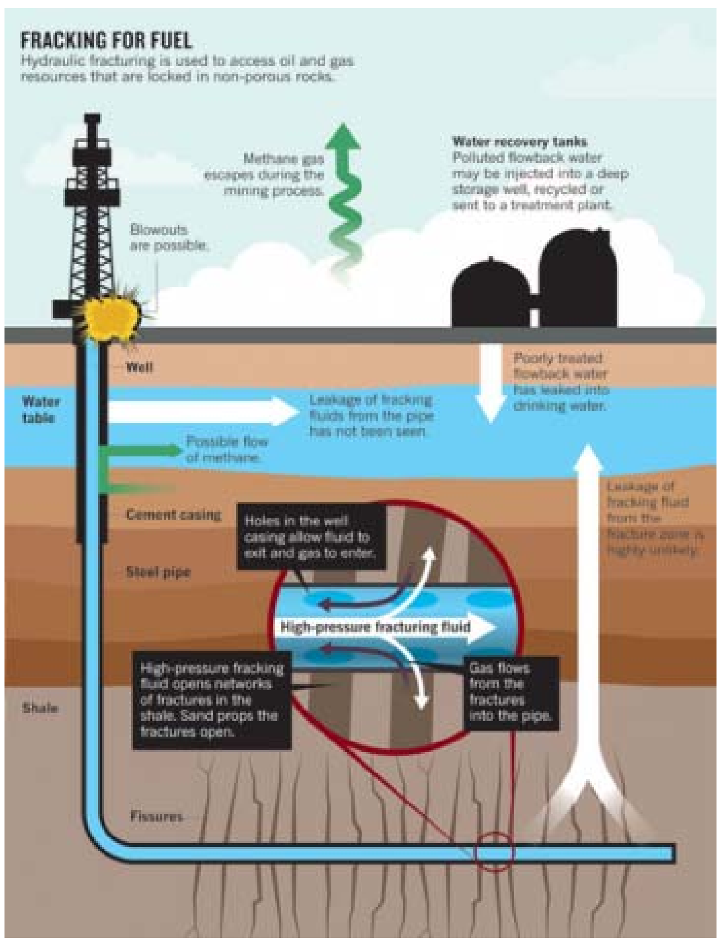


Figure 4: Schematic illustrating potential problems associated with shale gas activities (taken from Howarth et al., 2011a)

## Discussions

The group first listed issues that should be included in the topic of wastewater management: storage containment, recycling (re-use) and wastewater disposal. Indeed, drilling mud and chemically-charged flowback water must be stored, at least temporarily, before being re-injected at depth or treated. Participants agreed that percentages of additives in fracking fluids are very small (typically 2-3%), but recognized that since the volumes of water are large, the mass of chemicals may be significant and thus, of concern. Over the life of a typical well, a participant had heard that it could represent about 100,000 gallons (380 $m^3$) of chemical additives. Knowing that only a few micrograms per litre (μm/L) of toxic chemicals in drinking water could be harmful, the subject is indeed of concern.

Wastes may include, besides wastewater: drilling muds, solid wastes (the most significant being drill cuttings that can be affected by oxidation and mobilization, since shales may have an affinity for radionuclides and toxic metals and, to a lesser extent, they may generate acid mine drainage if not appropriately stored) and air emissions. Therefore, there was an absolute consensus that studies must be carried out to make sure that these chemicals do not find their way through existing and generated (via fracking) fracture networks up to surficial aquifers. Since a gas frac is supposed to clean up better than a hydraulic frac, a participant asked how gas was recovered after a "gas" frac and what was the average success rate. A participant responded that this is a relatively new technology used in about a dozen wells in BC and that its efficiency is not known yet. The main issue is probably the volume of proppant that the fluid (gas) is capable of carrying into the formation. This opinion was shared by another participant, who added that he believed that the success rate is similar to hydraulic fracturing. He went on to explain that recovery of flowback, for instance for butane and propane, is carried out through pipes, using the same equipment used to capture natural gas liquids, and separated out at the surface in condensers. Other gases like $CO_2$ or $N_2$ have to be separated out in a gas processing plant. These are used where natural gas resources contain a significant concentration of undesirable gases (such as carbon dioxide or hydrogen sulphide), which must be removed before the produced gas can be sold to a pipeline company.

Similar to the "Water quantity" group, this group said that the best option would probably be to reduce the amount of water as much as possible from the beginning with an economic incentive, then recycling should be fostered, as these practices are better from both an environmental and management perspective. Recycling may solve several issues and, if coordinated regionally, economies of scale may exist. If water reductions and recycling leave only a minimal amount of water, wastewater may not need to be transported. In addition, it is probably cheaper for companies to manage smaller volumes of processed water for upcoming fracking jobs than store, treat and dispose large quantities. Therefore, the "reduce, reuse, recycle" classic approach is also applicable to shale gas activities, but everyone agreed that there was a need for research to get to this point. Recycling may, however, be impractical in areas where there is a large distance between wells.

To the above-listed environmental issues, cumulative indirect impacts could also be added, such as those related to infrastructure (roads, pipes, etc.), since water and waste products must often be transported into or out of the site by trucks or pipelines, resulting in a risk of spills. Moreover, issues of space necessary to store large volumes of water or flowback water may also emerge in certain regions. For instance, large areas are being used for "borrow pits" in BC (called "monster pits") to store fresh or saline water.

The group thus concurred to say that future activities should include research for ways to reduce consumption and increase recycling. For example, research should focus on a better understanding of the mechanisms behind hydraulic fracturing in the context of minimizing waste production. Nonetheless, a participant noted that re-use of (saline) fracking waters not only implies that friction reducers must be added due to the high salt content, but it also implies that water that will have to be stored for a certain period of time, then ultimately be treated or injected, will have an even higher chemical and salt content.

Wastewater storage at the surface within lined ponds or tanks, along with temporary constructed pipelines taking the wastewater and chemicals to processing facilities, were thought by some participants to represent the highest risk for contamination of freshwater, higher than the threat related to casing leaks or underground migration. Contamination may occur through leaks, evaporation of volatile chemicals into the atmosphere, or overflow when there are important rain events. Ponds lined with geomembranes are rarely free of flaws, even when they are constructed with a double lining. Participants suggested that several areas should be considered when deciding on surface storage and disposal options, including suitable geologic structures and jurisdictions.

When wastewater cannot be re-used to frac a well, disposal options include re-injection into deep geological formations or water treatment. Injection of produced water into deep, briny aquifers is standard practice in the oil and gas industry. It thus appears to be an interesting approach, but it was thought that more research must be done to study its long-term safety, depending on the local geology. Injection wells are generally shallower than the horizontal producing well, but nonetheless much deeper than surficial aquifers (on the order of -500 m to -1 km?). BC and Alberta protect freshwater down to 600 m unless the interface can be proven to be shallower. They can be completed, for example, in a saline porous bedrock (e.g. sandstone). Re-injection can be done on site directly or elsewhere, including in existing oil and gas wells. Currently in the Horn River Basin region (BC), all produced water is sent back down the hole at a depth of 800 m in the Debolt Formation, from where it was previously withdrawn.

Wastewater can also be disposed of through specialized treatment facilities on site or off-site to remove, among other things, salts, metals and radionuclides. Use of municipal water treatment plants was not considered an option, due to the presence of chemical additives, potential radioactive compounds and significant TDS content in wastewater that these systems are not designed to treat and remove. Municipal plants only remove organic matter and flocculate the solids rather than treating, with the exception of some highly biodegradable organics. Alberta, which has the most experienced jurisdiction in the country, is moving towards end-use requirements to determine regulations and is moving away from surface disposal.

Since wastewater must reach certain standards before returning to the environment, participants underlined that measuring the quantity of wastewater and its initial and final quality might be an issue. Treating or re-injecting wastewater on site might be a good environment solution since it might contribute to eliminate a large part of the storage, transport and spill issues. The range of technologies for portable systems varies and depends on what must be treated. Participants highlighted that potential environmental impacts should be thoroughly analyzed before selecting a disposal technique to avoid surficial aquifer contamination (chemicals returning to the surface), depending on the geology and the composition of the fluids (additives and their concentrations), including organics, radioactivity, salinity and acidic conditions. A participant wondered how do these elements stack up against other industrial effluents and thought they should be compared.

A participant asked about differences between fracking processed water used for shale gas versus that used for conventional oil and gas activities, since fracking into deep horizontal wells to release oil is common. He was curious because TDS does not appear to be an issue for conventional oil companies in Saskatchewan, whereas shale gas companies seem to want the freshest water possible for fracking jobs (even though groundwater in this province often has 15,000–20,000 TDS). A participant replied that it may be because shale gas companies do not yet have the appropriate equipment to use water with high salt content. Another added that technology is evolving quickly: companies initially didn't think they would get successful fracs with saline water because fracking for oil is different. Also, the fact that freshwater is often easily available limits the incentive to use saline water.

Specific regulations must be developed before returning wastewater back to the environment (although for the moment, all flowback water in BC is re-used or re-injected), like any other industrial water, to make sure it returns to the ambient conditions. The group agreed on the fact that wastewater treatment should also be regulated, to avoid aggravation of the situation i.e., develop more harmful molecules from initial organic compounds (e.g. with potential health and greenhouse gases concerns). The need for environmental confidence, predictability, and measurability leads to a monitoring requirement.

Someone suggested that if regulation forces companies to treat wastewater on site to avoid trucking, companies would probably find more efficient and cheaper ways to do it. The key factor is probably cost, not effectiveness. Another participant agreed that the cost of trucking versus on site treatment facilities, although much cheaper, should not be considered if environmental issues (e.g. emissions, potential spills) are to be expected, even if the issue of wastewater disposal is holding development back. A third person noted that the road network which would have to be constructed if gas is extracted in northern regions may be one of the most significant footprints associated with the shale gas industry, since it has considerable impacts on the environment (e.g. on surface hydrology, air pollution such as dust, noise and GHG emissions from trucks, as well as potential spills) and that a permit to construct an open road is usually easy to obtain. A rough calculation for a typical exploration well estimated that approximately 200 trucks would be needed to ship out fluids. In the Northwest Territories, there is currently no regional land infrastructure and wastes are transported further south, to Alberta.

The group then addressed the question: "what do we need to know to treat these waters?" The need for a relevant regulatory framework based on scientific facts was discussed many times. For instance, participants underlined that it would be important that all fracking water additives be reported to authorities (preferably to a common, centralized system (or organization) before obtaining a permit for a frac job. Participants debated on the need to release the "recipe" (where the quantities of each chemical would be known) and to forbid the reporting of a "secret ingredient", which would be a sensitive issue for companies. Participants talked about developing a decision tool, a strategic plan or a guidance document to detail options and decision criteria to help water resource managers, based on the quality and quantity of wastewater to manage, the location of the well (in a populated area or not), and geological conditions (in accordance with the decision tree proposed by the "Migration mechanisms" group, see Section 2.3).

Participants agreed that there is no one-size-fits-all solution. There could be different solutions under the same jurisdiction, i.e. that solutions may be regional or even site-specific. This implies that solutions may involve different monitoring and mitigation measures defined according to specific circumstances. For example, additional issues should be taken into account for populated areas or cold regions, including problems related to permafrost, surface water disposal when the ground is frozen, heating storage water tanks, or lack of facilities in some cases. Participants highlighted that provinces have to be careful about adopting or keeping outdated regulations and best practices. Since this industry moves fast, so should the regulation.

Saskatchewan regulations for disposed water allow drilling fluids with a TDS content of up to 1,400 mg/L to be disposed of on land surfaces. Prairies soils are, however, often already very salty. Elsewhere, regulations on the salinity would have to be much lower (e.g. where shallow groundwater has a typical TDS concentration of less than 300 mg/L).

Participants also highlighted the need to identify best practices, among other things by looking at what has been done so far in Canada, the U.S. and elsewhere. Best practices could include training and licensing. A participant observed that there are differences between larger players with more resources, who are less likely to cut corners, and junior companies with less money who may cut corners, causing higher-risk scenarios. From a regulatory perspective, one cannot discriminate based on company size, so training requirements and regulation enforcement may have to be put in place to ensure compliance by smaller companies. A last observation was that the same level of diligence for water recovery as there is for drilling mud should be applied: as water becomes more expensive, users will be more careful. Right now, water is cheap, contrary to drilling mud.

## 2.3 Migration mechanisms

### Background

Multistage hydraulic fracturing makes it possible to considerably increase the permeability of gas-rich rock units at the periphery of the horizontal well bore, because it creates small fractures that extend radially between 100 and 300 m at the most. Slickwater may migrate towards surficial aquifers in three ways: 1) through a defective cement casing, 2) from below via fracture networks and faults connecting the shale formation to surficial aquifers, and 3) from leaky surface ponds used for storage of wastewater. On average, 30% of the slickwater volumes used for frac jobs are recovered, leaving about 70% of this chemically-charged water underground.

In Canada, a triple casing regulation for the production well is in effect in BC and AB to reduce risks of upward leaks along the casing itself or horizontal seepage into the ground, before reaching the targeted horizon. A triple casing (Figure 5) consists of a surface casing to protect the surficial aquifer, an intermediate casing that extends below fresh water aquifers, and a production casing, from the surface down to the lateral (or even to the end of it).

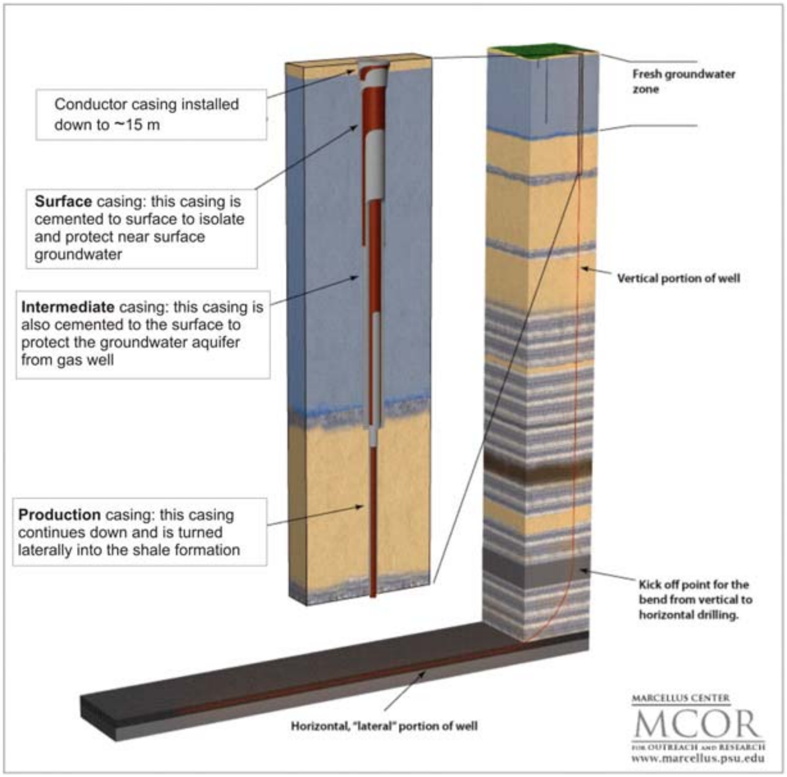


Figure 5: Schematic of a triple-casing well: surface, intermediate and production casings (slightly adapted from http://marcelluscoalition.org/marcellus-shale/production-processes/casing-the-well/)

Gas may also leak from the wellhead; all shale gas wells must thus have vents. There is an increasing consensus that all wells leak, to different degrees. According to a very recent large-scale study from the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado (Boulder), production wells in an area known as the Denver-Julesburg Basin are losing about 4% of their gas to the atmosphere (not including additional losses in the pipeline and distribution system), i.e. more than double what the industry reports in the official inventory (reported in Nature: http://www.nature.com/news/air-sampling-reveals-high-emissions-from-gas-field-1.9982). However, the high leak rate in this case is likely due to direct venting of wells to the atmosphere (propane, ethane and other hydrocarbon gases were detected); this is not the usual case. Gases are typically directed to a flare and converted to $CO_2$. This percentage is nonetheless in agreement with the controversial conclusions from the Howarth et al. (2011b) study that claimed that 3.7 to 7.9% of the methane produced by a well will leak into the atmosphere during the well's lifetime. Their conclusion was that the advantage of using natural gas over other fossil fuels (even coal) would be canceled by these greenhouse gas emissions of methane. However, more data need to be collected to confirm actual gas emissions. Indeed, it is also important to note that another group of Cornell University professors have disputed Howarth et al.'s claims (Cathles, 2012), and the debate goes on.

Two types of gases may be present in the soil: 1) biogenic, i.e. formed at shallow depths and low temperatures by anaerobic bacterial decomposition of organic matter (and thus unrelated to the formation of oil); and 2) thermogenic, i.e. produced at depth under high temperatures and pressures. Thermogenic gas is associated with oil formations. When gas is present in the soil, its source must therefore be identified so as to be able to assert whether it may be related to deep formations or not and, ideally, identify the formation from which it comes. It is noteworthy that a few economic biogenic shale gas deposits (e.g. Antrim shale in the Michigan Basin, U.S.) or mixed (biogenic/thermogenic) sources (such as in the St. Lawrence Lowlands near Trois-Rivières, QC), may also be exploited.

Thermogenic gas may be released through drilling, and then migrate. Gas remobilization, which can result from drilling and/or hydraulic fracturing, may impact groundwater quality and infrastructure. Dissolved gas can make water "milky" or change its taste, but is not toxic. The worst that can happen is an explosion (which is very rare) if gas accumulates in a closed area (for example, a well exploded in Dimock, north-eastern Pennsylvania in 2010). However, it is noteworthy that thermogenic gases can also be naturally present in other formations above the fractured target formation.

The biggest public concern is contamination of drinking water wells. The famous video extract from the documentary "Gasland" where a land owner lights tap water on fire has had a positive repercussion in the sense that it alerted the population to potential negative effects of inadequately-managed shale gas activities. However, it was further established (by the U.S. Geological Survey, among others) that this water well penetrates four shallow coal seams that contain methane gas. Therefore, methane in this water came from coalbeds and had nothing to do with shale gas exploration or production. Many complaints in Alberta have come from coal-bed methane activities, as these formations are much shallower than shale gas resources and are usually closer to population centres. To avoid complaints and lawsuits, companies have started monitoring neighbouring wells so as to be able to prove that they did not affect the water.

The migration mechanism subgroup was asked to discuss the current state of knowledge about contaminant transport mechanisms to groundwater from shale gas operations, to identify best practices and opportunities for future research and discussion.

## Discussions

### *Migration related to well integrity*

The group started their discussions on borehole integrity. There was a rapid consensus that the casing integrity plays a key role because grouting creates the seal. Problems may occur if the cement from the intermediate casing is not pushed far enough down below the freshwater zone, allowing frac water to leak into other geological formations or gas to flow up to the surface and blow out into someone's basement (this is rare, but a participant noted that it once happened in Ohio, U.S.). Cement drilling pipe casing may also leak due to either corrosion or poor cementation.

Development of a standardized procedure for the cement casing structure, including a triple casing and borehole wall testing, was considered crucial to ensure well integrity. A participant stated that indeed, the number of incidents (casing leaks) in the U.S. appears to go down as regulations for casing standards increase. Pennsylvania did not have the triple-casing regulation until 2010. These regulations include the time needed to cure the cement, porosity, density, and quantifying amount of cement lost in the subsurface, which could migrate short distances. Participants agreed that a triple casing (surficial, intermediate and production) should be mandatory in all provinces. The casing design should also depend on the local geology. For example, in New Brunswick, they need to prevent migration of salts into the formation, so the materials they use in the casing must be suitably designed. Precise calculations of the weight of the casing are needed to prevent possible issues at the bend between the vertical and horizontal portions of the well.

Tests for the casing integrity should include 1) a 3-phase pressure test that provides data on the casing integrity (the casing is pressurized with water or gas to see if it leaks), 2) a "cement bond log" that determines the degree of cement bonding using a wireline tool that utilizes acoustic sensors, and 3) geophysical logging to make sure that the cement is solid along the entire hole. In an ideal world, results from these tests should be obtained and approved by an inspector before drilling the next level. Each test should be performed on each casing (surface, intermediate and production casings). A drill stem test (a procedure for isolating and testing the surrounding geological formation, allowing the measurement of pressure within the formation and sampling of the fluids) should also be performed. Some participants objected that these inspection and time requirements would likely be far too onerous to be practical. In geological formations where known fracture and fault zones are present, such as in the Utica Shale formation in Quebec, these types of precautions should likely be taken. To prevent gas leaks, requirements for the wellhead vent should also be set. In Alberta and NB, the casing must set for a certain amount of time before getting the approval for exploration. BC requires neutron and gamma ray logs during their geophysical borehole logging. Although these procedures slow down the process (and thus significantly increase the cost of the well), they ensure the casing's integrity.

Long-term integrity of wells is another possible issue regarding leakage and seepage. Long-term monitoring should thus be imposed (see Section 2.5). In addition, well abandonment (i.e. closure) is an important topic, since pollutants could easily propagate through improperly abandoned wells. Indeed, orphaned holes represent other migration issues in terms of gas, water and chemical flow from depth to surface. Lithostatic pressure prevents propagation at depth, but as soon as the pressure is reduced, the fluid tends to return up the wellhead. Well abandonment should thus be strictly regulated. In many provinces, inventories and monitoring is not performed on abandoned wells/boreholes and leaks could be significant. Participants recommended establishing a bond and well abandonment security plan that industry would have to start funding. This money could also be used in case of an emergency issue. A participant noted that BC, AB and SK already have an orphan well fund.

All participants agreed that monitoring is essential to discover whether the casing is leaking and to understand why it is leaking. The root cause may, for instance, be that the hydraulic fracturing itself is shearing the casing and, in this case, manufacturers could develop new products that would not crack or engineers could develop new techniques for well installation. Monitoring gas leaks from the wellhead is also important since there are serious and non-serious leaks. For non-serious leaks (below a threshold), continued monitoring would be required, while for serious leaks (that could be > 1% of production volume), the formation would need to be sealed-off, i.e. the production well would be "killed".

Another technical issue also discussed, that gave rise to some concerns from a few participants, was over-pressuring downhole into the injection formation. However, a participant said that, for naturally over-pressured deep formations, this was not a problem as long as engineers know about it: they simply increase the weight of the drilling mud to compensate. He added that over-pressured gas reservoirs are actually targets since in general, the higher the pressure, the more gas there is. The participant also remarked that over-pressuring during a frac job is temporary: it is needed to overcome the rock strength and crack the formation, but as soon as the pumps are stopped, the pressure drops back to hydrostatic. If the casing integrity has initially been verified, there should not be any associated safety issues.

*Migration related to hydraulic fracturing and surface storage*

Participants first addressed the issue of the flow of fluids in general. One participant indicated that before flow could be understood, the mechanism of how ground conditions change through hydraulic fracturing had to be understood. Another participant added that the mechanics of fluid migration towards surficial formations was not well understood either. They thought research projects should be initiated rapidly to study these aspects (for instance, where does the fracturing fluid go and why so little water comes back to the surface, what is the location, orientation and length of the fractures, etc.).

The issues of migration through large structural features and inappropriately abandoned wells, as well as of shallow targeted units were then discussed. If during fracking a fault or a vertical non-cemented abandoned well is intercepted, the effects should be immediately detectable. However, indirect long migration pathways will not be perceived during this operation. In BC, fracking shallower than 600 m is not permitted due to the proximity of shallow aquifers. In Alberta (e.g. in Rosebud), complaints are related to fracs performed in coal-bed methane formations, which are shallower than shale gas formations. A participant noted that hydraulic fracturing is not run long enough to allow fractures to extend more than 200-300 m. However, new fractures could connect to existing (natural) fracture networks and, this way, flow could find its way to surficial aquifers. Therefore, on a general basis, the shallower the unit, the more risks there are. A participant noted that the greatest risk of gas or fluid migration along faults and fractures is during and immediately after the hydraulic fracturing, when new flowpaths have been opened up and the formation is at the highest pressure it will ever experience. Once the well is in production, pore pressures will have dropped to hydrostatic or less, and risks decrease significantly, as all fluids will tend to flow toward the wellbore, not toward the surface. Another participant responded that even if flow is towards the well, the risk then becomes leakage along the wellbore to shallow aquifers or to ground surface.

Some participants started discussions on additives put into slickwater. They suggested that a closer look could be taken regarding whether some products should be banned and replaced by others, due to their toxicity. Although upward migration is a limited risk, only harmless products should be used, in case unpredictable interconnected pathways do exist. Everyone agreed that the list of additives and the quantity of flowback water need to be reported (see Sections 2.2). A participant said that this was already the case in BC: oil & gas industry provide information on daily production and cumulative production of produced water that is available through OGC (BC Oil & Gas Commission).

Similar to the "Wastewater management" group, surface storage was thought to represent one of the most important risks of aquifer contamination by several participants, since large quantities of wastewater must be stored after each fracking job. A participant remarked that lined ponds usually leak, to a certain degree, due to imperfections of the liner system. In Pennsylvania (USA), where a lot of shale gas production has been going on in the last decade, companies are gradually moving to tanks to store flowback water instead of using pits to limit leaks. BC does not currently use surface ponds to store flowback water.

*Gas migration and re-mobilization*

Gas from deep formations can migrate to the surface through the casing or through indirect fracture pathways, which can also serve as natural pathways for longer-term contaminant migration. This is why sampling gas in soils and dissolved gas in groundwater from surface wells, and identifying their source is so important. Measuring gas leaks from wellheads is also crucial, as mentioned above. There is a need to improve techniques to ensure $CH_4$ stays in the shale formation after production; this may not represent a big challenge a few participants said. A participant added that if we want natural gas to be the cleanest fossil fuel source, methane emissions have to be reduced. Another participant noted that the knowledge gained in the $CO_2$ sequestration area may be transferrable to shale gas.

A participant stated that in Pennsylvania, it has been observed that much less methane was being released when the "wait on cement" time procedure to let the cement dry was applied. In NB, the “wait on cement” will be part of the regulation. At present in Saskatchewan, the cement has to cure to a certain pressure: no additional drilling is permitted until grouting is able to support this pressure. A participant shared that in the U.S., the “wait on cement” procedure is similar; the cement must support a compressive strength of 500 psi. This procedure is not in effect in BC. The group concurred to say that this measure appeared to be important and should be part of regulation.

The level of risk of gas remobilization varies, participants declared, due to the pressure and micro-seismicity induced from fracking, depending on the pressure of the deep formation, on whether the surficial formation is naturally pressurized or not, and on the fracture network. Hydraulic fracturing produces significant additional pressure, which could result in upward flow and thus could impact shallow aquifers. It was noted that fracking may also mobilize biogenic gas already present in these aquifers. A participant also said that it is likely that fracture networks would be known and would have already provided a conduit for gas migration, meaning that the resources would have left the local shale formation. Another participant responded that pathways are likely indirect (thereby resulting in very slow migration) and might not have been perceived during fracking; however, fracking could have initiated a leak or aggravate the situation. It was concluded that more research is required to support the development of regulations for these issues.

Gas venting from wellheads and gas present in soils at or close to the surface are a concern for the population. In gas-charged aquifers, the pressure can make bubbles, which may rise to the surface. As previously mentioned, this gas can be either biogenic or thermogenic; its source must be determined. Dissolved gas in groundwater can be detected and differentiated using special water samplers and isotopic analyses. A participant mentioned the following analyses, which could routinely be performed: dissolved gas concentrations ($CO_2$, $H_2$, $N_2$, $CH_4$), light hydrocarbons (ethane, benzene, xylene and other short chain HC), and isotopic signature of methane and ethane.

If a well leaks gas, the company can easily be accused. However, the cause of gas remobilization in the ground is not so easy to determine. If dissolved gas has not been monitored before drilling and fracking, no data will be available to identify the source or cause. It is therefore crucial to monitor dissolved gas before, during and after fracking and production. A participant noted that it would also be important to know how this gas was mobilized.

R*esearch*

Participants discussed assessment of aquifer vulnerability from surface contamination and/or from upward leakage (of remobilized gas or slickwater) and discussed issues related to vertical migration through fracture networks. There is a general fear of vertical migration, i.e. that the shale formation may not be fully confined by an impermeable caprock. Some participants thought that the fact that gas was still within the formation proved that the caprock was efficient and that no link was present with the surface. Others said that we cannot be too prudent with groundwater and research must be initiated since little is known. In the Appalachian piedmont (QC), where the Utica Shale is present, there are natural faults and fractures, potentially leading to slickwater migration.

Because the geologic substructures control the flow of fluid in the subsurface, there is a need to better understand (and model) the flow of fluids through different kinds of shale formations, at various depths and scales, and with different overburden conditions, because of their potential to affect the flow of fluids. The area must be large enough so characteristics of the caprock are known to be sufficient to prevent fluid from leaking to the surface, but the fractures, that may serve as migration pathways, must also be identified at the local scale. An example of groundwater contamination by hydraulic fracturing, potentially through existing or enlarged fractures, is in Pavillion, Wyoming, U.S. (http://www.epa.gov/region8/superfund/wy/pavillion/index.html), where contaminants were detected in both drinking water wells and EPA monitoring wells. The fracturing was performed in conventional gas wells as shallow as 372 m below ground surface. Conceptual modeling of typical sites within each basin was suggested. However, some participants noted that a conceptual model to study migration mechanisms could not adequately represent transport, since fracture characteristics must also be known.

A good theoretical way to evaluate whether natural links exist between the shale formation and surficial aquifers (and their location) would be to conduct a tracer test. However, it would take years to obtain results as groundwater, even through fractures, circulates relatively slowly and that the distance is quite large (> 1 km). It was suggested that non-toxic tracers could be used as an extra ingredient to hydraulic fracturing additives, to help identify sources of possible contamination for reclamation. A participant added that it would be difficult to make the industry add a new component to their recipe and, furthermore, there should be several existing frac fluid ingredients that would be able to show evidence of a link with a nearby frac. There has been discussion in New Brunswick about requiring companies to add specific tracers to their hydraulic fracturing fluids to act as signatures. In Quebec, while the government offered companies the right to continue exploration activities within the framework of research projects, the companies refused and said they will wait until the environmental assessment is complete.

There is also a need for more research to identify deep formation parameters such as porosity, permeability, and pressure (see Section 2.4). A participant added that a clear understanding of the geology was crucial, which could be probably acquired through progressive exploration. The industry has evolved and is better at developing predictive models, but objective models (and therefore results) are also required. Geological, geomechanical, geotechnical, and hydrogeological issues must all be discussed and parameters must be quantified (see Section 2.4). Although the question of how to monitor fluid flows at depths of several kilometres was raised, the group decided that the best focus for monitoring would be the flow within fairly shallow units, as this is where groundwater in aquifers is found.

As more pressure is needed to force slickwater through the pipe to create the fractures in the shale formation than with other types of fracs, it was deduced that more surface leakage may be expected. There is thus a need to compare and match the different types of fracking, along with the materials and methods used for the surface and intermediate casings, to help prevent leakage and study the resulting fracture network. A participant noted that one of the issues that concern the engineers who design and run hydraulic fracturing treatments is pressure loss downhole due to friction. A pressure of 12,000 psi at the surface applied to the frac fluid may only be about half of that down at the toe of the lateral. There are limits to the pressures that can be applied at the surface: if the required pressure is above 15,000 psi, a different set of equipment and casing is needed, which affects the cost (Soeder, 2012). The trade-offs between stimulated reservoir volume, pressures needed, pump rates, strength of tubulars, stimulation equipment needed, volumes of materials, and costs are juggled every day by the financial people and engineers at production companies and service companies who plan these frac jobs.

Discussions then addressed vulnerability issues. A participant suggested that aquifer vulnerability could be assessed using a multi-layer model similar to the DRASTIC methodology. DRASTIC was developed for surface contamination, but this methodology could be adapted to study vulnerability from below. A participant noted that the first step would be to obtain a better understanding of the geology, which can have significant local variations in density and complexity of local fracturing, type of shale, and many other factors. Therefore, a vulnerability assessment performed at the regional scale using averaged parameter values, as in DRASTIC, appeared to be much simpler than the assessment of a site-specific vulnerability. A participant noted that certain issues, such as contaminant migration, cannot be addressed at the regional scale; this could, however, represent a good start and this could be carried out quite rapidly at the national scale.

In summary, to assess and monitor vulnerability, four areas were given precedence:

- Assessment of the wellbore integrity;
- Assessment of the nature of the caprock in terms of permeability and possible connections between shallow and deep formations;
- Measurement of gas in soil and identification of its source;
- Monitoring (see Section 2.5), with different levels depending on assessed level of vulnerability and intensity of development to make sure potential contamination via the three key migration mechanisms (casing, storage ponds and fracture networks) would be caught rapidly. This monitoring would include a geochemical baseline study of surficial aquifers for standard ions, as well as common organics used for fracking and dissolved gas (see Section 2.4).

The discussion of risks raised the idea of a decision tree, which would provide a tool to assess both possible risk and subsequent actions to mitigate risk. The purpose of the tree would be to help make decisions, according to a number of criteria such as population, depth of the shale unit, presence of nearby fresh water aquifers and presence of gas at the surface. For instance, if the spacing between the shale formation and the aquifer were less than a certain specified distance, one course of action would be necessary. If it were a greater distance, then a different course of action, or potentially no action, would be taken. Similarly, if the presence of gas is detected, the decision tree would have to consider the identification of the source of gas within the aquifer prior to hydraulic fracturing, then take action according to the result.

The group recognized that research on migration mechanisms and the development of a decision tree would be complex, since flow must be studied at a large scale to integrate deep formations, while contaminant transport mechanisms must be studied at the local scale, a scale for which little information is available for fractures and potential migration paths. Quantifying risks is a challenge, but it seemed important to all.

## 2.4 Data gaps

### Background

There are evidently many data gaps in our knowledge of subsurface processes relating to shale gas development. These gaps limit our ability to predict behaviour and to develop regulations to minimize risk of environmental contamination from gas leaks or wastewater fluids. Many questions/issues must be addressed. For example, should the methods used to collect and acquire data be standardized? Which data should be available and delivered to the responsible authority? Should government organizations (provincial or federal) be conducting work to provide general knowledge to help minimize risks to groundwater resources? Should the presence of deep saline aquifers that may be appropriate for injection be identified? Is there a potential conflict between provincial departments of natural resources (that have the mandate to favour the economical viability of mineral resources) and departments of environment (that have the mandate to protect the environment)? If so, how should this be addressed? All these questions should be answered before large-scale production begins.

One important data gap relates to the lack of data on natural groundwater chemistry at regional scales across Canada, and on fracture networks at the local scale. These data are, among others, necessary to trace contaminants that could migrate vertically from deeper units towards surficial aquifers. Not only are the data not available in most areas, but regulations are in their infancy and it is important to identify what should be included in a list of essential information that would allow a province to grant an exploration or production permit to a company.

### Discussions

*Baseline data*

Baseline monitoring in water wells was the first suggestion from participants, to fill the data gap on regional background chemistry. There was indeed an agreement that baseline data is a critical issue to identify existing conditions prior to drilling and fracturing because we have to know whether operations have altered the groundwater quality or not. This would include natural geochemical background signatures of the aquifer, the type of aquifer (confined/unconfined, porous, granular/fractured, etc.) and its properties (hydraulic conductivity, porosity, storage coefficient), water levels, gas concentrations near the surface (dissolved and gas phases), caprock properties, and identification of nearby fracture/fault zones within a radius of ~ 500-1000 m from production wells, where the most probable source of leaks would be located. Capture zones for municipal wells were also identified to be important information within potential development areas. Basic physical properties of the deep formations could include the shale and caprock porosity and permeability, hydraulic pressures, temperature and fluid density, as well as water and gas contents. Geochemical parameters to be collected could include: major ions, physico-chemical parameters such as pH, TDS, electric conductivity, organic species (targeting those typically and/or potentially present in slickwater), dissolved gas, age-dating parameters ($^{3}H$ and $^{14}C$), and perhaps radioactive elements. There was a consensus that all data should be collected before and after the hydraulic fracturing and that wellbore casing integrity testing should also be part of this baseline study (see Sections 2.3 and 2.5). In addition, recharge and discharge zone identification, as well as any useful information to plan for future water use, were considered important to collect.

The group believed that the industry probably has much of these data already, at least in the drilling pad area. A participant noted that Alberta already requires this kind of characterization in coal bed methane (CBM) development areas, and industry is already doing some monitoring because it is in their own interest. There is thus a need to make these data accessible, at least to government and for research.

These local data should also be linked to regional-scale or watershed-scale background surveys, where available, taking into account that differences might exist between regional (less detailed information) and local-scale monitoring data. At first, the group concurred that existing data should be used to assess potential impacts from a regional perspective. Then, in collaboration with the industry, local-scale studies should be carried out for a given pad before drilling begins. Among other things, a borehole geophysical study of the surficial casing (within bedrock), if not already available, should be conducted to investigate fracture orientation, dip, frequency and the fracture individual flow close to the surface (where aquifers are located), as well as seismic surveys to identify existing fractures and faults at depth and at the surface to complement the information on fracturing. The degree of fracture interconnection studied using, for instance, statistical simulations, would provide crucial information for flow system and travel time modelling.

As a first step, standard questions could be sent in the form of a checklist or flowchart to each company at each active site to know what information they have in hand. Also, a participant suggested that shale gas areas and aquifers that have been mapped be superimposed to see whether key aquifers are present above these shale gas formations. This could perhaps represent a first step in the development of vulnerability maps.

A participant noted that mapping and characterization efforts of regional key aquifers, such as those carried out by the GSC, Quebec and Alberta should be done regardless of shale gas exploration and development and hoped that all provinces would put more effort towards that goal. These baseline studies could be used to ultimately map aquifer vulnerability across Canada to identify the most sensitive areas. This vulnerability map could be refined as more data is available.

Since it is not yet clear whether shale gas vents less gas into the atmosphere than conventional oil and gas development, the magnitude of the cumulative environmental footprint (including waste management, potential water and gas leaks) must be addressed. A participant suggested that a Canada-wide study on leaks from wellheads be conducted. A participant said that the University of BC (UBC) is currently working with OGC (BC Oil and Gas Commission) on a fairing report focusing on unconventional fuels. In addition, water volumes used in conventional oil and gas activities versus (actually larger) volumes used for shale gas must also be evaluated, as well as gas composition.

Since water resources are limited in some regions, participants discussed whether the 4,000 mg/l limit for brackish water was the right standard to define groundwater to be protected. It was suggested, as in the "Water quantity" group, that the price of water could go up exponentially as TDS goes down, to favour the use of brackish or saline water. The use of potential saline formations for re-injection was also suggested as an important topic of investigation.

*Research*

The group suggested that many data gaps could be addressed through “research sites”, at selected drilling pads dedicated for research use. The group concluded that relatively local-scale sites are more practical and financially more reasonable for research projects, with more direct links to public concerns, than regional-scale sites. Participants all agreed that more effort should be devoted to the shallow part of the system, considered to represent the missing link. Aquifers indeed represent the link between regulators and the public, because they contain drinking water and are part of the active water cycle. Participants suggested that for all core above 300 metres, it should be mandatory to collect, log and store a given percentage to facilitate vulnerability assessments through the creation of a database of rock properties.

The percentage of research that goes into shale formations that have already been hydraulically fractured versus those that are currently not hydraulically fractured would need to be determined. Representative test sites across Canada for this baseline research must therefore be identified. Participants recognized that it would be beneficial to rapidly identify a few sites, typical or worst-case of major shale gas formations in the country, and to collect and interpret data from shallow aquifers at these sites (baseline study). Since new wells cannot be drilled every 100 metres in every provable zone, participants thought they could propose to use a science-based approach to determine what is reasonable in terms of cost and resources. One participant said that the agricultural sector was already doing something similar (through the NWSEP program of Agriculture Canada) and the GSC should collaborate with them and Environment Canada. Some added that these studies should not be a priority in remote areas (northern regions).

The Canadian Association of Petroleum Producers (CAPP) recently issued guidelines on hydraulic fracking, saying they are interested in disclosure of ingredients (but not the “recipe”, i.e. the percentages or quantity of each additive). Alberta and British Columbia already require the use of non-toxic drilling fluids, to the base of fresh groundwater for AB, or to 600 metres in British Columbia. These jurisdictions are therefore open to this type of disclosure. While such data were once considered proprietary, the situation seems to have changed. However, participants thought that even the “recipe” should be reported, since quantities are important in order not to exceed potable standards in groundwater. As proposed by the province of NB (see presentation by A. Daigle), the government could get the recipe and the public could get the ingredients. A participant added that the composition of flowback water should also be reported.

Geomechanical properties should be investigated in order to better understand the fracking process and fracturing itself (see Section 2.3), to be able to better estimate and especially increase the amount of water recovered. Moreover, it would be important to better understand why most flowback water (60 to 90%) does not come back to the surface after hydraulic fracturing. This could be carried out within a collaborative framework among industry, universities and government research scientists.

Data, even if sparse, could be used in conceptual numerical modelling for scenario analysis to identify most probable risk factors. These conceptual models would need to be verified with data to assess their representativeness. Detailed numerical models should be constructed when sufficient data at the local scale are available. Collected data would be used to constrain the model. Participants noted that two scales could be useful for a better understanding of the hydrodynamics: a regional scale for understanding groundwater flow and a local scale for transport models to assess risk of migration and leaks.

Projections for future water needs were considered a moving target. Future needs will depend on a combination of factors, such as the ability of industry to develop new, less water-intensive technology that has better tolerance to salinity, storage location, and the choice between water recycling and treatment.

Group members discussed the available experience and research on wastewater treatment processes. A participant stated that CANMET, a component of NRCan, has not done direct research on wastewater, but has completed some research for co-produced fluids injected into the formations. CANMET has focused, for the moment, on methods to recover methane gas in place, with potential to suppress $CO_2$, and to store it in a deep formation.

Participants summarized the research topic needs as follows:

- Guideline design tool for selection of the sites, disposal options and best practices for each approach;
- Data mining for historical information from several sources including geological and hydrogeological modelling on a regional scale, as well as new data collection in different locations;
- Research studies for reducing water usage and for improving waste management as well as better technology for the industry including fracking in association with horizontal drilling, disposal techniques, and fate of consumptive water.

*Data management*

Participants noted that there is not only a data gap, there is also a data access gap, stemming back to who controls the data. Data are usually located in different places, including private consultants, different provincial and federal departments, as well as in industry files. A single contact point (warehouse) was suggested, where everyone would send data on shale gas. Databases should be constructed with a common template in, if possible, open source (free) software. Requests would access the data in a standard form. The GSC could help with a template since they have been developing hydrogeological databases for the last 10 years.

A participant added that provincial and federal groundwater data, when available, are often not public or readily accessible, especially those related to groundwater quality. Participants agreed that all groundwater data should be public, like oil and gas data. A participant added that it is already the case in AB and BC: both provinces offer a brief period of confidentiality before it goes public (from 2 months to 3 years, depending on the nature of the well and how expensive, innovative and exploratory the work is). Another participant seemed sceptic, saying that data, at least some of it, is always difficult to obtain, especially from the industry. He recognized that the industry is becoming proactive as more and more data are being collected, but it does not necessarily want to share all of it. The group thought that since the public is now more aware of groundwater, people probably expect more access to information. Provinces also need to make the data accessible, at least for research studies. NB will soon be posting a web viewer which is a GIS interface allowing interactive access to well information; AB and BC already have this type of tool.

*Other related issues (seismicity, gas versus water, abandoned wells)*

Participants discussed data gaps related to seismicity, which represents an increasing public concern. It is now well known that fracturing shales can induce seismicity (micro-seismic events). It is, however, not known whether it may trigger small earthquakes (on the order of 1 to

3 on the Richter scale) or not. A participant noted that we still don't clearly know if induced seismicity is a real issue or to what extent we can predict it, and what the impacts might be on bedrock and on surficial geological conditions. Could a level-2 or 3 seismic event be an issue for a given site? A participant added that this issue was highly dependent on location. Nonetheless, a participant said that many people believe that shales are too weak to build up much stress that can be relieved by a hydraulic fracturing.

For example, a participant related that a Swiss geothermal project (that included fracking) apparently triggered a level-3 earthquake. The project was near a fault where thermal energy was being tapped. This is not typical for oil and gas reservoirs, which are usually located away from faults. However, in Quebec, a fault zone including the Logan line lies within the targeted zone for shale gas development. The group thus concurred that more work needs to be carried out on regional stress fields and micro-seismicity induced by hydraulic fracturing, including acquisition of data during fracking jobs (see Section 2.5).

Also, advantages and drawbacks of using propane ($C_3H_8$), butane ($C_4H_{10}$), carbon dioxide ($CO_2$) and nitrogen ($N_2$) for "gas" frac, instead of water were discussed. The conclusion was that our knowledge is very limited and that they should be further investigated. In addition, their potential effects on aquifers, given a leak, should also be studied in detail. Participants knew that nitrogen (N) could be transformed to nitrate, and that $CO_2$ dissolution in water may reduce the pH, which may mobilize metals already present in groundwater (mobilized reduced metals can be toxic). Propane and butane, two light chain hydrocarbons, were thought to be relatively soluble in groundwater; they should, nonetheless, be relatively easily biodegradable if their concentration is low. A participant noted that nitrates, pH, as well as propane and butane have maximum limits for drinkable water.

In addition, the group considered that there was a reporting/regulatory data gap that should be looked at promptly. However, this subject was not the focus of this geoscientific workshop. The group also briefly discussed orphan/abandoned wells and thought that industry could be required to identify where the deep wells are. Finally, the data gaps in short- and long-term economic/societal conflicts were briefly discussed. These conflicts may be due to competing uses that might affect current or future water uses, and also to impacts of "industrialization" in rural areas (e.g. transport, noise, traffic, pollution).

*Responsibility and authority*

A participant raised the question of how much government should be aware of industry's actions and whether companies should continue to report only on exploration/production wells, total water consumptive use, and the technique used for fracking. A list of mandatory information to be reported by each company should be made.

Participants thought there was a need for government financial support for collecting data and to develop 3D models based on integrated geotechnical and hydrogeological data, oil and gas log data, water survey and quality data, and GSC geological baseline data. There are only a limited number of regional aquifer studies across Canada, while municipal wells, for which interesting data are usually available, are also limited in number since most communities in Canada use surface water resources. In remote areas (e.g. Horn River, BC), even domestic water wells are scarce. Therefore, the funding required for a complete hydrogeological evaluation might be significant.

Participants talked about cumulative effects of shale gas development and the regulations that are currently not designed for this scale of development. A participant said there is an important need for a recommendation to synthesize existing databases from various government organizations and to have a concentrated effort by various agencies to work together and perhaps establish baseline studies. He suggested more discussions could take place to explore how much government should do to acquire these data. Another participant noted that the industry could oversee data gathering using a common database template developed and managed by the government. A participant noted that the U.S. government also wanted to manage the data to be able to study potential impacts of shale gas activities, but obtaining data appears to be difficult.

Participants underlined the fact that it may be hard to convince all companies to spend the money upfront, to avoid liabilities. The group said that, nonetheless, some of them have begun to do their own groundwater sampling, in the drilling pad area, to avoid future lawsuits. Since no regulation forces them to do it, participants thought that the government should probably play a role in regulating these activities, in collaboration with all the provinces and territories, and in consultation with professors. It was indeed thought that it would be best that the government (NRCan, EC) specifies some standard analyses that should be run on all water samples, including the methods (based, for example on U.S. EPA requirements). This will provide comparable data between companies and provinces. In addition, governments should team up with the industry to pay for research wells since each horizontal well costs at least $10 million. The government, in collaboration with universities, could perform multiple tests and analyses, as well as multi-level monitoring. A participant noted that sampling only around the pad area, which companies currently do, is probably not enough, and, moreover, it would probably be best if an objective authority managed or supervised these operations. Nonetheless, industry should undoubtedly participate in the overall cost of monitoring, related both to groundwater quality and water levels, gas content, and micro-seismicity.

Seismic surveys, which are usually conducted by oil and gas companies, were deemed an important part of site characterization. These surveys are very expensive (~15 K$/km), but they allow them to obtain deep and shallow geologic information. Governments cannot afford to have this kind of survey done. However, this information could be used to study potential connections between deep shale formations and surficial aquifers. Fracture and fault distributions are typically only known at the regional scale (large fractured and faulted zones). However, gas and contaminant migration is a local-scale issue. For the moment, only "old" deep surveys are publically available (~1970-1990's). Additional surface seismic surveys would have to be carried out to obtain information on shallow aquifers (~200-300 m deep) and statistical tools would have to be used to make correlations to establish potential connections. Industry also runs borehole geophysics and airborne TEM and FEM (electromagnetic methods) to identify, among other things, shallow aquifers and paleovalleys (80-200 m depth range). Perhaps the industry, in order to get a permit, should be releasing this information to provincial departments of natural resources. In addition, only the industry has deep wells and related characterization data that would allow a better understanding of system dynamics and thus, enough information to build a reasonably suitable numerical model for regulators to work with. Should the government force them to report these data?

Participants all agreed on the need for collaborative efforts between industry, government, and non-governmental organizations to find joint solutions to protect groundwater resources. Participants generally agreed that government (provincial and federal), and not industry, needs to take the lead on defining and assessing background or baseline conditions prior to shale gas exploration. Certified labs should do the analyses, while independent third-party companies should collect the samples and interpret data. There was a clear consensus that industry should not do all the research and baseline study on its own due to evident potential conflicts of interests: independent research is needed for credibility. Academia was suggested as a possible source of future research, in as much as studies are not completely funded by the industry and, therefore, their results can be considered independent and unbiased. A participant added that there is a need to keep up with new technology as it is approved and keep abreast of potential impacts.

Regarding a possible conflict between different government departments and levels (federal versus provincial), the group suggested that each organization should have specific mandates for various aspects of the whole process. In the U.S., coordinated efforts among agencies have seemed to work well so far.

## 2.5 Monitoring methodology

### Background

Monitoring is undeniably a key operation within the framework of shale gas activities. However, how should this environmental monitoring be carried out? Which environmental parameters should be monitored? How many wells should there be and at what locations? What should be the duration of the monitoring program? Shale gas production is fairly recent and regulation is not quite ready yet. Nonetheless, groundwater is a vital commodity and its potential contamination is a significant concern for the public. Governments should therefore be prepared to take preventative measures, before any irreversible damage occurs. Indeed, once contaminated, an aquifer is difficult and costly to remediate, sometimes even impossible. We must therefore ensure groundwater is protected and minimize risks before the industry begins exploration and exploitation.

Ground vibration and micro-seismicity is also another public concern. Fracking is performed using high pressure (~100 MPa or 15,000 psi), and when the “frac and perf” method is used (see Section 2.1), guns are utilized to perforate the production casing (laterals). These activities induce vibrations that may even be felt at the surface. Fracking and drilling operations could potentially also induce landslides when sensitive clays are present at the surface. These operations should thus be planned and managed with caution and must be carefully monitored.

### Discussions

*Monitoring plans*

The group agreed that effort needs to be placed on monitoring of shallow aquifers as a major concern lies with any changes that occur to water-supply aquifers due to shale gas activities. There was agreement within the group that monitoring should be carried out before, during and after fracking and gas production to better assess the changes these activities may have produced and to ensure traceability. Monitoring should also continue after the well is closed to monitor potential long-term effects due to pressures remaining in the well and flows at depth (such as in conventional oil and gas wells, which are closed when they are no longer economical, but still retain pressure). Participants suggested that monitoring programs should include sampling of groundwater, surface water, gas in the soil, and dissolved gas in groundwater.

Monitoring to detect changes in both quality and quantity of water should be imposed. A participant said that a monitoring plan should consider what is manageable and what tools we need over time to protect the resource and manage the uncertainty.

Before any exploration or production begins, a geochemical baseline study including a water-well survey, should be carried out. Participants suggested beginning with existing well data from provincial and federal databases and existing reports from consultants. Groundwater should then be sampled at the production site and nearby, as well as off-site to complete the geochemical portrait. Samples should be collected from outside taps, like any other geochemical study.

The production well itself and its close neighbourhood were considered a high priority area for research and monitoring due to potential casing leaks and gas release: the sooner a problem is identified, the sooner remediation can be initiated. In the U.S., companies must sample existing wells within a 120 m (400 ft) radius. Nonetheless, a few wells in a much larger area should be monitored (~2-3 km) to make sure the groundwater is not affected by these activities even at distance (due to indirect pathways). As aforementioned, fracking may reactivate a fault or connect fractures and affect other wells. Groundwater should also be monitored at multiple depths and even regionally. It was also proposed that more populated areas could have more monitoring wells (stations).

The group thought that monitoring for chemicals should include relatively inert tracers to detect fluid migration, and to provide evidence if migration is occurring. In addition, specific chemical additives used in fracking, especially any toxic chemicals, should also be integrated into routine sampling. TDS, chloride and bromide could be used for first detection of a contamination event. Radium is also targeted in certain areas (e.g. in NB) since the natural gas may contain radium gas and other daughter products. If present, radioactive materials can become concentrated on oil and gas-field equipment. A participant said that currently in the U.S, the main elements and parameter that are being tracked in water are Ba, Sr, Br, Cl and TDS. In addition to chemical parameters, total dissolved gas, pressure, temperature, pH, and water levels should be routinely collected. Some participants questioned current monitoring capacities within the government and the list of parameters and questioned whether they are adequate to detect changes in groundwater quality and quantity related to shale gas operations.

Discussions then addressed isotopic analyses, which can be used to identify elements not normally occurring in shallow aquifers. For instance, to know if shale gas activities could have an impact on aquifers, isotopic analyses can be used *a priori*, among other methods, to detect any thermogenic gas near the surface. Its occurrence would imply that a preferential pathway already exists, which fracturing may aggravate. A participant suggested that this cost could be assumed by the companies since isotopic analyses are very expensive. Another participant recommended that isotopic ratios for differentiating biogenic versus thermogenic methane from wellhead leaks be measured across Canada and results integrated into the common database.

Wellbore casing integrity tests should also be part of a monitoring plan. Indeed, as mentioned in Section 2.3, the wellbore is a key part to ensure integrity of the system and prevent leaks. A participant noted that the technology for monitoring casings has significantly improved over the last few decades and that this testing was a great added value that was not so expensive (compared to the overall drilling and fracking budget). The group agreed that this monitoring procedure for well integrity should first be carried out prior to fracturing (such as in NY State where wells are inspected prior to hydraulic fracturing) and after (to make sure high pressures have not damaged the casing).

Throughout the discussions, different suggestions were made by the participants to improve monitoring programs. For instance: 1) most vulnerable and/or populated areas could be studied first, similarly to what has been done by the province of Quebec; 2) remote sensing could be used as a tool to detect gas emissions in the air: radar technology is currently being used for the oil sands; 3) more analyses through environmental evaluations (EA) should be requested in areas at risk; 4) inspiration could be taken from the current EPA study on potential impacts of hydraulic fracturing (available at: http://www.epa.gov/hfstudy/HF_Study__Plan_110211_FINAL_508.pdf).

Appropriate monitoring was considered by all a win-win situation, as it helps companies and authorities to understand the geological context and structure and helps to manage potential effects and avoid major and undesired contamination events. Indeed, complaints can't adequately be addressed if no baseline data are available (e.g. in West Virginia, U.S.). The cost for monitoring should not be a problem for the industry since, compared to the costs of drilling (in the order of a few millions of dollars), this aspect is almost insignificant in the overall budget. Monitoring was also considered an appropriate approach to identifying trace elements to better understand mechanisms of migration. The group also highlighted the fact that it is very important to have partners, to share information and avoid work duplication and past mistakes. A participant said that many companies in the U.S. are now doing routine baseline analysis of groundwater within ~1 km of a shale gas well prior to drilling. However, it is still hard for government agencies to get the data, because it is personally identifiable to a landowner, and it could therefore violate U.S. privacy laws. Another participant said that BC Government just put in 6 monitoring wells in the Montney and that there are discussion/plans to put wells in the Horn River Basin.

*Seismicity*

The use of technology to visualize the subsurface was considered a highly valuable tool: industry is ahead of government and academia in this area because they use micro-seismic and 3D seismic to understand where fractures are generated in the subsurface. 3D seismic is being used to identify large and moderate-scale fault systems from deep into the shale formation up to the surface. Micro-seismic monitoring allows the measurement of stress during fracking; it can also detect slippage on faults and pinpoint the location. It can thus provide information on the growth and location of the fractures. A participant argued that this technique is not suitable to monitor small earthquakes because it cannot measure ground motion. Even if small earthquakes are not dangerous, it is a concern for the public. It may trigger major events. It may also induce landslides if sensitive clays are present (such as in the St. Lawrence Lowlands and Appalachian piedmont above the Utica Shale formation).

As a general practice, companies monitor to understand fracture orientation and how many fracking jobs are required. However, it can be expensive and there may be monitoring issues. To maximize the value of the well, engineering design and experience, as well as monitoring data are required to optimize the efficiency of a fracking job and optimize their number. Participants thought that these data should be made public because they contribute to the understanding of the system hydrodynamics and, therefore, on prevention of potential contamination.

*Responsibility, management and regulations*

There was a consensus that monitoring should consider an array of tracers, to be able to observe evidence of changes in groundwater quality and quantity. Some participants thought that site monitoring issues could be the industry responsibility (as in the mining industry), whereas regional scale monitoring could be the government responsibility. However, to make sure that published data and results are reliable, an objective person/organization should also be involved in the site monitoring. Participants suggested that regulations should be adapted based on monitoring results at the well casing and well pad. Regulations for monitoring are currently active in BC, Alberta and Saskatchewan and will soon be in NB. However, they differ from one province to another, and they can even be site specific.

A general agreement was that when developing an area, provincial geological agencies need to have an increased role by establishing several monitoring stations. In addition, it was said that more expertise on monitoring should be developed within the government, especially since more and more groundwater is being used for water supply.

The group addressed the issue of which individuals or organizations should be responsible for developing the baseline study plans, creating a common template for the database, management of these databases, and monitoring. Whatever group is chosen, the group thought that it should be one that the public trusts so that it is possible to maintain the integrity of the results. This was not generally thought to be industry, although industry should fund a part of this research since they will also benefit from it. Participants said academics might also be suspect, as industry often directly funds their research. Participants identified government as possibly the most neutral body to be responsible for these activities. The provinces, as well as the GSC, Environment Canada (EC) and Health Canada (HC) were identified to team up, as their mandates are complementary. The issue of both trust and credibility appeared to be important to the group.

Management issues will likely include confidentiality of wells, politics of jurisdictions and lack of cooperation from industry in sharing data. For instance, collaborations/partnerships with industry was thought to result in a confidentiality issue (at least over a certain period), which may not be desirable. However, a participant believed that confidentiality could be beneficial, as it would allow industry to recognize and respond to issues before the public becomes aware of them (e.g. gas leaks from wellheads). Opinions differed on this issue, i.e. whether confidentiality should be avoided or not. Regulation was suggested as an alternative to volunteer collaboration, since companies may not want to fully collaborate.

Some participants shared their concerns on upcoming government cutbacks and potential additional cuts in the future since monitoring involves long-term plans for human resources and equipment, including drilling, if required. This concern is particularly relevant where there is little or no expertise in government agencies, and modest resources.

## CONCLUSIONS

Participants discussed water and waste management issues, including temporary storage, re-use, re-injection and treatment, resulting from shale gas exploration and production operations. Water consumption and monitoring were also examined. Environmental risks for surficial aquifers from upward migration, waste storage (especially cuttings), fluid transport, as well as casing and surface pond or tank leaks gave rise to many animated discussions.

The main conclusions of this geoscientific workshop can be summarized as follows:

- Research studies should be carried out to reduce water needed for fracking. Minimizing water consumption with improved technology indeed appeared to be the best solution, to reduce the overall quantity of water use and wastewater to be treated or stored, followed by or, better, combined with, recycling.
- It would also be important to develop new technologies that improve the recovery rate of water, especially if fresh water is to be used. Since approximately 30% of water comes back up each time within a relatively short period, it still needs to be topped up each time with considerable volumes of new water.
- The use of brackish or saline water, which is not in conflict with other water demands, along with the use of “green” additives, should be considered promising avenues of research.
- Baseline studies should be carried out to ensure that groundwater is characterized prior to exploration.
- Research studies must be carried out since little is known on potential migration of fluids and gas from the casing or shale formation towards surficial aquifers.
- Monitoring plans should be developed based on the site characteristics for water, gas and well casings. Participants concurred to say that pre, during and post fracturing and production monitoring will benefit the community.
- Data from all sources need to be made available, at least to research groups and government, and integrated into a common database. Participants agreed that data access and database management should be transparent, as open data is now very important for the public.
- Collaboration across provincial borders and with other countries such as the U.S. and joint discussions should be sought. If Canada or each province works independently, this may lead to environmental problems due, among other things, to a lack of knowledge and regulatory disparities. Furthermore, federal and provincial governments should work together for the protection of groundwater resources, and the industry should be part of research studies, to share their data and contribute financially.

The participants also discussed government responsibility; they suggested, among others things, that a regional development plan (including locations of pads, type of frac, estimated water consumption and source, pipelines, ponds, etc.) could be imposed to obtain a permit before development can proceed. The role of government may be to inspire innovation by setting reasonable regulations, which are challenging to meet. For example, a minimum percentage of recycled water could be set. Industry would then be more motivated to innovate. Participants suggested that water pricing and environmental liability be used as incentives to reduce water consumption and favour recycling (reuse), as well as the use of “green” (non-toxic and shorter-life) additives for hydraulic fracturing. This appeared to be a win-win situation, since the "greener" the oil companies are, the more "accepted" they will become. The industry image is definitely a problem, due to bad past experiences.

Participants underlined the fact that the production of shale gas is new and regulations are based on old ideas from the conventional oil and gas operations. Therefore, research studies must be carried out to be able to develop regulations and policies that are well adapted to these new activities to ensure sustainable development of both groundwater and shale gas resources.

The identification of potential or upcoming targets for shale gas exploration, as well as their estimated production volumes were identified as topics to be addressed by the GSC. However, with changing technologies and market conditions, and complex geological relationships between temperature, pressure and storage of adsorbed gas in organic matter, the quantitative evaluation of in-situ and recoverable resources is a challenging task (see Open File 7088).

The group felt that the public is not well informed, but are very focussed, and that there is a critical need for additional, and more accurate, information. The public is very apprehensive about these activities, especially fracking, and this is part of the government's mandate to find answers and provide them to the public. Research will help reassure the public. For instance, the European Union currently uses this strategy for all its nuclear sites. Both provincial (natural resources and environment) and federal (including GSC, Environment Canada and Health Canada) levels should work hand-in-hand on this upmost priority topic, to protect our valuable aquifers.

Finally, it was noted that some of the issues are similar to those in the conventional oil industry (where injection is performed to increase the oil recovery) or in carbon capture (where $CO_2$ is injected at high pressure in deep saline formations) and therefore we should establish links with groups working in these fields. Conversely, insights gained from studies on shale gas may be usable in other domains.

## ACKNOWLEDGEMENTS

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# APPENDIX – PDFS OF ORAL PRESENTATIONS

# United States

Daniel J. Soeder, Senior geologist, U.S. Department of Energy

NATIONAL ENERGY TECHNOLOGY LABORATORY

# Environmental Risk Assessment for Shale Gas Development

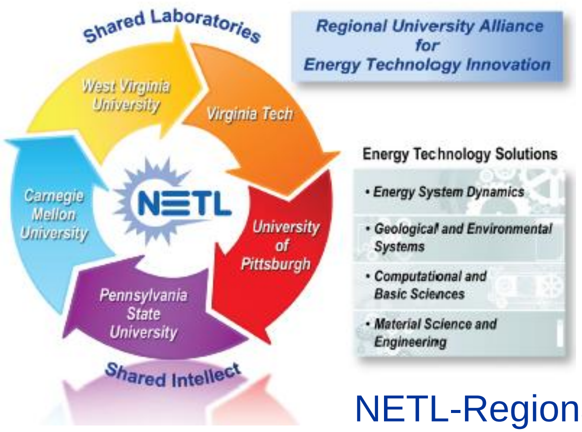
Daniel J. Soeder, NETL. Morgantown, WV

Presentation for Geological Survey of Canada
Calgary, 25 November 2011

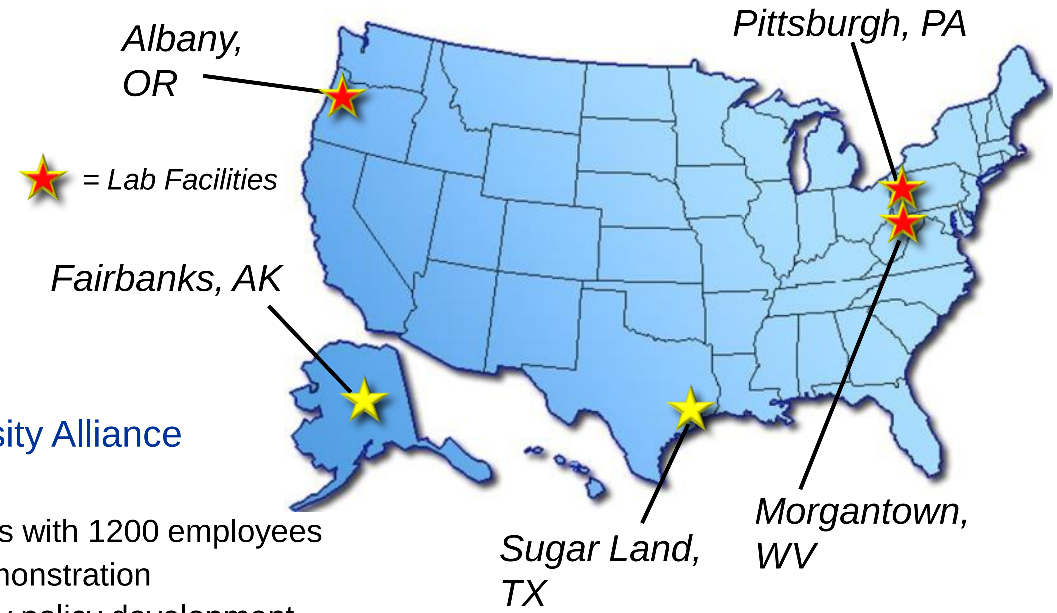
NETL-RUA Regional University Alliance

U.S. DEPARTMENT OF ENERGY

# DOE National Energy Technology Laboratory




NETL-Regional University Alliance




- National lab dedicated to fossil energy; 3 sites with 1200 employees
- From fundamental science to technology demonstration
- Onsite research, extramural R&D, and energy policy development

*Oregon*

*Pennsylvania*

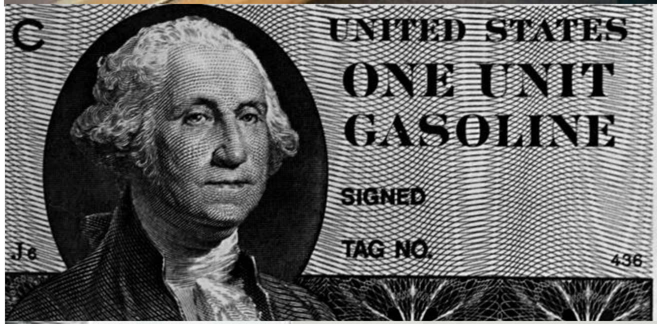
*West Virginia*

# This Presentation

- Brief history of U.S. shale gas research
- Production technology for shale gas
- Concepts of risk
- Risk assessment process for shale gas
- Environmental concerns
- What we know, don't know and are trying to learn

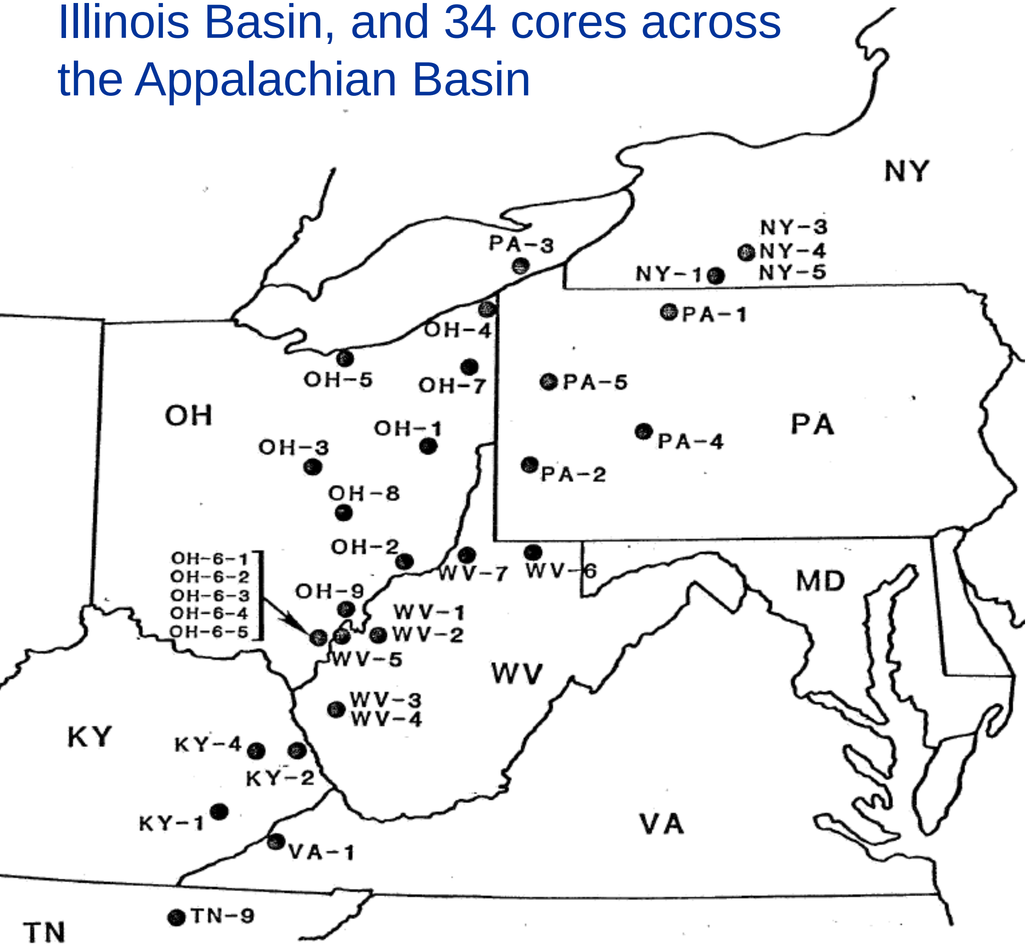
# Why Shale Gas?

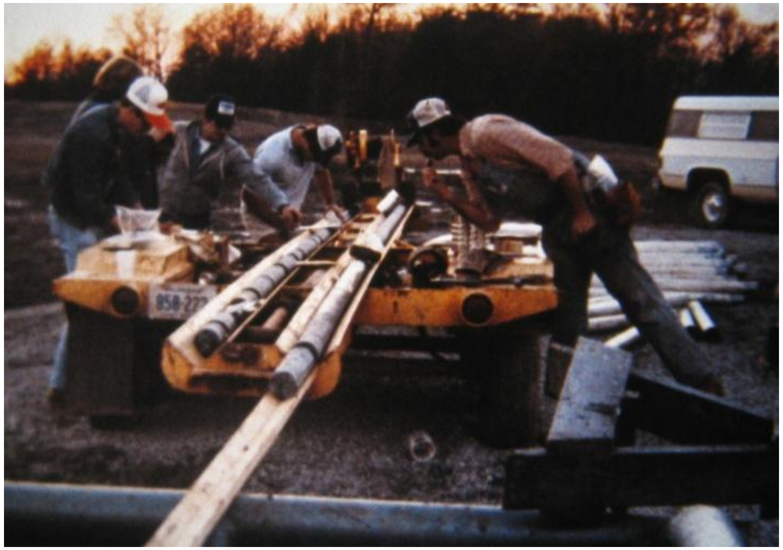
- **October 20, 1973 to Spring 1974: OPEC oil embargo against United States**
  - Price of gasoline quadrupled ($0.40-$1.60)
  - Gasoline was also  short supply
- **U.S. Department of Energy formed by Carter Administration on August 4, 1977**
- **Natural gas R&D projects funded by DOE to increase domestic energy supplies**
  - **Eastern Gas Shales**
  - Western Tight Gas Sands
  - Coal Bed Methane
  - Later projects: methane hydrates, E&P tech research, and environmental impact studies.
- **Objective: Encourage development of domestic sources of oil and gas**
  - Resource characterization/data transfer
  - Better technology and engineering


# DOE Eastern Gas Shales Project 1976-1992

44 total cores, including 3 from the Antrim Shale of the Michigan Basin, 7 from the New Albany Shale of the Illinois Basin, and 34 cores across the Appalachian Basin



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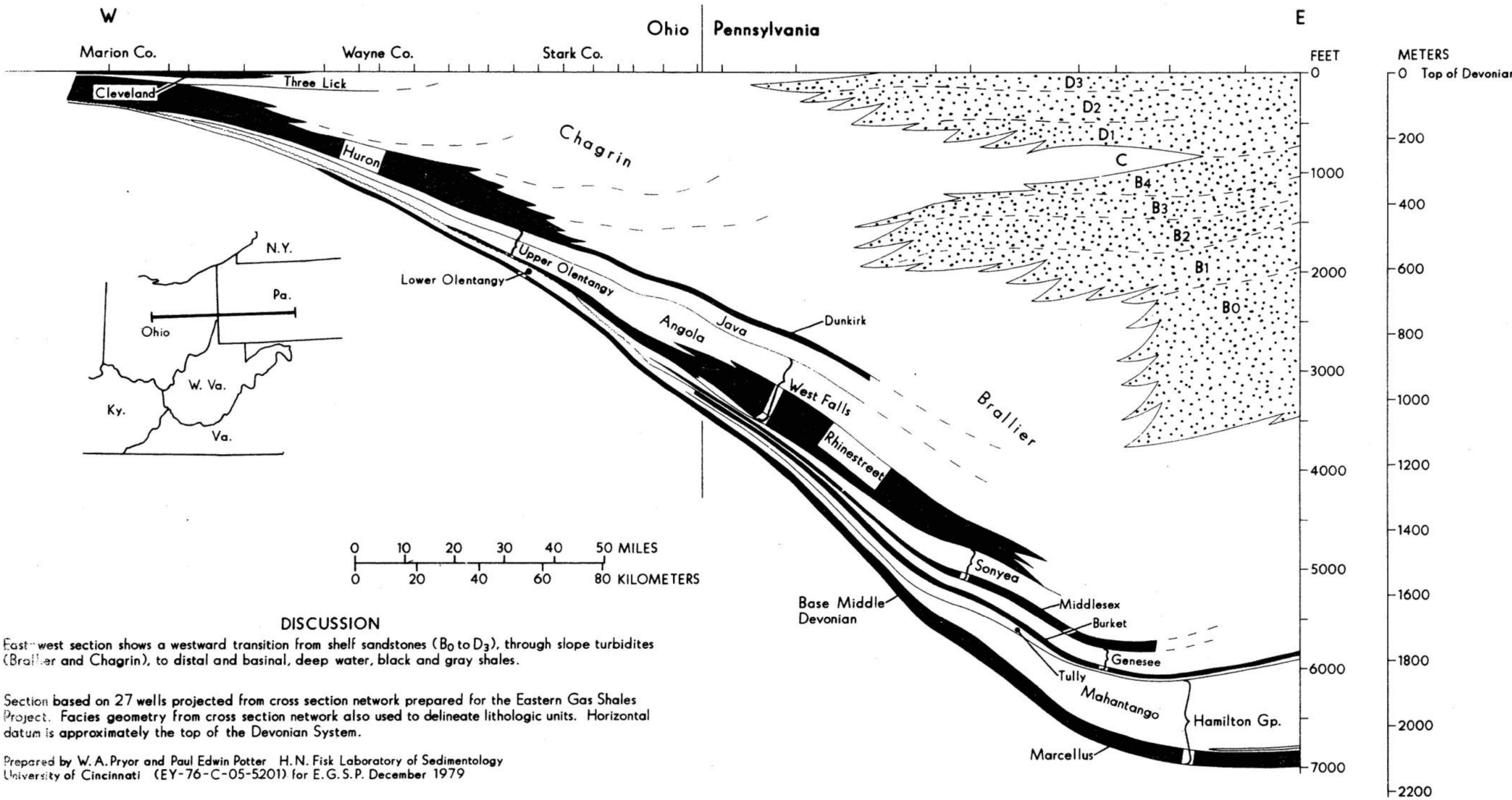
NATIONAL ENERGY TECHNOLOGY LABORATORY

# Appalachian Basin Devonian Shale



# Gas Shale Geology

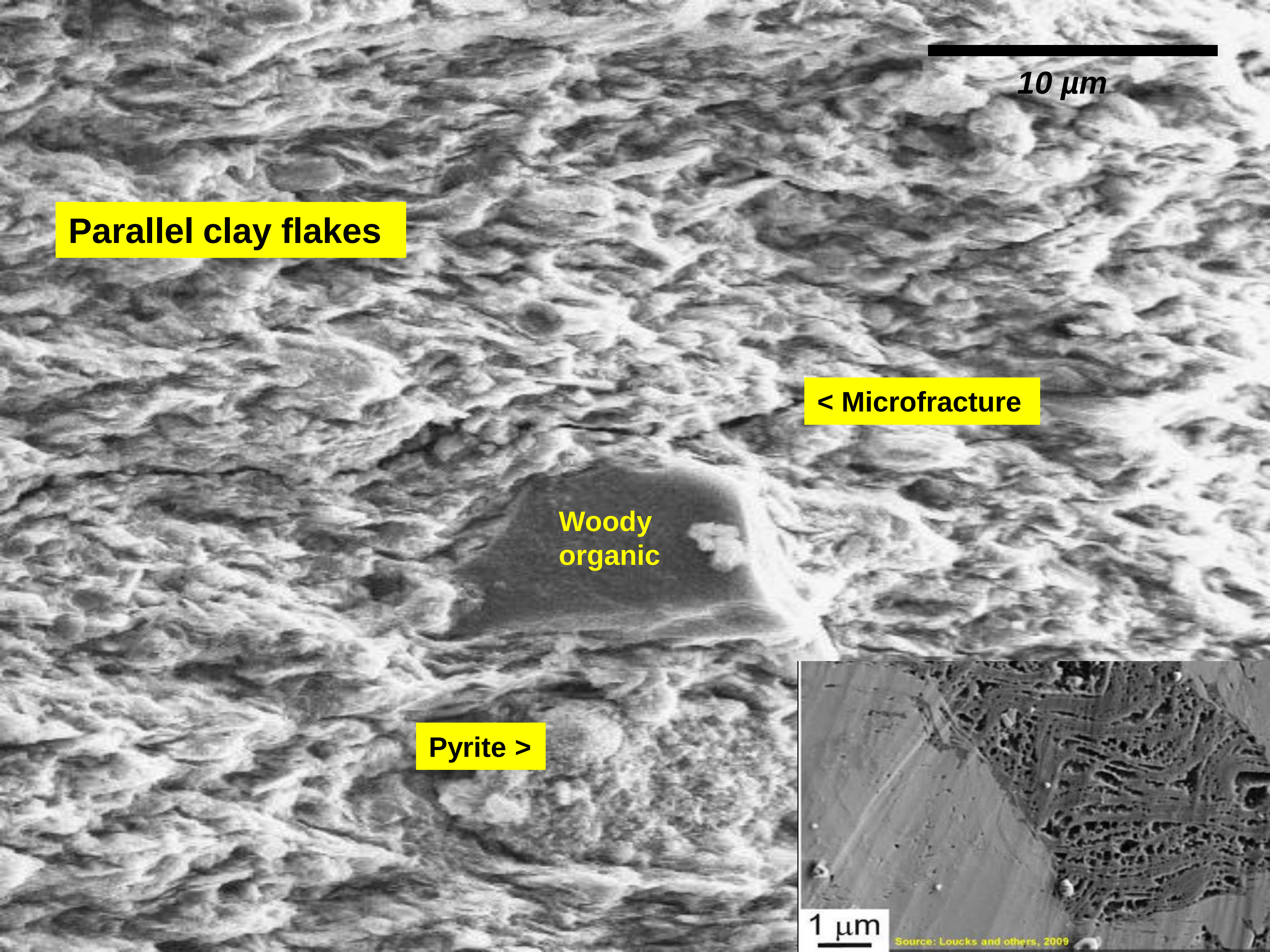
- Sedimentary rock formed from mud, composed of fine-grained clay, quartz, organic matter, and other minerals.

- Shale (mudstone) types:
  - organic-rich (black)
  - organic lean (gray or red)

- Porosity ~ 10%
- Permeability $\mu$d to nd.

- Small grains = small pores: flat pores between flakes, stacked house of cards, nanopores within the organic matter.

- Gas occurs in fractures, in pores and adsorbed or dissolved onto organic materials and clays.

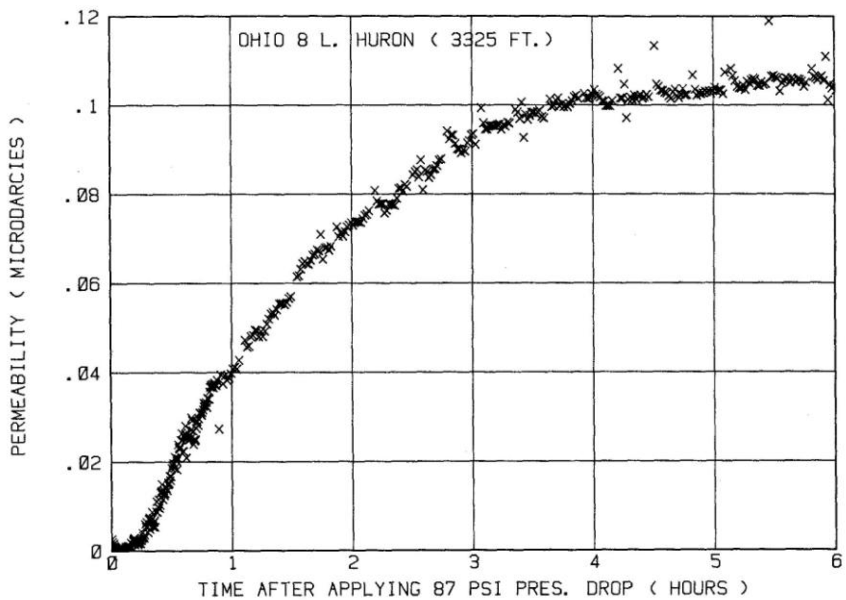

10 µm
Parallel clay flakes
< Microfracture
Woody
organic
Pyrite >
1 µm
Source: Loucks and others, 2009

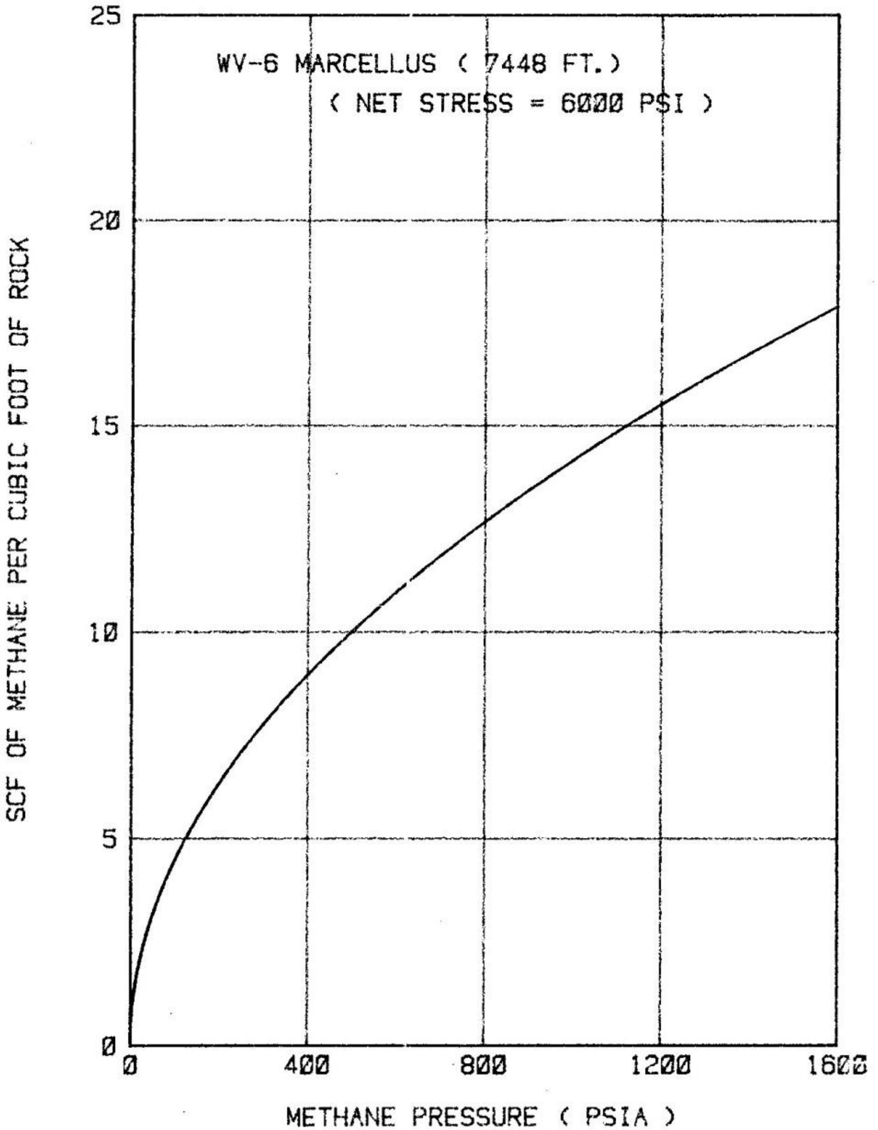
# IGT Core Analysis Results

EGSP shale samples analyzed in 1986: 7 Lower Huron and 1 Marcellus, data published in 1988.

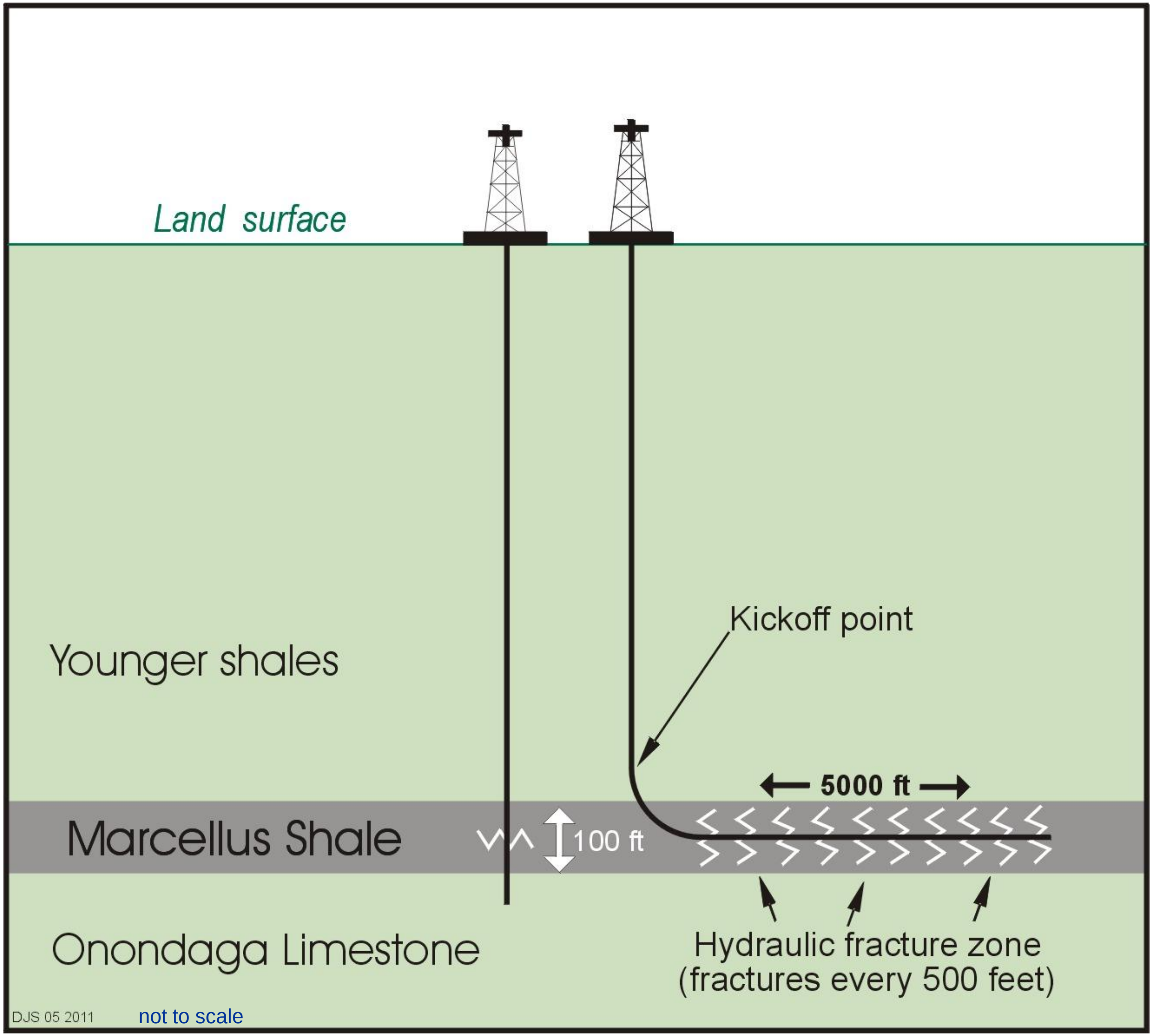
Two-phase flow in shale occurs only with great difficulty.

Marcellus: 26.5 SCF/ft$^3$ at 3500 psi reservoir pressure, compared to1980 NPC resource estimates for shale: 0.1 to 0.6 scf gas/ft$^3$ (44 to 265 X greater)



# New Technology Needed for Shale Gas




- Directional drilling
- Downhole hydraulic motors
- Measurement while drilling
- Better inertial navigation
- Better telemetry: mud pulse and electronic
- 5000 ft laterals
- Light sand frac
- Slickwater frac

# Shale Gas Production

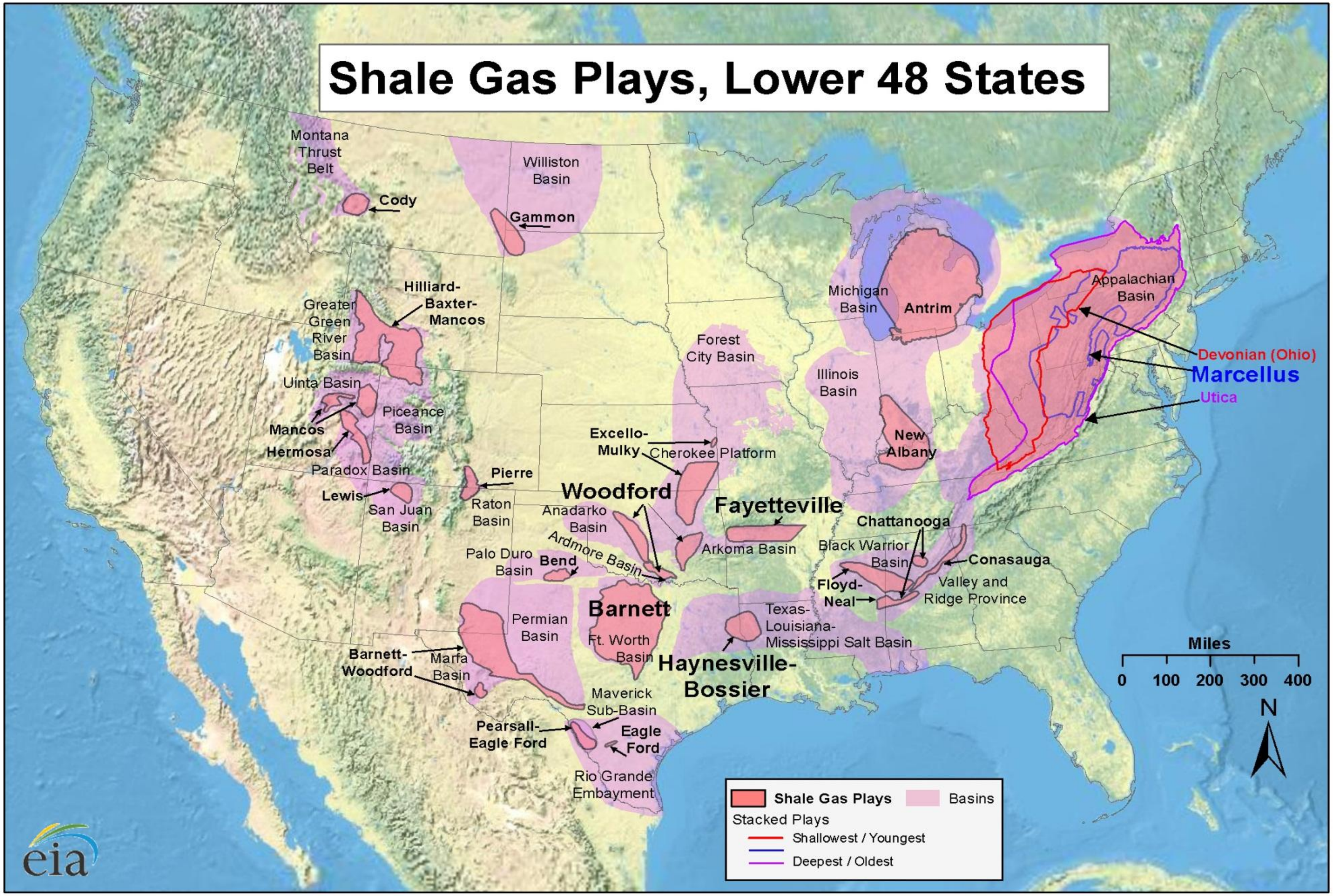
- **Barnett Shale**, Ft. Worth Basin, Texas: Mitchell Energy adapted offshore technology for economic production of shale gas in the 1990s
  - Directional drilling, long laterals & light sand fracs
- **Fayetteville Shale**: 2004, Southwestern Energy, Arkansas
- **Haynesville Shale**: Same period, ArkLaTex area
- **Marcellus Shale**: Range Resources, vertical well to deeper target in 2005; dry, recompleted vertically in Marcellus Shale
  - Several horizontal wells were tried the following year, without success
- Range Resources, Gulla #9 "discovery" well drilled in 2007
  - Drilled horizontally in Washington County
  - Slickwater frac completion with light sand; IP 4.9 MMCFD
- Nearly 8000 Marcellus Shale wells permitted or drilled in PA and WV between January 2008 and October 2011.
- New targets: Woodford Shale, Arkoma Basin, Utica Shale, Appalachian Basin, Eagle Ford Shale, Texas Gulf Coast/Maverick Basin


CAT

# Water supply impoundment at frac site

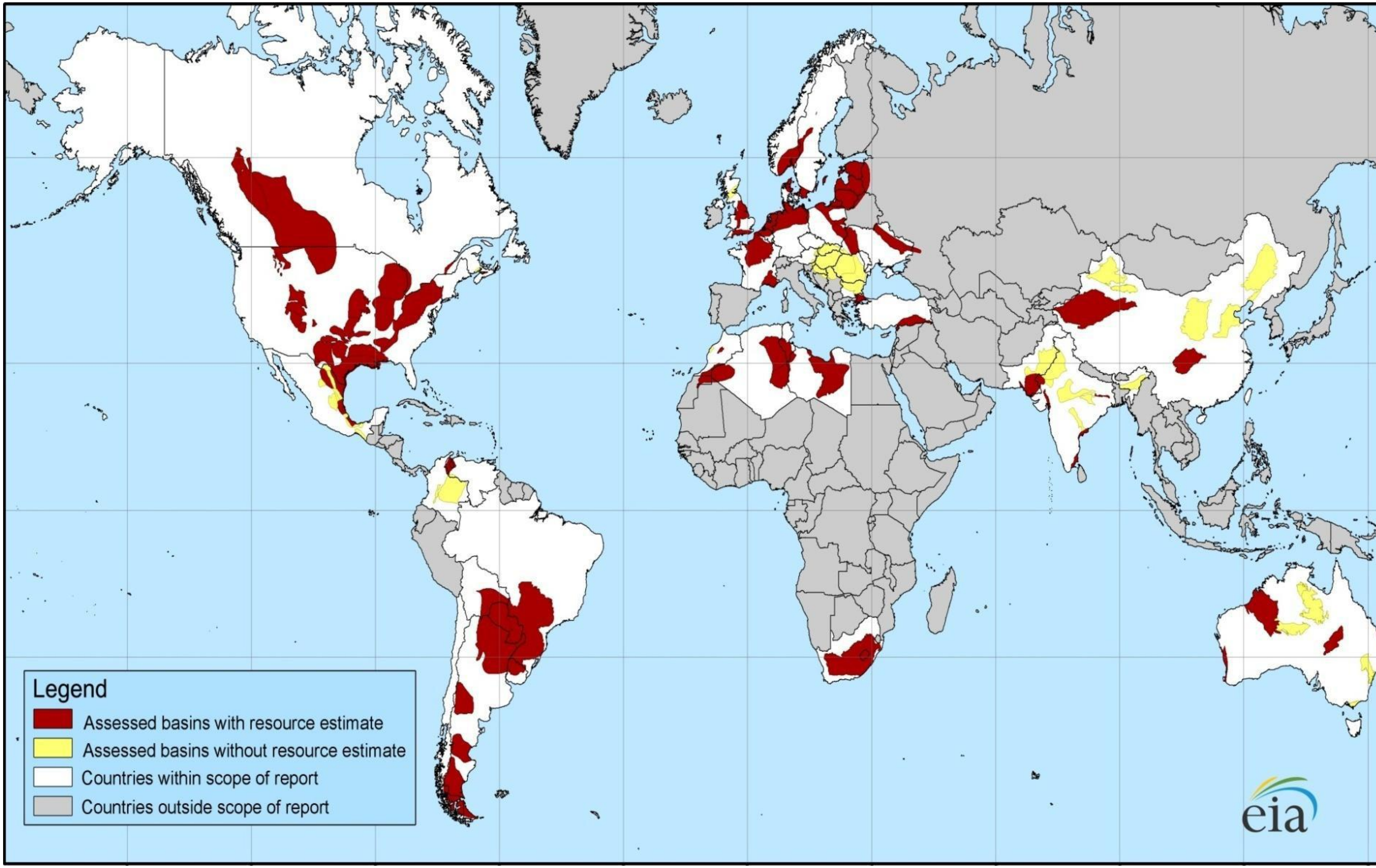

NATIONAL CRANE
NATIONAL CRANE
TITAN
Tow Master

# Production Well Pad




Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

# Shale Gas Worldwide




Source: U.S. Energy Information Administration

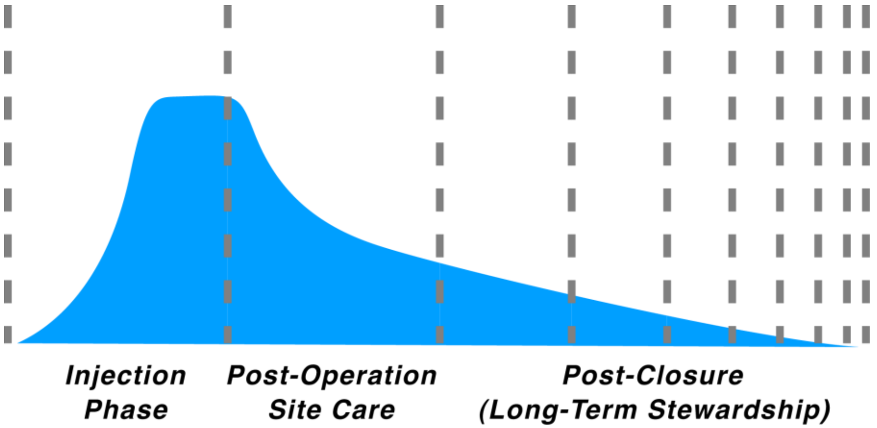
# NETL Office of Research and Development


- New program charge in 2011: Assess risk from oil and gas production
- Program Technical Areas:
  - Ultra-Deep Offshore/Frontier Regions
  - Unconventional Resources, primarily shale gas
- Focus Areas for Risk Assessment:
  - Potential impacts from hydraulic fracturing
  - Potential impacts from poor wellbore integrity
  - Potential impacts to water quality
  - Potential impacts to air quality

# Concepts of Risk

**Risk = probability X consequence**

Risk can vary over time >>
($CO_2$ injection example)




- **Threat: external events that cause risk**
  - Threats can exploit vulnerabilities
  - Threats are assessed in terms of probability (Precautionary Principle)
- **Vulnerability: internal weakness that invites risk**
  - Vulnerability only exists in the face of a threat
  - Vulnerability is assessed in terms of likely threats (Calculated Risk)
- **Both threats and vulnerabilities must be assessed to properly understand risk.**

# Site Risk Assessment

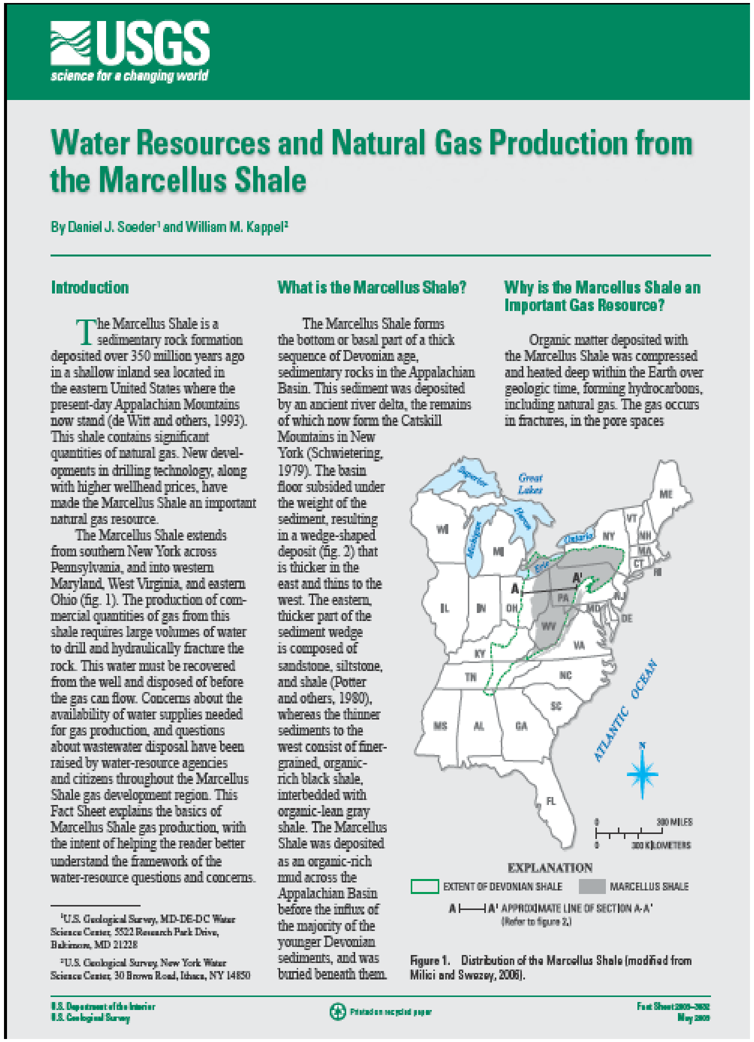
- **DOE National Risk Assessment Partnership (NRAP)**
  - Cooperative effort between multiple National Labs
  - Scenario-based, site modeling for carbon storage in engineered geologic systems
- **Sometimes called site performance assessment**
- **Uses FEP-based scenarios and probabilities**
  - **F**eature: property of a geologic system that may affect risk
  - **E**vent: an action that introduces higher risk conditions into a system
  - **P**rocess: a method or procedure that increases risk
- **Predict performance of components using high fidelity models**
- **Validate by moving to simpler, faster reduced-order models (ROM), define and reduce uncertainty**
- **Provide quantitative basis for geologic storage security**

# System Risk Assessment

- **Integrated Assessment Models (IAM)**
  - Probabalistic assessment of system risk (multi-site)
  - Interaction of sites can increase or decrease risk
- **Divide system into components, develop detailed, validated models, reduce uncertainty**
- **Develop reduced order models (ROM) to reproduce component detailed model predictions**
- **Link ROMs through IAM to predict total system performance, interactions and risk**
- **Calibrate using field data and databases**
- **Quantify potential long-term liability**

**Risk Profile (Quantify) → Risk Management (Strategy) → Validation (Field Data)**

# Water Resource Risks



USGS
science for a changing world

## Water Resources and Natural Gas Production from the Marcellus Shale

By Daniel J. Soeder[1] and William M. Kappel[2]

### Introduction

The Marcellus Shale is a sedimentary rock formation deposited over 350 million years ago in a shallow inland sea located in the eastern United States where the present-day Appalachian Mountains now stand (de Witt and others, 1993). This shale contains significant quantities of natural gas. New developments in drilling technology, along with higher wellhead prices, have made the Marcellus Shale an important natural gas resource.

The Marcellus Shale extends from southern New York across Pennsylvania, and into western Maryland, West Virginia, and eastern Ohio (fig. 1). The production of commercial quantities of gas from this shale requires large volumes of water to drill and hydraulically fracture the rock. This water must be recovered from the well and disposed of before the gas can flow. Concerns about the availability of water supplies needed for gas production, and questions about wastewater disposal have been raised by water-resource agencies and citizens throughout the Marcellus Shale gas development region. This Fact Sheet explains the basics of Marcellus Shale gas production, with the intent of helping the reader better understand the framework of the water-resource questions and concerns.

[1] U.S. Geological Survey, MD-DE-DC Water Science Center, 5522 Research Park Drive, Baltimore, MD 21228

[2] U.S. Geological Survey, New York Water Science Center, 30 Brown Road, Ithaca, NY 14850

### What is the Marcellus Shale?

The Marcellus Shale forms the bottom or basal part of a thick sequence of Devonian age, sedimentary rocks in the Appalachian Basin. This sediment was deposited by an ancient river delta, the remains of which now form the Catskill Mountains in New York (Schwietering, 1979). The basin floor subsided under the weight of the sediment, resulting in a wedge-shaped deposit (fig. 2) that is thicker in the east and thins to the west. The eastern, thicker part of the sediment wedge is composed of sandstone, siltstone, and shale (Potter and others, 1980), whereas the thinner sediments to the west consist of finer-grained, organic-rich black shale, interbedded with organic-lean gray shale. The Marcellus Shale was deposited as an organic-rich mud across the Appalachian Basin before the influx of the majority of the younger Devonian sediments, and was buried beneath them.

### Why is the Marcellus Shale an Important Gas Resource?

Organic matter deposited with the Marcellus Shale was compressed and heated deep within the Earth over geologic time, forming hydrocarbons, including natural gas. The gas occurs in fractures, in the pore spaces



Figure 1. Distribution of the Marcellus Shale (modified from Milici and Swezey, 2006).

U.S. Department of the Interior
U.S. Geological Survey

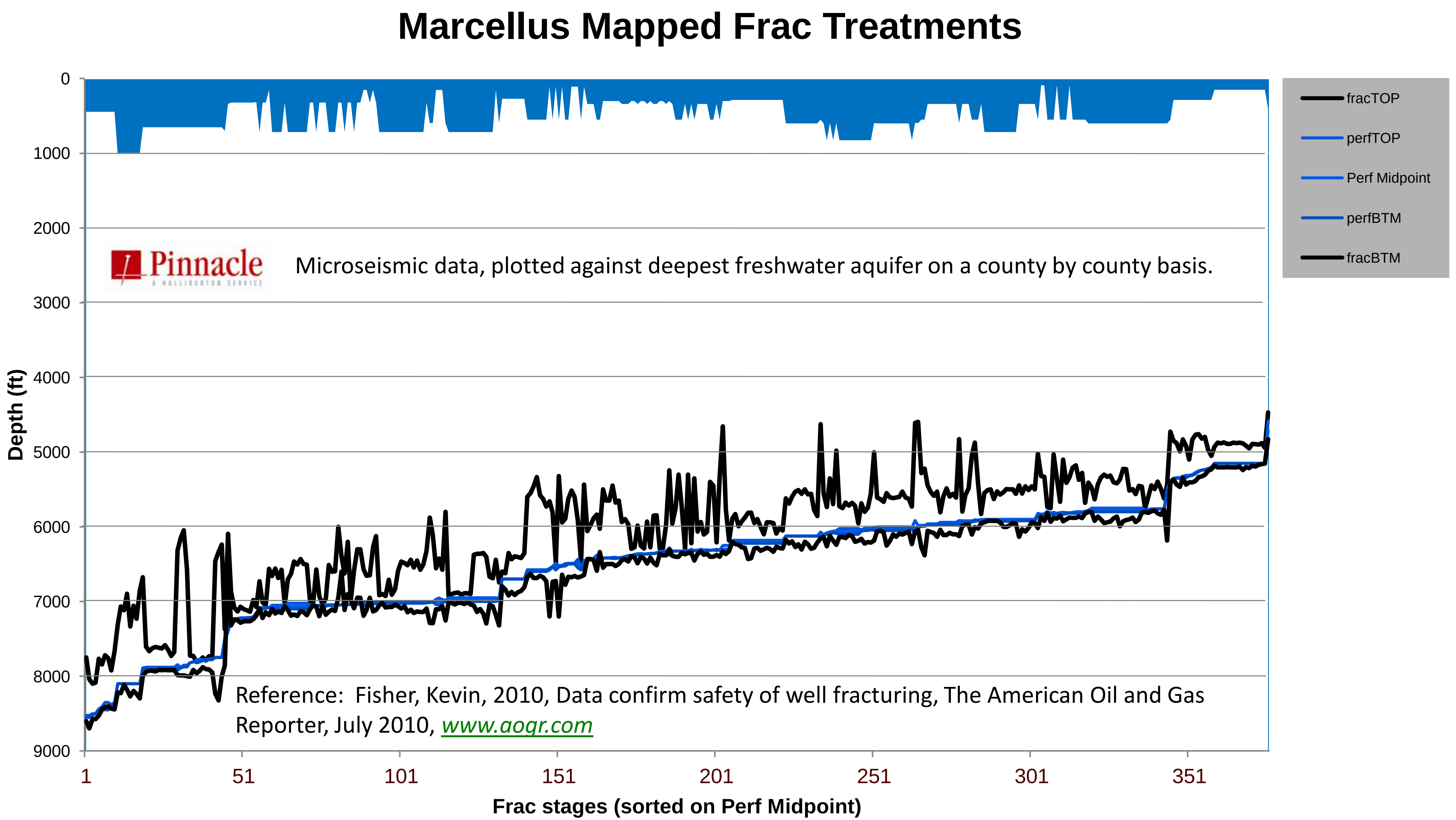
Printed on recycled paper

Fact Sheet 2009–3032
May 2009

http://pubs.usgs.gov/fs/2009/3032/

- **Supply**
  - 3 to 4 million gallons per well
  - 2/3 to 3/4 consumptive use
- **Watersheds**
  - Stream degradation from roads-pads-operations
  - Water quality degradation from leaks/spills
- **Groundwater**
  - Infiltration from above
  - Frac fluid/fm water from below
  - Changes in GW flow directions or gradients
  - Fate of fluids that remain underground
- **Water quality**
  - Infiltration of chemicals/spills into shallow groundwater
  - Long-term leaching of drill cuttings
  - Minerals-sediment-gas  contaminating nearby water wells

# Hydraulic Fracture Heights and Aquifers




Geochemical verification: Add chemical tracer to frac fluid and try to detect in shallow groundwater, on faults and old wells, and in deeper formation waters.

# Surface Leaks and Spills

- Potentially  more risk to groundwater and surface water than underground frac
- Stream monitoring and groundwater sampling can detect chemicals.
- Baseline data on existing contaminants are required to assess drilling impacts.
- Studies planned for 2012 (WVU):
  - Retrospective investigation of impacted small streams
  - Comparison of stream reaches: affected and unaffected; may also compare two similar watersheds
  - Assessment of impacts, damage, costs
  - Infiltration, movement through shallow groundwater and discharge to stream
  - Forensics of what caused the leak
  - Better leak detection and warning

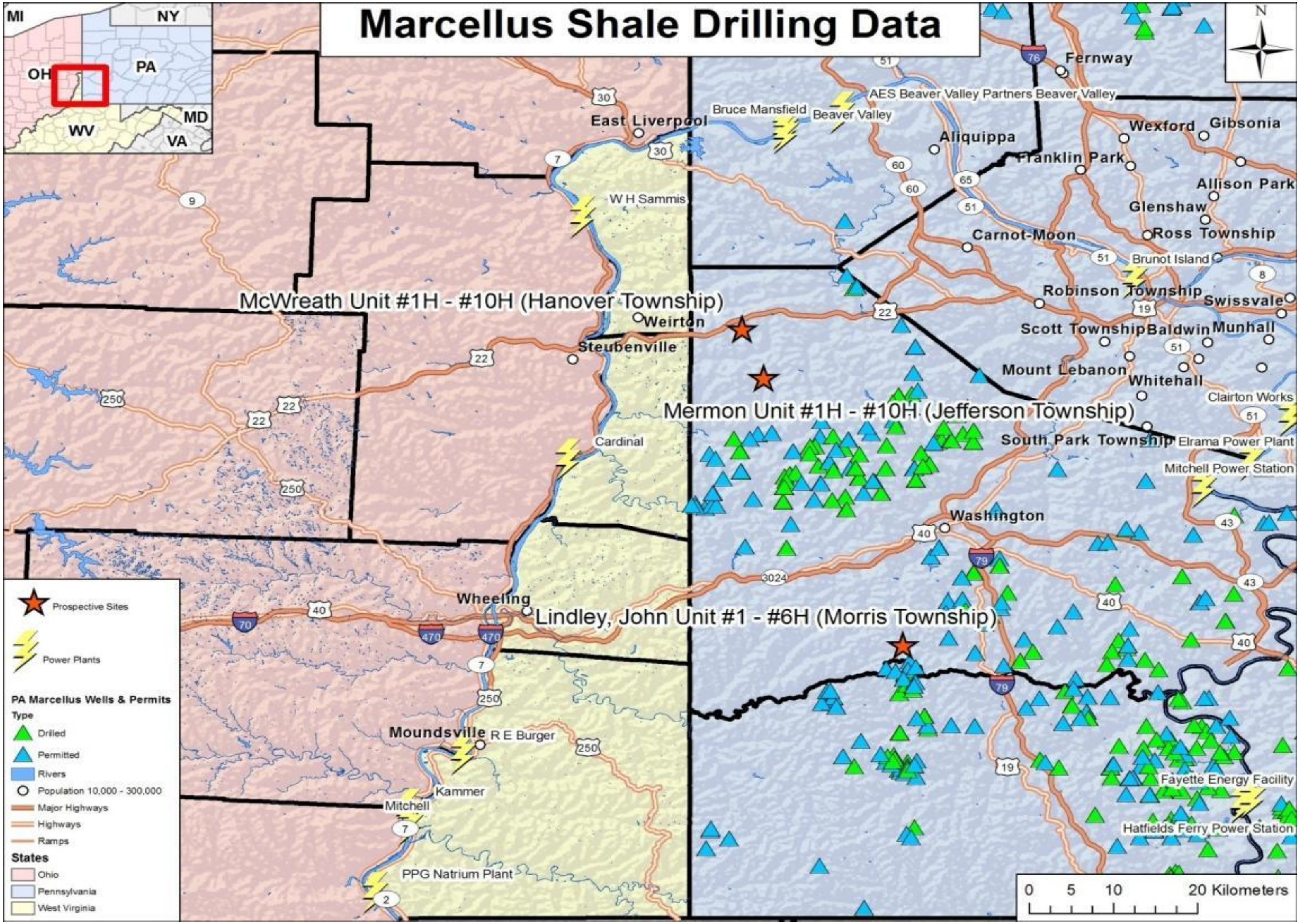
# Shale Drill Cuttings

Vertical 12 in dia. X 100 ft: **5.3 metric tons** of cuttings
Horizontal 12 in dia. X 5,000 ft: **267 metric tons** of cuttings

**Potential for oxidation and mobilization**.

- Analysis of organic-rich shale for metals content and associations using time of flight secondary ion mass spectrometry (TOF-SIMS).
- Organics analyses planned as well.

# Marcellus Test Site for Baseline Monitoring



# Marcellus Monitoring Team

1. **U.S. Dept. of Energy-NETL**: Air emissions, soil gas surveys, electromagnetic surveys for abandoned wells, avian surveys
2. **U.S. Environmental Protection Agency:** prospective site in USDW – hydrofrac investigation
3. **U.S. Geological Survey**: Groundwater monitoring
4. **U.S. Fish and Wildlife Service:** Rare and endangered species
5. **U.S.D.A. NRCS:** soil surveys, erosion
6. **U.S. Army Corps of Engineers:** Stream water quality, sedimentation
7. **PA DCNR (Geological Survey):** drill site monitoring and completion
8. **Pennsylvania DEP**: Fish and macroinvertebrate surveys

# DOE Shale Gas Environmental Risk Assessment


**Goals**

Assess short/long term environmental impacts.

Investigate scientific concerns

**Outcomes**

Rigorous study with conclusions supported by well-documented data

**Benefits**

Public information to create a more informed environmental debate.

Improved management practices for shale gas production.

Environmental indicators for focused regulatory monitoring.

# Questions?

U.S. DEPARTMENT OF ENERGY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USDOE/NETL
3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507 USA
(304) 285-5258
Daniel.Soeder@netl.doe.gov

http://www/netl.doe.gov


**Websites for additional information:**

American Petroleum Institute (hydraulic fracturing info., how it is done): **http://www.api.org/**

EPA hydraulic fracturing & drinking water info: **http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm** (or go to epa.gov and do a search)

Environmentally friendly drilling research & engineering: **http://www.efdsystems.org/**

FracFocus: Ground Water Protection Council and Interstate Oil & Gas Compact Commission website for hydrofracture chemical info: **http://fracfocus.org/**

Marcellus Shale Coalition (industry site; drilling process video): **http://marcelluscoalition.org/**

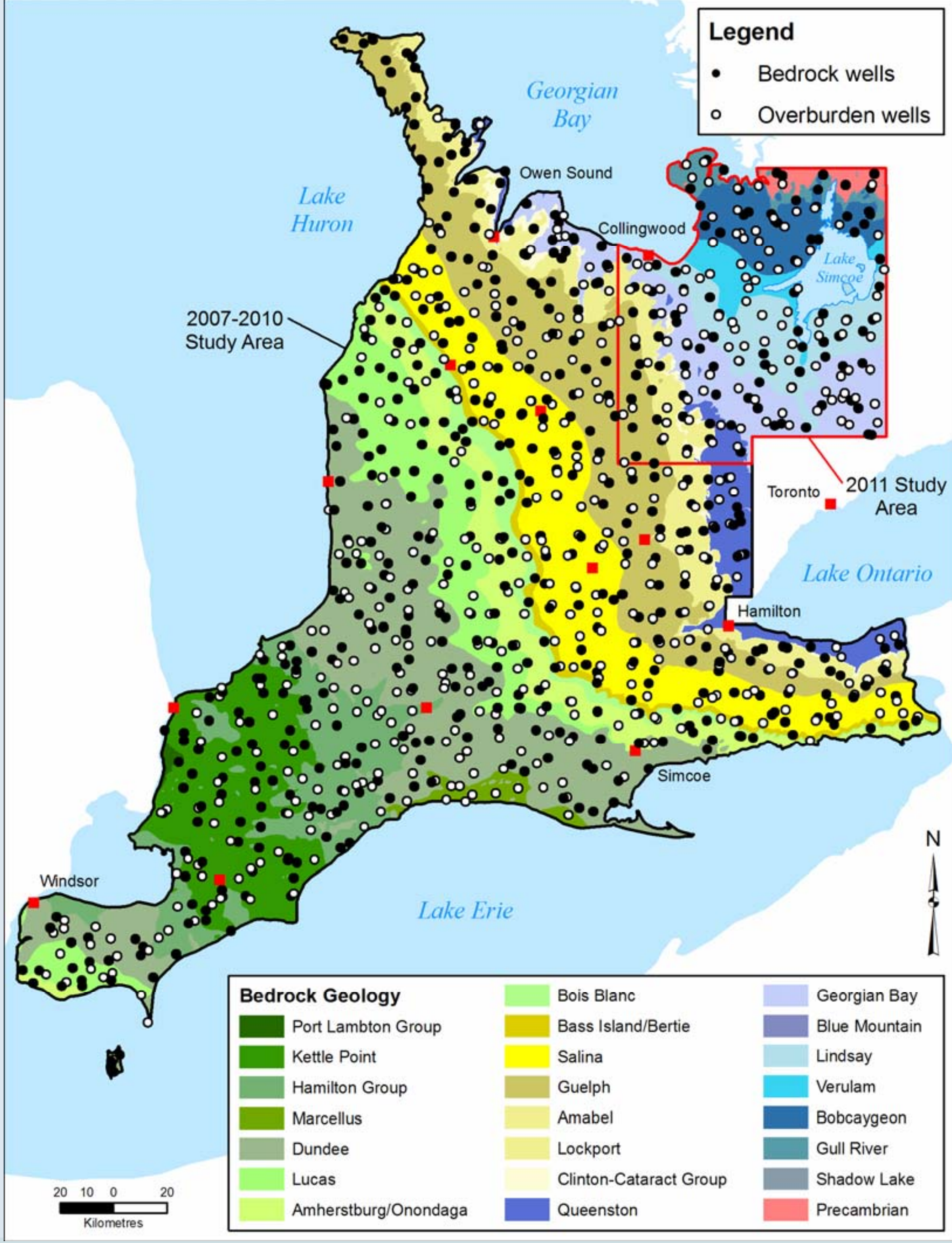
# Ontario

Stewart Hamilton, Ph.D., Senior geologist, Ontario Geological Survey

# Ambient groundwater geochemistry of bedrock in southwestern Ontario

selected results of interest to the oil and gas community

Stew Hamilton



# Talk Outline

1. The Ambient Groundwater Program
   - Why we study groundwater at the OGS
   - The relationship between lithology and chemistry
2. Results: 2 examples of interest to the oil and gas industry
   - Biogenic methane in water wells
   - Niagara peninsula geochemical 'anomaly'

# Introduction: the Ambient Groundwater Geochemistry Program


1. An initiative by the Ontario Geological Survey to characterize the state of groundwater quality and chemistry across the province.
2. As with other programs at the OGS such as bedrock mapping, the AGG program is primarily concerned with delineating the natural state of groundwater and the controls thereof.
3. Groundwater is sampled at a consistent density and is accessed by a variety of means including springs and monitoring wells but the majority of samples come from domestic wells.
4. The program began in 2007 and has mapped approximately 10,000 $km^2$ in each subsequent field season.

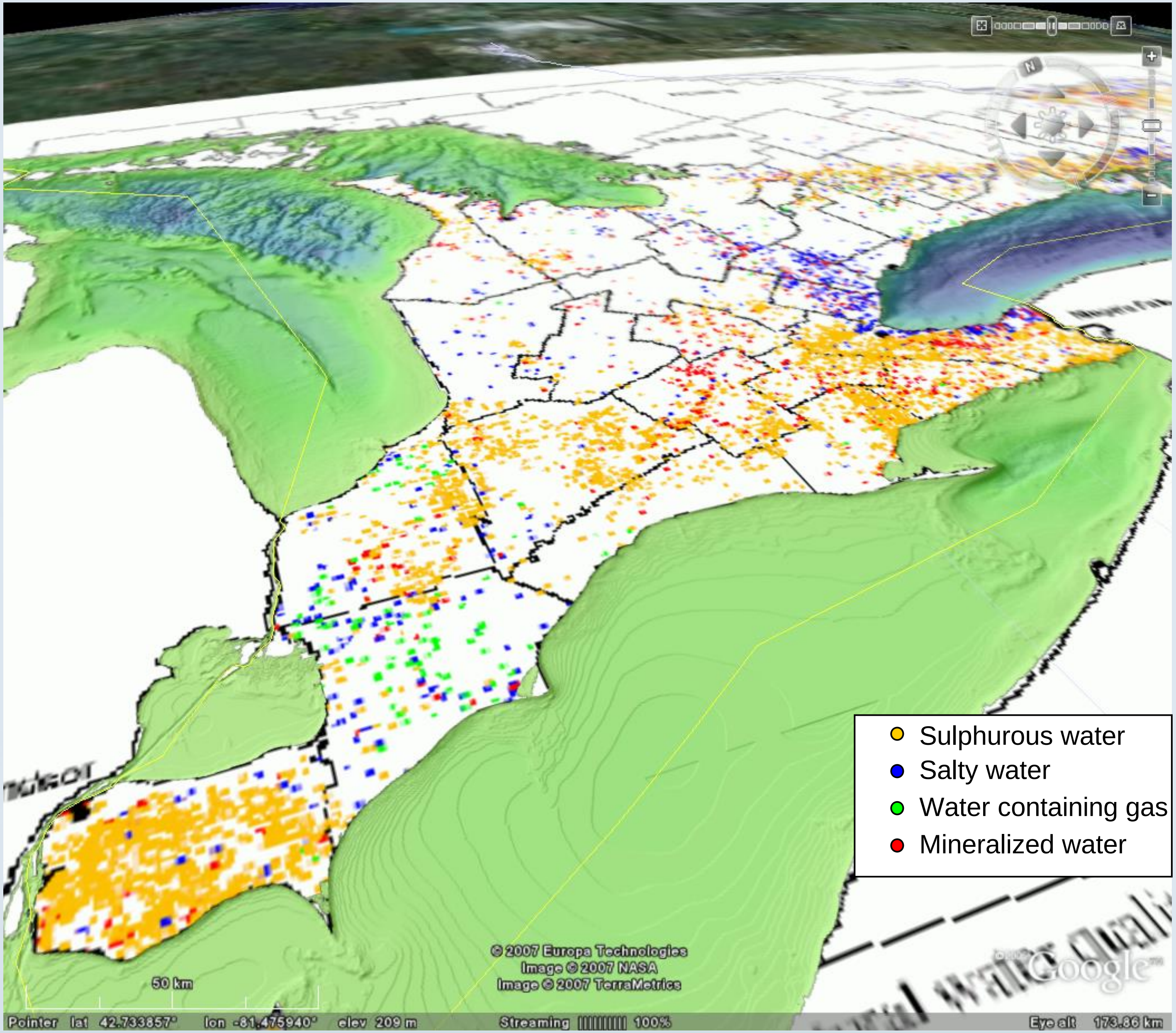
# Ambient Groundwater Geochemistry
## Technical Objectives

1. Characterize baseline groundwater geochemistry of the major rock and overburden units province-wide (subject to accessibility)
2. Relate water chemistry to aquifer chemistry
3. Support the determination of groundwater flow conditions and transport.

# Analysis

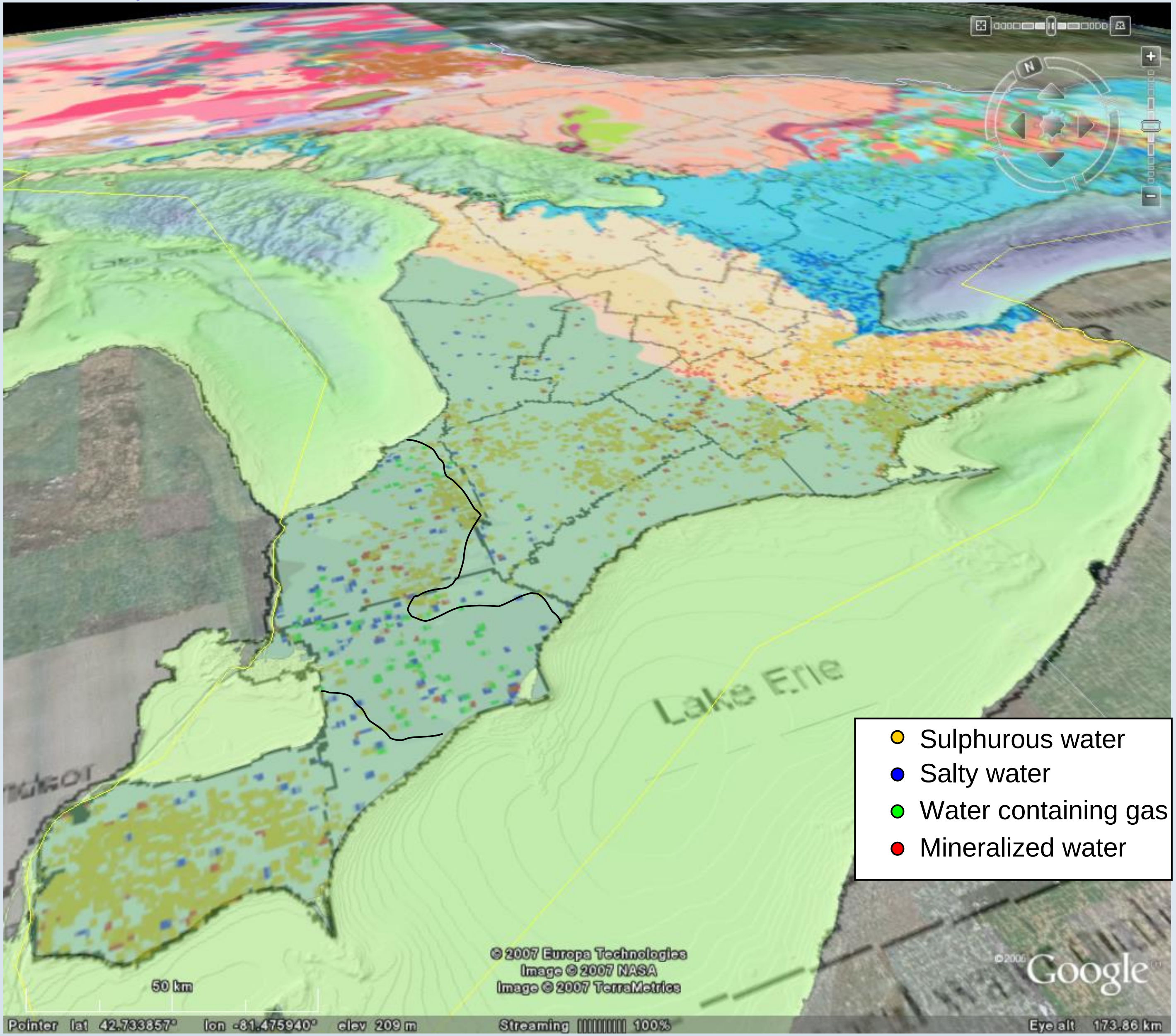
- **Field parameters** – pH, redox, temperature, conductivity, alkalinity
- **Major ions** – $Ca^{2+}$, $Mg^{2+}$, $K^{+}$, $Na^{+}$, $SO_4^{2-}$, $Cl^{-}$, $HCO_3^{-}$
- **Dissolved gases** – $H_2S$, $O_2$, $CO_2$, $CH_4$ – in field
- **Trace metals** (filtered) – by ICPMS & ES; Hg
- **Trace anions** – $F^{-}$, $Br^{-}$, $I^{-}_{(in\text{-}field)}$, $PO_4^{3-}$
- **Bacteria** – fecal & total coliform
- **Nitrogen parameters** – $NH_3$, $NO_2^{-}$, $NO_3^{-}$, TKN, $N_{org}$
- **DIC/DOC**
- **Isotopes** – ($\delta^{18}O$, $\delta^{2}H$, $\delta^{13}C_{(CH4)}$, $^{3}H$)

# Water Quality Problems in Bedrock Wells




Data source
Singer et al., 2003

# Water Quality Problems in Bedrock Wells




Data source
Singer et al., 2003

# Ambient Groundwater Project Study Areas

The first 4 years of AGGP covered 40,000 km$^2$ ~ all of southwestern Ontario

MRD-283

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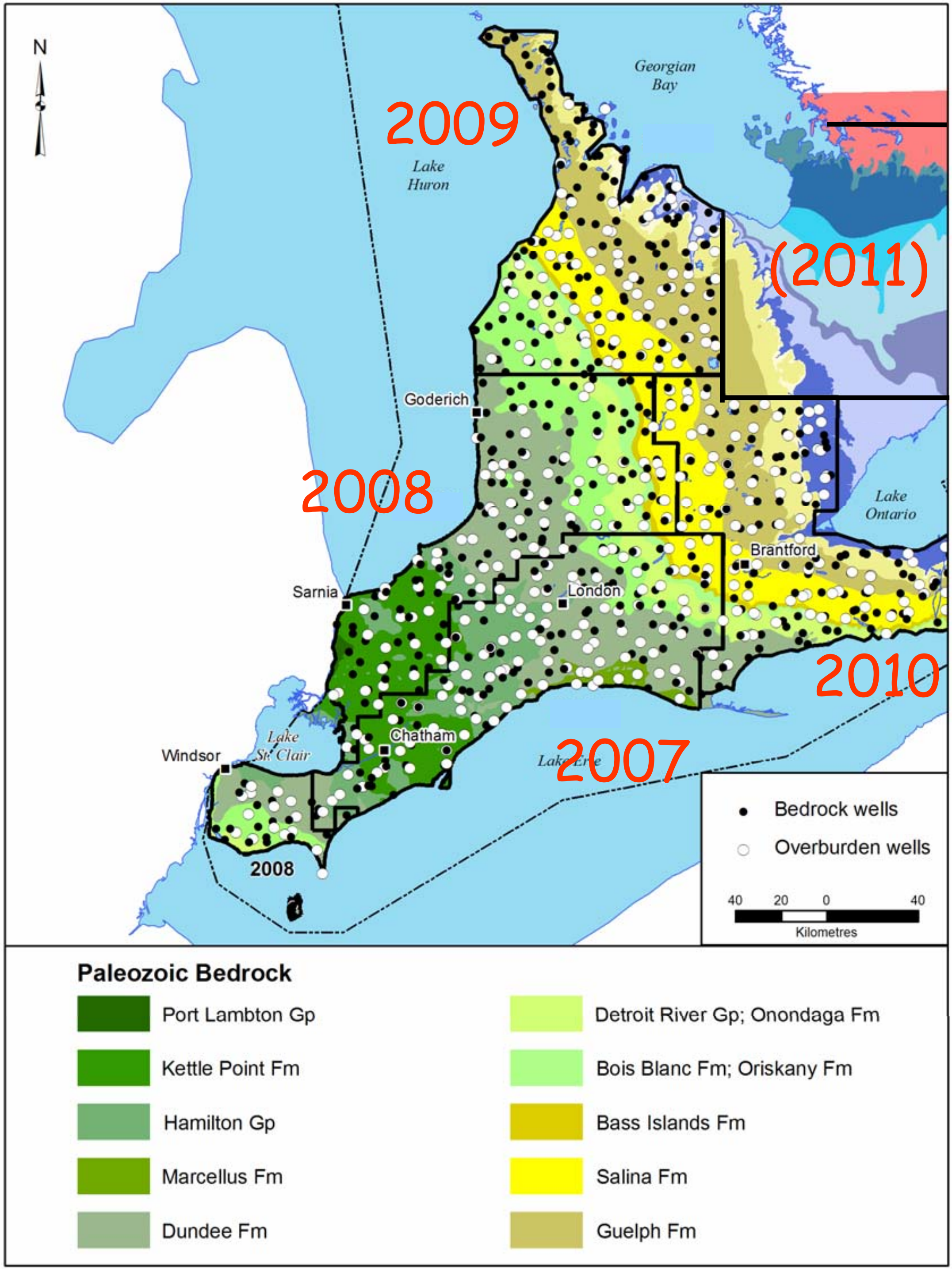
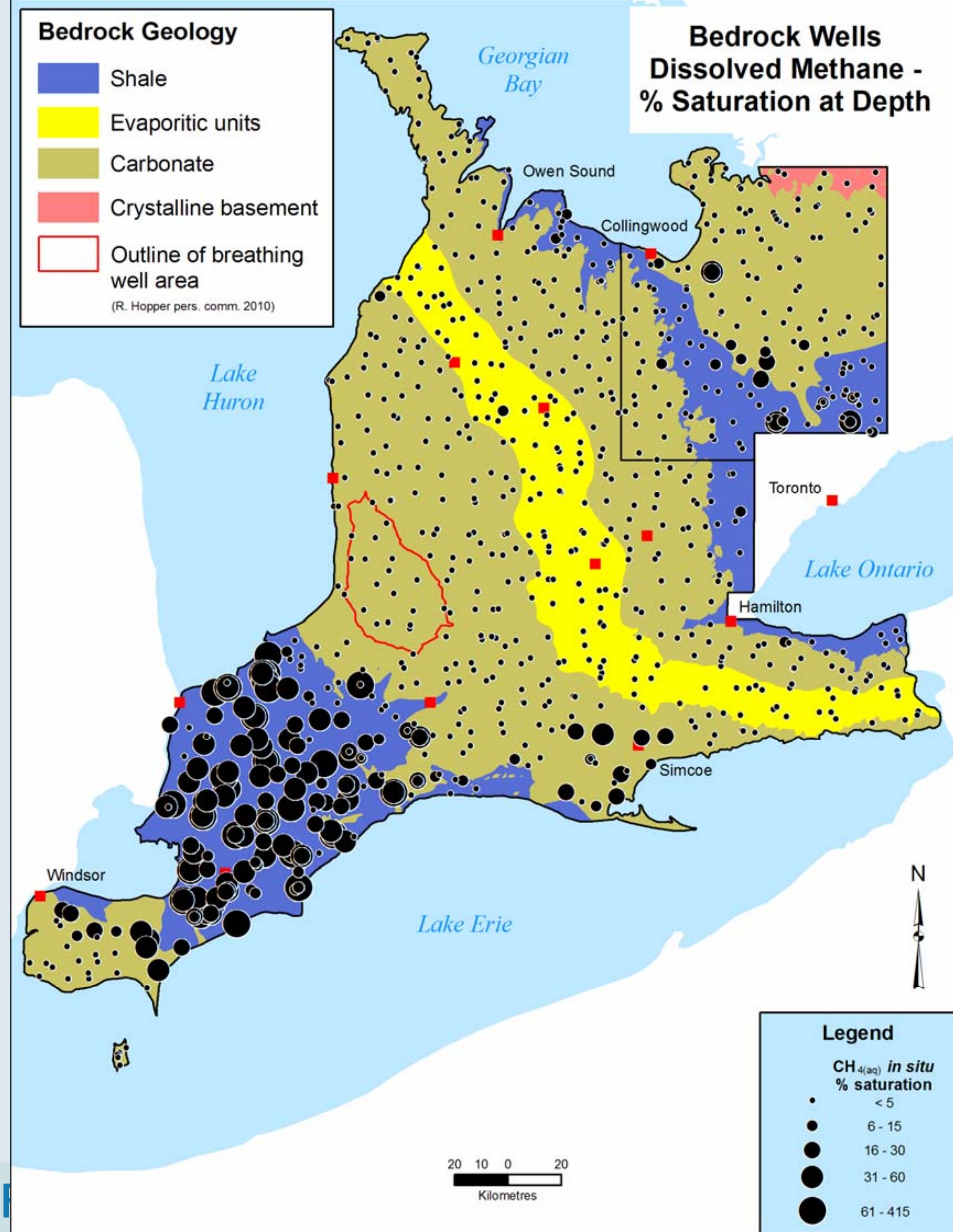


# Selected Results

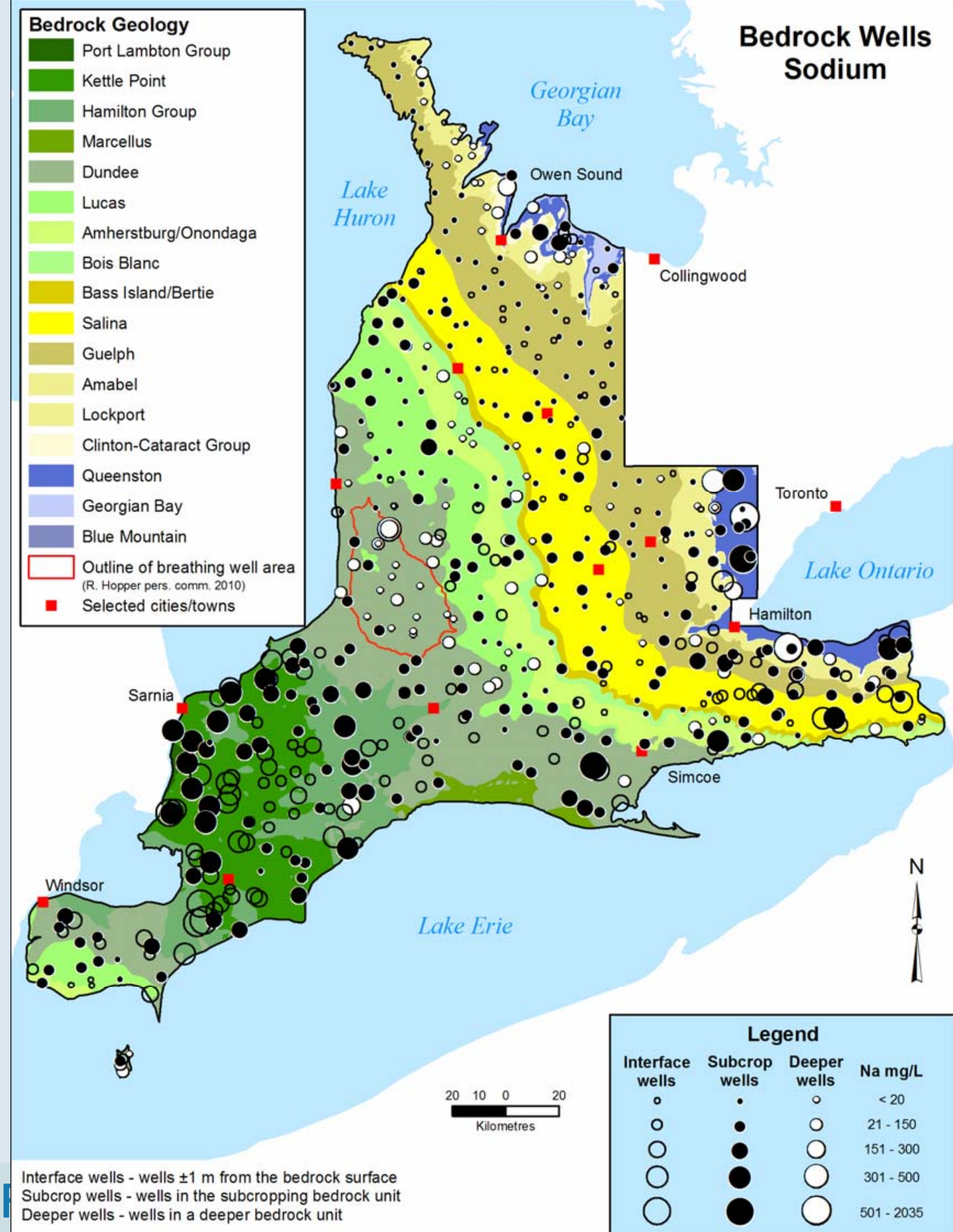
1. The lithological association with water chemistry
2. Karst influence
3. Shale gas methane
4. Niagara peninsula geochemical anomaly

…

# $CH_4$ in bedrock well water



# Sodium in bedrock well water

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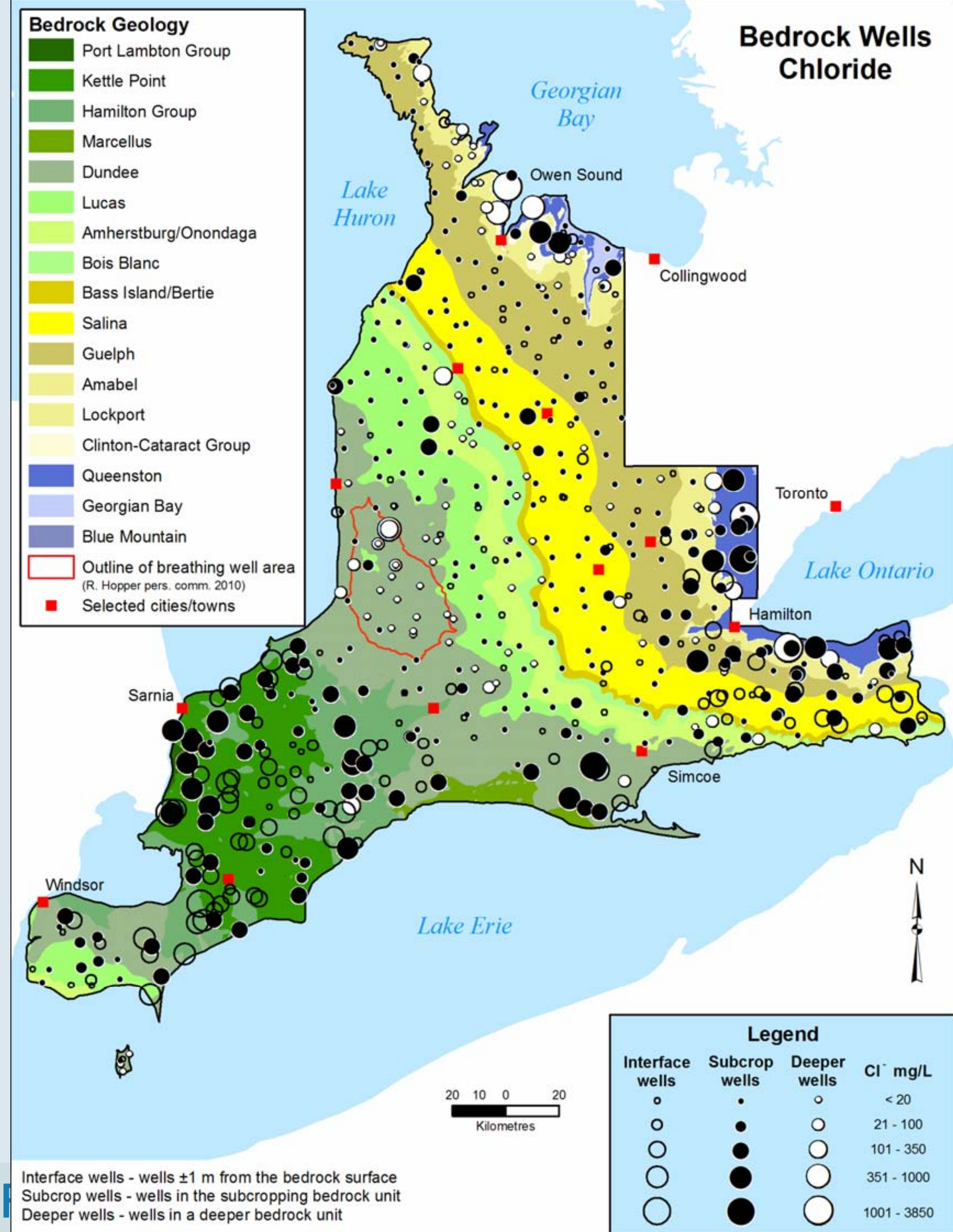
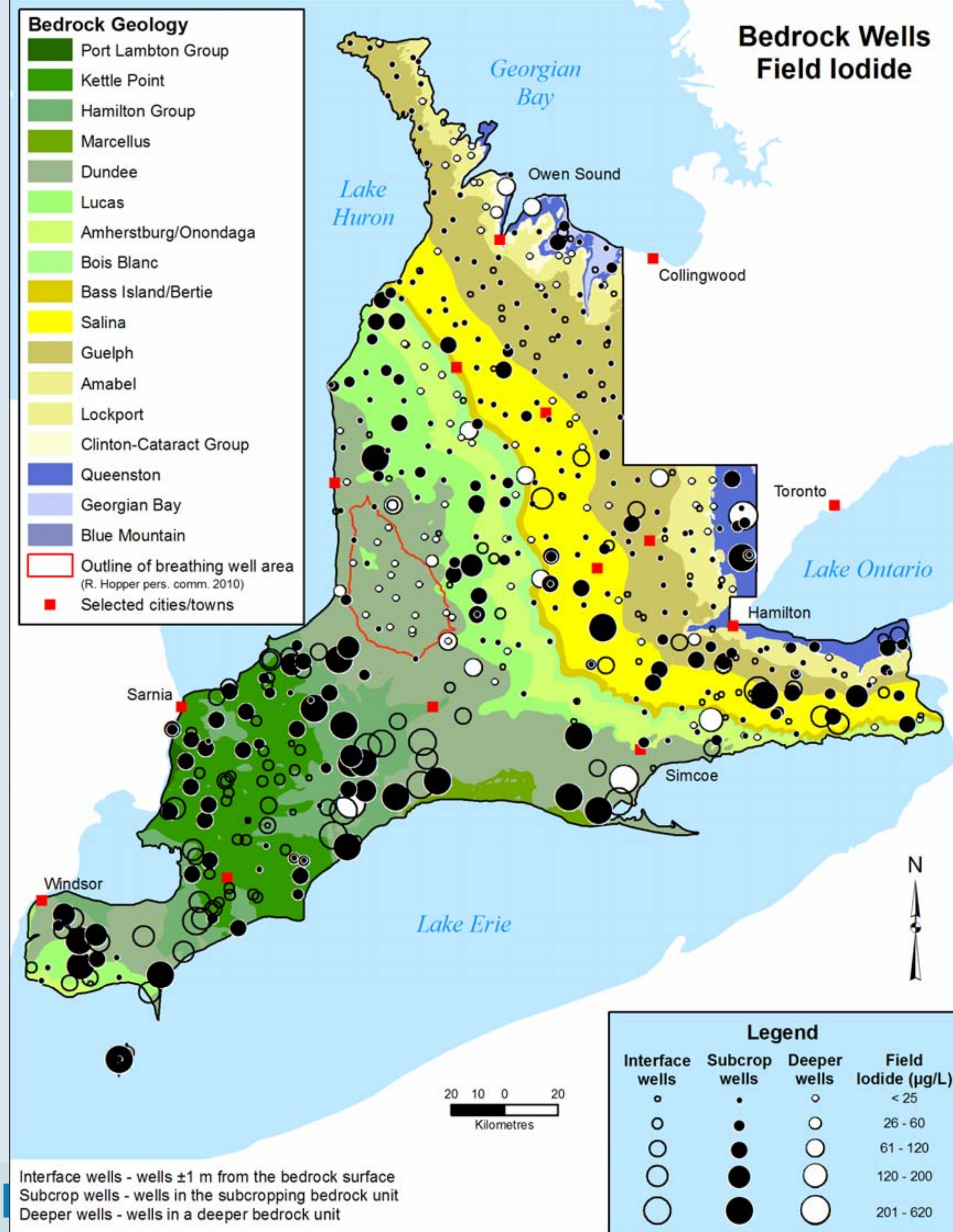
# Chloride in bedrock well water



# Iodide in bedrock well water

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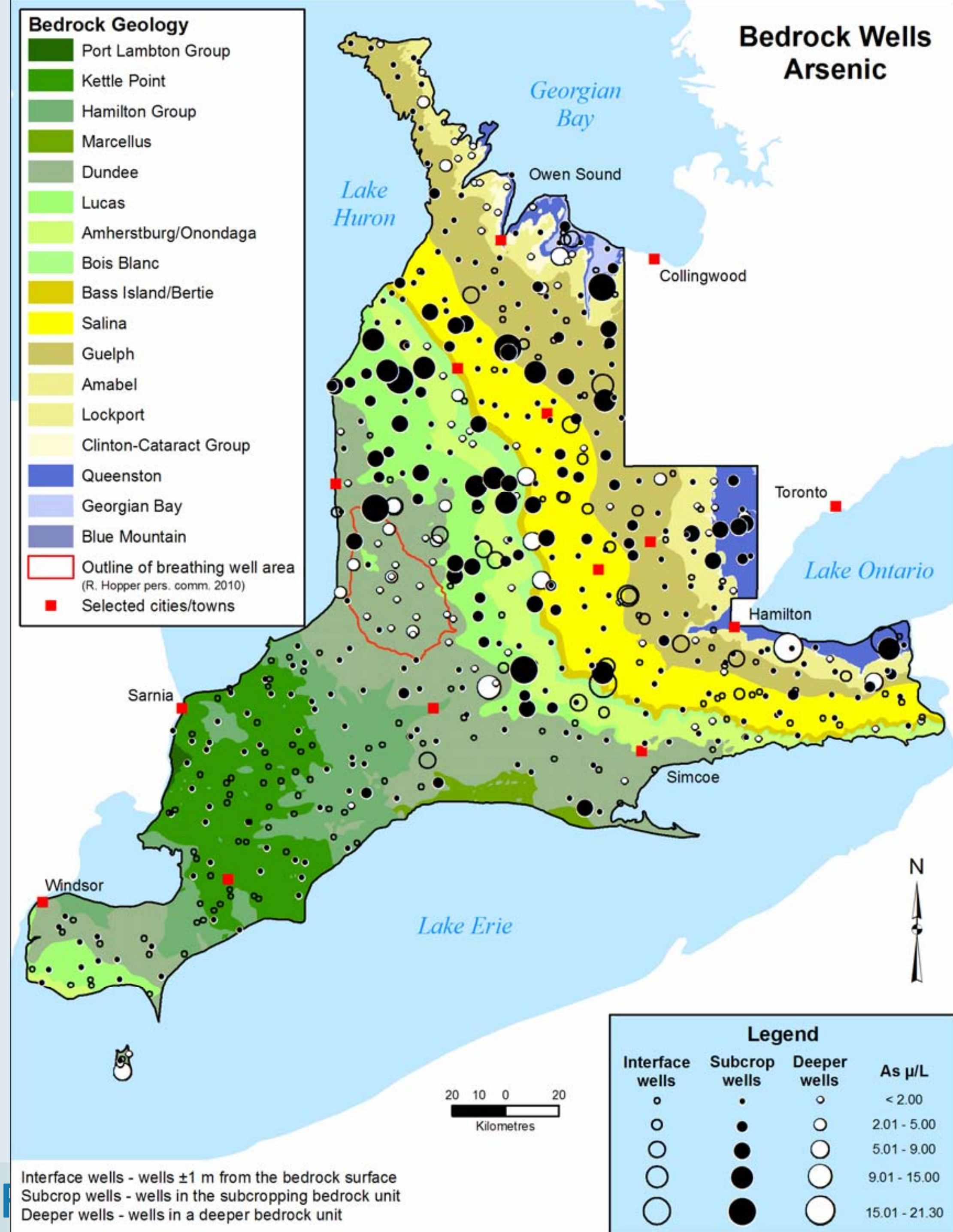
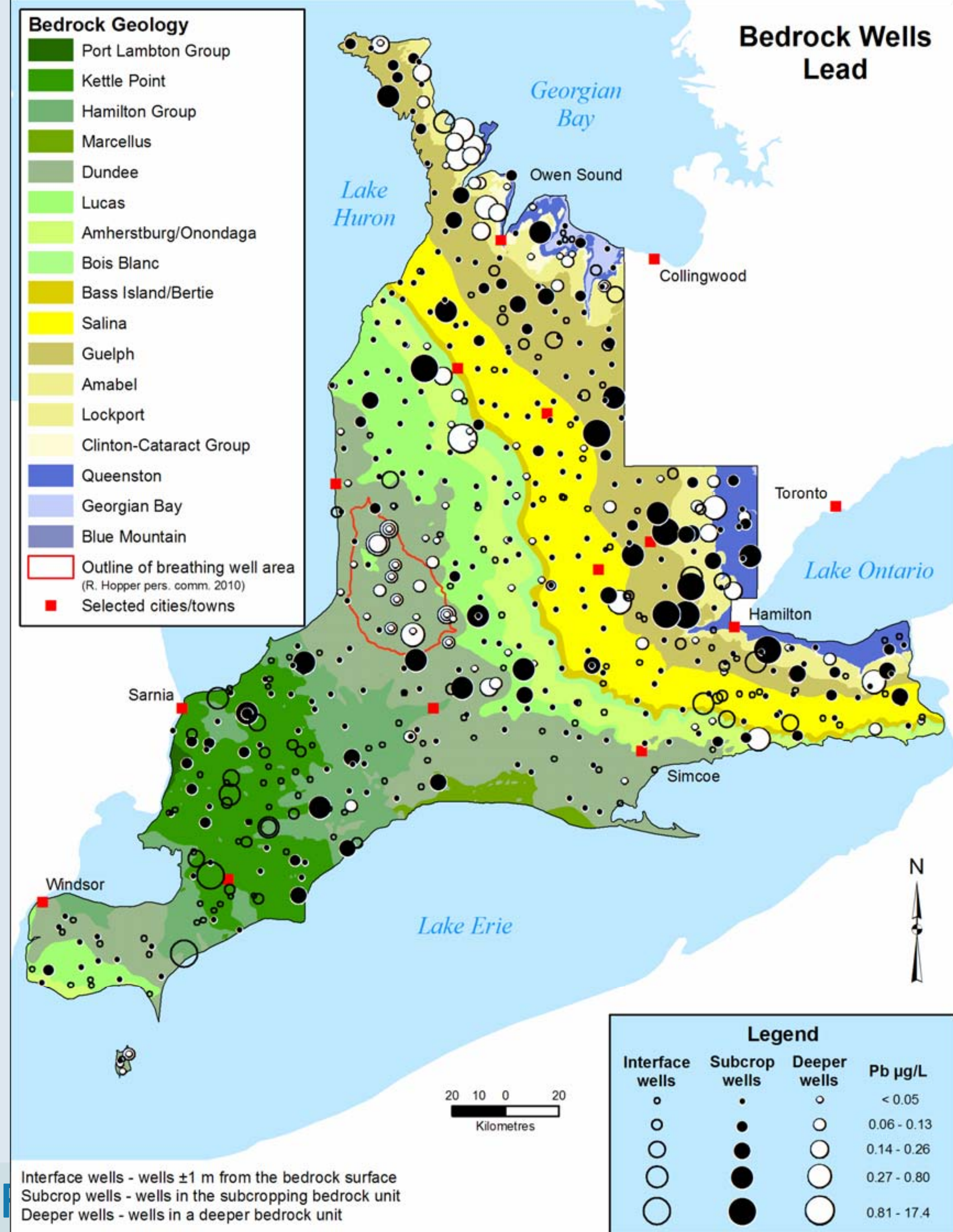
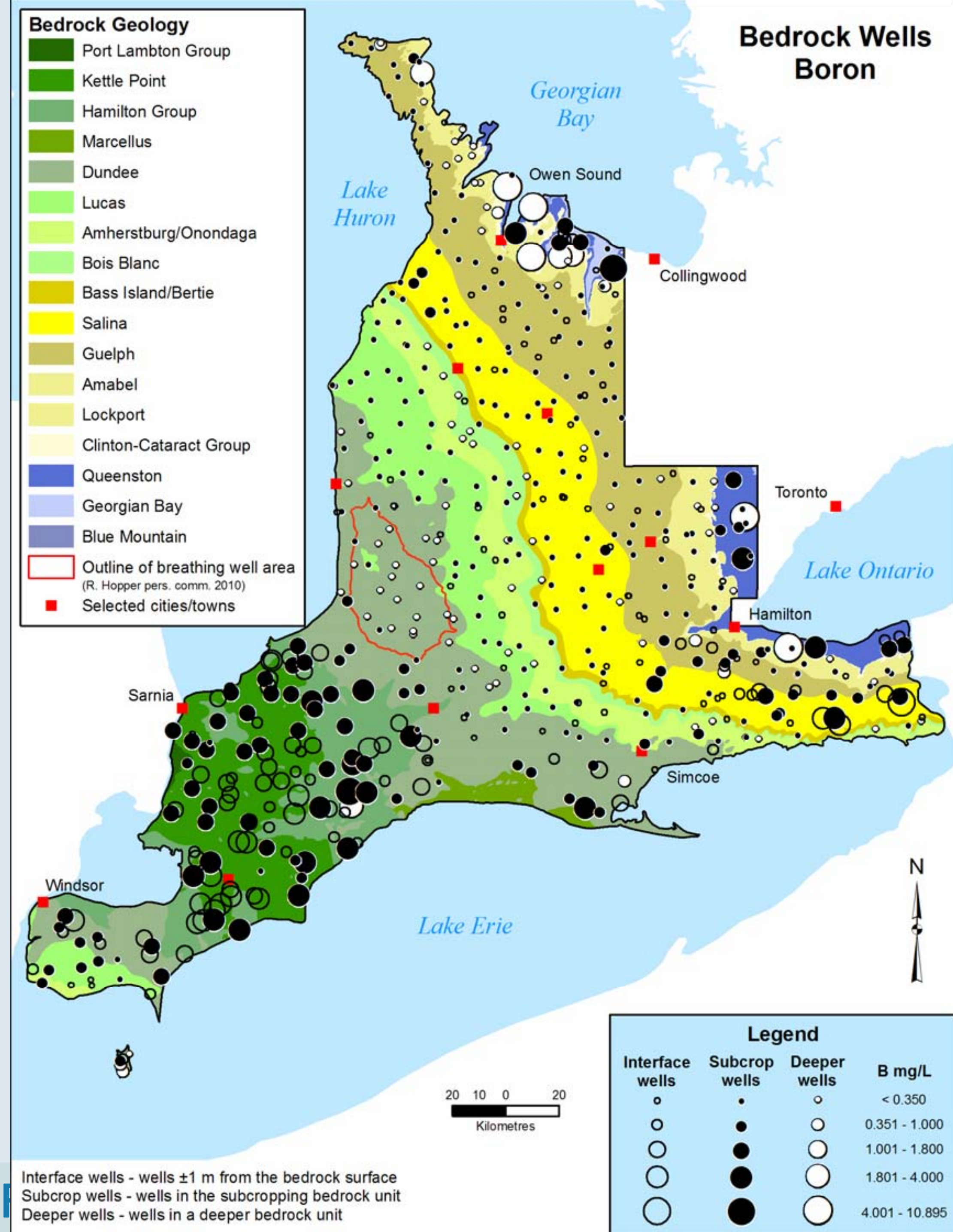
# Arsenic in bedrock well water



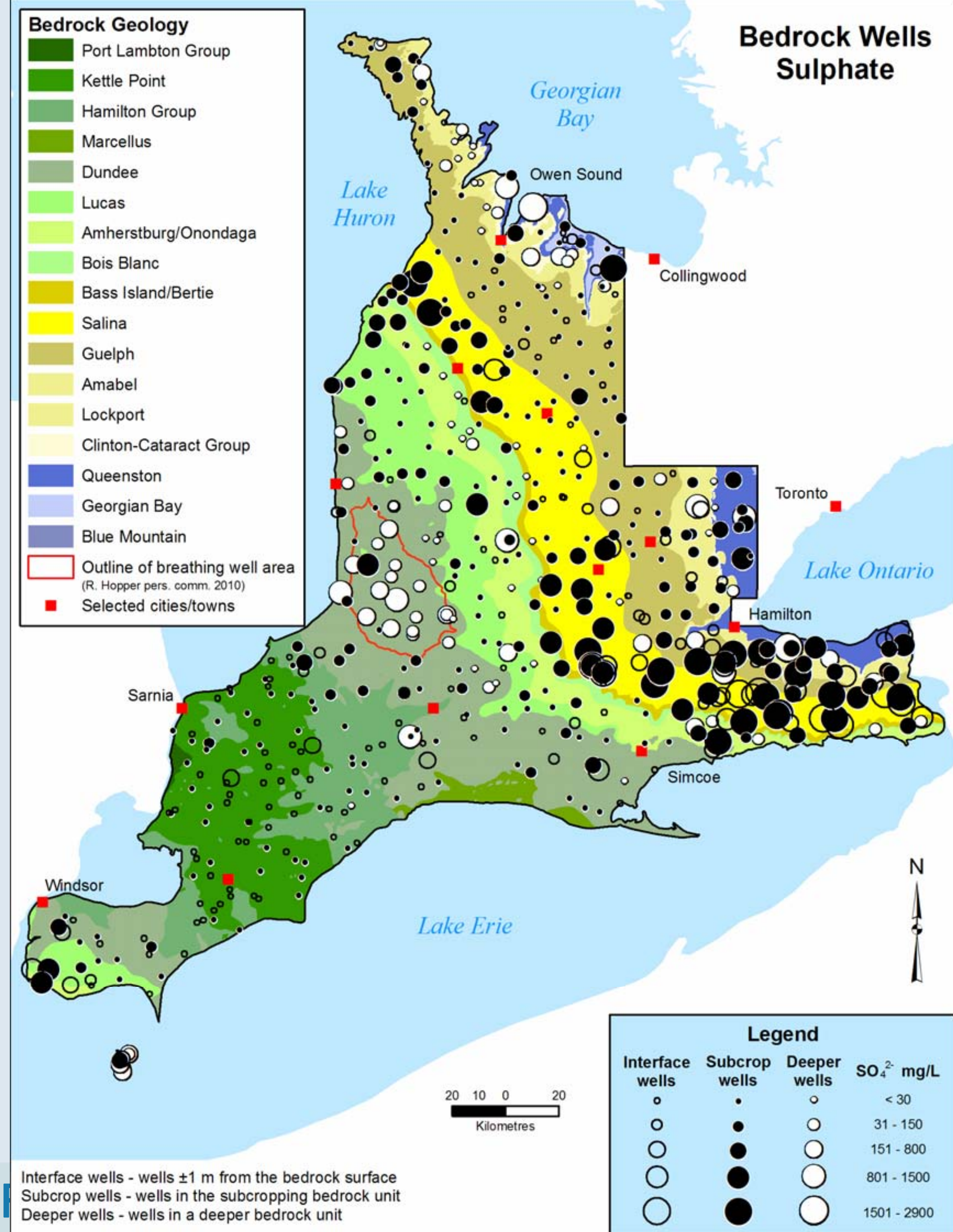
# Lead in bedrock well water



# Boron in bedrock well water




# Sulphate in bedrock well water

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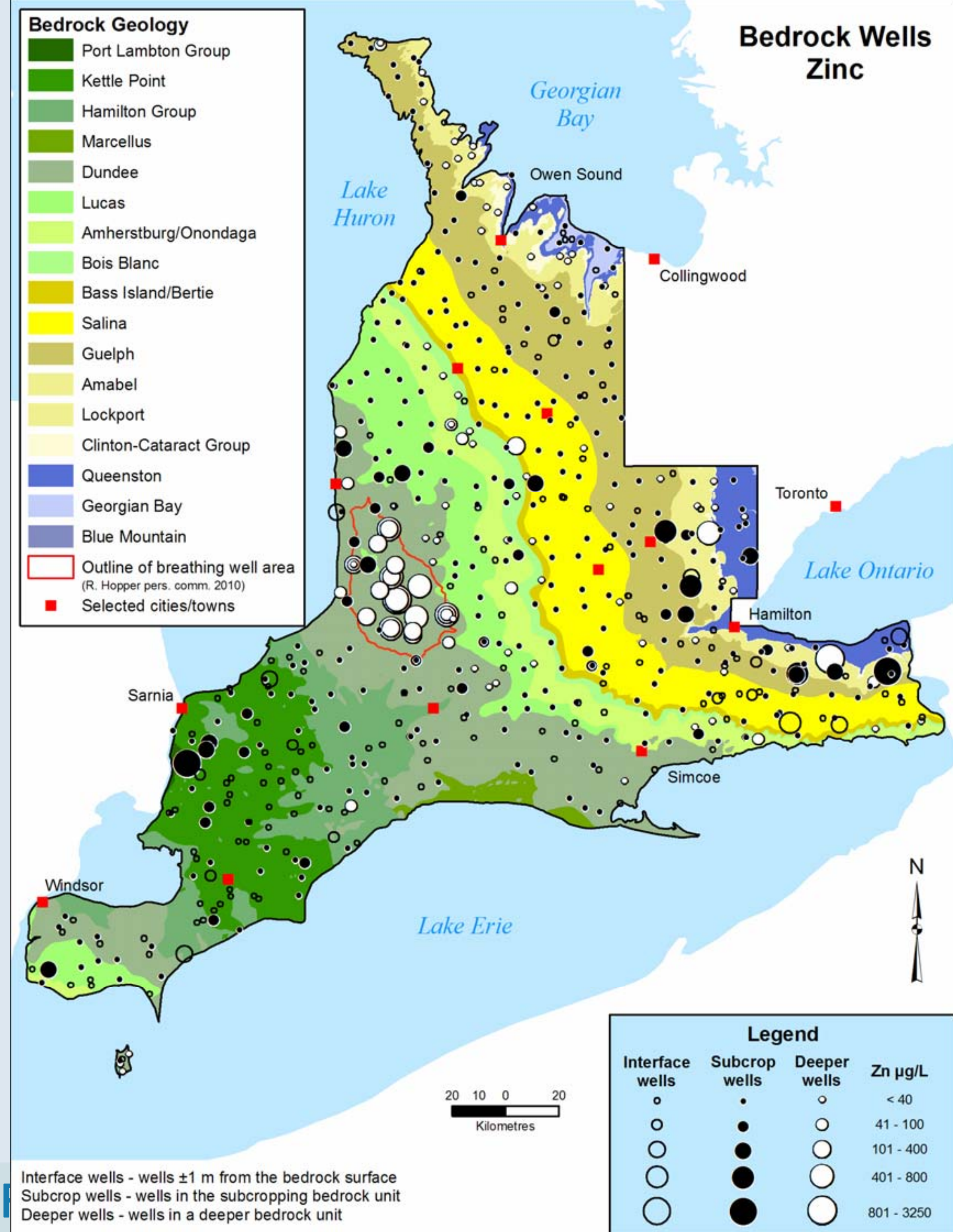
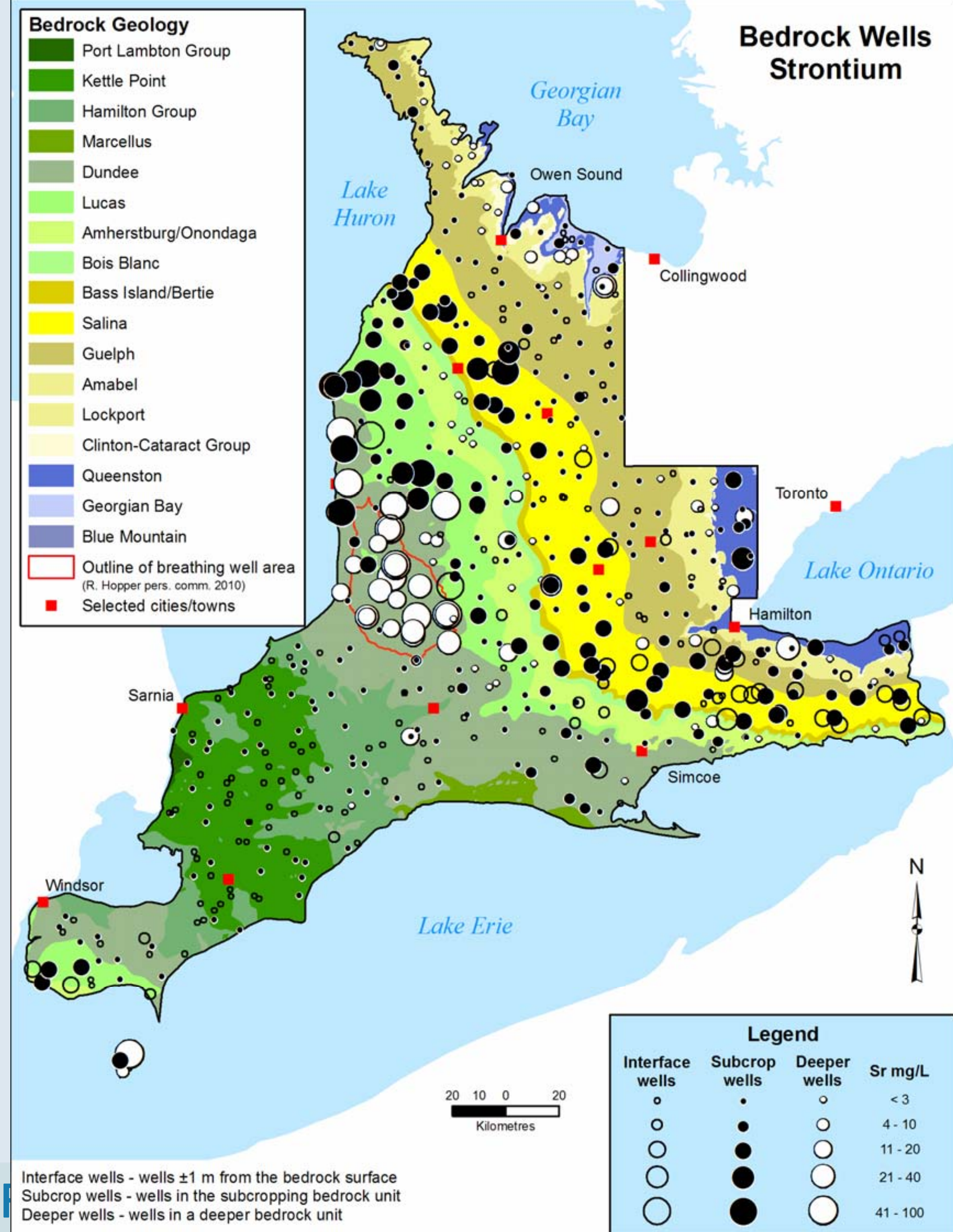
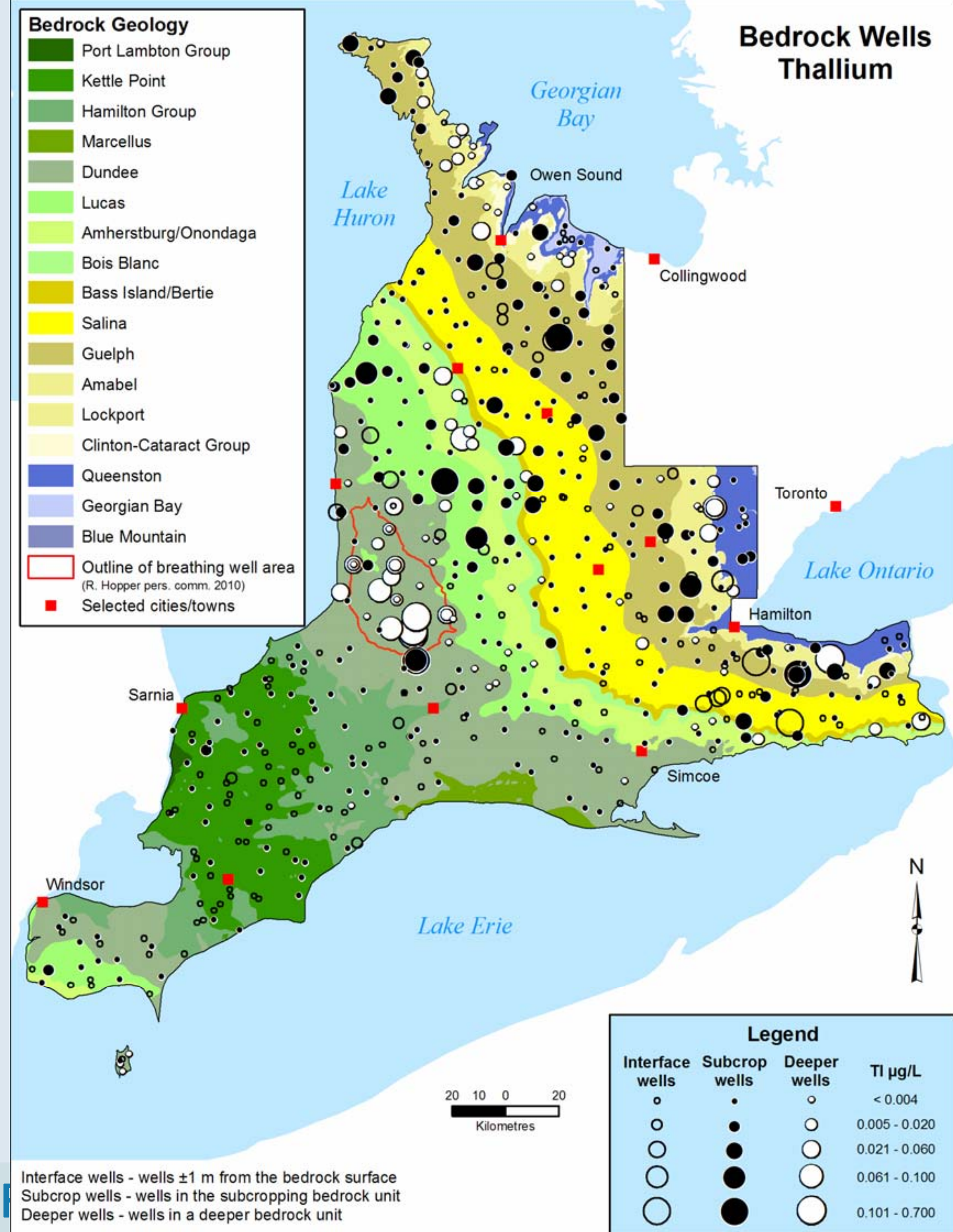
# Zinc in bedrock well water



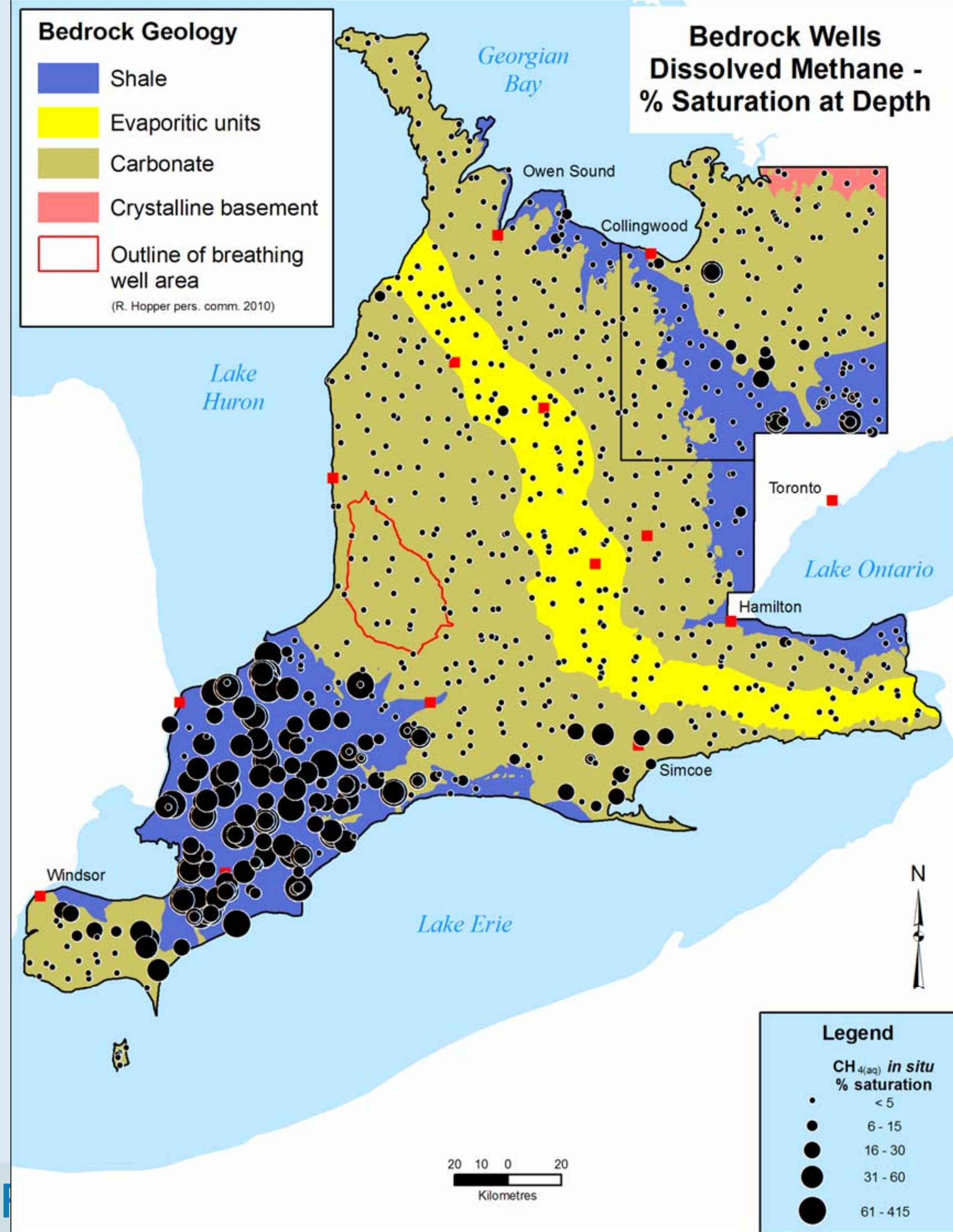
# Strontium in bedrock well water



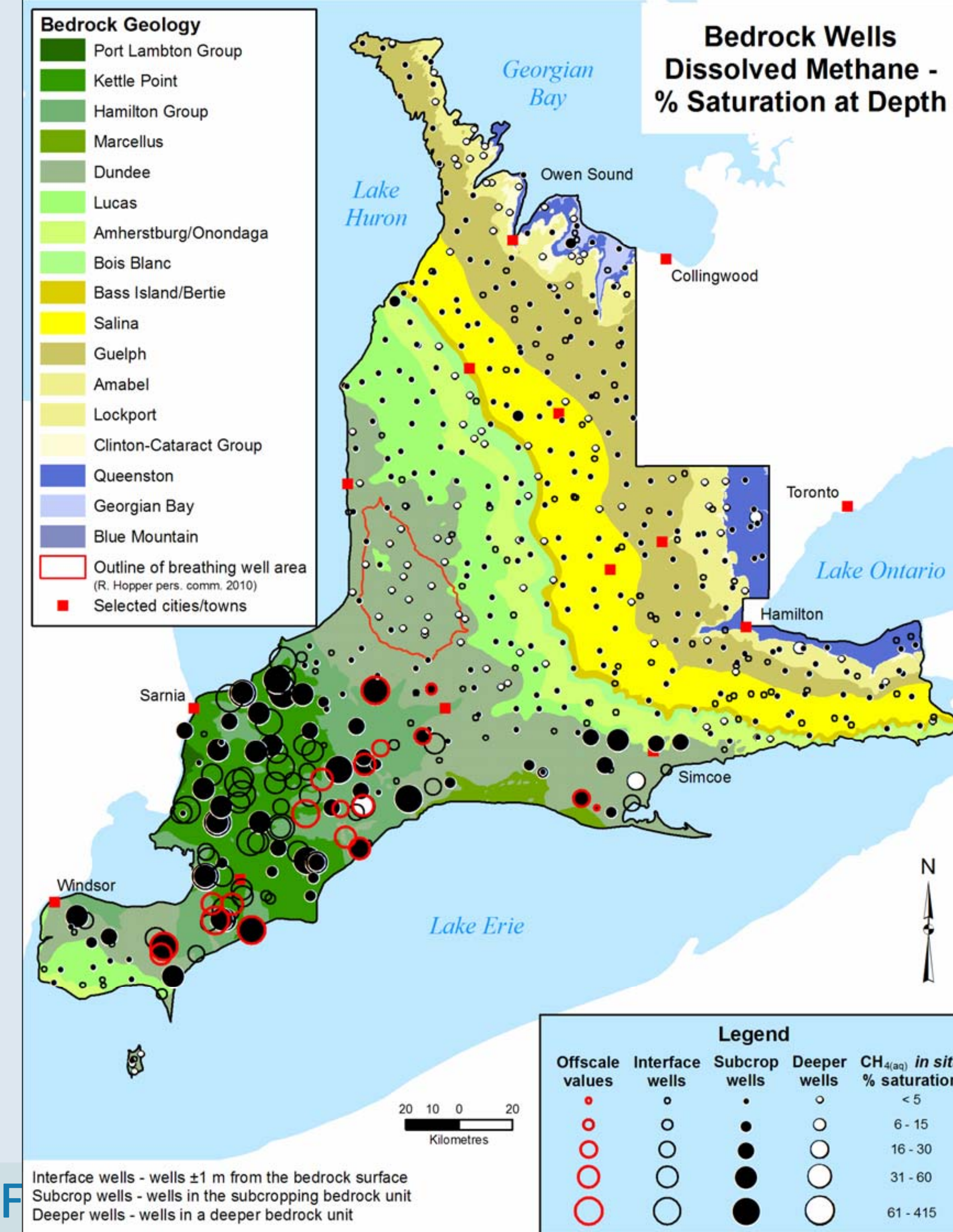
# Thallium in bedrock well water



# Natural shale gas in well water



# $CH_4$ in Bedrock well water

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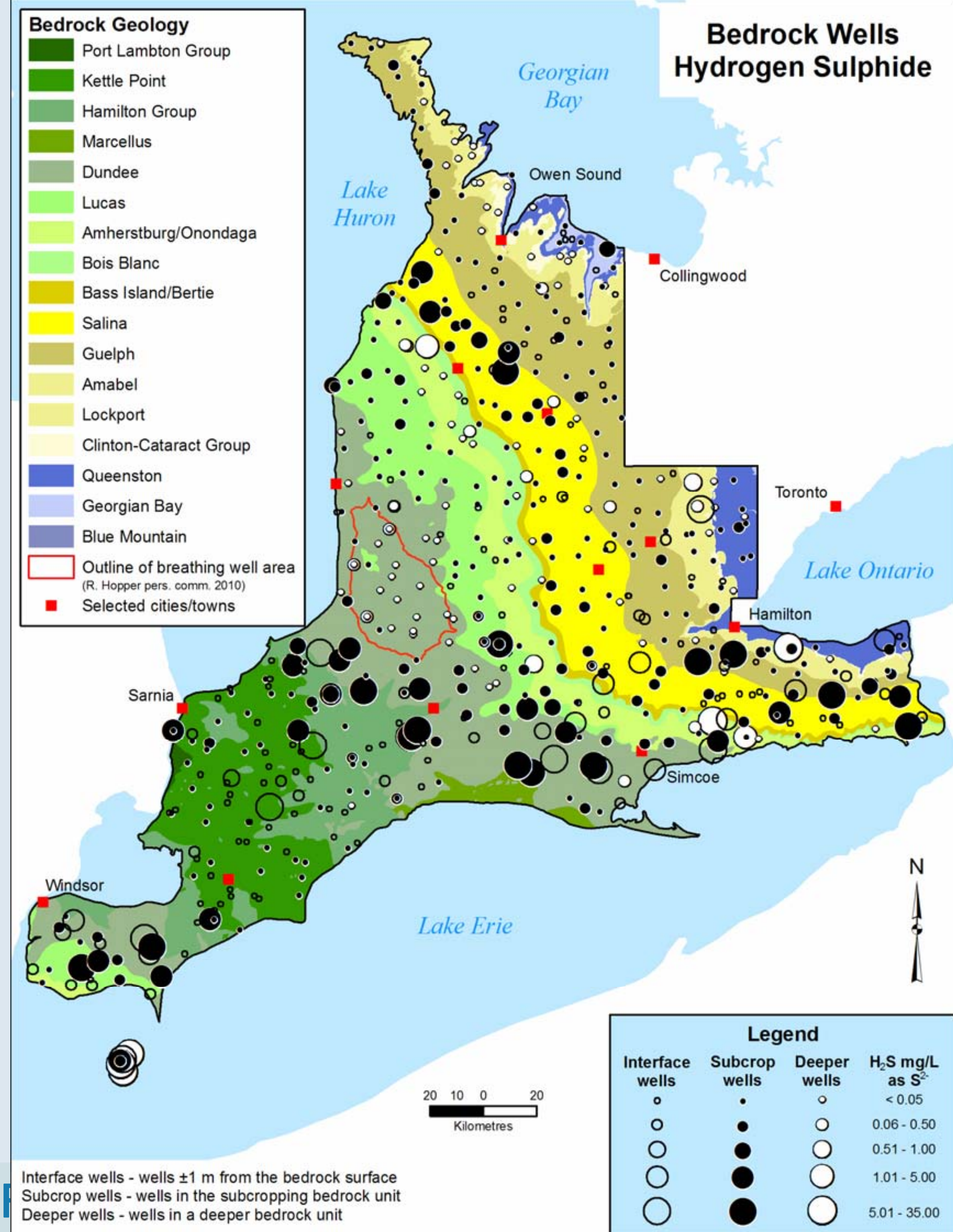
# 'Sulphur' in bedrock well

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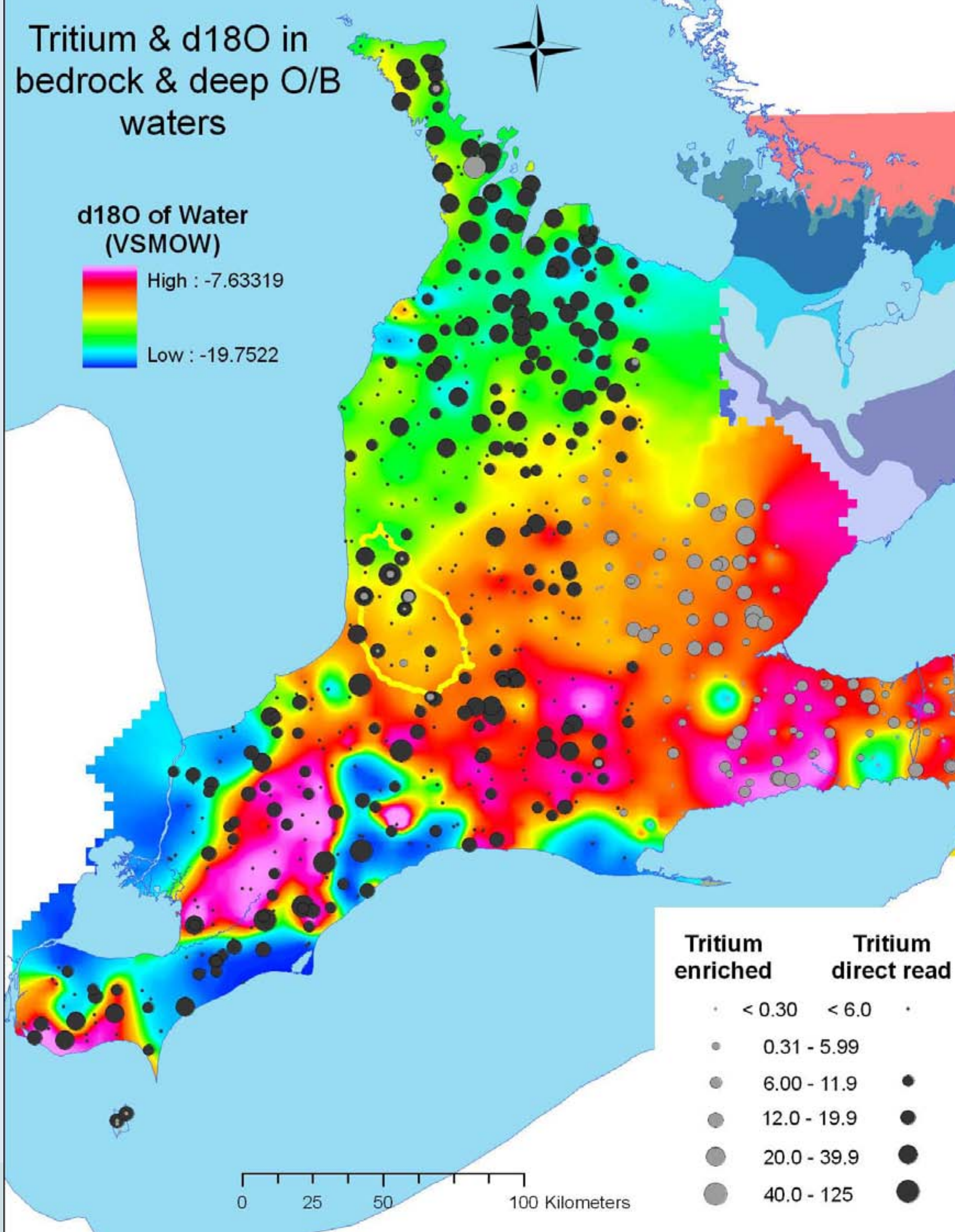
# $^{18}O$ in deep well water

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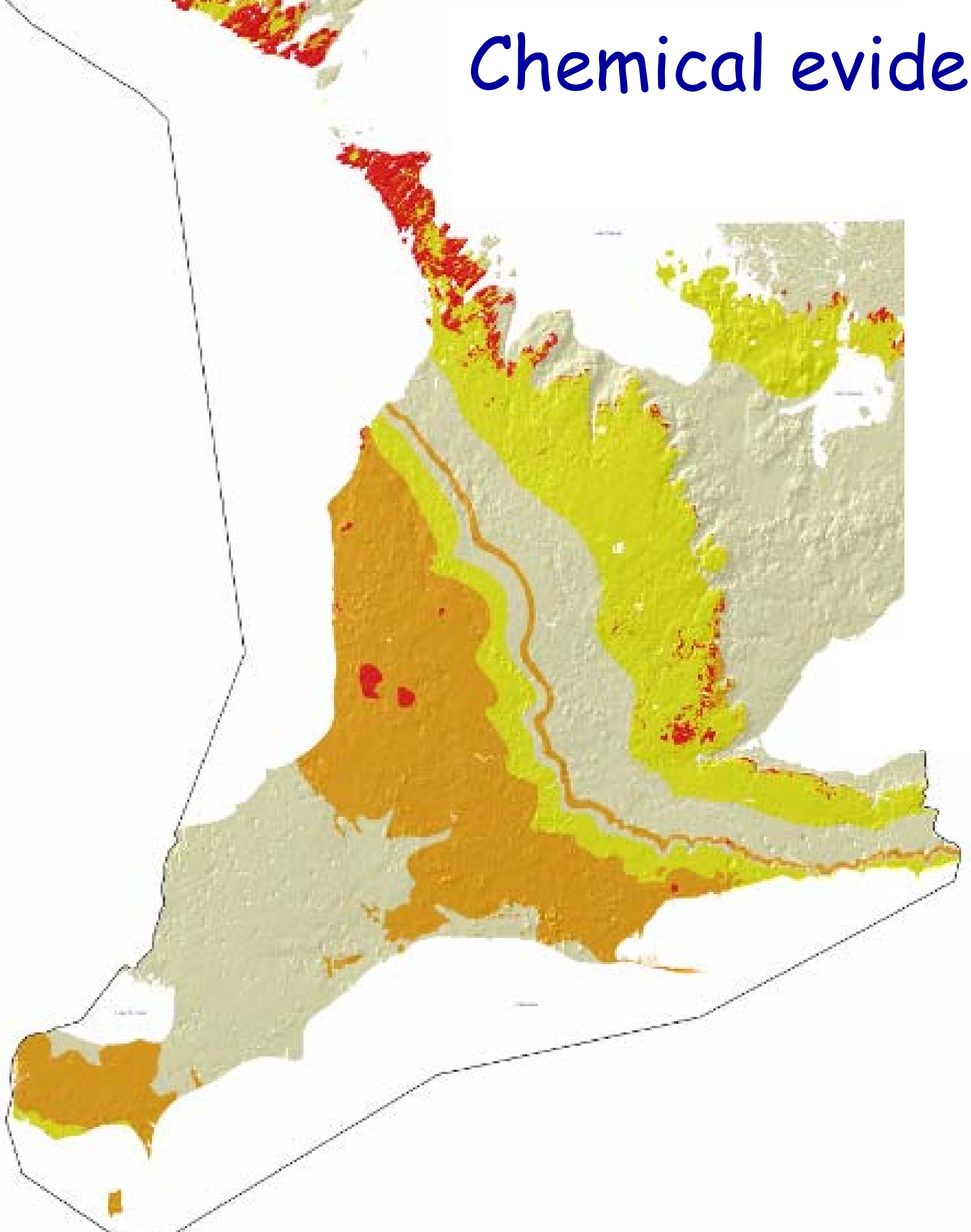
# Chemical evidence of Karstic Flow

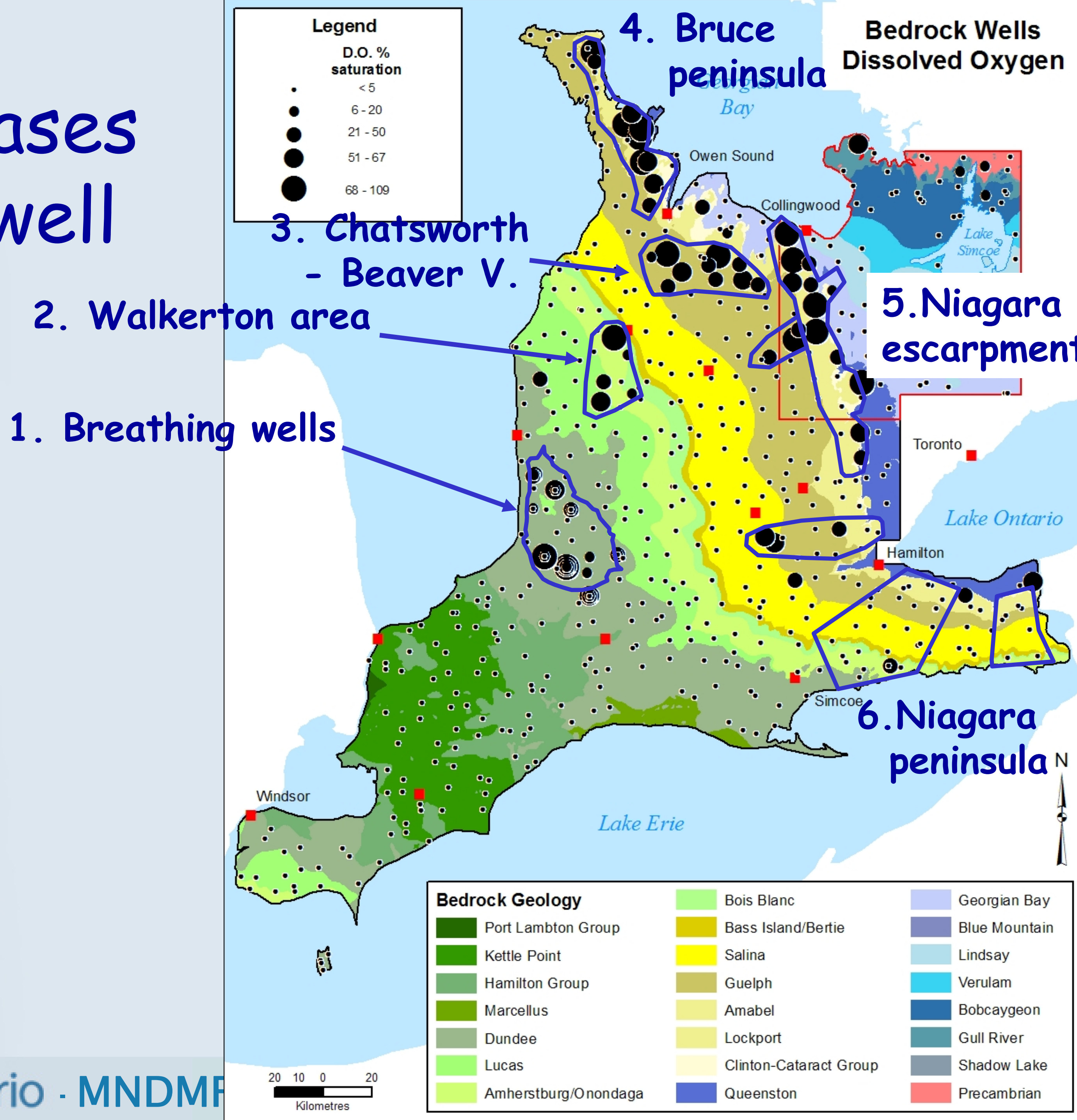


Physical evidence of karst


Brunton and Dodge, 2008

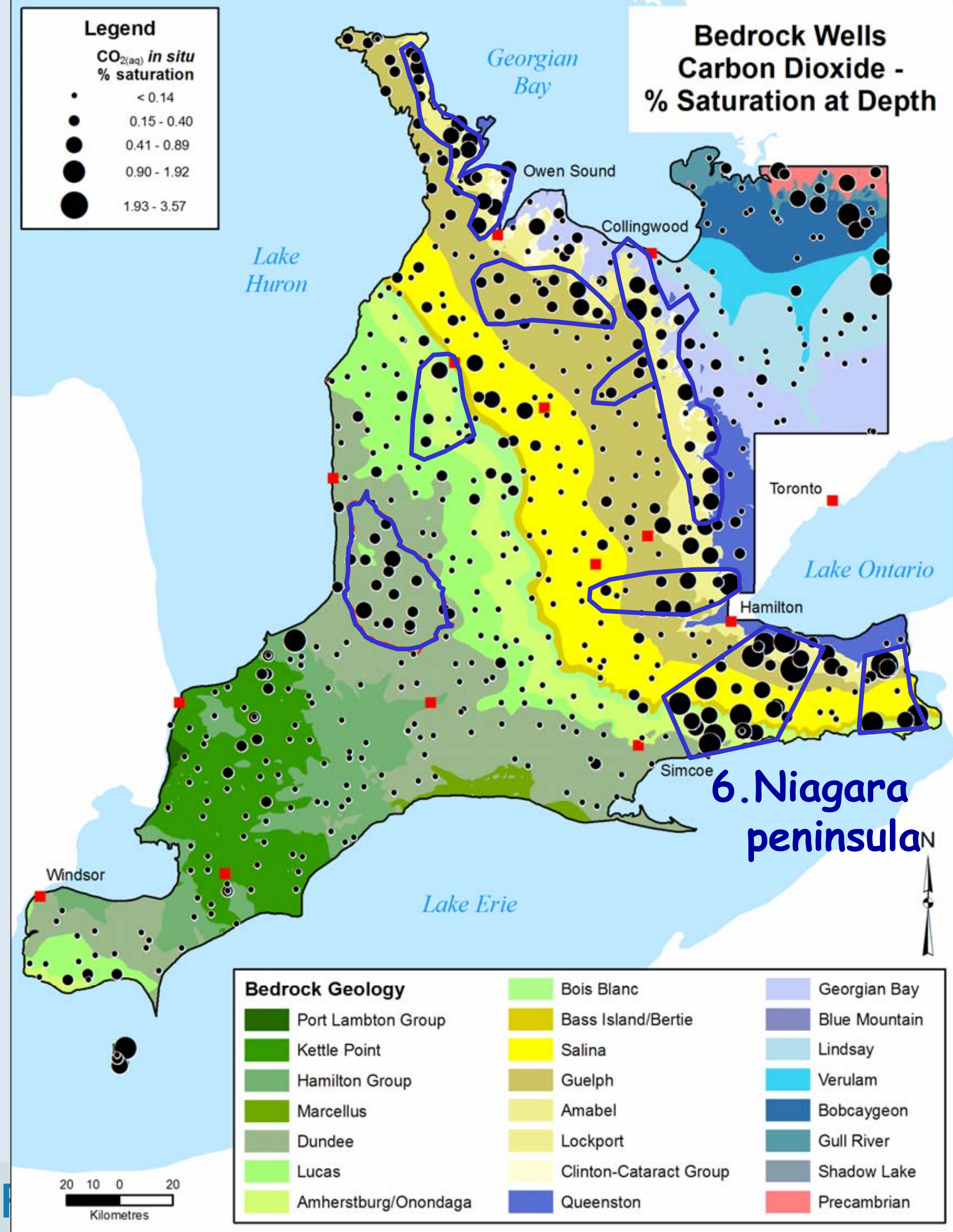
# Dissolved gases in bedrock well water

## Oxygen

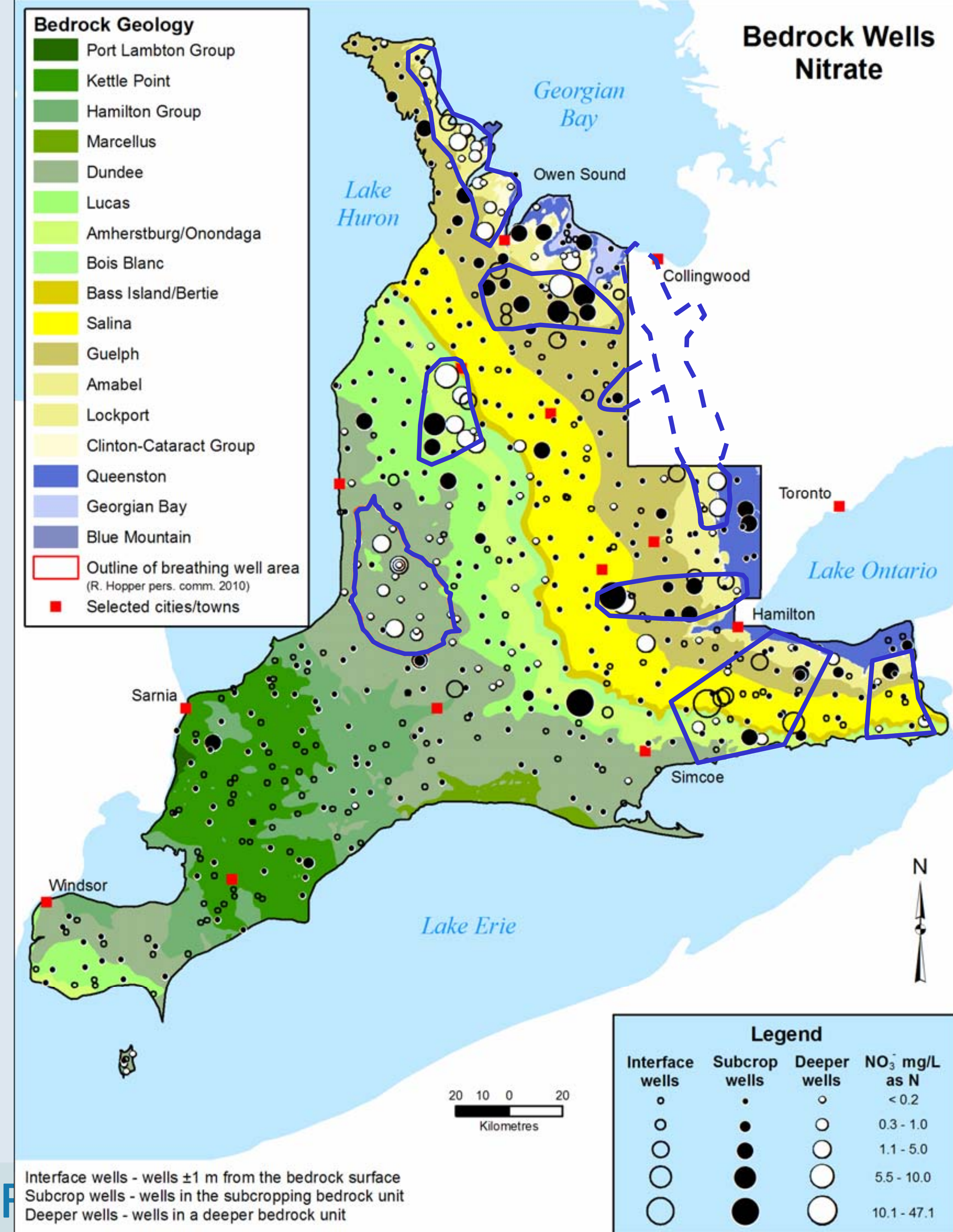


# Dissolved gases in bedrock well water

## Carbon Dioxide



# Nitrate in bedrock well water

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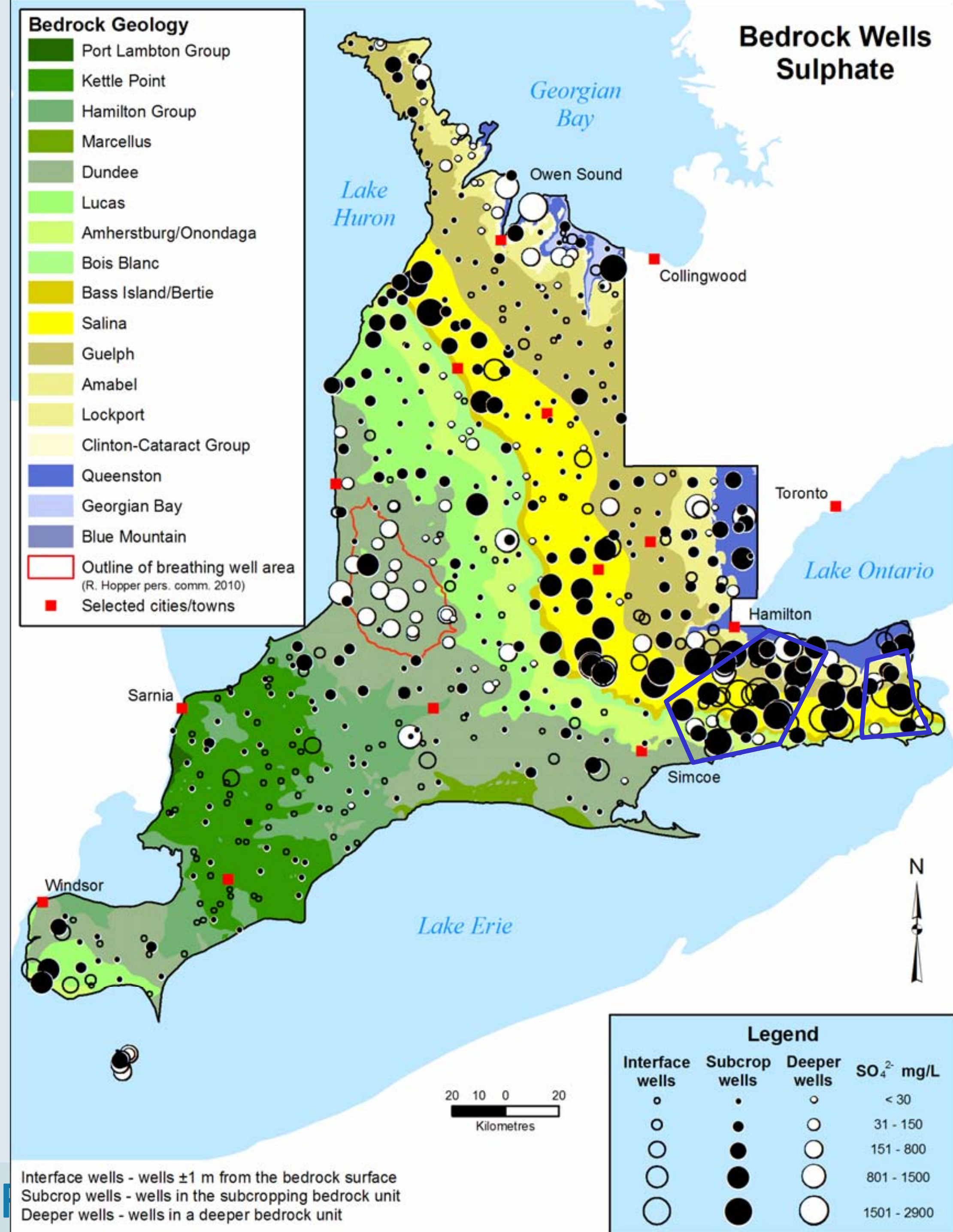
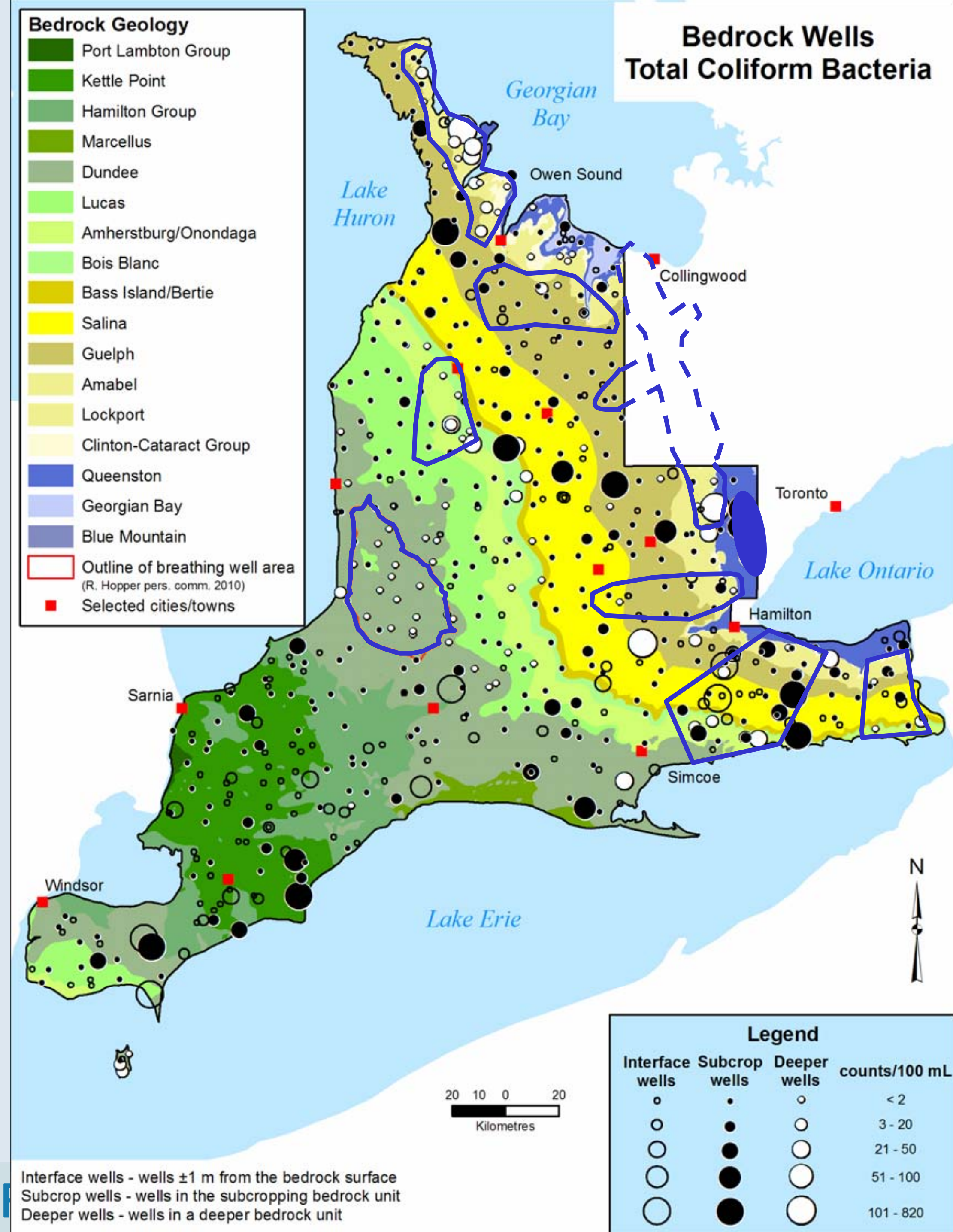
# Niagara Peninsula Water Quality Anomaly

# The Niagara Peninsula Anomaly



# Total Coliform bacteria in deep well water

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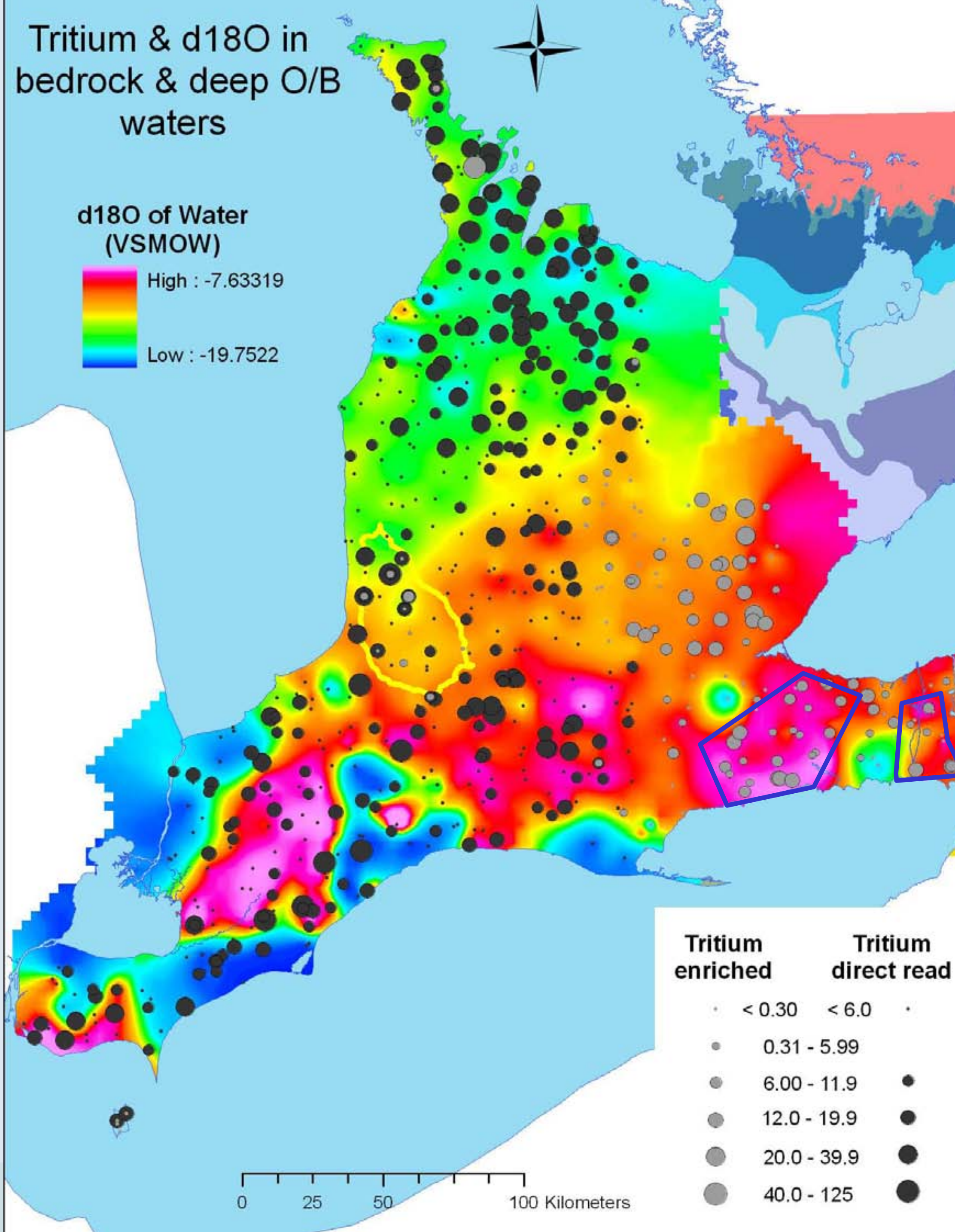
# Evidence of northward flow across the Niagara peninsula

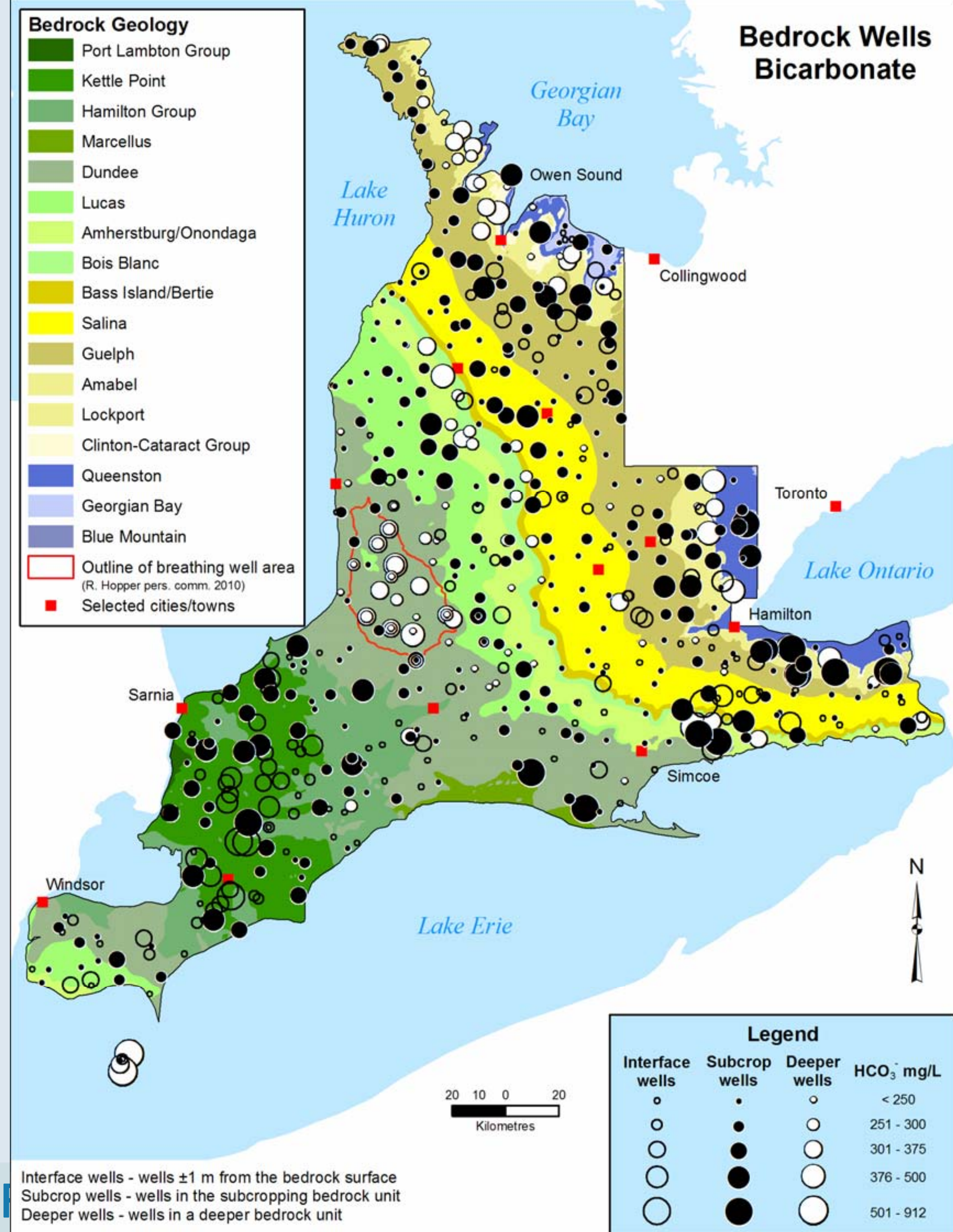
1. Hydraulics
2. Isotopes
3. Major ion chemistry
4. Bacteria and Nitrates (suggestive of karst)
5. Trace element chemistry

# 2. Isotopes

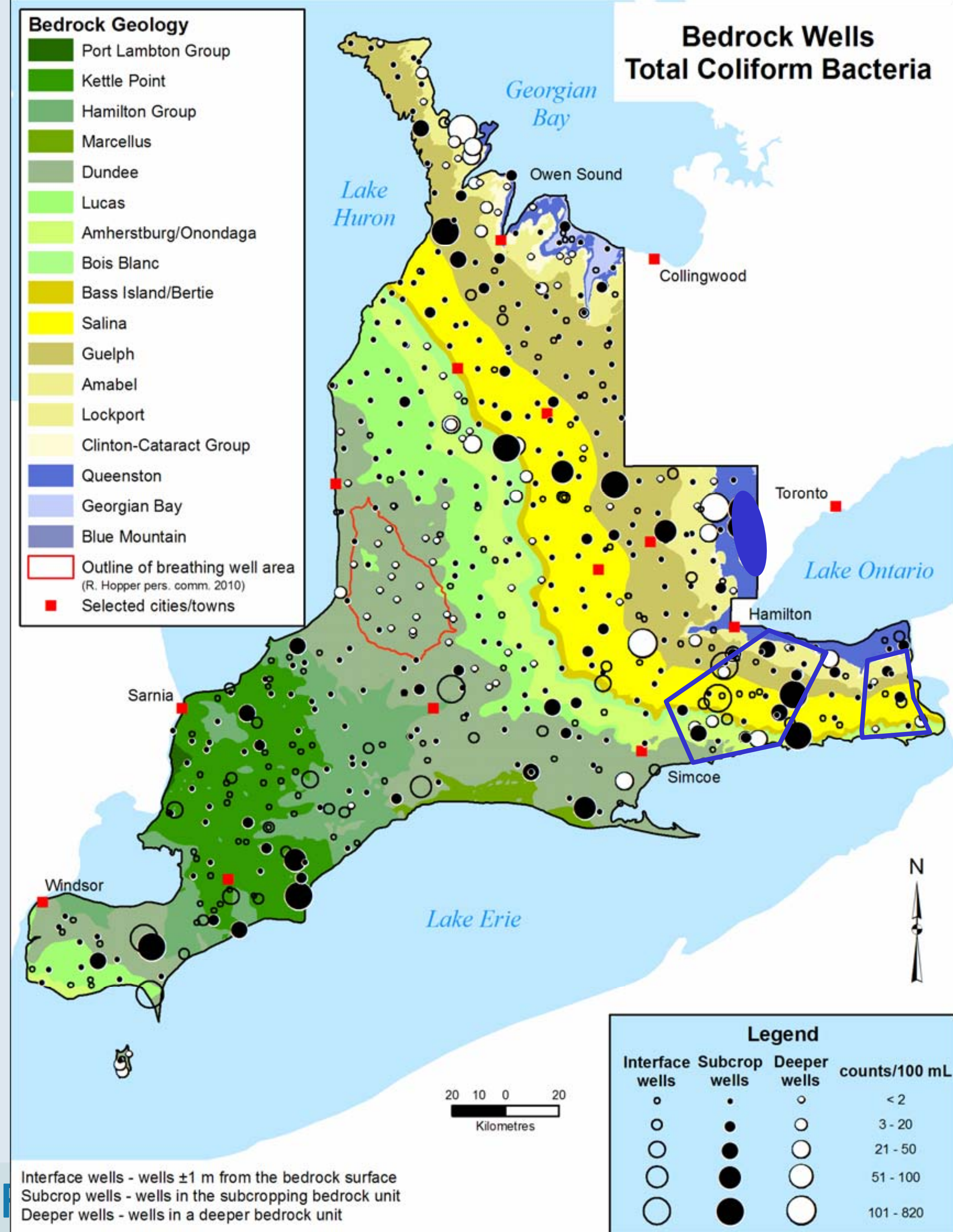
## $^{18}O$ and $^{3}H$ in deep well water



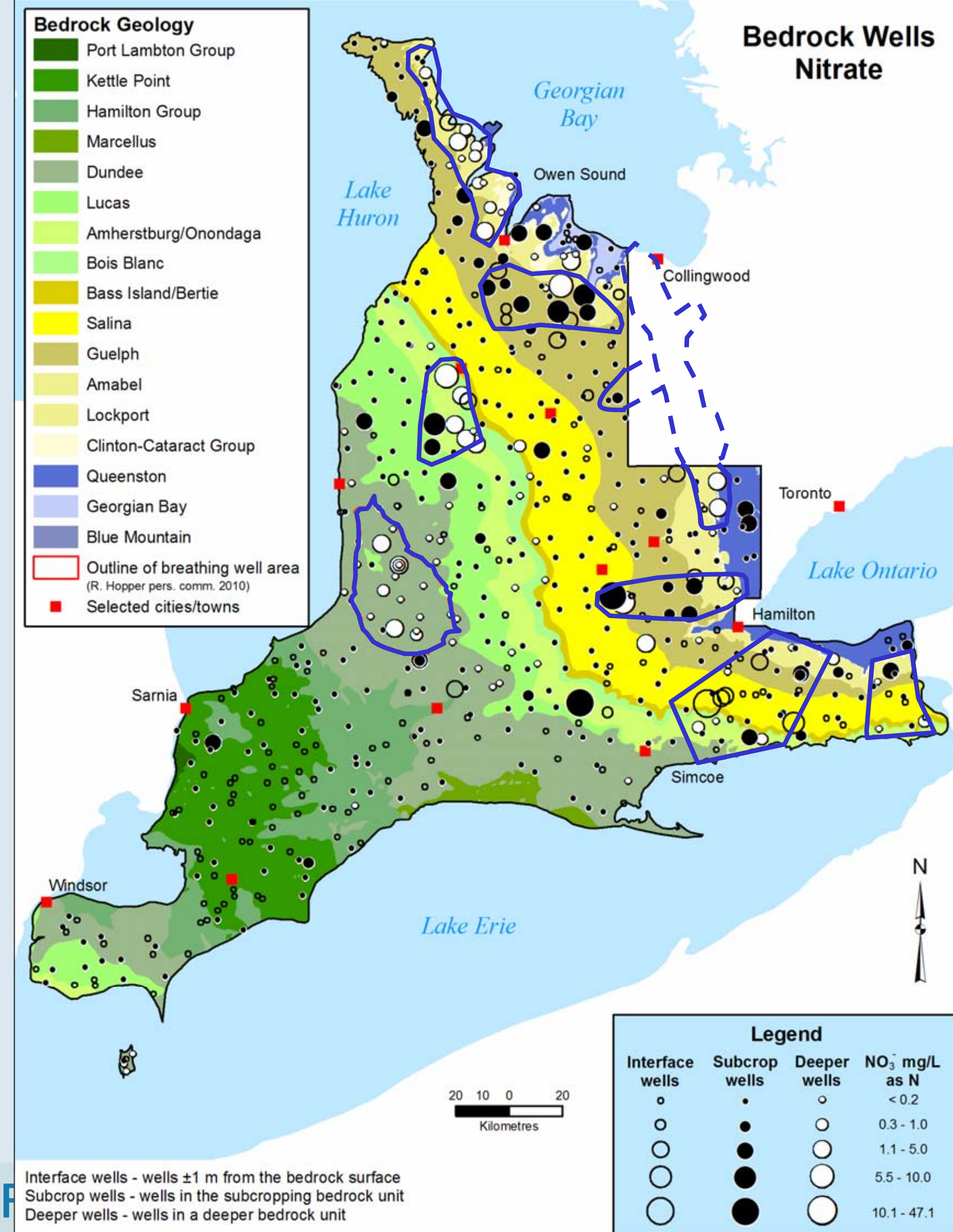
# 3. Major ion chemistry: order of encounter



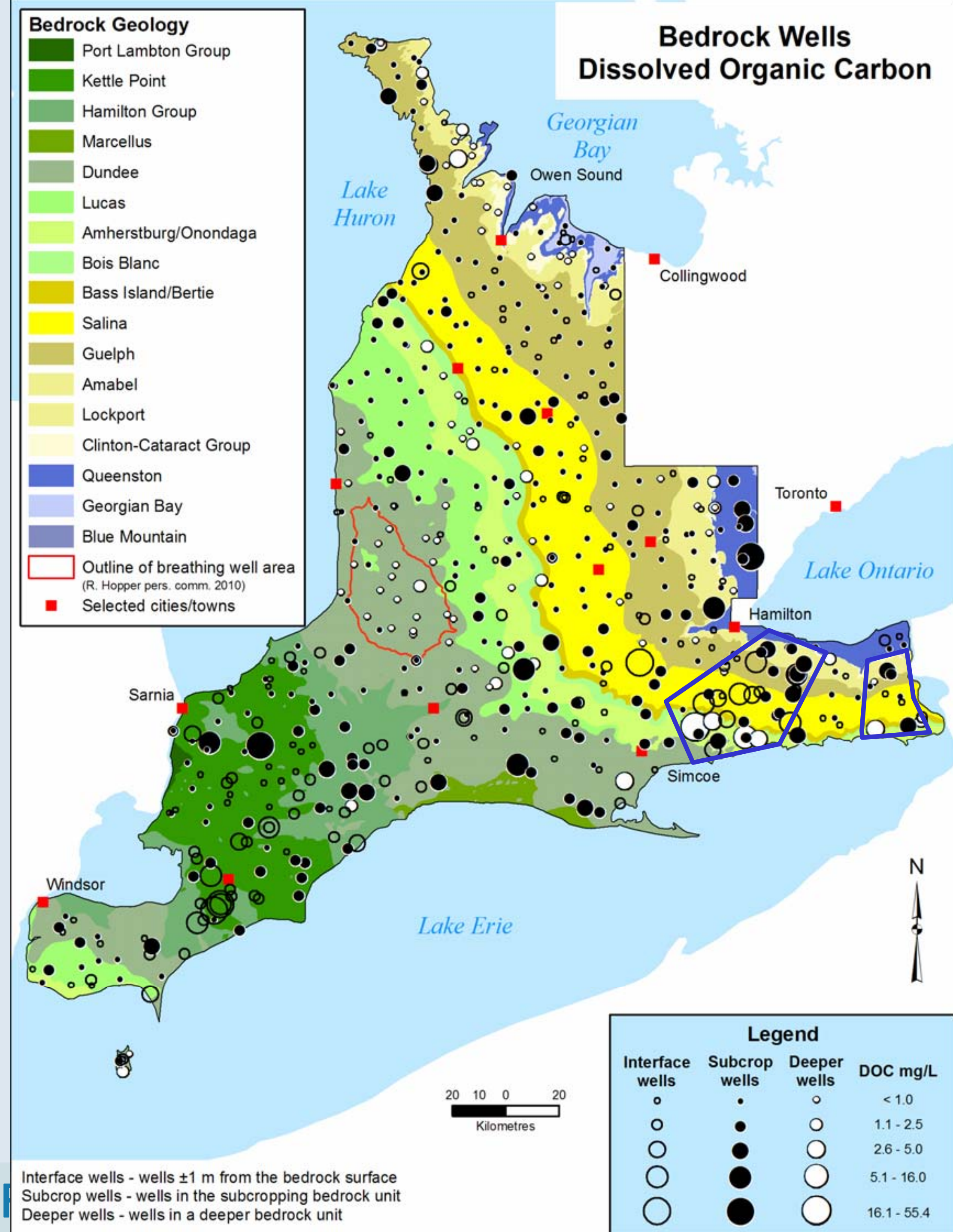
# 5a. Bacteria Total Coliform in deep well water



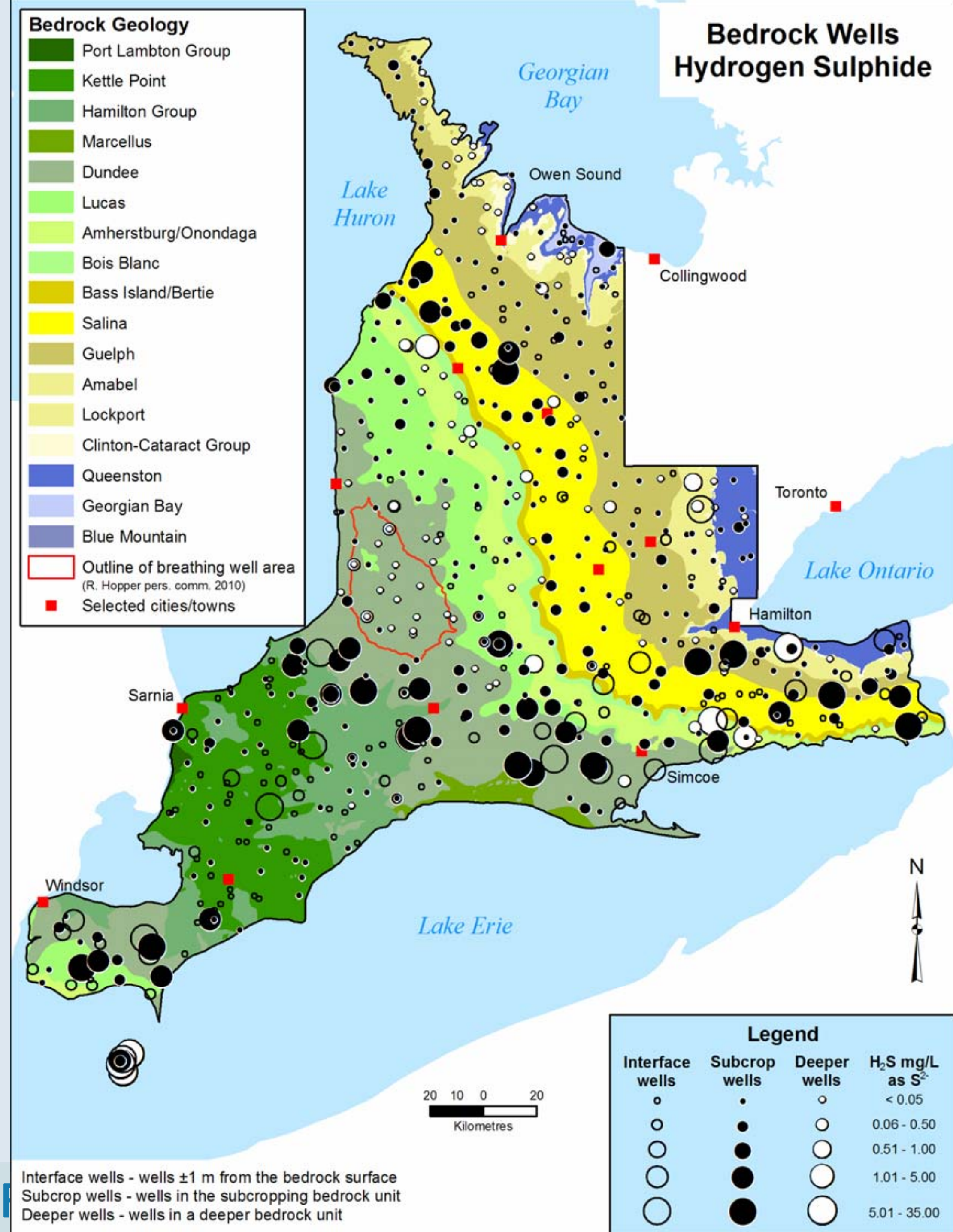
# 5b. Nitrate in bedrock well water



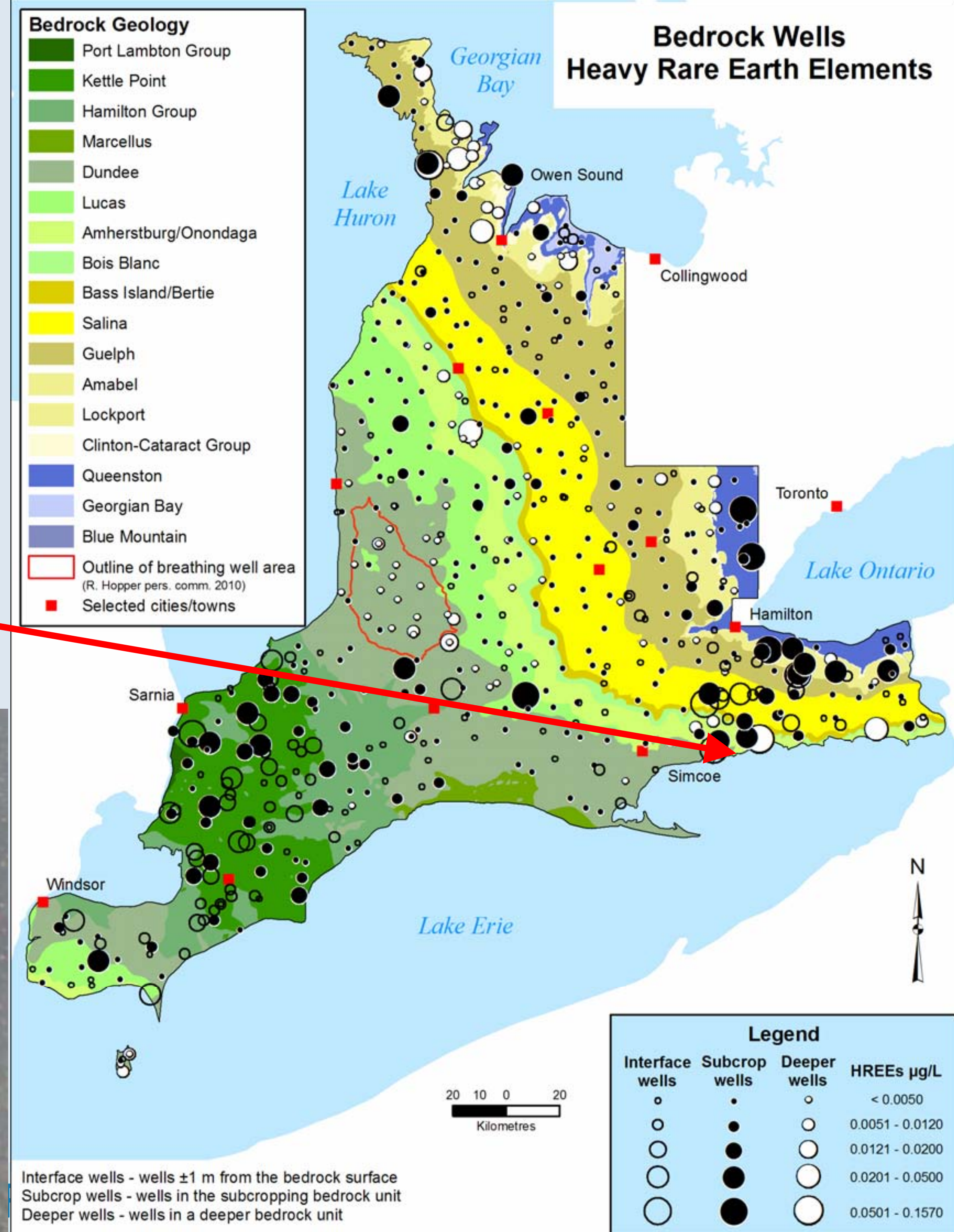
# 6. Trace elements DOC in bedrock well water



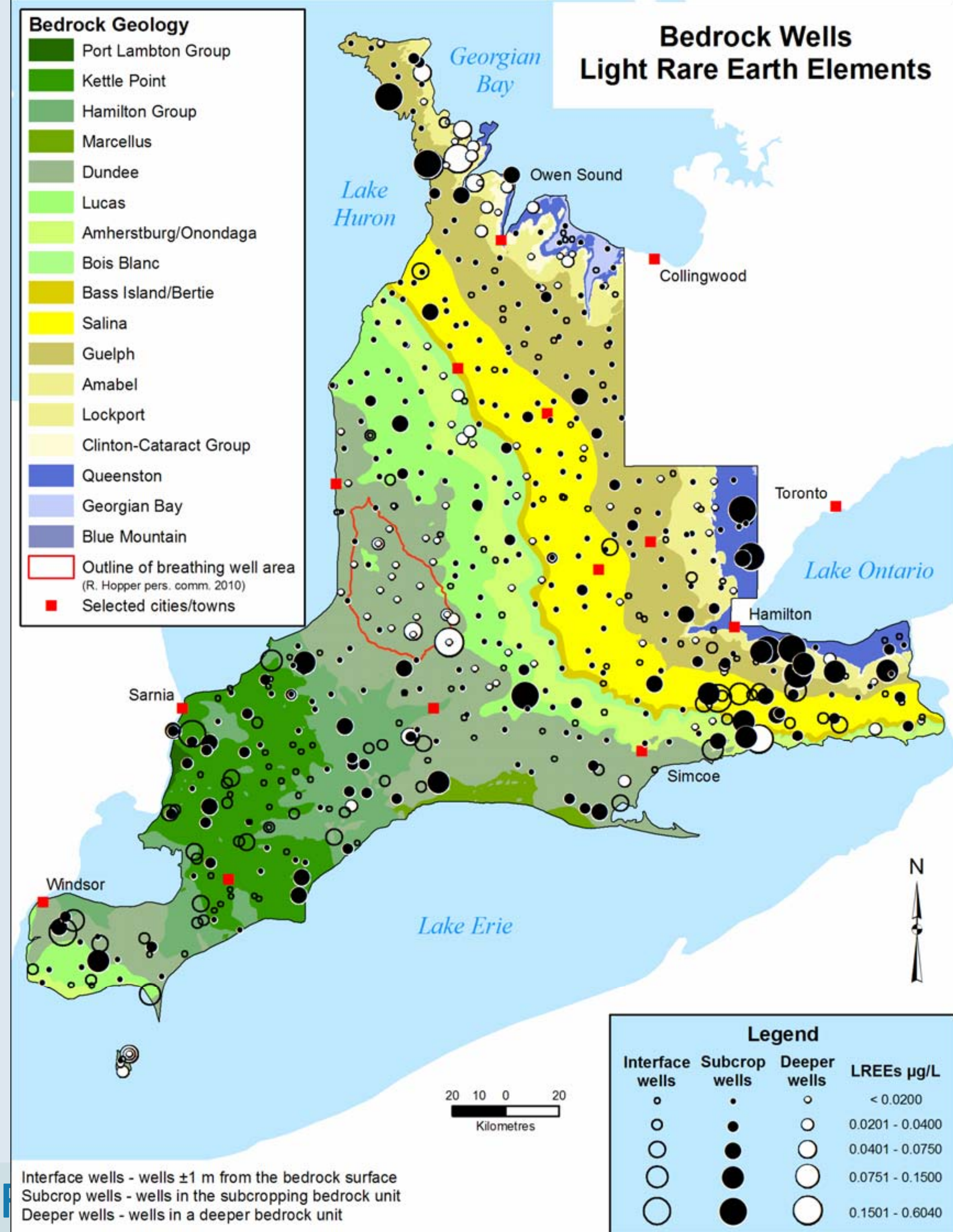
# 6. Trace elements Sulphide in bedrock well water



# Heavy REEs in bedrock well water

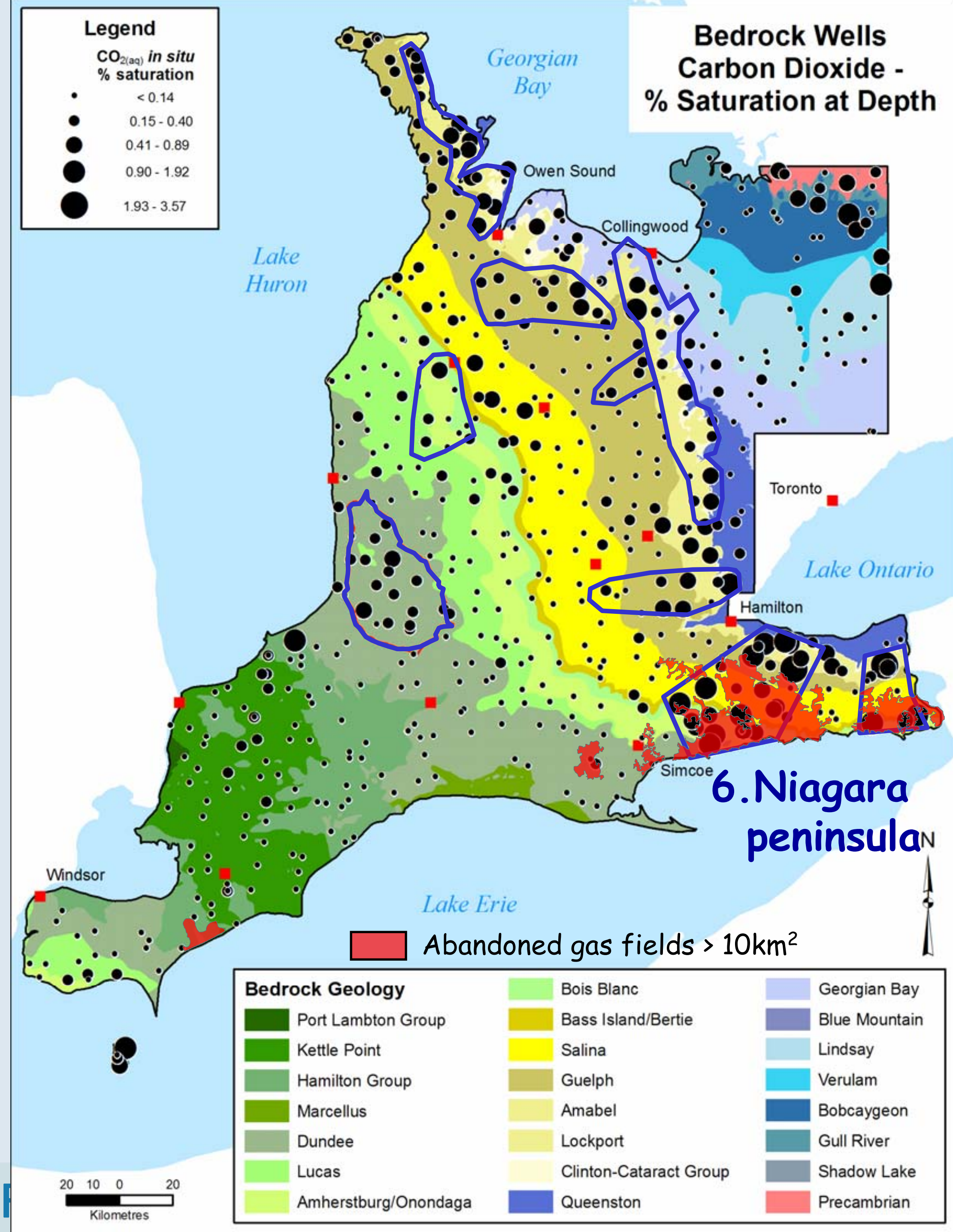


# Light REEs in bedrock well water

# Dissolved gases in bedrock well water

# Carbon Dioxide



# Summary

- Ontario's ambient groundwater program has provided a unique dataset that allows the assessment of current groundwater quality and serves as a benchmark for possible future changes
- An initial review of the data shows a number of phenomena of interest including:
  - Profound correlations between water chemistry and rock type
  - Extensive natural shale gas methane in domestic well water
  - Extensive areas of karstic conditions that appear to control local groundwater flow characteristics
  - One of these karstic areas is on the Niagara Peninsula and may be enhancing regional northward flow of anthropogencially impacted groundwater across the peninsula

# Thank You

# Nova Scotia

John Drage, Senior hydrogeologist, Nova Scotia Environment

# Shale Gas in Nova Scotia

Shale Gas Workshop

GSC, Calgary

November 24th, 2011

John Drage

Nova Scotia Environment

NOVA SCOTIA

# Overview

1) History of onshore oil & gas in NS
2) Current activity in NS
3) NS regulations
4) NS hydraulic fracturing review

NOVA SCOTIA

# History of Onshore Oil & Gas in NS

- Exploration began in 1869 - oil in Cape Breton
- 133+ exploration wells have been drilled
- No commercial success yet
- First wells hydraulically fractured in 1970s
- Most recent was in 2007/08: 3 shale gas wells

NOVA SCOTIA

# Elmworth – shale gas wells - 2007

NOVA SCOTIA

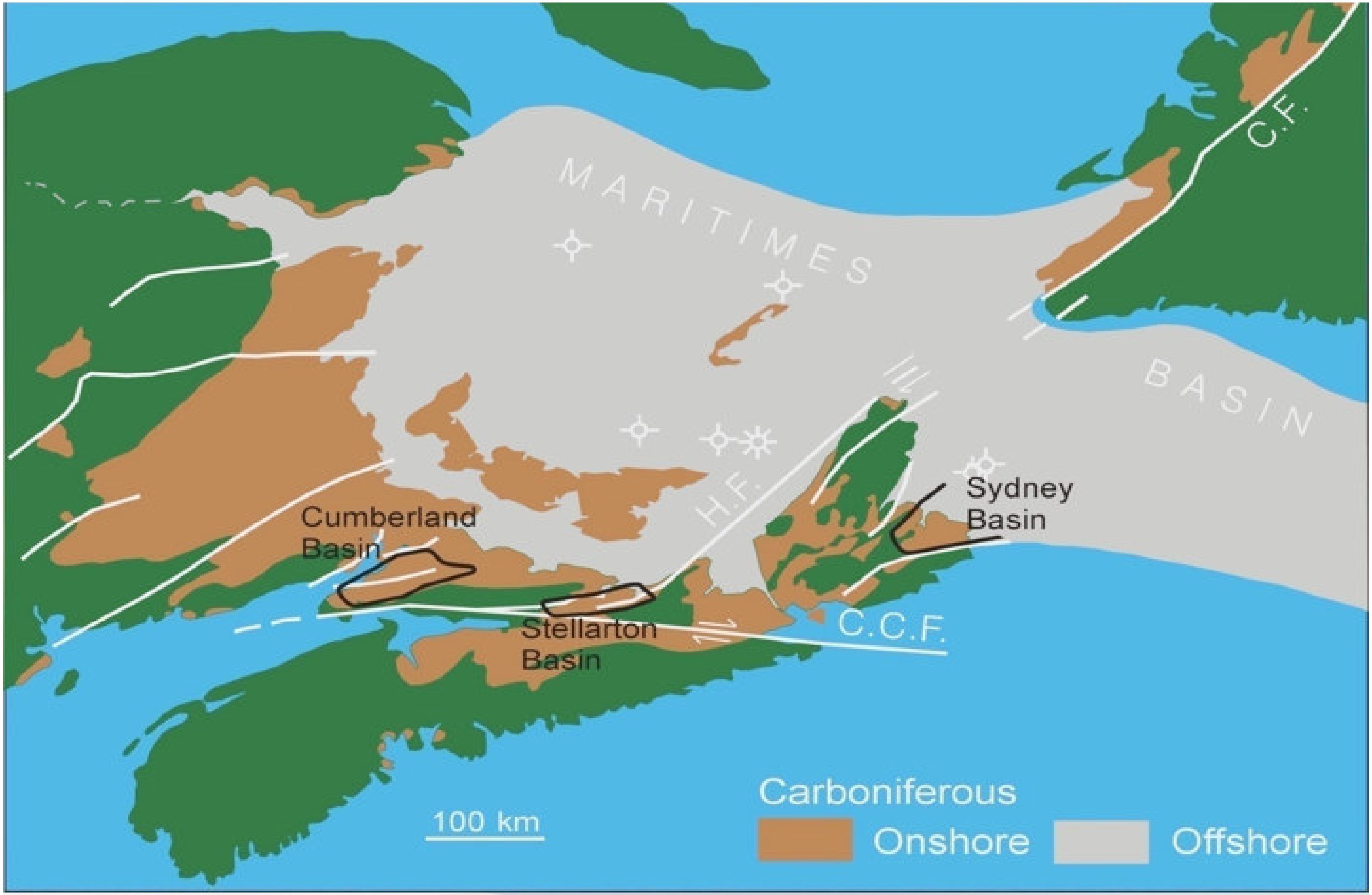
# Stealth – coal bed methane - 2006

NOVA SCOTIA

# History of oil & gas in NS - Geology

- All exploration activity in NS has been in the Carboniferous sedimentary basin
- Target rocks: Cumberland Group, Windsor Group, Horton Group
- These include shales, sandstone, coal bed methane, carbonates

NOVA SCOTIA


MARITIMES
BASIN
C.F.
H.F.
C.C.F.
Cumberland Basin
Stellarton Basin
Sydney Basin
100 km
Carboniferous
Onshore
Offshore

NOVA SCOTIA

Cumberland Group

Windsor Group

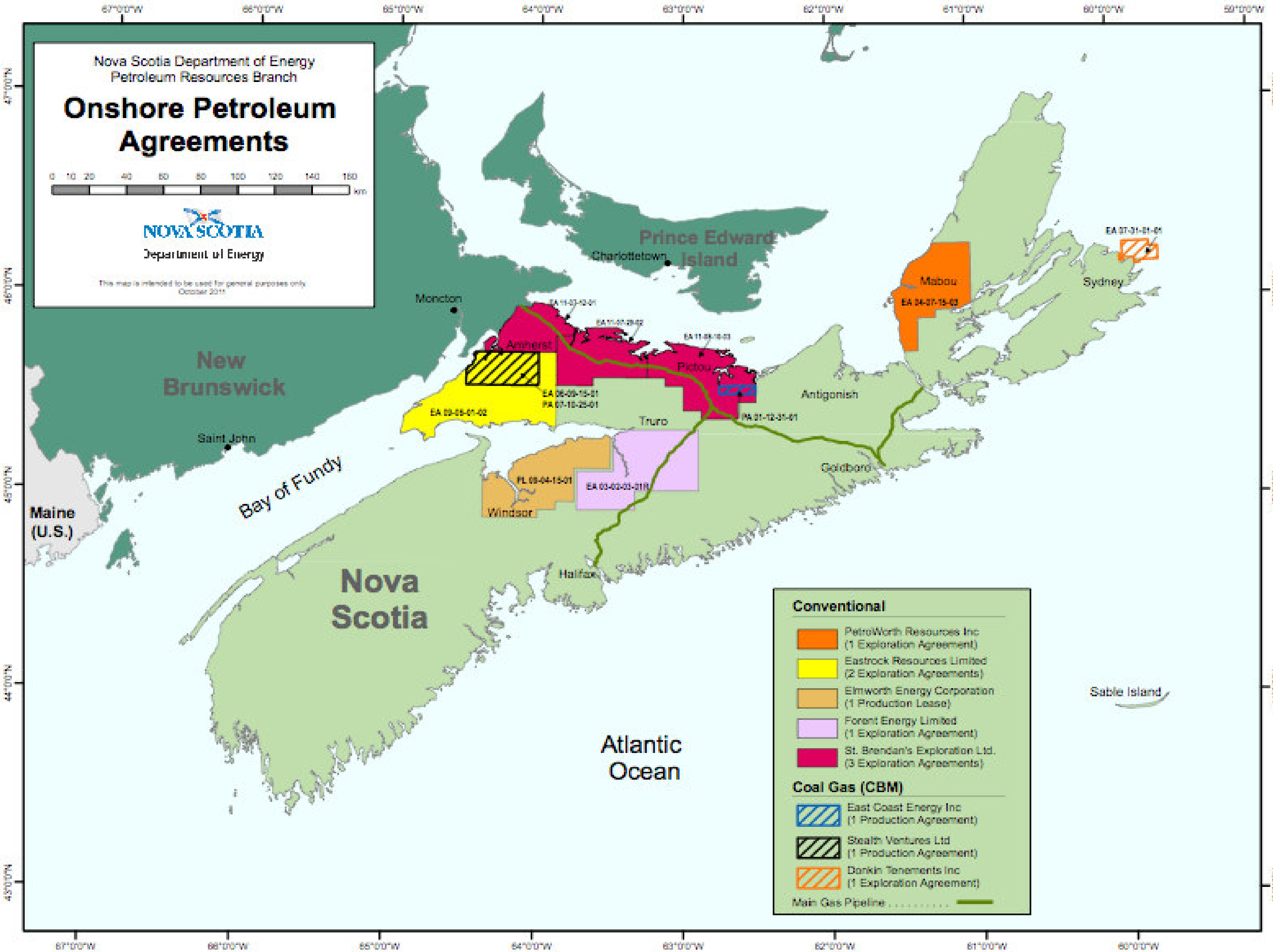
Horton Group

NOVA SCOTIA

# Current Activity

- No current applications for hydraulic fracturing
- Petroleum agreements currently in place:
  - 8 conventional (shale, sands) agreements
  - 3 coal bed methane agreements
- Sep 2011 - PetroWorth approval for 1 oil well in Cape Breton
- Nov 2011 – Forent Energy approval for 3 oil wells on mainland NS

NOVA SCOTIA



Nova Scotia Department of Energy
Petroleum Resources Branch
Onshore Petroleum Agreements
km
NOVA SCOTIA
Department of Energy
This map is intended to be used for general purposes only.
October 2011
Prince Edward Island
Charlottetown
Moncton
New Brunswick
Saint John
Maine (U.S.)
Bay of Fundy
Amherst
Pictou
Truro
Windsor
Halifax
Antigonish
Goldboro
Mabou
Sydney
Sable Island
Nova Scotia
Atlantic Ocean
EA 06-09-15-01
PA 07-10-25-01
PA 01-12-31-01
Conventional
PetroWorth Resources Inc (1 Exploration Agreement)
Eastrock Resources Limited (2 Exploration Agreements)
Elmworth Energy Corporation (1 Production Lease)
Forent Energy Limited (1 Exploration Agreement)
St. Brendan's Exploration Ltd. (3 Exploration Agreements)
Coal Gas (CBM)
East Coast Energy Inc (1 Production Agreement)
Stealth Ventures Ltd (1 Production Agreement)
Donkin Tenements Inc (1 Exploration Agreement)
Main Gas Pipeline

# NS Regulations

- Three approvals needed before drilling:
- 1) Exploration Agreement - NS Dept of Energy
- 2) Authority to Drill - NS Dept of Energy
  - Public meetings, drilling plan, land owner agreement
- 3) Industrial Approval - NS Environment
  - Groundwater protection measures include: baseline/post operation water well survey within 1000m; casing/cement integrity check; lined/bermed drill pad; secondary containment for liquid wastes
- Separate application for hydraulic fracturing

NOVA SCOTIA

# NS Hydraulic Fracturing Review

- Technical review of potential environmental issues with hydraulic fracturing
- Review underway, to be complete in 2012
- Review looks at potential impacts:
  - Groundwater, surface water, land,
  - Management of additives in hydraulic fracturing fluids
  - Waste water management
  - Site restoration
  - Hydraulic fracturing operational designs
  - Financial security and insurance

NOVA SCOTIA

# Summary of Key Points

- Oil & gas exploration began in NS in 1869
- 133+ wells drilled, but only 3 shale gas wells
- Wells hydraulically fractured in NS since 1970s
- No hydraulic fracture applications currently in NS
- NS hydraulic fracture review is due in 2012
- Disposal of produced water is a key challenge

Thank you!

Questions?

John Drage
Hydrogeologist
Nova Scotia Environment

# New Brunswick

Annie Daigle, Hydrogeologist, New Brunswick Department of Environment

# Natural Gas Development in New Brunswick

**November 24, 2011**

# Current Natural Gas and Oil Industry in New Brunswick:

- First oil well drilled at Dover in 1859
- 300 wells were drilled in NB by 2010
- Since 1990, 40 Oil wells drilled and 40 Natural Gas wells
- 30 Natural Gas wells are currently producing
- 9 wells have been horizontally drilled, 5 gas and 4 oil
- Since 1990 49 wells have been fraced in NB

# Proven Resources

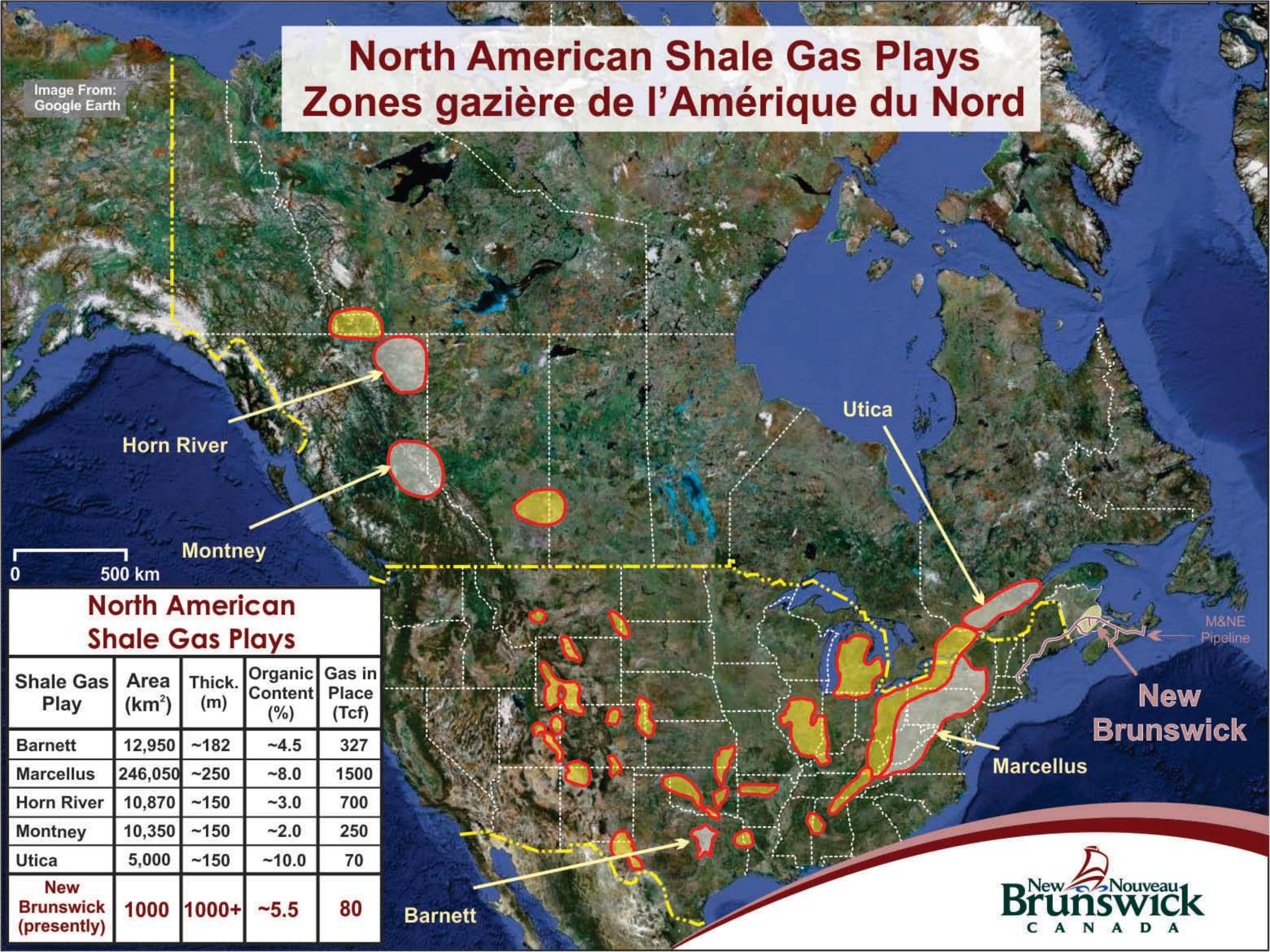
*McCully Gas Field*

- Discovered in 2000
- Tight gas sandstone
- 30 wells producing ~18 mmcf/d
- 121 Bcf gross gas reserve (sandstone)
- 67 Tcf shale gas resource estimate

*Stoney Creek Oilfield*

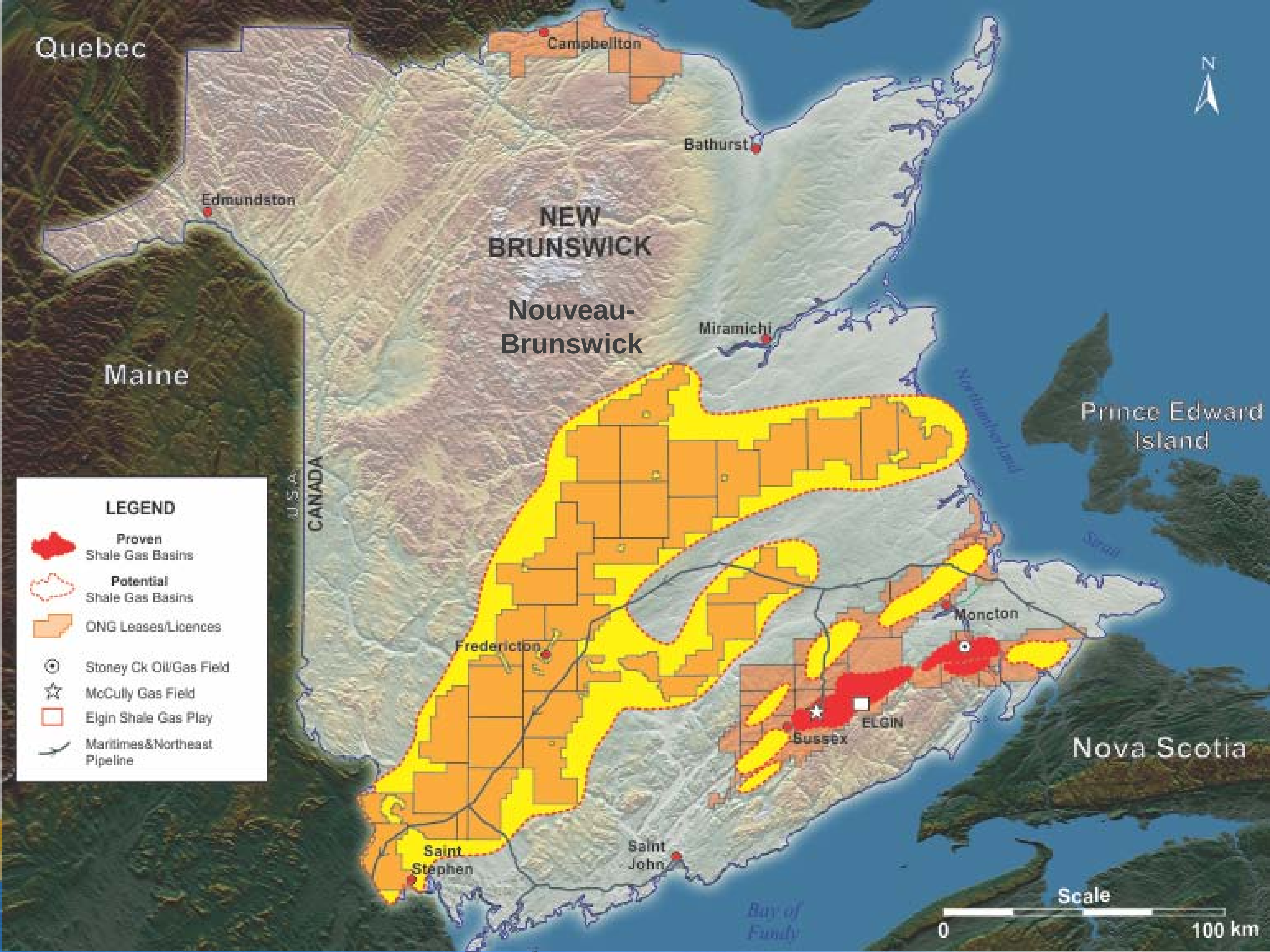
- Discovered in 1909
- Tight oil and gas sandstone
- 16 oil wells producing ~100 barrels/day
- 1.3 mmbbl gross oil reserve
- 7.9 Bcf gross gas reserve (sandstone)
- 11 Tcf shale gas resource estimate

# North American Shale Gas Plays
# Zones gazière de l'Amérique du Nord




## North American Shale Gas Plays

| Shale Gas Play | Area ($km^2$) | Thick. (m) | Organic Content (%) | Gas in Place (Tcf) |
|---|---|---|---|---|
| Barnett | 12,950 | ~182 | ~4.5 | 327 |
| Marcellus | 246,050 | ~250 | ~8.0 | 1500 |
| Horn River | 10,870 | ~150 | ~3.0 | 700 |
| Montney | 10,350 | ~150 | ~2.0 | 250 |
| Utica | 5,000 | ~150 | ~10.0 | 70 |
| **New Brunswick (presently)** | **1000** | **1000+** | **~5.5** | **80** |



Quebec
Campbellton
Bathurst
Edmundston
NEW BRUNSWICK
Nouveau-Brunswick
Miramichi
Maine
Northumberland
Prince Edward Island
Strait
U.S.A.
CANADA
LEGEND
Proven Shale Gas Basins
Potential Shale Gas Basins
ONG Leases/Licences
Stoney Ck Oil/Gas Field
McCully Gas Field
Elgin Shale Gas Play
Maritimes&Northeast Pipeline
Fredericton
Moncton
ELGIN
Sussex
Nova Scotia
Saint Stephen
Saint John
Bay of Fundy
Scale
0
100 km
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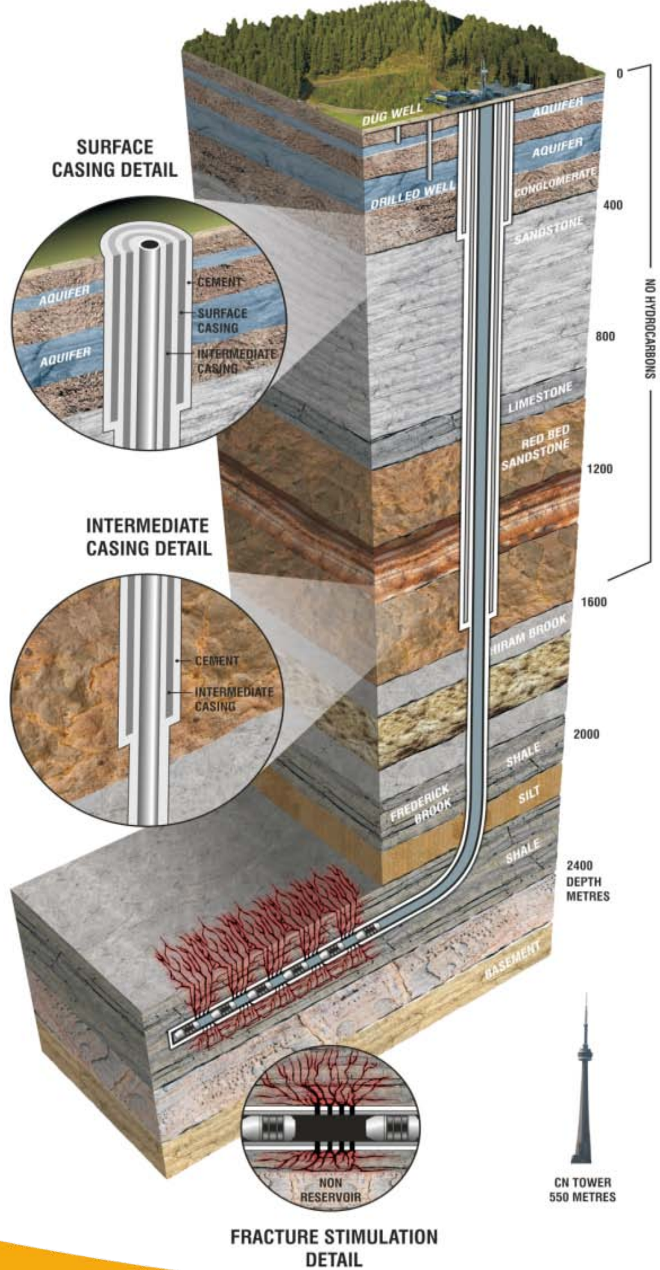


# Geologic Setting

- Deep shale formations
  - Drinking water supplies less than 300m deep
  - Gas shales typically greater than 2km deep

- Intervening geology
  - Mabou/Sussex Group “Red Beds”
  - Extremely low vertical permeability
  - 1km or more thick

New Nouveau Brunswick

# Responsible Management of Oil and Gas Activities:

## New Brunswick's Approach

# Meeting a Government Commitment

In the government's platform, *Putting New Brunswick First*, and in the November 23, 2010 Speech from the Throne, commitments were made to assure New Brunswickers that expansion of the natural gas sector will be conducted in a ***responsible manner.***

# The Natural Gas Group

- Formed in April to assist government in preparing the Natural Gas Action Plan deliverables
- Team members are on temporary assignment until the end of year and consist of staff from the following government departments:
    - Executive Council Office
    - Environment
    - Natural Resources
    - Communications
    - Energy
    - Business New Brunswick

# Natural Gas Development Action Plan

1. Project Management Structure
2. Communications Plan
3. Environmental Protection Plan
4. Economic Benefits Plan
5. Resource Development Plan
6. Community Development Approach
7. Regulatory Framework.

# Current Legistlation

- Oil and Natural Gas Act
- Crown Lands and Forests Act
- Clean Environment Act ⟵ EIA Regulation
- Clean Water Act
- Clean Air Act
- Community Planning Act
- Pipeline Act
- Highway Act
- Occupational Health and Safety Act
- Workplace Health, Safety and Compensation Commission Act
- Workers' Compensation Act
- Boiler and Pressure Vessel Act
- Emergency Measures Act

# Stronger Requirements

Announced June 23, 2011 in order to strengthen the regulatory framework for oil and natural gas exploration, development and production in the province.

1. **Baseline Testing**
   - Water quality testing of all potable water wells within 200m of seismic testing and 500m of oil or natural gas well pads.
2. **Full Disclosure of Chemical Additives**
   - Disclosure of all proposed and actual contents of any fluids, chemicals and additives used in the hydraulic fracturing (fracing) process.
3. **Security Bond**
   - Companies must establish a security bond to protect property owners and taxpayers from the impact of industrial accidents, including the loss of, or contamination of, drinking water.
   - Burden of proof to rest with the oil and gas company.

* Also committed to developing a profit sharing formula so landowners and communities can share in the financial benefits of the oil and natural gas industry.

New Nouveau Brunswick

# Natural Gas Development Action Plan

1. Project Management Structure
2. Communications Plan
3. **Environmental Protection Plan**
4. Economic Benefits Plan
5. Resource Development Plan
6. Community Development Approach
7. Regulatory Framework.

New Nouveau Brunswick

# Environmental Protection Plan
## Purpose

To help ensure the responsible environmental management of land-based oil and gas activities in New Brunswick.

# Water Supply Management

## Where will the water come from?

- Available water supply options include:
  - Surface water
  - Groundwater
  - Municipal water
  - Deep saline formation water (non-potable)
  - Sea water
  - **Recycling and reuse of flowback and produced water**

- Water Supply and Disposal Strategy currently under development.

- Keeping NB's best quality water for drinking water and protecting aquatic ecosystems are top priorities.

# Environmental Protection Plan

## Key issues addressed:

1. Sharing Information
2. Reducing Financial Exposure of Taxpayers and Protecting Landowner Rights
3. Addressing Potential Impacts of Geophysical (Seismic) Activities
4. Ensuring that Contaminants do not Escape from the Wellbore
5. Verifying Geological Containment Outside the Wellbore
6. Managing Wastes and Ensuring that Contaminants do not Escape from the Well Pad
7. Monitoring to Protect Water Quality
8. Ensuring Sustainable Water Use
9. Addressing Air Emissions including GHGs
10. Protecting Public Health and Safety
11. Managing Impacts on Communities and the Environment
12. Ensuring an Effective Regulatory Framework

New Nouveau Brunswick

# Waste Water Management

- In NB all waste water is currently collected and stored in enclosed tanks with secondary containment and sent to approved facilities for treatment and discharge (Debert, NS).
- Should shale gas prove to be commercially viable, other options will have to be explored
  - Dedicated treatment facilities
  - Recycling and reuse technologies
- Stronger requirements currently proposed to take a “cradle to grave” approach to water management for ONG industry
- **Deep well injection is not an option for New Brunswick**

New Nouveau Brunswick

# Natural Gas Opportunities

- Potential for significant economic benefits for NB if we "**do it right**"
  - Royalties
  - Jobs
  - Opportunities for NB companies
  - Expanded tax base

# Natural Gas Challenges

- Potential environmental, economic and social impacts
    - Quality and quantity of water
    - Air emissions
    - Land use change
    - Road use
    - Royalties
- Sufficient revenue for the resource
- Public acceptance
- Effective regulatory framework

# Contact Information

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New Nouveau Brunswick

# British Columbia

Elizabeth Johnson, Ph.D., Senior hydrogeologist, British Columbia Ministry of Energy and Mines

BRITISH COLUMBIA
Ministry of Energy and Mines

# Water Issues Associated with Hydraulic Fracturing in Northeast British Columbia

Elizabeth Johnson
Geoscience and Strategic Initiatives Branch
Ministry of Energy and Mines

**Nov 24-25, 2011**
**Natural Resources Canada Shale Workshop**

# Hydraulic Fracturing

- **Hydraulic fracturing is not "new"**
  - First hydraulic frac 1947
  - $CO_2$ and $N_2$ gas use dates back to 1950's
  - Slickwater fracs date back to 1950's
- **Horizontal drilling improving since 1970's**
  - Mud driven motors
  - Directional control
- **Technological development driven by economics**
  - Successful use of slickwater on Barnett shales (1997)
  - Accelerated development Montney tight gas using gas fracs (2005)
  - Horn River Basin shales using slickwater (2007)

BRITISH COLUMBIA
Ministry of Energy and Mines

# Fracture Treatment

$CO_2$ and $N_2$ gas treatments are "energized"
- Gas helps water return to surface
- Mod to high concentration sand
- Relatively low volume water

Slickwater treatments are 99.5% water and sand
- Thin fluid at high pressure with low concentration of sand
- Friction reducers used so termed "slick"
- High water volume per fracture

## Treatment method varies with geology

- Moderate brittleness
- clay, carbonate, silica content
- Depth constraint

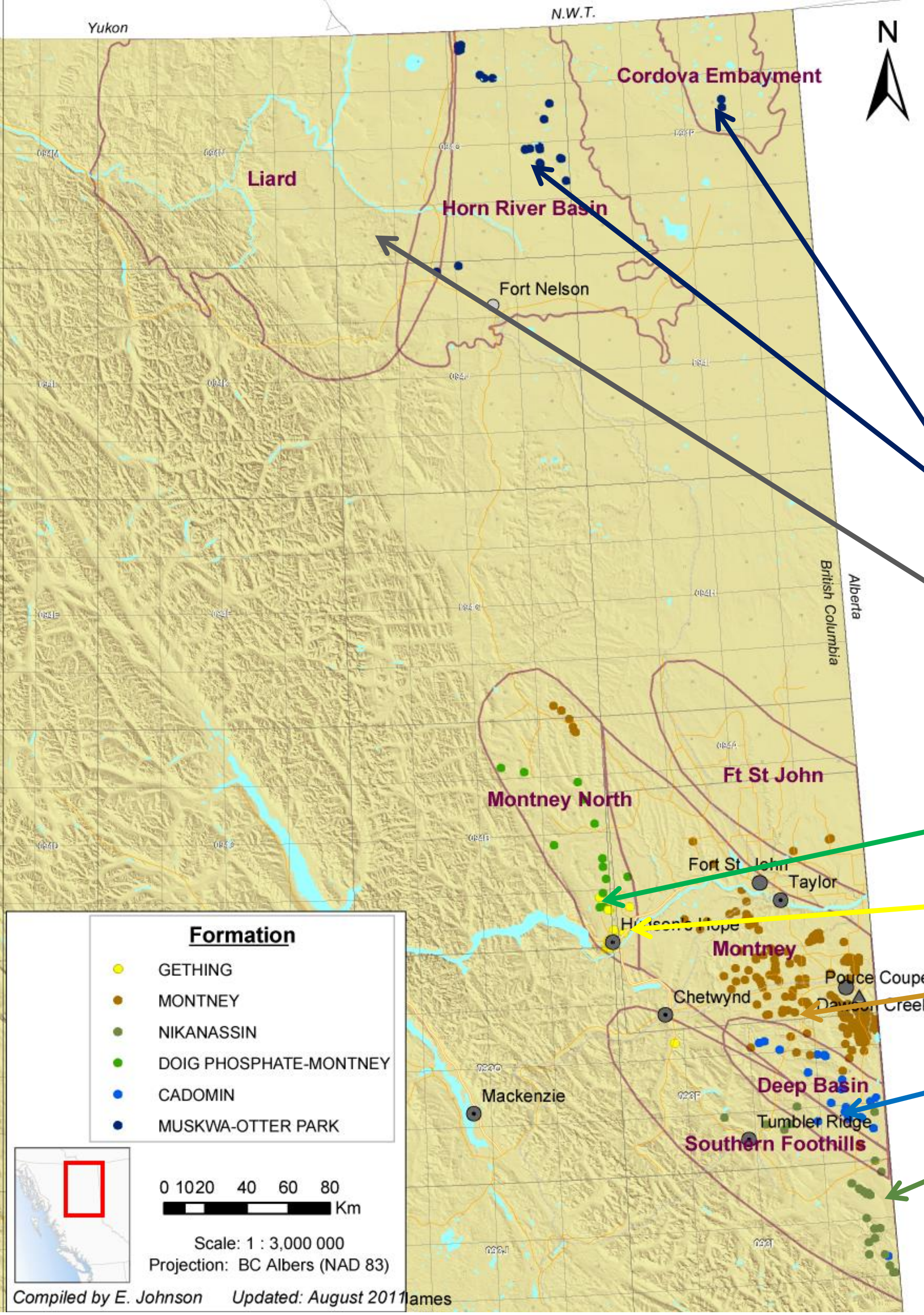
- High brittleness
- Low clay content, high silica

BRITISH COLUMBIA
Ministry of Energy and Mines

# Multistage wells

- Over 30,000 wells in BC since 1950 (OGC IRIS database)
- Database of wells with multiple fracture stages (~475 wells)
- Removed vertical wells in Gething Fm targeting CBM

| | Montney | Horn River | Montney North | Deep Basin | Southern Foothills |
|---|---|---|---|---|---|
| MONTNEY | 310 | | 7 | | |
| MUSKWA-OTTER PARK | | 46 | | | |
| EVIE | | 20 | | | |
| DOIG PHOSPHATE | | | 13 | | |
| CADOMIN | | | | 31 | |
| NIKANASSIN | 15 | | | | 11 |
| GETHING | 2 | | 16 | | 1 |

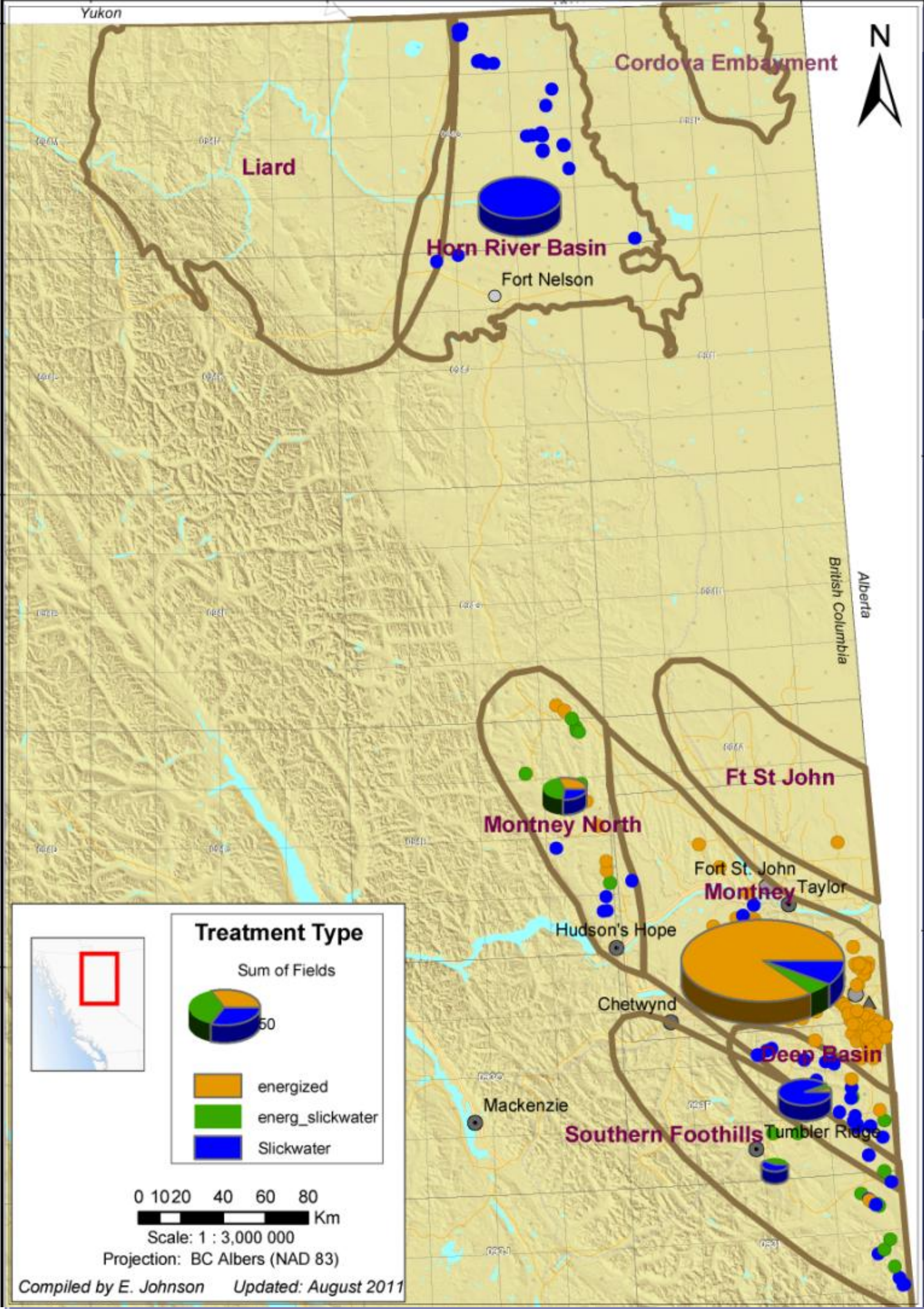



# Wells with Multiple Hydraulic Fractures

## Formation

- Muskwa, Otter park, Evie
- Besa River

- **Doig Phosphate**
- ~~**Gething**~~
- **Montney**
- **Cadomin**
- **Nikanassin**




# Hydraulic Fracture Treatment Type

- **Most wells in the Montney are fractured using $N_2$ or $CO_2$ gas**
- **Wells in the HRB, and Deep Basin are fractured using slickwater treatments**
- **Variety of methods in Montney North and Southern Foothills**

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Ministry of Energy and Mines

# Hydraulic Fracturing
# Montney versus HRB

## Montney

- Tight siltstone – shale
- Depth 1.7 – 4 km
- Energized fracs ($N_2$, $CO_2$)
- 200 $m^3$/frac water
- 40 to 100 T sand / frac
- 6 to 12 fracs per well
- 52,000 kPa stim. pressure

## Horn River Basin

- Siliceous shale
- Depth 2.5 - 3 km
- Slickwater fracs
- 2500 to 5000 $m^3$/frac water
- 200 to 300 T sand / frac
- 12 to 21 fracs per well
- 62,000 kPa stim. pressure

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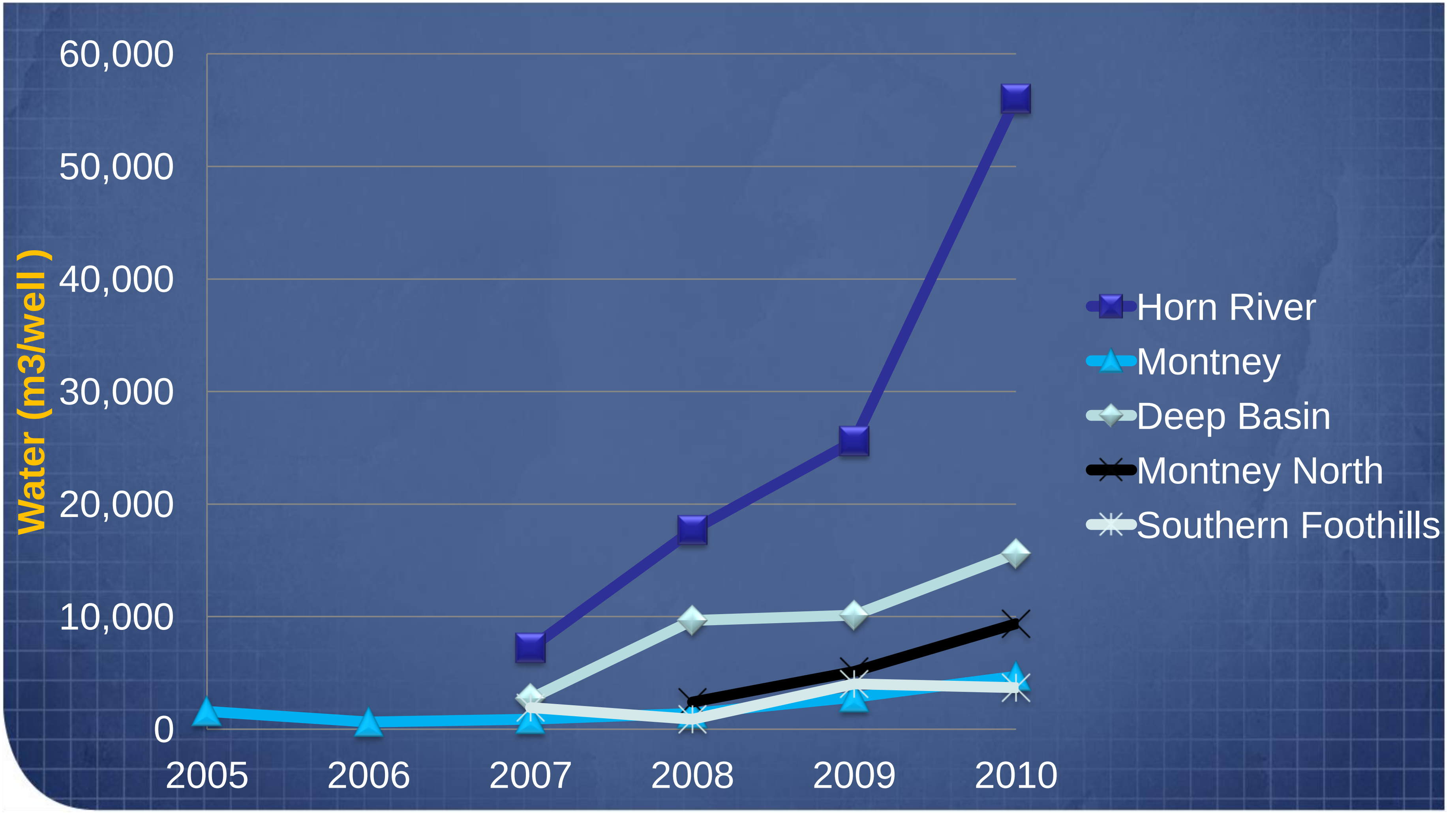
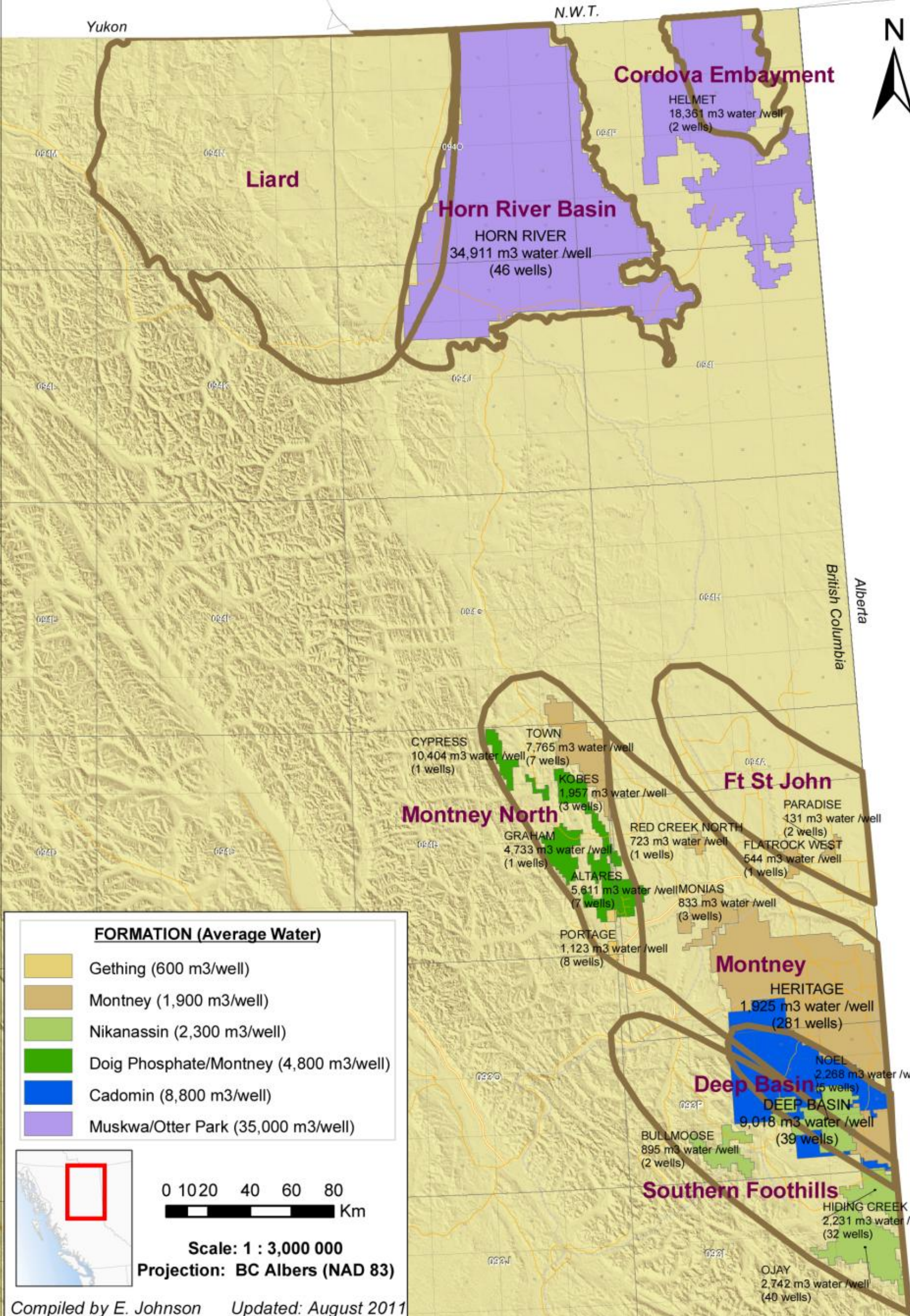
Ministry of Energy and Mines

# Evolving Fracture Technology

- Vertical and horizontal placement staggering
  - Dual and triple laterals
- Increased frac stages per well
  - From 4 (2005) to 22 (2010)
  - From 40 (2011) to 100 (2014?)
- Longer horizontal laterals
  - From 1,000m (2007) to 3,000m (2011)
- Closer spacing between fracs
  - 400m (2007) to 100m (2010)
- Water placement
  - 1500$m^3$ (2007) to 5000$m^3$ (2010)

# Water Usage by Well

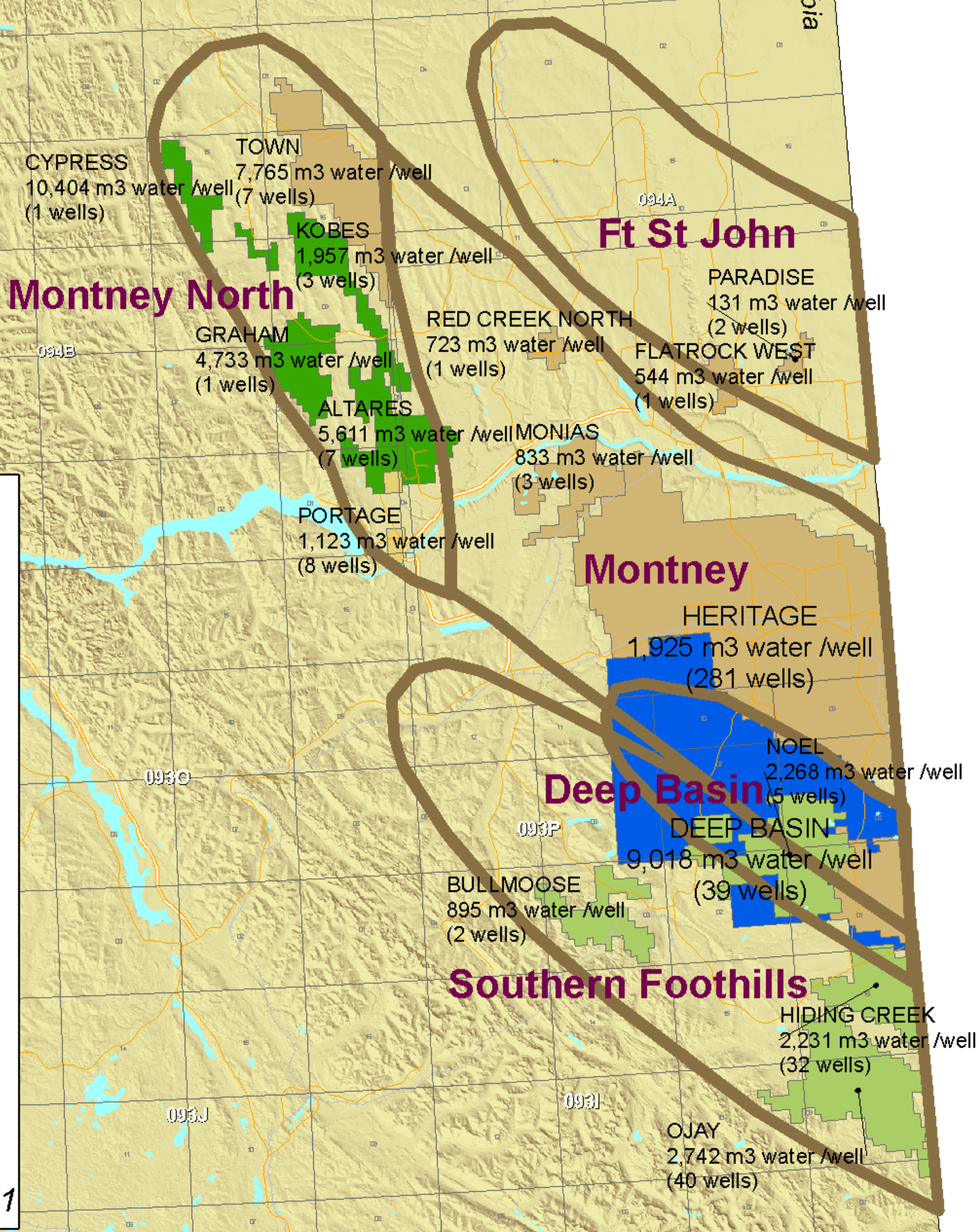





# Average Water Use per Well by Field

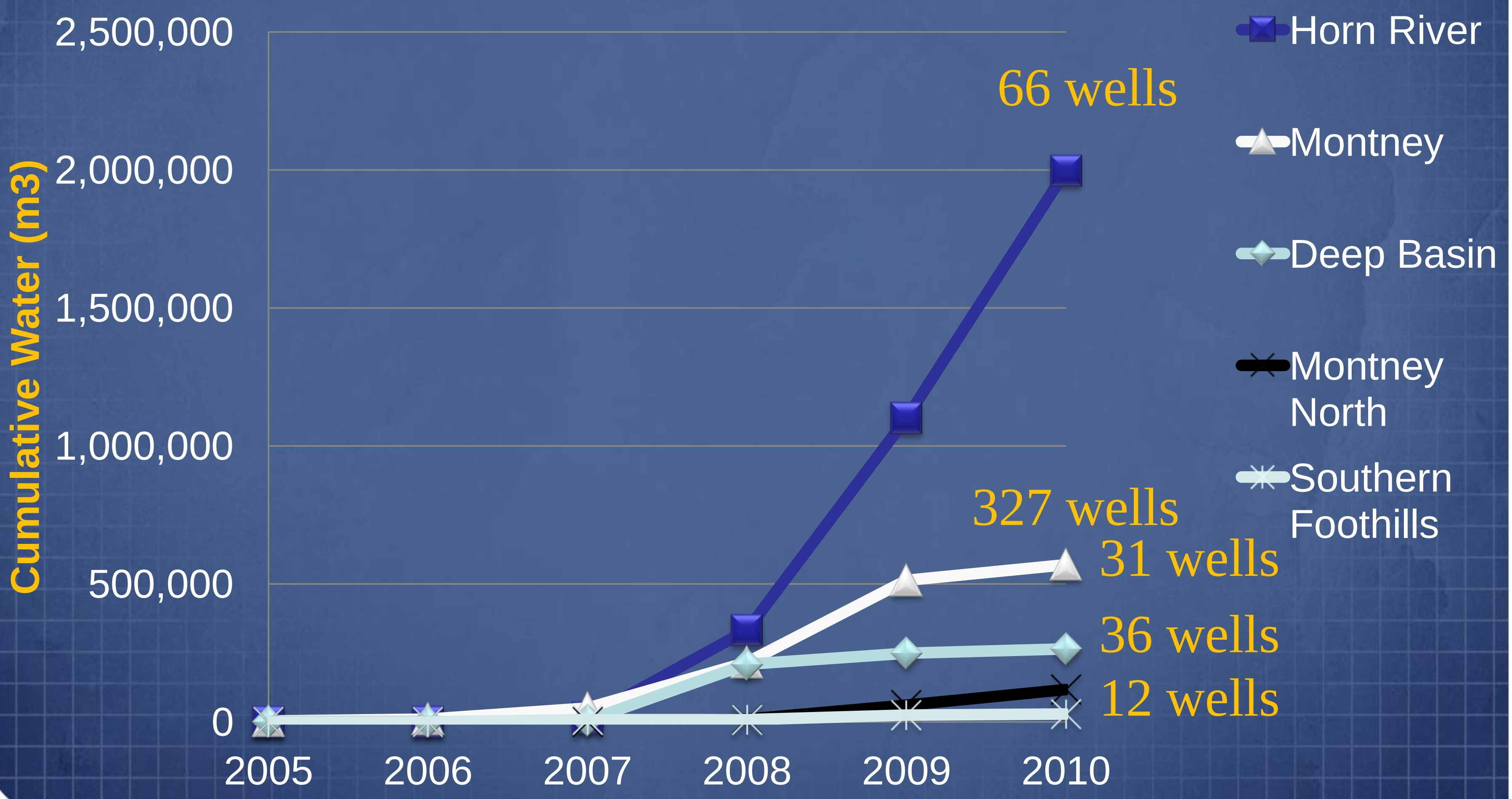
- Water use varies geographically
- Water use higher for slickwater fracturing
- Horn River Basin has highest average
  - ~ 20x Montney
  - ~ 10x Montney North

# Average Water Use per Well by Field




- Higher water use in
  - Cadomin Fm
    - Deep Basin
  - Doig Phosphate Fm
    - Altares
  - Montney Fm
    - Town

# Water by Region



BRITISH COLUMBIA
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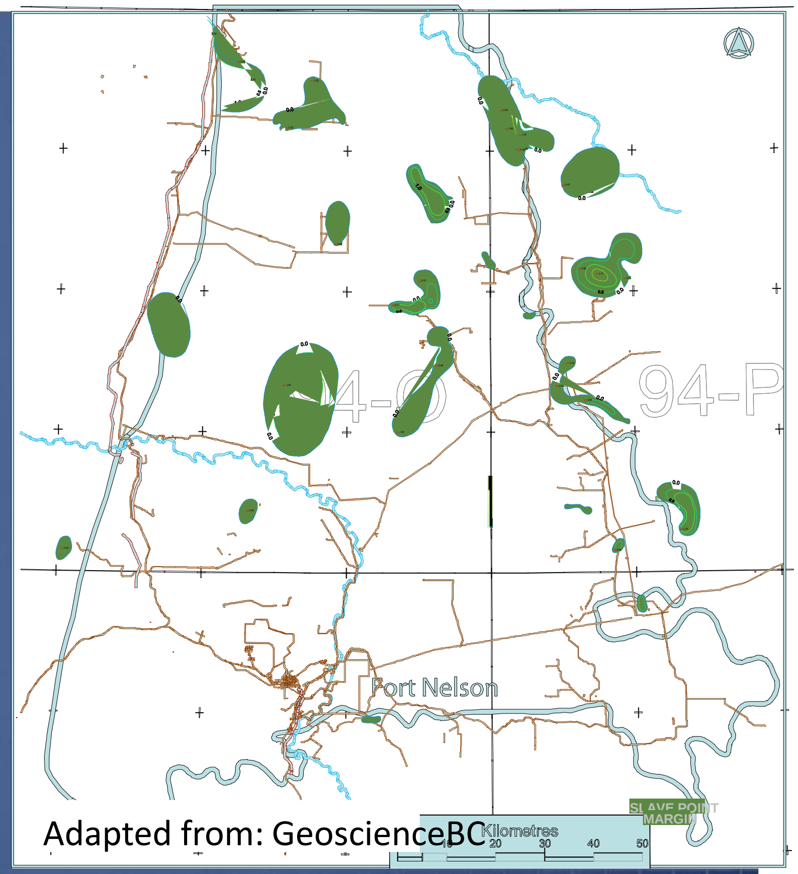
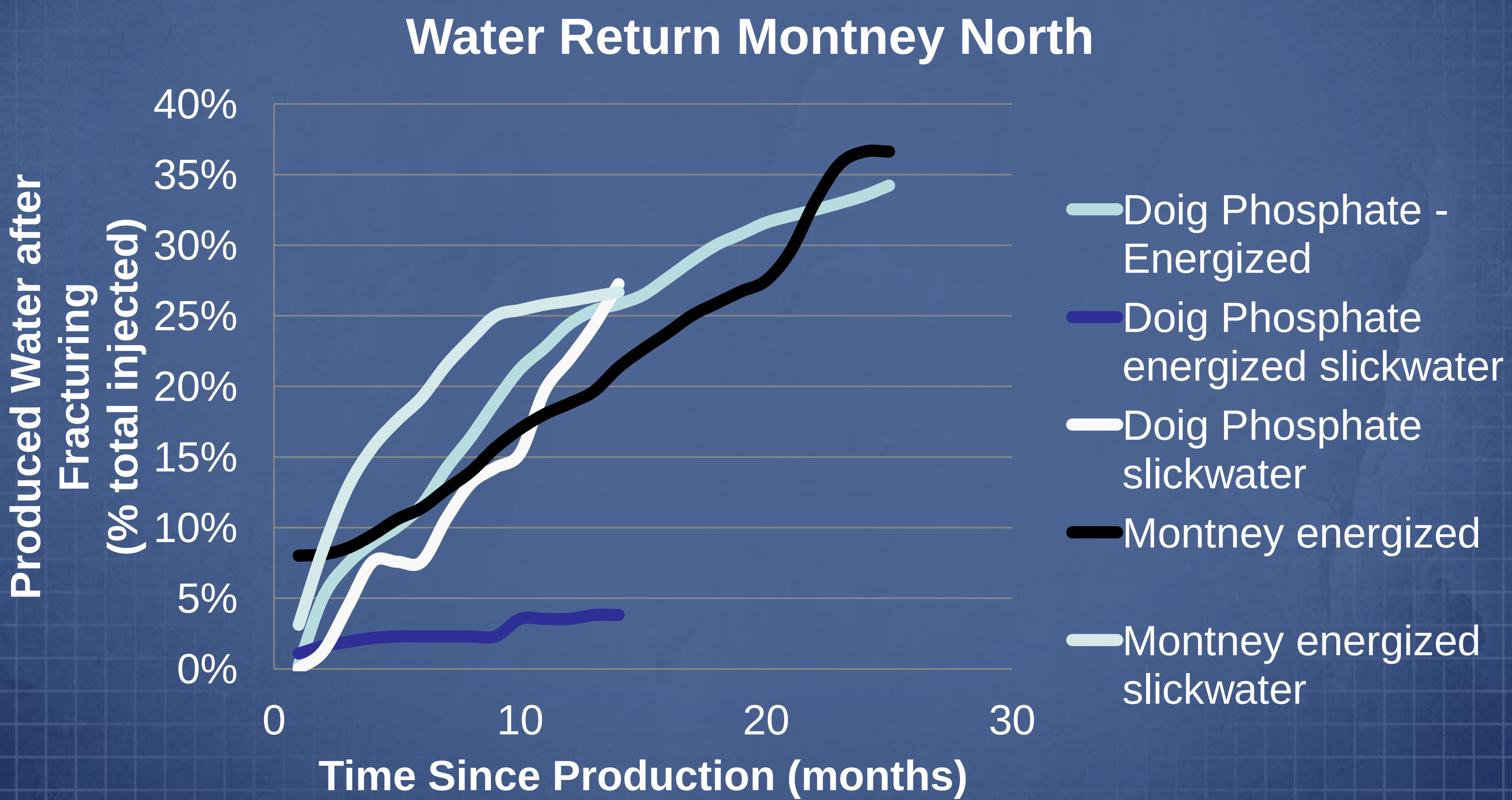
# Water Source
# Saline Water

- The Debolt Formation is ~800m depth
- The water in the Debolt is saline with $H_2S$ and gas but usable for fracing
- Zones with porosity and thickness where the Debolt Formation is capable of supplying sufficient saline water
- EnCana has built a plant to process $H_2S$ associated with Debolt water
  - It can process up to 16,000m$^3$/day
- Not all companies have access to Debolt water

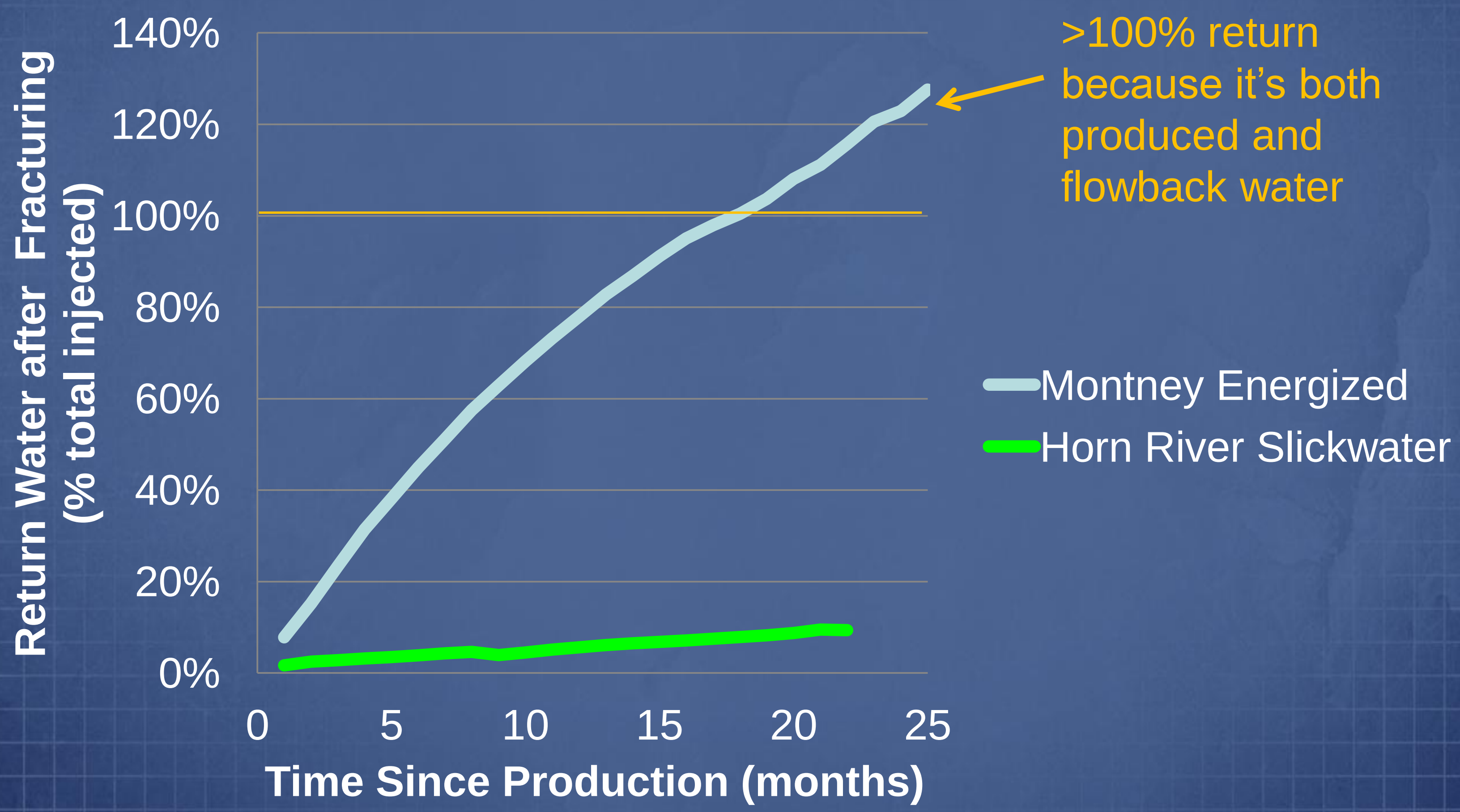


Adapted from: GeoscienceBC

# Return Water Montney North

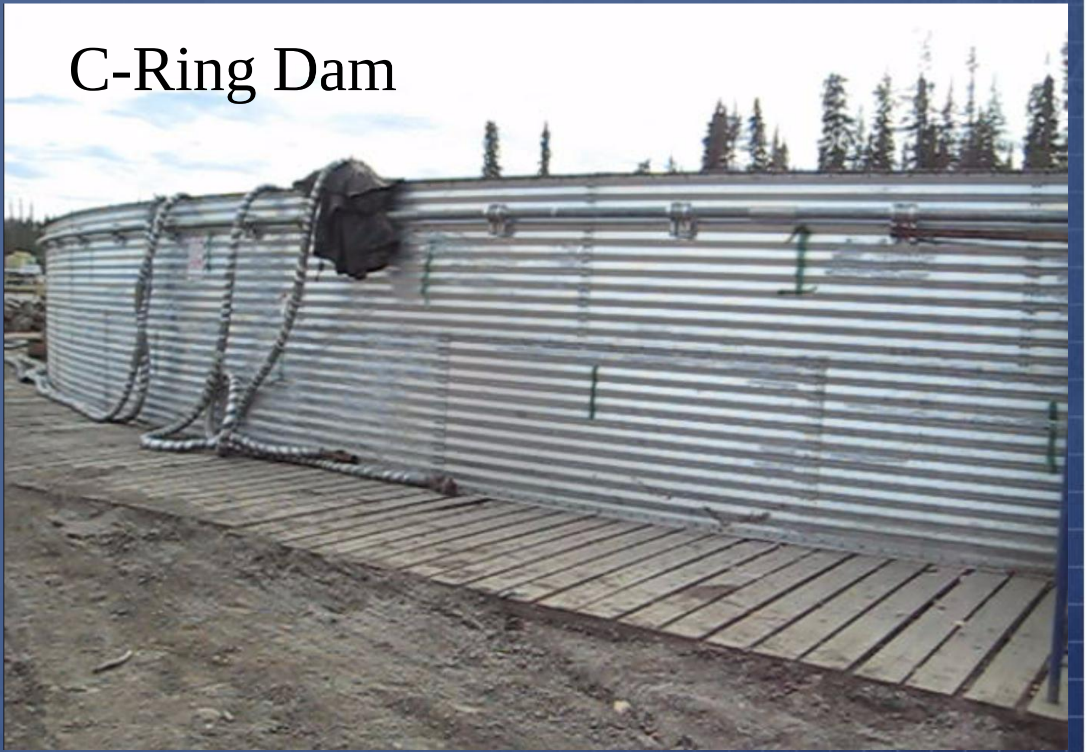


# Return Water



# Return Water and Recycling

- **Holdings in tanks and lined pits**
- **Temporary storage on surface (3 month max)**



# Water Conditioning: Additives or Treatment

- **Water at 25,000 ppm can be reused for fracturing**
  - **High saline water up to 100,000 ppm can be used with expensive specialty friction reducers**
- **Recycling options include:**
  - **Chemical conditioning**
  - **blending**
  - **filtering**
  - **flocculation/coagulation**
  - **reverse osmosis**
  - **mechanical vapour recompression**
  - **electrical coagulation**

# Quebec

John Molson, Ph.D., Assistant Professor, Department of Geology and Geological Engineering, Université Laval

# Shale Gas: Quebec Perspective


**J. W. Molson, PhD. Ing.**

**Dept. of Geology & Geological Engineering, Université Laval**

**Canada Research Chair:**
**Quantitative Hydrogeology of Fractured Porous Media**

[*john.molson@ggl.ulaval.ca*](mailto:john.molson@ggl.ulaval.ca)


Gaz de schiste : l'industrie a fait le plein de conseillers libéraux

LESAFFAIRES.COM . les affaires.com . 03-09-2010 (modifié le 03-09-2010 à 12:41)

Tags : Énergie, Environnement, Ethique, Gaz de schiste, Gouvernement, Québec

À VOIR AUSSI

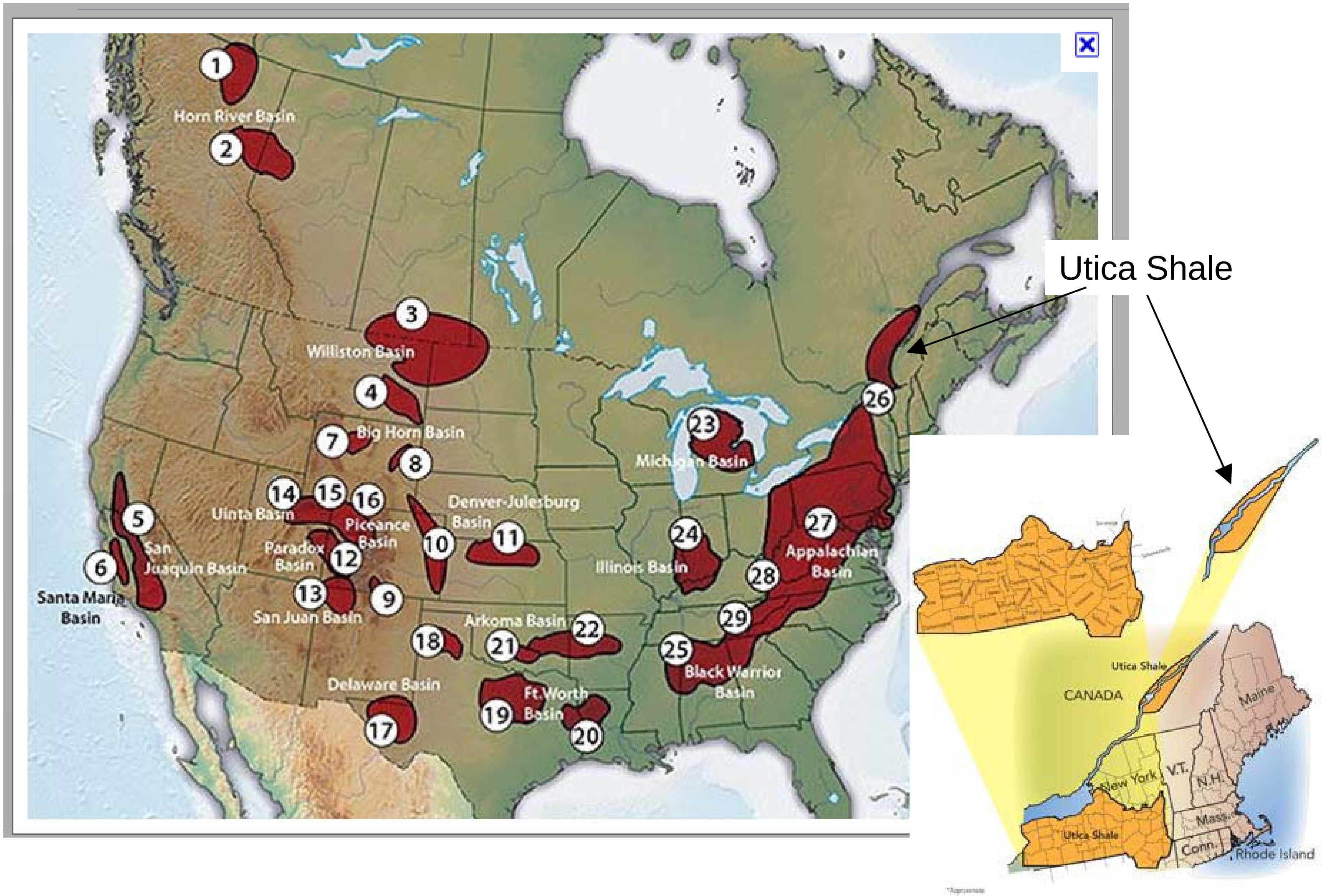
Gaz de schiste : la FCCQ entre dan dossier

NOS DOSSIERS

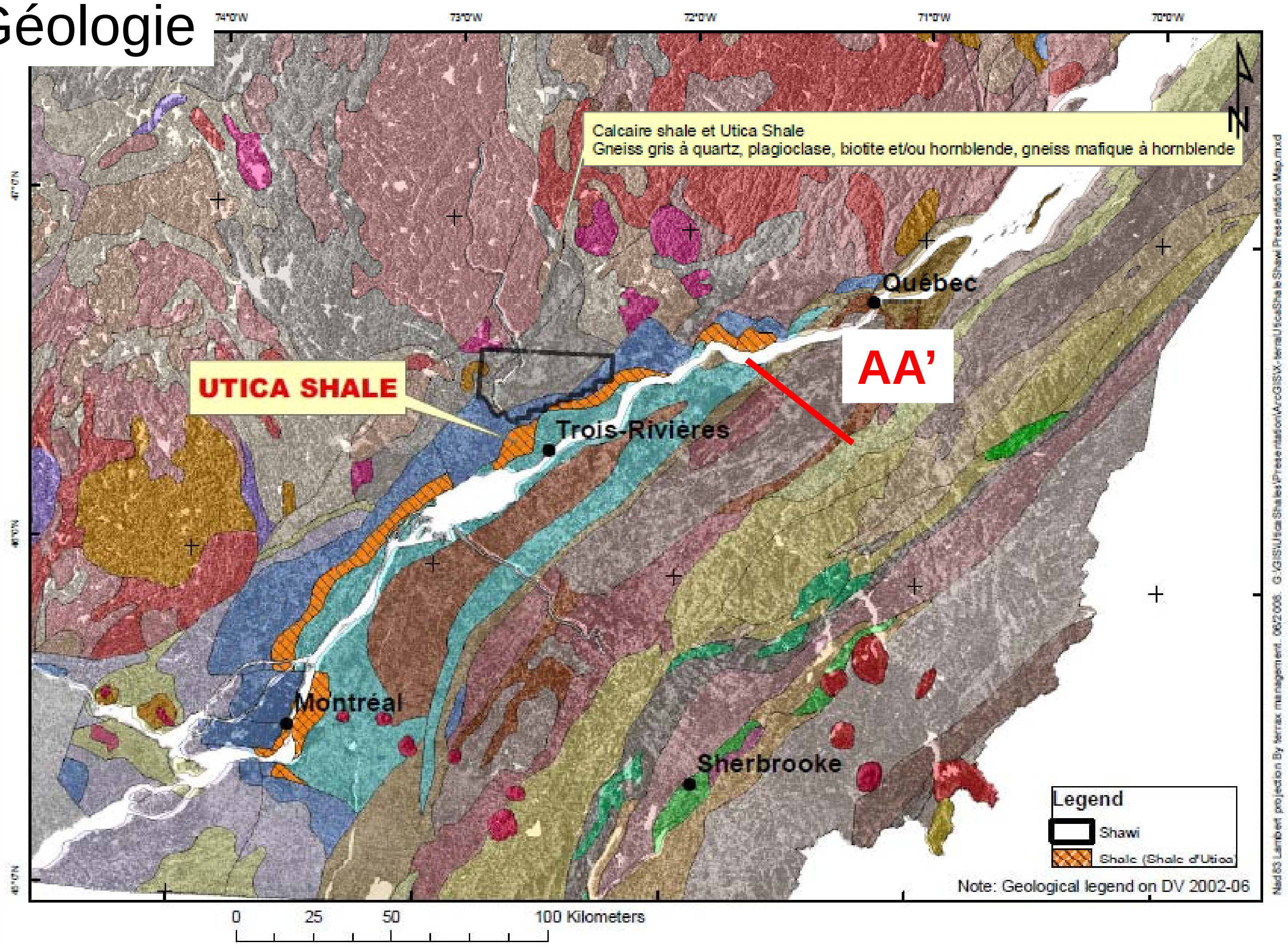
Les gaz de schiste au Québe

***Calgary Workshop, November 2011***

# Ressources en Gaz de Shale

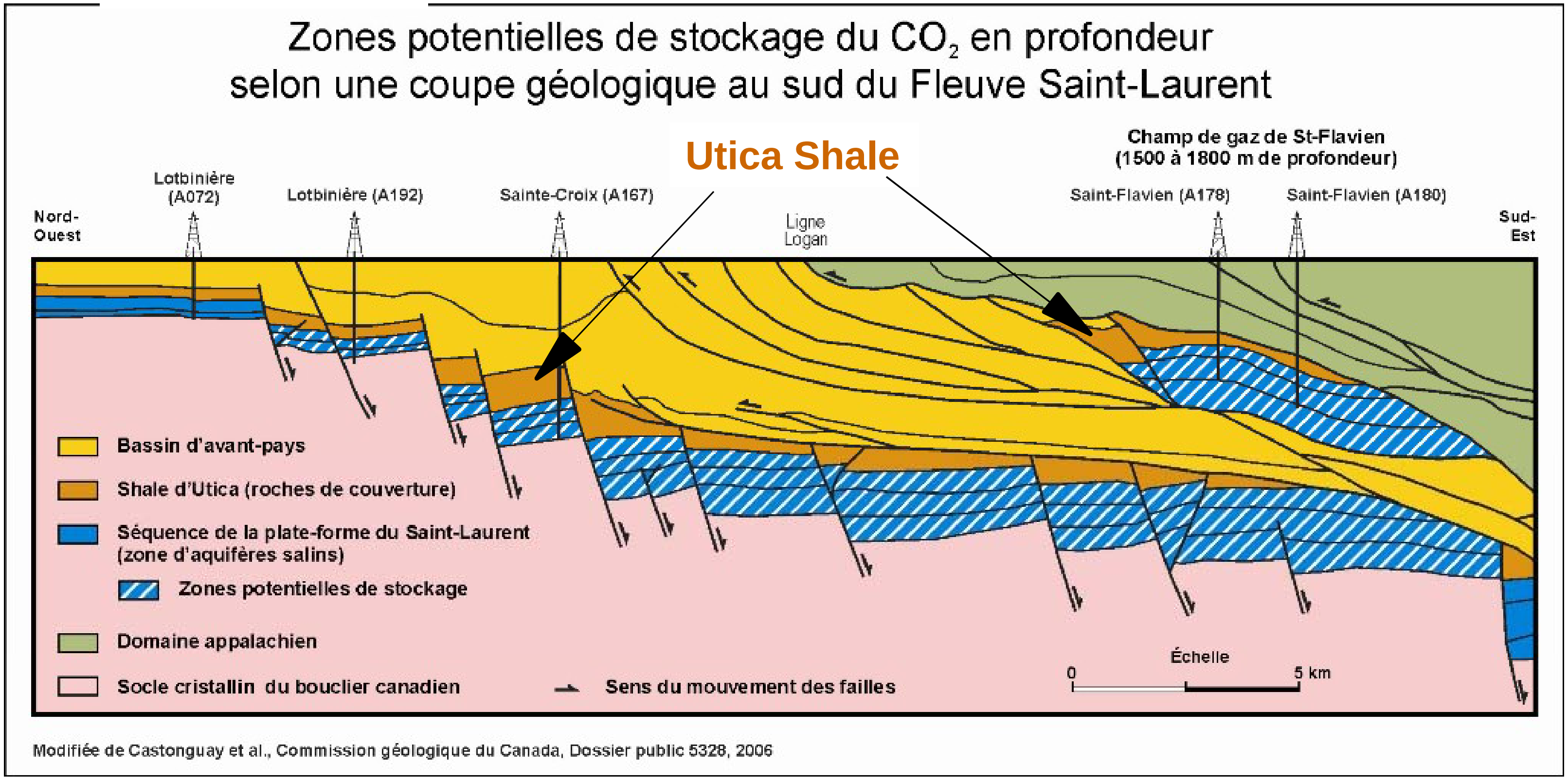


# Géologie

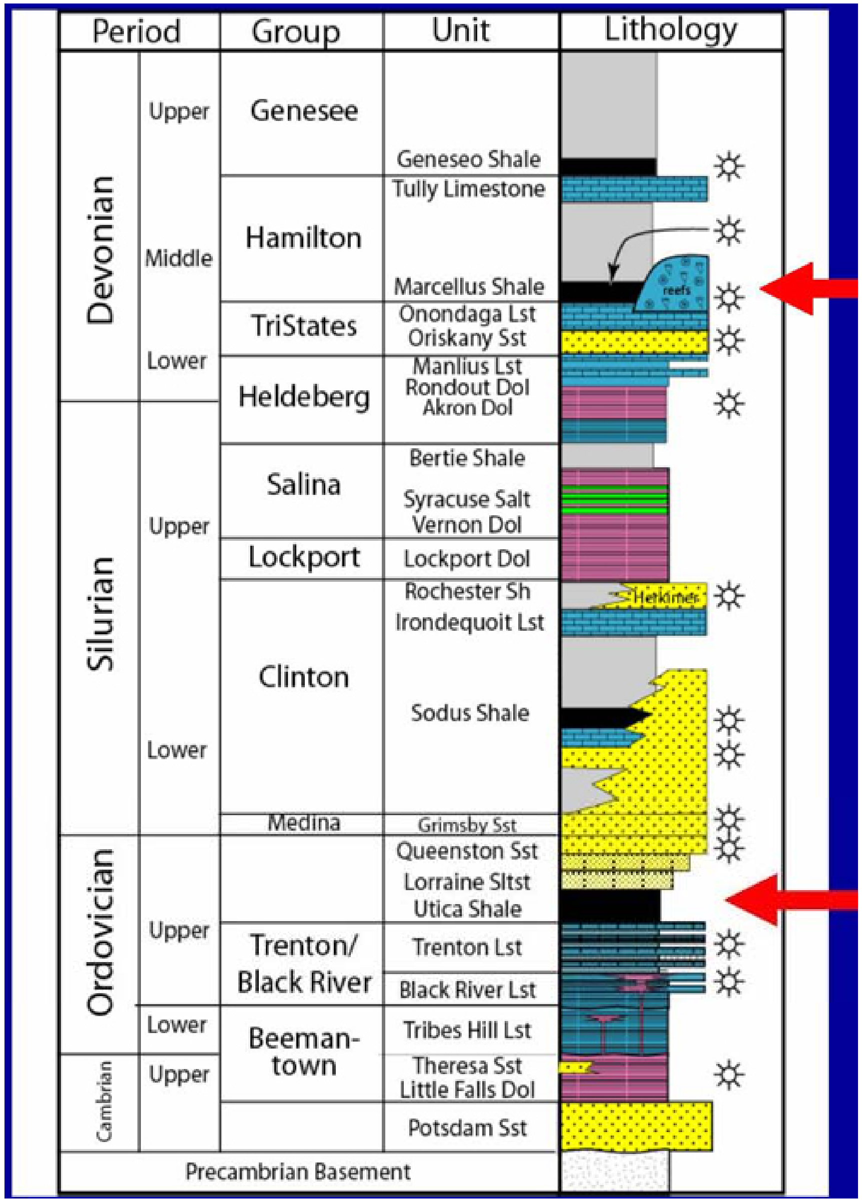


74°0'W
73°0'W
72°0'W
71°0'W
70°0'W
Calcaire shale et Utica Shale
Gneiss gris à quartz, plagioclase, biotite et/ou hornblende, gneiss mafique à hornblende
N
UTICA SHALE
Québec
AA'
Trois-Rivières
Montréal
Sherbrooke
Legend
Shawi
Shale (Shale d'Utica)
Note: Geological legend on DV 2002-06
0
25
50
100 Kilometers

# Section AA'



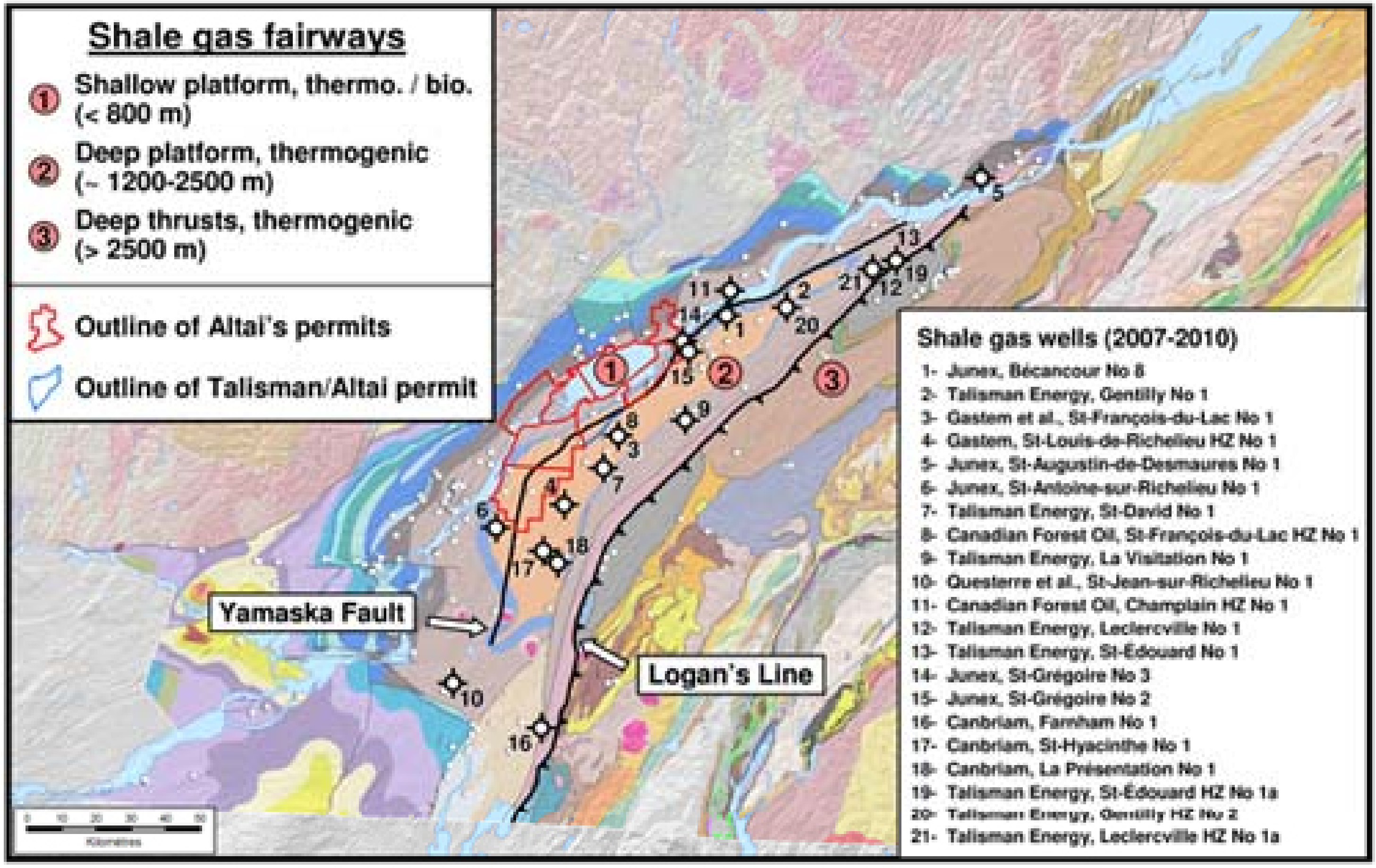

Modifiée de Castonguay et al., Commission géologique du Canada, Dossier public 5328, 2006




Marcellus Shale

Utica Shale
Source zone:
~500-2000 m depth

# Shale gas wells - Lowlands




**29 wells drilled to date, 12 fractured**

Ressources naturelles et Faune
Québec

# Utica Shale: Donnaconna

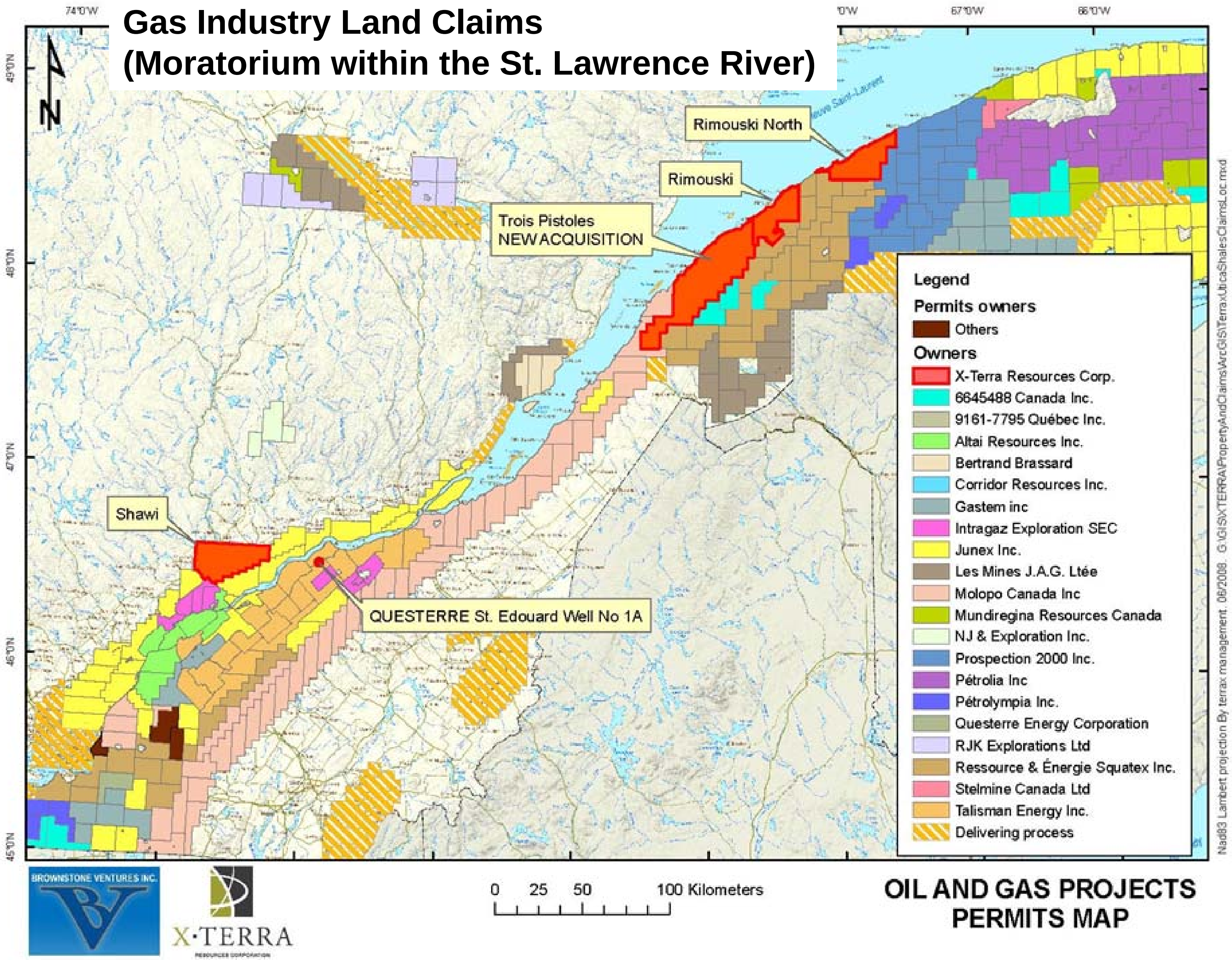
**UTICA, LORRAINE SHALE CHARACTERISTICS**

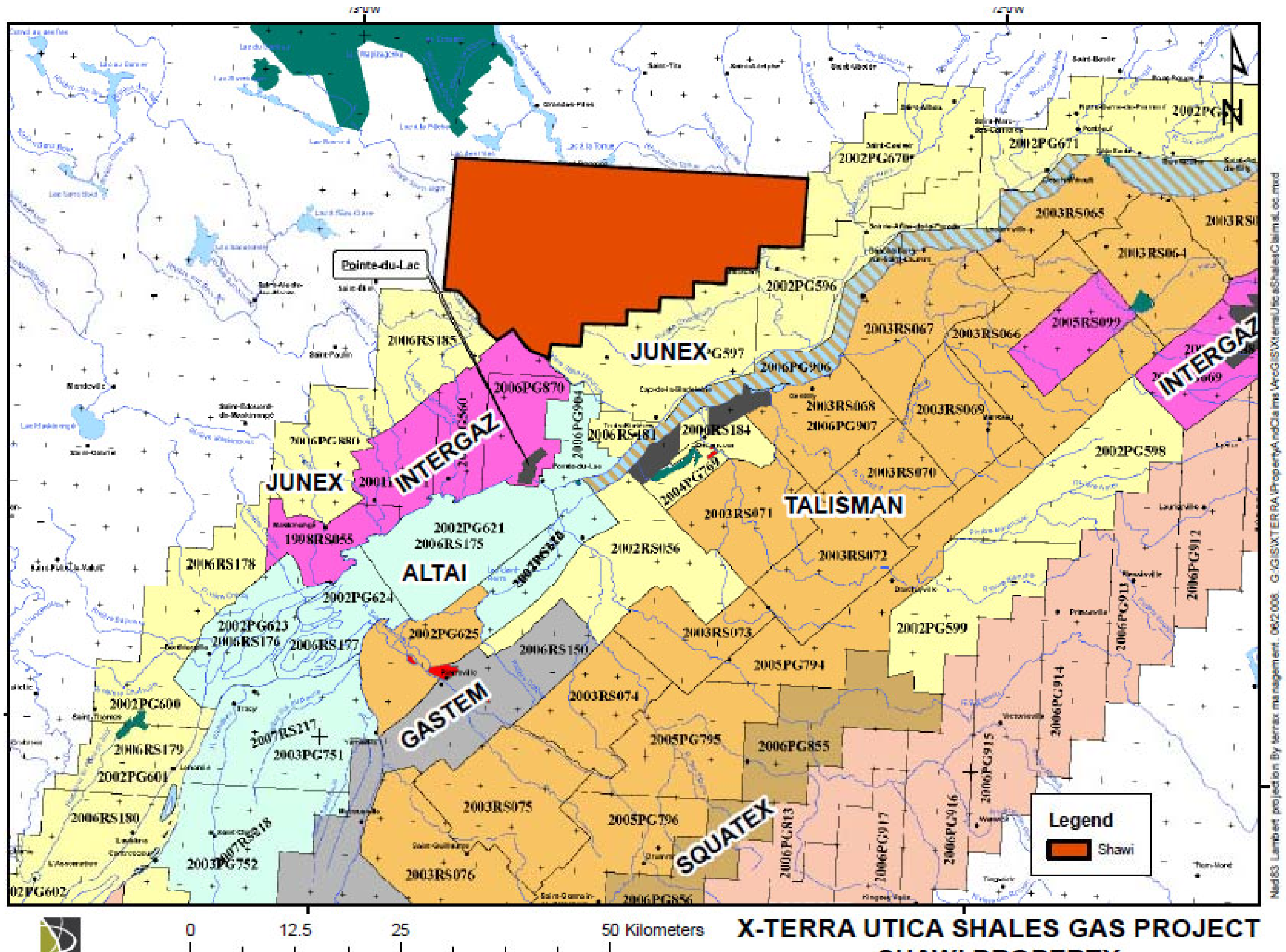
Table 2

| Parameter | Lorraine | Utica |
|---|---|---|
| Prospective depth, ft | 1,500-10,000 | 1,500-11,000 |
| Thickness, ft | 1,500-6,500 | 300-1,000 |
| TOC weight, % | 01.-1.5 | 0.3-2.5 |
| Ro, % | 1.1-4.0 | 1.1-4.0 |
| Silica weight, % | 30-35 | 12-51 |
| Clay weight, % | 30-38 | 8-66 |
| Gas-filled porosity, % | 1.2-3.2 | 2.2-3.5 |
| Pressure gradient, psi/ft | 0.6 | 0.6 |
| OGIP, bcf/section | 50-190 | 25-160 |

Source: Talisman Energy Inc.

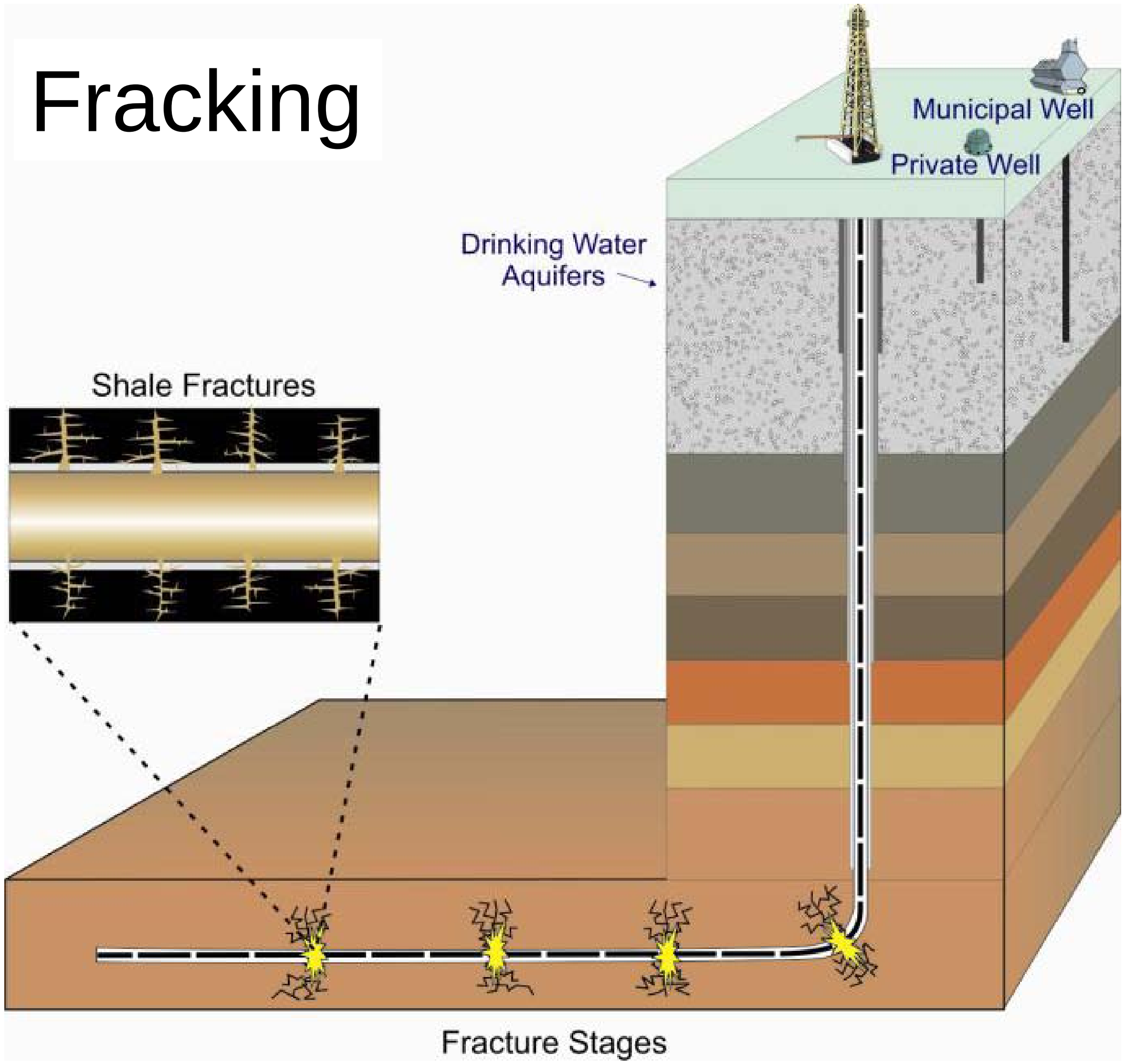
# Gas Industry Land Claims
# (Moratorium within the St. Lawrence River)



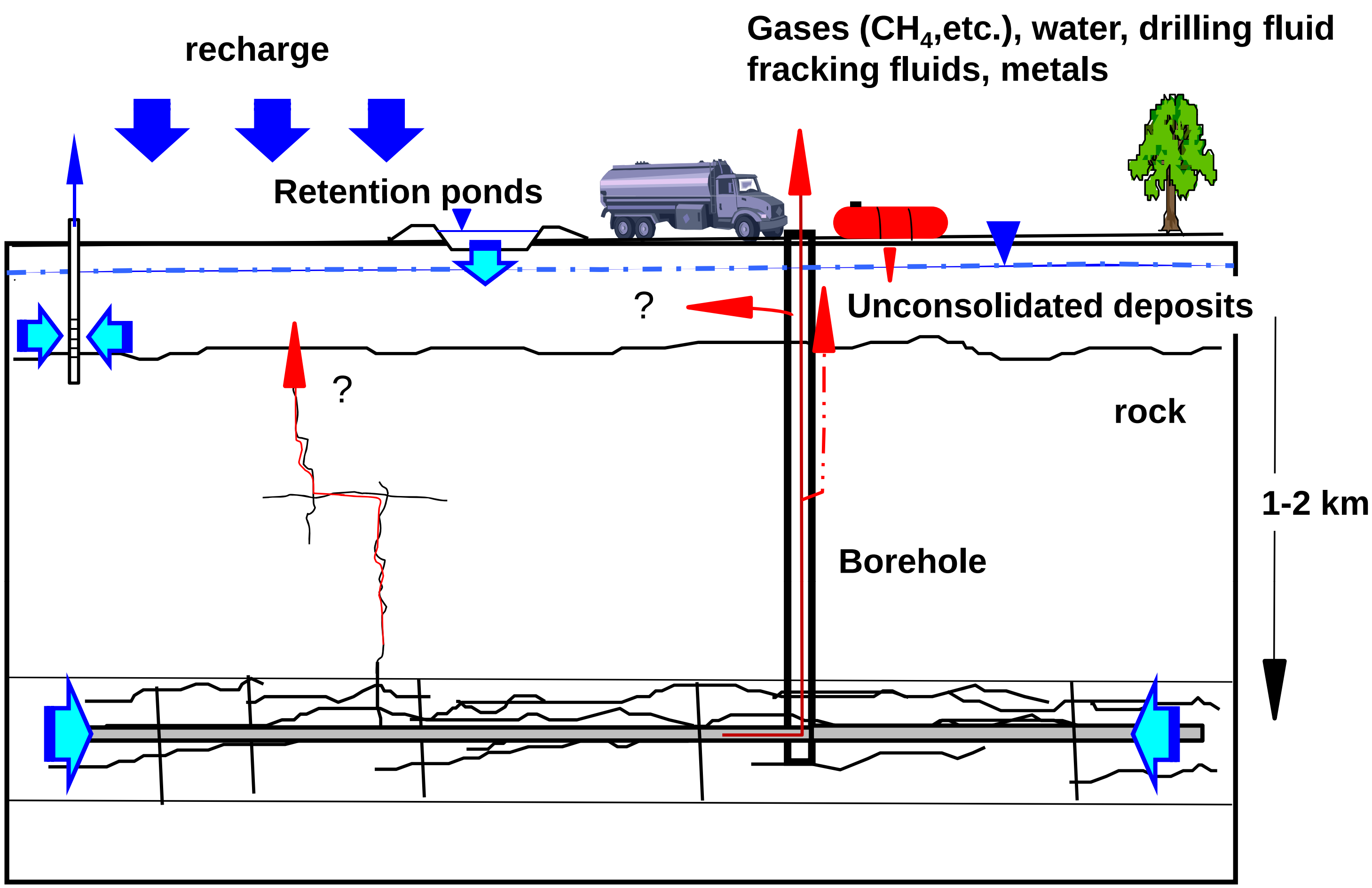



X-TERRA

**X-TERRA UTICA SHALES GAS PROJECT**
**SHAWI PROPERTY**
**PERMITS MAP**

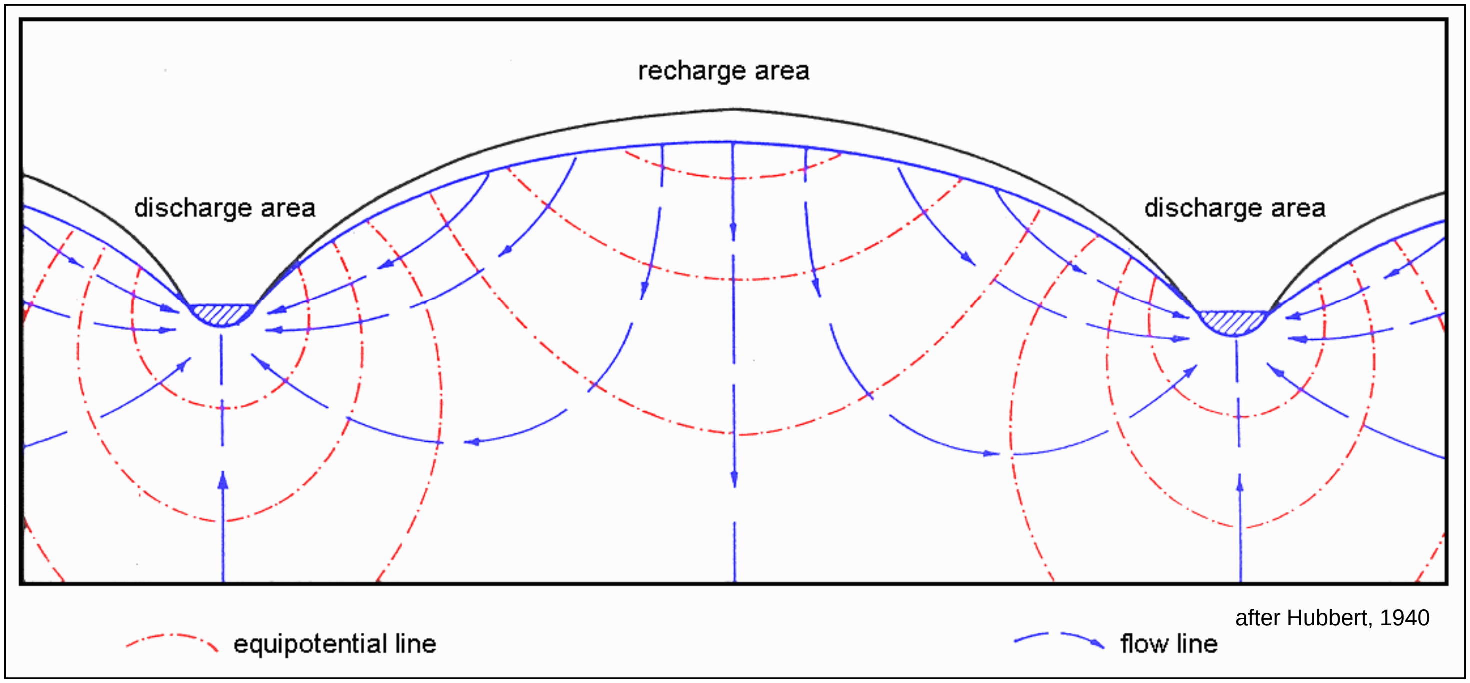

Fracking
Municipal Well
Private Well
Drinking Water
Aquifers
Shale Fractures
Fracture Stages

# Conceptual Model : Potential Pathways



## Limited understanding of deep regional flow systems in St. Lawrence Lowlands

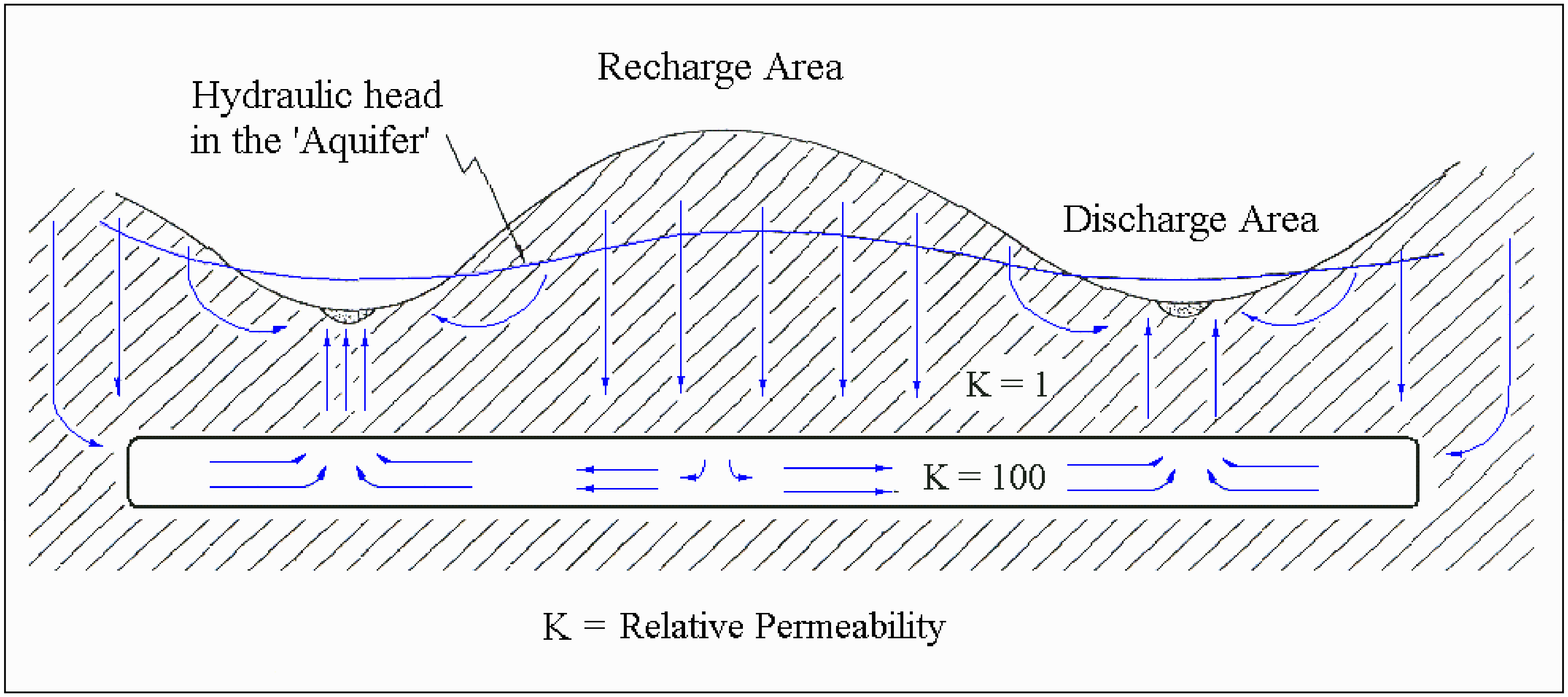
Hubbert’s schematic diagram of gravitational groundwater flow between two valleys




The terminology ‘recharge’ and ‘discharge area’ was introduced by Tóth, 1962
Recharge area = area of groundwater table whzere water moves into the groundwater body
Discharge area = area of groundwater table where water moves out of the groundwater body

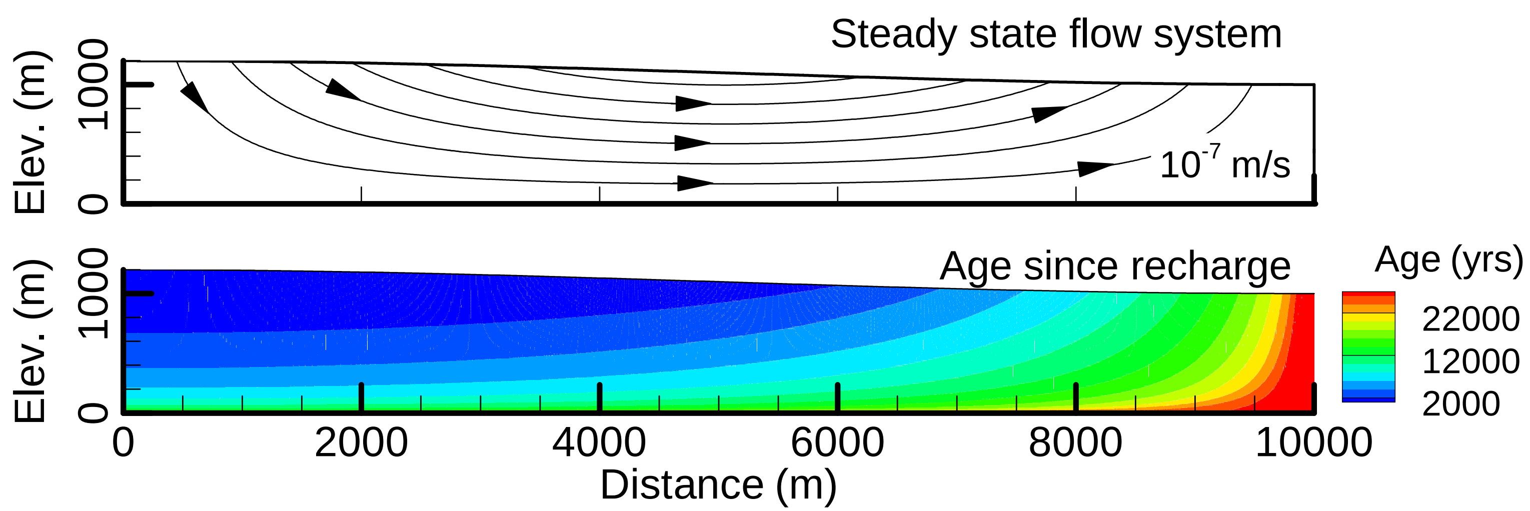
**Effect of Fracking on Flow ? Preferential flowpaths ?**

Schematic diagram of groundwater flow with high K zone




Weyer & Altebäumer, 1993

**‘Old’ , deep water can still discharge to surface …**
**Conceptual simulation – Homogeneous system:**




**Possibly long travel times under natural conditions, but:**

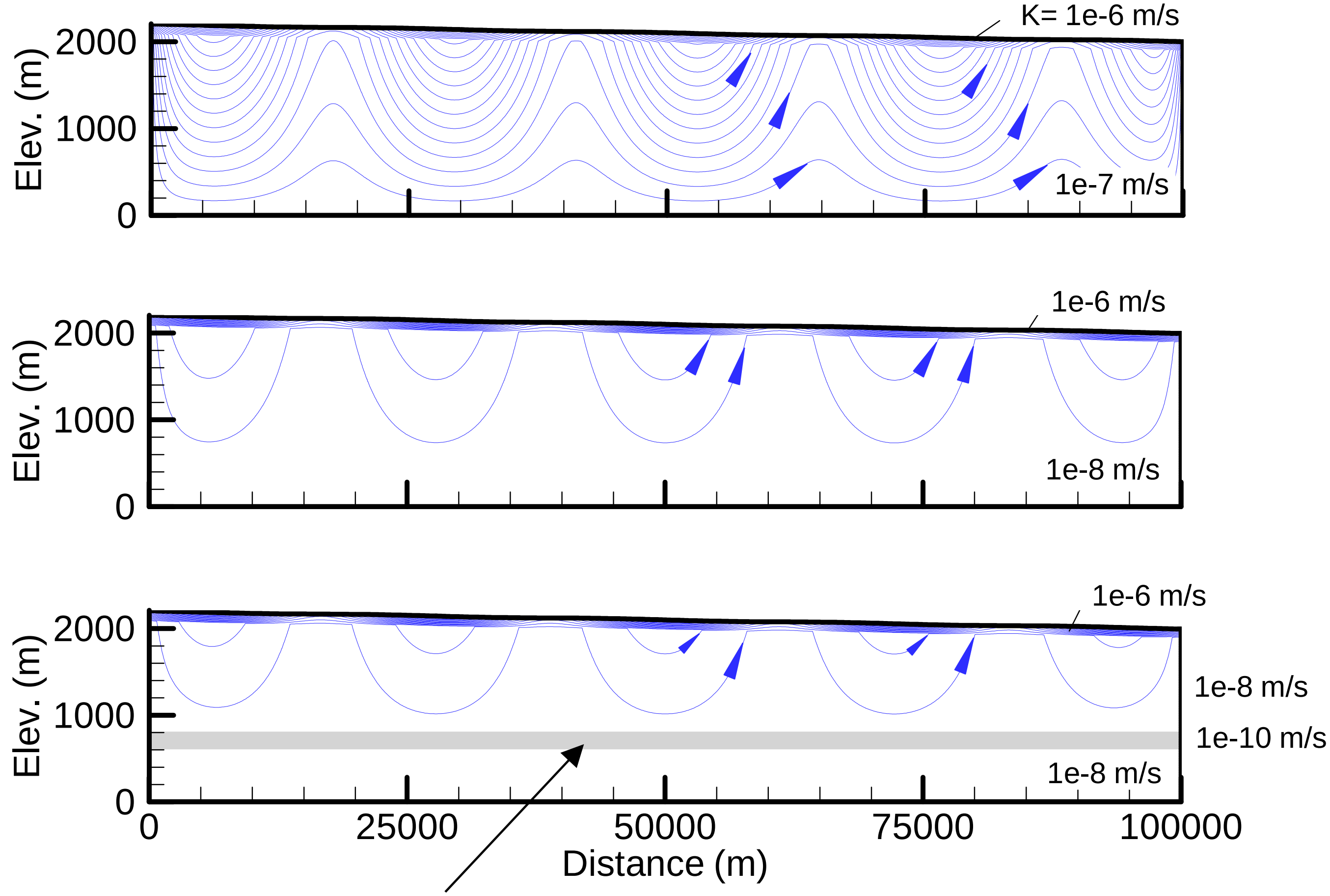
- **preferential pathways along fractures or faults ?**
- **leakage along well-bore ?**
- **disturbance from re-injection of fluids ?**

Conceptual Simulations:

Regional & Local Flow Systems

$\Delta h = -0.002$

amplitude = 5 m, 4.25 cycles



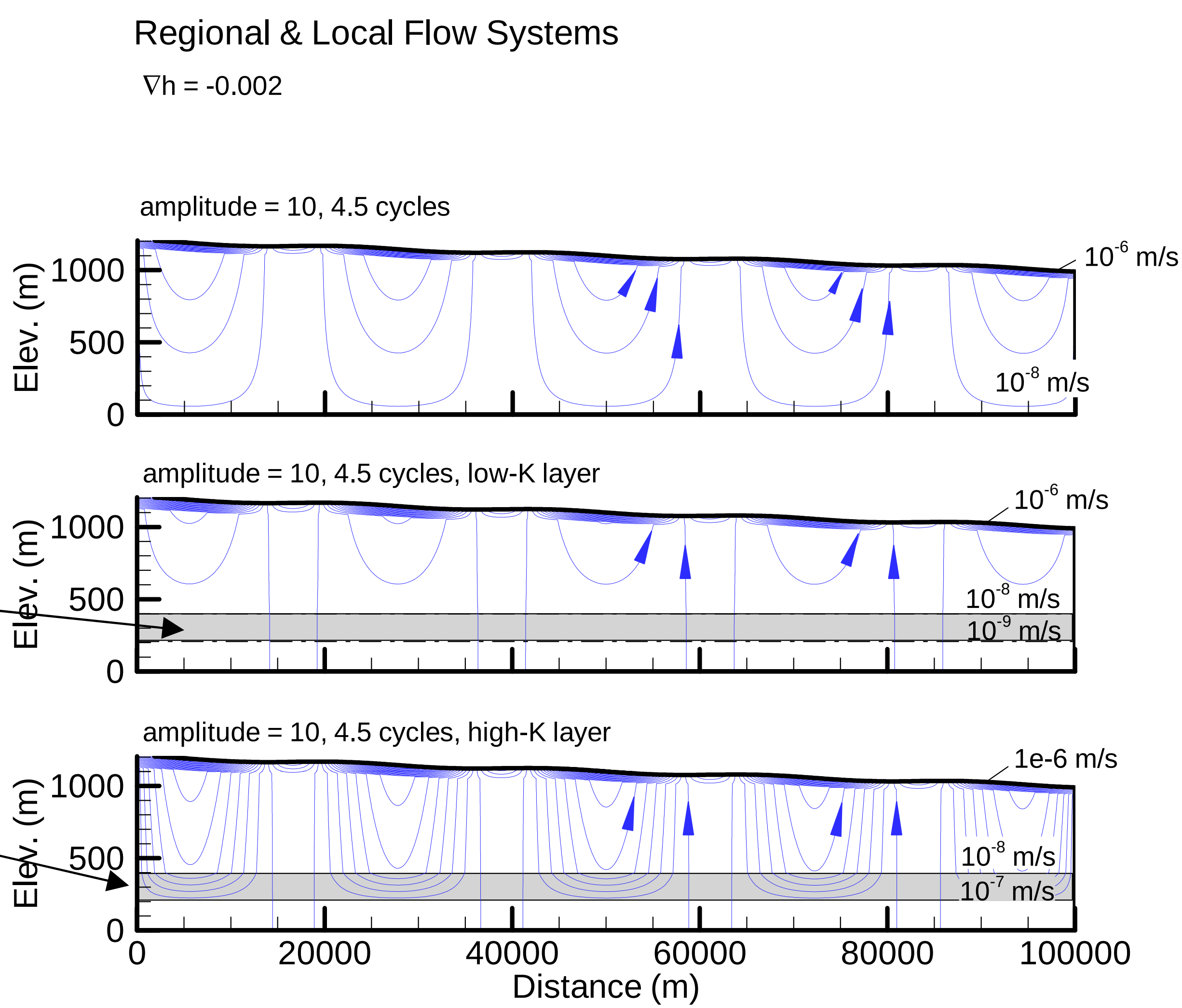

Utica Shale – pre-fracking – no flow

# Conceptual Simulations:

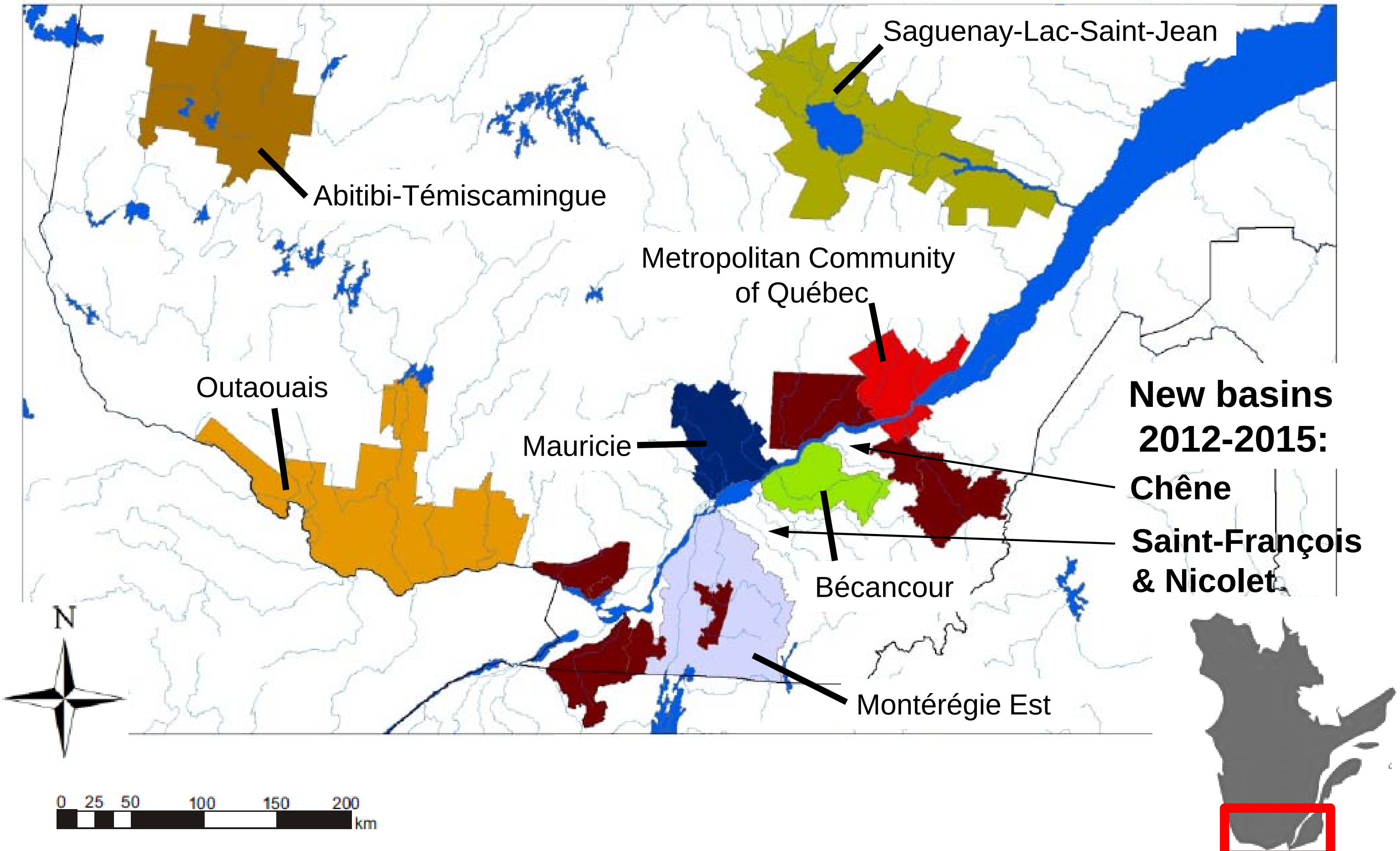
Utica Shale: pre-fracking

Utica Shale: post-fracking

Enhanced flow ? Discharge to surface ?



# Current regional aquifer characterization & hydrogeology projects (PACES)



# Quebec Initiatives:

Développement durable,
Environnement
et Parcs
Québec

- 2009-2015: PACES projects, funded by Environment Ministry MDDEP
  - Watershed-scale aquifer characterization and water quality
  - http://www.mddep.gouv.qc.ca/eau/souterraines/programmes/acquisition-connaissance.htm

- 2010-2011: BAPE Commission and Report on Quebec Shale gas
  - Bureau d'Audiences Publiques sur l'Environnement
  - http://www.bape.gouv.qc.ca/sections/rapports/publications/bape273.pdf

- May 2011: CÉES – Strategic environmental assessment committee
  - http://ees-gazdeschiste.gouv.qc.ca/
  - 3 year study of risks, assessment of regulations etc.
  - health, safety, environment, society, economics etc.

- Moratorium on drilling in St. Lawrence estuary
- New land drilling must be approved by CÉES committee & ministry